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ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

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

Bluebonnet Sequestration Hub LLC (P5 # 102323)
5 Greenway Plaza, Suite 110
Houston, TX 77046

Class VI Permit Number: 57900
Project/Facility Name: Bluebonnet Sequestration Hub
Counties: Chambers and Liberty, District 03

Effective Date: XXXXXX, 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 XXXXXX, 2031.

Authority is granted to inject **anthropogenic CO2** into the wells 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 application dated September 2025, subject to the following terms and conditions:

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TABLE 1: GENERAL INFORMATION

Source of CO2	Total CO2 Storage Mass (Million Metric Tons)	Duration of Injection (Years)	Top Confining Zone	Injection Zone Formation Name
Industrial Sources	157.2	20	Miocene Composite, Lower Miocene Anahuac Frio Shale and Hackberry Shale	Lower Miocene, Frio and Hackberry

TABLE 2: INJECTION WELLS IDENTIFICATION AND PERMIT PARAMETERS

Well Name & No.	Latitude (NAD83)	Longitude (NAD83)	Top Inj. Interval, TVD (Feet)	Bottom Inj. Interval, TVD (Feet)	Max. Injection Mass Rate (Metric Tons per day)	Max. Surface Injection Pressure (psig)	Max. Bottom Hole Injection Pressure (psig)
Bluebonnet CCS 1	29.812013	-94.436632	7,828	8,768	6,850	2,500	5,876
Bluebonnet CCS 2	29.804773	-94.464128	7,766	8,230			5,454
Bluebonnet CCS 3	29.853032	-94.49827	7,433	8,459			5,566
Bluebonnet CCS 5	29.812354	-94.436646	5,481	6,464		2,300	4,330
Bluebonnet CCS 6	29.817638	-94.464295	5,523	6,347			4,250
Bluebonnet CCS 7	29.853442	-94.49827	5,186	6,124			4,124

TABLE 3: MONITOR WELLS IDENTIFICATION

Well Name & No.	API No./Well ID	Purpose	Total Depth, TVD (Feet)	Date Drilled
Bluebonnet IZM FM1	TBD	Monitoring Lower Miocene, Frio and Hackberry Injection Zones	8,400	TBD
Bluebonnet IZM FM2	TBD	Monitoring Lower Miocene, Frio and Hackberry Injection Zones	9,000	TBD
Encanto #01 (strat. well)	071-32664	Monitoring Lower Miocene Injection Zones	CIBP @ 6,184 TD: 8,581	02/10/2023
Bluebonnet IZM M1	TBD	Monitoring within the permeable interval located between Seal 2 and Seal 3 of the Miocene Composite Confining Zone (upper Miocene)	2,900	TBD
Bluebonnet IZM M2	TBD	Monitoring the permeable interval immediately below Seal 1 within the Miocene Composite Confining Zone (upper Miocene)	2,000	TBD
Bluebonnet IZM M3	TBD	Monitoring the permeable interval immediately below Seal 1 within the Miocene Composite Confining Zone (upper Miocene)	1,900	TBD
Bluebonnet USDW 1	071-32672	Monitoring USDW zone (lower Chicot)	PBTD: 1,420 TD: 1,630	06/25/2024
Bluebonnet USDW 8	071-32676	Monitoring USDW zone (lower Chicot)	PBTD: 1,050 TD: 2,750	05/29/2025
Bluebonnet USDW 2	TBD	Monitoring USDW zone (lower Chicot)	1,500	TBD

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 CO_2 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.

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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. 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 of the state (TexNet) seismic monitoring network.

16. 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.

17. 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.

18. 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.

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

20. 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.

21. 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.

22. 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.

23. 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.

24. 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 16 TAC §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.

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25. 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.

26. 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).

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

SPECIAL CONDITIONS:

1. The following twenty-five (25) wells will require phased corrective action as shown below:

API Number	Lease Name	Well No	Total Depth (ft)	Schedule (Year)	No. of Wells
4207101954	J W Garth Jr Etal	1	9,012	0	12
4207101955	Drought H P	1	9,505		
4207101956	Garth Brothers	1	9,250		
4207101958	Sterrett Eat Fred R	1	9,550		
4207101959	Wm Doornbos Etal	1	9,025		
4207101960	Trinity Rice	1	8,019		
4207101968	Simon Walter	1	7,788		
4207103165	C H Lanz	1	7,629		
4207130564	M E Hunter	1	12,665		
4207131036	Garth	1	11,000		
4207132174	Holter Et Al	1	11,000		
4207132233	Doornbos	1	10,800		
4207130032	Earl Cooper Etal	1	9,500	5	3
4207130073	Garth Co	3	9,265		
4207131267	Doornbos Willim Etl	1	18,950		
4207101961	Ogden L G Etal	1	9,617	10	1
4207101962	Debellvue Mrs Maria	1	9,348	15	9
4207103394	O C DevillierJr	1	9,317		
4207130451	O C Devillier	4	12,215		
4207130469	Beaumnt Rc Mll	1	9,008		
4207130837	O C Devillier	6	10,993		
4207130967	Devillier O C	7	11,270		
4207131164	Garth	1	16,000		
4207131389	Simon S E	1	9,119		
4207131394	Devillier L C	1	9,300		
			Total No. of Wells =		**25**

Within **30 days** after plugging and/or recompletion, a complete well plugging record (Form W-3) and/or Form W-2 must be filed.

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2. Injection cannot begin until a letter of credit in an amount of **$35,925,514** has been filed. The letter of credit must be renewed and continued in effect until the conditions of the 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 XXXXXXX, 2026

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Rob Castillo, Manager
Special Injection Permits Unit

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Class VI Permit Condition & Details

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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.

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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 –

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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 in accordance with **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 in accordance with 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)**.

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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, twenty-five (25) wellbore penetrations within the AoR require plugging and recompletion because these wellbores penetrated the injection zone or confining layer within the Bluebonnet Storage Project prior to injection.

- The following **twelve** (12) wells will require corrective action **prior** to the commencement of CO2 injection operations:

  - Garth Well No. 1 (API 42-071-31036)
  - Drought H. P. Well No.1 (API 42-071-01955)
  - Trinity Rice Well No. 1 (API 42-071-01960)
  - Holter et al. Well No. 1 (API 42-071-32174)
  - M.E. Hunter Well No. 1 (API 42-071-30564)
  - Fred R. Sterrett et al. Well No. 1 (API 42-071-01958)
  - Wm. Doombos Well No. 1 (API 42-071-01959)
  - Doombos Well No. 1 (API 42-071-32233)
  - Garth Brothers Well No. 1 (API 42-071-01956)
  - Simon Walter Well No. 1 (API 42-071-01968)
  - J.W. Garth Jr. et al. Well No. 1 (API 42-071-01954)
  - C.H. Lanz Well No. 1 (API 42-071-03165)

- The following **three** (3) wells will require corrective action in **Year 5** after commencement of CO2 injection operations:

  - Doombos Wm et al. Well No. 1 (API 42-071-31267)
  - Garth Company Well No.3 (API 42-071-30073)
  - Earl Cooper et al. Well No. 1 (API 42-071-30032)

- The following **one** (1) well will require corrective action in **Year 10** after commencement of CO2 injection operations:

  - Ogden L.G. et al. Well No. 1 (API 42-071-01961)

- The following **nine** (9) wells will require corrective action in **Year 15** after commencement of CO2 injection operations:

  - Garth Well No. 1 (API 42-071-31164)
  - Devillier L. C. Well No. 1 (API 42-071-31394)
  - Simon S. E. Well No. 1 (API 42-071-31389)
  - O. C. Devillier Well No. 4 (API 42-071-30451)
  - O.C. Devillier Jr. Well No. 1 (API 42-071-03394)
  - O.C. Devillier Well No. 6 (API 42-071-30837)

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- Devillier O. C. Well No. 7 (API 42-071-30967)
- Debellvue Mrs. Maria Well No. 1 (API 42-071-01962)
- Beaumont RC M.L.L. Well No. 1 (API 42-071-30469)

Within **30 days** after plugging and/or recompletion, a complete well plugging record (Form W-3) and/or Form W-2 must be filed.

3. At least sixty (60) days prior to commencing corrective action, the permittee shall notify the Director. As corrective action activities are completed, the permittee shall provide periodic updates, including plugging reports, to the Director.

4. 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.

5. 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 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).**

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(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.

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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 wells shall be constructed in accordance with **16 TAC §§3.13** and **5.203(e)(1)**. 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. 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.

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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 in accordance with 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).**

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(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 carbon dioxide to be sequestered comes from industrial power-generating plants, refineries, and chemical production, natural-gas processing, and natural-gas liquefaction facilities along the Gulf Coast, from the Beaumont/Port Arthur area to the east and to the Houston area in the west. The project will get custody of the CO2 captured by these emitters through offtake agreements and transport the captured CO2 via a third-party pipeline to the site, where the CO2 will be stored. 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

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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 –

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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 injections based on new information; and

(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

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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).**

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(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

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(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 procedures 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 MONITORING AND RESPONSE

The operator shall develop and implement a seismic monitoring plan that provides for the contribution of data to an existing public seismic network (e.g., TexNet, see http://www.beg.utexas.edu/texnet-cisr/texnet). The purpose of seismic monitoring is to contribute to the body of knowledge available to better resolve earthquake locations, especially depth, and to provide local seismic data to better implement earthquake response plans after an injection well permit is issued. The seismic monitoring plan should include the

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method of seismic monitoring, location and type of instrumentation, and an archive of the data in a public seismic database. Use the following webpage to obtain minimal station requirements: http://www.beg.utexas.edu/texnet-cisr/seismic-station-requirements.

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 of 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 surface monitors and/or downhole monitors 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) 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.

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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

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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. Soil & Soil Gas Sampling –

Soil and soil gas sampling will be contingent upon and triggered by detection of any USDW contamination in the monitor wells. In such an instance, the permittee shall monitor near-surface unsaturated zone soil and soil gas to meet the requirements of **16 TAC §5.203(j)(2)(H).**

6. 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.

7. 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**

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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)**.

8. 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)**.

9. 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)**.

10. 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.

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(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. Twenty-Four (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

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(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.

6. 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

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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.

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P. WELL PLUGGING, POST-INJECTION SITE CARE AND 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

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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 in **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 endanger a USDW. The permittee shall also restore the surface site to its pre-injection condition.

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

(a) 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 **16 TAC §§5.203 or 5.206** of this title;

(b) 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

(c) 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

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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:

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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)**.

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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 CLOSURE PLAN

J. FINANCIAL ASSURANCE DEMONSTRATION

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Underground Injection Control -Class VI Permit Application
Bluebonnet Sequestration Hub Project

Chambers County, Texas

Bluebonnet Sequestration Hub ,LLC

Houston, Tx

August 2025

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Claimed as PBI

Plan revision number: 3
Plan revision date: 09/25/2025

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

2.0 Overview

Pursuant to 40 CFR §146.82, 40 CFR §146.83, and 40 CFR §146.84, this plan describes the site characterization for the Bluebonnet Hub, delineates the Area of Review (AoR), and describes the action plans for the wells that require corrective action. Delineation of the AoR is one of the key elements in Class VI permit to ensure Underground Sources of Drinking Water (USDW) in the region surrounding the geologic sequestration project will not be endangered by the injection activity.

The AoR is defined as the larger of the maximum extent of the separate-phase plume and pressure front during the life of the project. Both the CO_2 plume and critical pressure front are determined using a multiphase CO_2-brine transport computational model, constructed from a geocellular model that accounts for the site-specific hydrogeology and physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids. The methods and approaches for developing this complex multiphase simulation model and delineating the AoR are defined below.

3.0 Site Characteristics

3.1 Site Overview

The Bluebonnet Hub is located west of the town of Winnie, between Houston and Beaumont, Texas. It comprises parts of Chambers, Liberty, and Jefferson Counties. The Bluebonnet

Sequestration Hub, LLC (Bluebonnet) (through its affiliates) has leased approximately Claimed as PBI acres across Chambers, Liberty, and Jefferson counties as part of the project development. These agreements include rights to sequester CO_2 in the pore space, surface use, and land access necessary to facilitate this proposed carbon sequestration project.

The Bluebonnet Hub is strategically located near a concentration of industrial power-generating plants, refineries, and chemical production, natural-gas processing, and natural-gas liquefaction facilities along the Gulf Coast from the Beaumont/Port Arthur area to the east to the Houston area in the west. The project will get custody of the CO_2 captured by these emitters through offtake agreements and transport the captured CO_2 via a third-party pipeline to the site, where the CO_2 will be stored.

The Bluebonnet Hub project team conducted detailed assessments of the surface and subsurface features of the proposed site via multiple integrated scientific methods, including regional geology, structural geology, hydrogeology, geophysics, petrophysics, fluid substitution, petrology, mineralogy, geochemistry, geomechanics, seismic history, legacy well analysis, and reservoir engineering to characterize the proposed storage complex consisting of multiple stacked confining and injection zones.

No previously recorded National Register of Historic Places (NRHP) districts or properties, sites designated as State Antiquities Landmarks, Recorded Texas Historic Landmarks, or historical markers are within the project AoR. The Texas Archeological Sites Atlas (TASA) revealed no previously recorded archaeological sites within 0.5 mile of the AoR (THC 2022). Note: Cultural resources review conducted by third-party contractor with access to restricted databases: Texas Historical Commission (THC) 2022; Texas Archeological Sites Atlas (TSA) restricted database; and Texas Historical Commission and Texas Archeological Research Laboratory. Available at: http://pedernales.thc.state.tx.us. Accessed November 2022.

No schools, hospitals, or nursing homes are known within the AoR. There is a local small-craft airport and a major interstate, I-10, within the boundaries of the AoR. There are Claimed as PBI or Claimed as PBI

No Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), aka Superfund, or Resource Conservation and Recovery Act (RCRA) sites were identified in a database search of the Bluebonnet AoR (EPA 2022e): U.S. Environmental Protection Agency (EPA) 2022e. Hazardous Waste Sites. Available at: https://www.map22.epa.gov.Accessed November 2024.

No springs were identified in the study area: USGS Database of Historically Documented Springs and Spring Flow Measurements in Texas: USGS Open-File Report 03-315. Maps | Data Basin. National Hydrography Dataset: USGS NHD Best Resolution for HU8 – Published 2024-01-04. The National Map Downloader Revisiting Major and Historical Springs of Texas by Gunnar Brune (1975) . Springs Database (February 2024). Groundwater Database Viewer (TWDB). Published May 2024. Accessed October 2024.

No mines or mineral deposits identified in the study area: USGS Mineral Resources Data System: Mineral Resources Data System: Records graded for completeness and consistency (usgs.gov) University of Texas at Austin: Texas Mineral Resources Map (utexas.edu) Accessed October 2024.

No quarries identified in the study area: Database of registrations for Aggregate Production Operations, maintained by the Texas Commission on Environmental Quality. Central Registry Search for Aggregate Production Operation. USGS Prospect- and mine- related features (Includes quarries, gravel and borrow pits, and other features): https://mrdata.usgs.gov/usmin/ Texas database Map: Map: Texas quarry sites (expressnews.com) Accessed October 2024.

Oxy Low Carbon Ventures, LLC (Oxy), the parent company of Bluebonnet, drilled and completed Encanto 01 as a stratigraphic test well in 2022-2023, and acquired an extensive set of site-based data to complete the site characterization and AoR delineation. The different datasets across multiple disciplines acquired in this well have been integrated and are presented in this permit. Oxy drilled Bluebonnet USDW 1 well in 2024 in the same location of the Encanto 01 well to 1,630 ft to characterize the water composition from the base of the USDW to surface. Bluebonnet drilled Bluebonnet USDW 8 in 2025 in the same location of Encanto 01 well to 2,750 ft to obtain whole core and Rotary Side Wall Cores (RSWC) to characterize the confining shales present in the Miocene Composite Confining Zone. Some remaining data integration is still in progress and awaiting laboratory results for the samples obtained while drilling Bluebonnet USDW 8.

A detailed regional and local geological evaluation of the area around the Bluebonnet Hub was conducted using geological, geophysical, and petrophysical data obtained from public literature and data, licensed data, and site-specific data collected for this project. These data are described in the following sections.


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3.2 Location and Data Control

The Bluebonnet Hub technical staff conducted a detailed subsurface evaluation over approximately 193 square miles in Chambers, Jefferson, and Liberty Counties. Multiple types of data were integrated, including publicly available literature, maps, and cross sections; publicly available GIS data including topography, surface geology, land use, and culture data; a licensed 3D seismic survey; and publicly available and licensed well data and logs. Also, core, mudlog, biostratigraphy, and wireline log data from the stratigraphic test well was included in the evaluation.

The Frio model includes 156 wells, 95 of those containing high quality logs with petrophysical analyses that were used to populate the 3D geocellular model and 61 of those containing basic logs (Figure AoR-2).

The Lower Miocene model includes 158 wells, 102 of which are inside the geo-mode Area of Interest (AOI) (Figure AoR-3). For facies classification, 158 wells were used, and 14 wells with triple combo and PEF that were used for facies classification as based wells to distribute petrophysical parameter to the rest of the 144 wells. For more detail on how the petrophysical properties were distributed in the field, refer to Appendix A.

The core database consists of three wells: the stratigraphic test well (Encanto 01) and two historical wells (Sterrett Eat Fred R_1 UWI: 42-071-019580000 and Debellvue Mrs Maria_1 UWI: 42-071-019620000). The Sterrett Eat Fred R_1 well had sidewall core (SWC) data confined to discrete intervals above and below the proposed Oligocene storage complex, and Debellvue Mrs Maria_1 well had percussion sidewall cores that were also confined to discrete intervals above and below the proposed Oligocene storage complex.

The most recent data point is the stratigraphic test well Encanto 01, in which whole cores, rotary sidewall cores (RSWCs), and mud cuttings data were acquired across the stratigraphic column, within, below, and above the proposed storage complex. Also, a series of petrophysical logs and well tests from TD to surface was received.


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3.3 Physical Geography

The Bluebonnet Hub is located on the Lower Coastal Gulf Plain, which is a flat, low-relief surface (Galloway 2008,Figure AoR-4).

Common features such as marshes and swamps occur along a belt of deltaic and interdeltaic sediments that typify the emerged Gulf segment of the coastal plain (USGS, 1996). This area grades landward to a band of steplike deposits and terraces of relatively young geologic age (USGS, 1996). The Paleogene, Neogene, and Quarternary sediments deposited in the Gulf Coastal Plain fall into two major classes: sand and clay. The sand layers are more resistant to erosion because they absorb rainfall, thereby reducing surface runoff. The clay sediments are less resistant, resulting in topographic lows. Soils develop on each geologic unit, which supports unique flora, so that vegetation is an aid in identifying both physiographic features and underlying rock type (USGS, 1996).

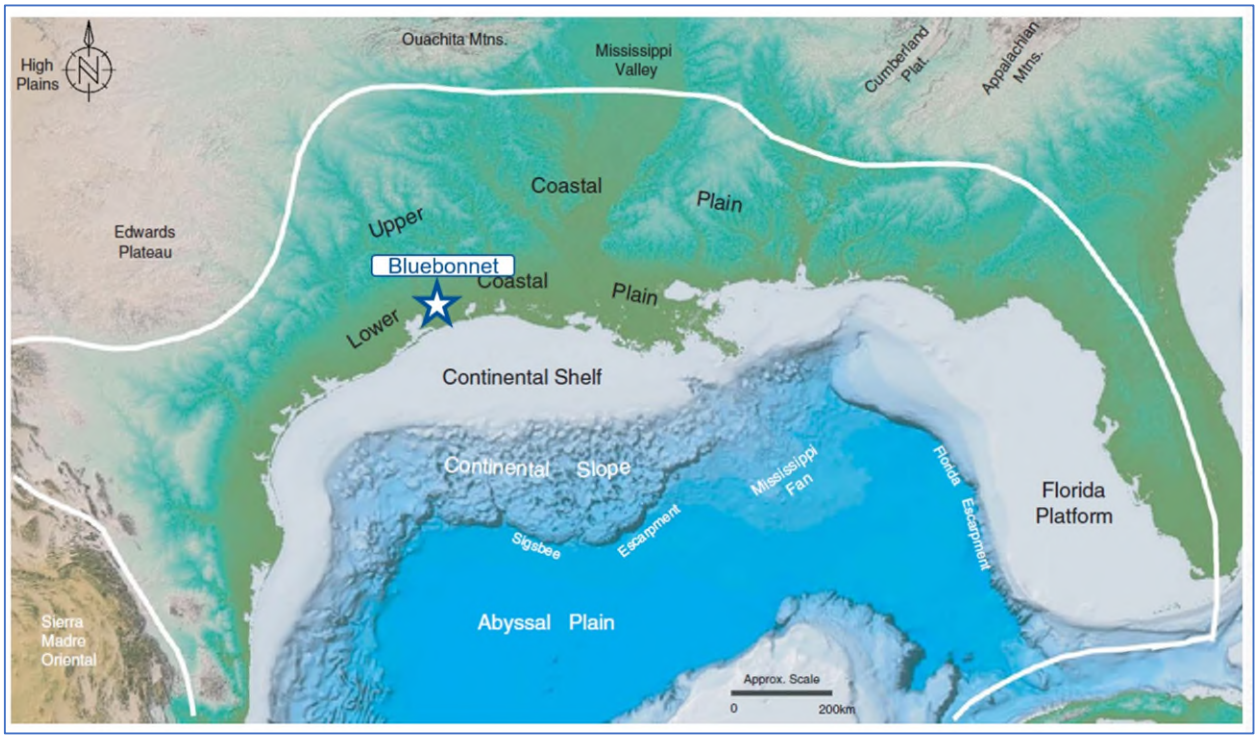


Figure AoR-4: Principal physiographic elements of the Gulf Coast. Source: Galloway, 2008.

The Bluebonnet Hub is located on the Houston Sheet (Figure AoR-5). The surface is covered by Quaternary strata, namely rocks of the Pleistocene-aged Beaumont Formation, which consist of barrier island and beach deposits. Lithologically, these rocks are constituted of clay, silt, and sand that were deposited in stream channels with meander patterns and ridges, point bars, natural levees, backswamp, and minor coastal marsh and mudflats. A majority of the project extent is underlain by “clay- and mud-rich deposits of low permeability, high water-holding capacity, high compressibility, high to very high shrink-swell potential, poor drainage, level to depressed relief, low shear strength, and high plasticity” (UT BEG, 1982). These geologic units represent interdistributary muds, abandoned channel-fill muds, and overbank fluvial muds.

The Trinity and Neches Rivers are the two closest major rivers, approximately ~12 miles to the west and ~21 miles to the east, respectively. These present-day Holocene-aged rivers cut into the Pleistocene rocks described above and deposit alluvium consisting of clay, silt, sand, and organic matter in similar depositional environments. The entire Bluebonnet Hub site is cut through by the Spindletop Bayou, flowing from north to south, eventually draining into the Gulf of Mexico.

The topographic elevation above mean sea level ranges from 25 – 40 ft across the project extent (Figure AoR-6).

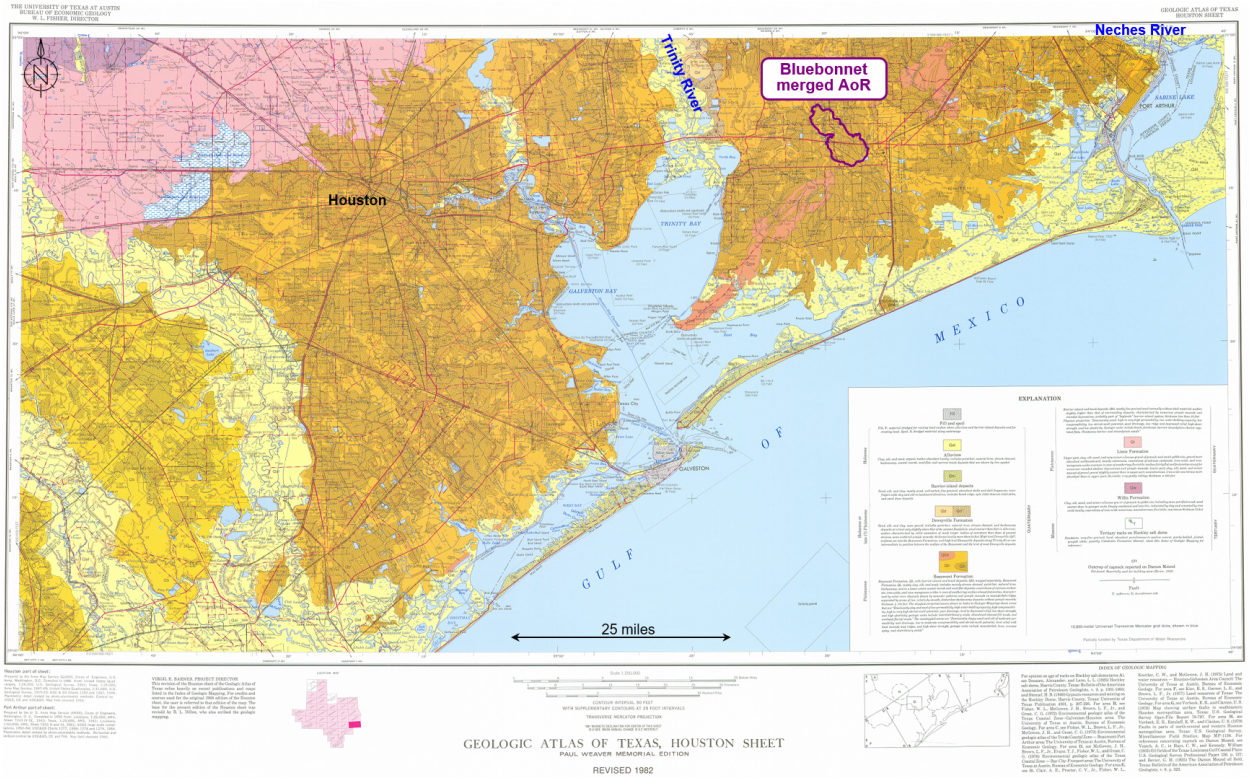
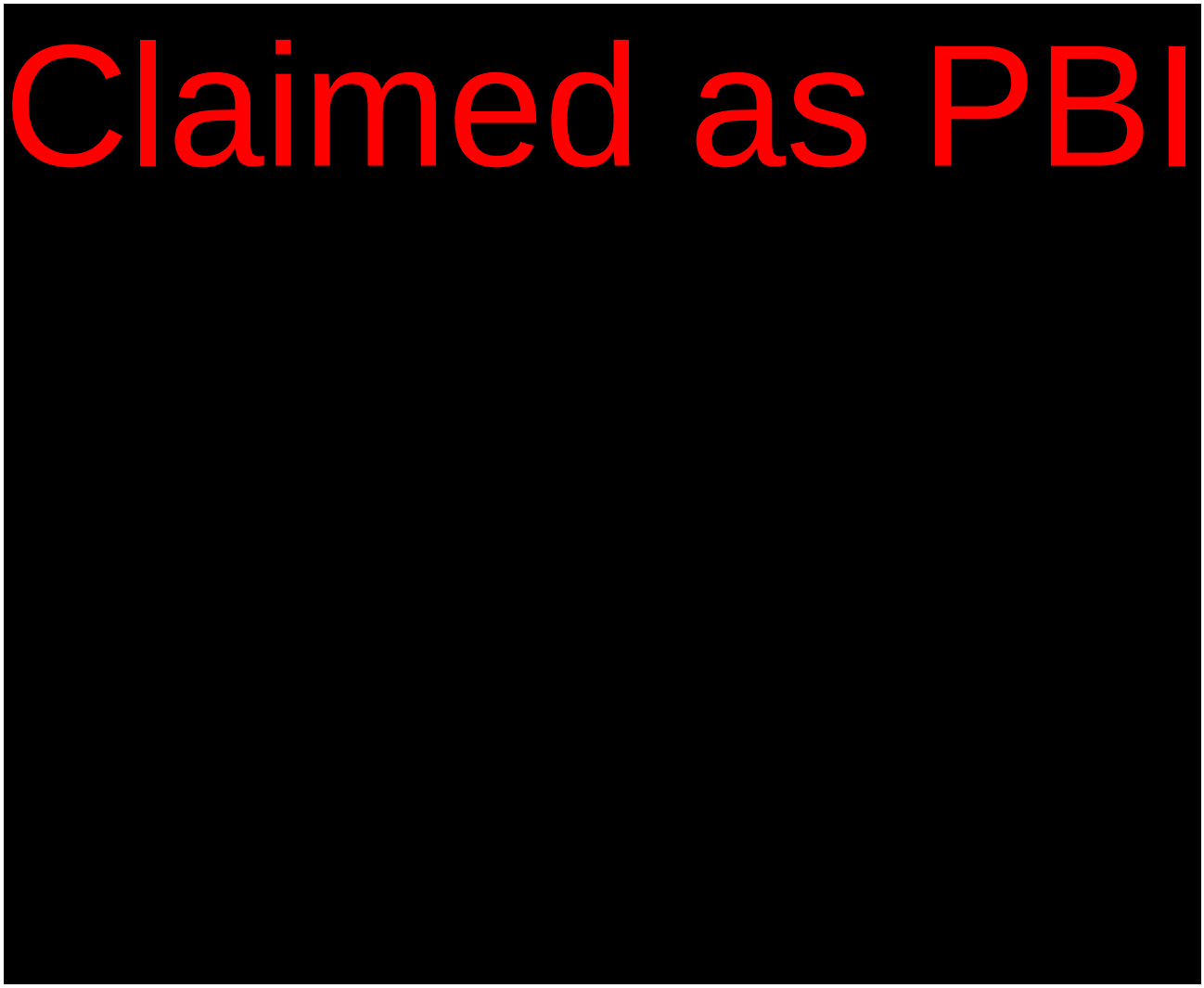


Figure AoR-5: Geologic Atlas of Texas, Houston Sheet, depicting the surface geology on a scale 1:250,000. Purple polygon: Bluebonnet Area of Review (AoR). Map source: University of Texas - Bureau of Economic Geology, 1982.



The surface land is classified as farmed palustrine wetland (Figure AoR-7). Palustrine systems include nontidal wetlands dominated by trees, shrubs, persistent emergent, emergent mosses, or lichens. Farmed wetlands occur where the soil surface has been mechanically or physically altered for production of crops, but where hydrophytes would become reestablished, if the farming were to be discontinued. Other physical surface characteristics of the Bluebonnet Sequestration Project site include minor freshwater forested/shrub wetland, minor freshwater emergent wetland, minor emergent persistent seasonally to temporarily flooded palustrine wetlands (seasonally flooded during the growing season but absent by the end of the season in most years; temporarily flooded for a few days to a few weeks during the growing season), perennial and intermittent lakes/ponds, a bayou, several ditches, roads, and canals (Figure AoR-8).



Figure AoR-7: National Wetland Inventory – this map shows that the Bluebonnet Sequestration Project site encompasses palustrine farmed wetland. The six CO_2 injection wells are shown with red triangles at their proposed surface location.


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3.4 Regional Geology

During the Cenozoic, the Gulf of Mexico (GoM) developed as a passive margin basin displaying a continuous record of basin infilling by terrigenous clastic sediments (Galloway et al., 2000). Across the northern Gulf, sediment supply by large continental rivers initiated continental margin offlap that continued throughout the remaining Cenozoic. The depositional history of the northern Gulf Basin was an interplay of several sedimentary distribution systems that sourced large deltas, one of them being the Houston Delta (Galloway et al., 2000). These sedimentary distribution systems are clustered in three major broad structurally defined entry points. These entry points are a series of gentle synclines and anticlines, which are oriented perpendicular to the coastline (USGS, 1996). One of the three distinct structural provinces of the onshore Texas Gulf Coast is the Houston Embayment, which is tied to the Houston Delta where the Bluebonnet Hub is located.

Within this province, Tertiary sediments were deposited as a series of gulfward-thickening, terrigenous clastic wedges (BEG Dodge and Posey, 1981). These sediments were transported to the coastal margin by rivers, and subsequently deposited in deltas or reworked by marine processes into strandplains and barrier bars (BEG Dodge and Posey, 1981). Contemporaneous growth faults developed parallel to the shelf margin and syndepositional movement resulted in sediment thickening on the downthrown side of the faults (Figure AoR-9). Due to the throw offsetting these sediments, they became isolated from sediments on the upthrown side of the fault. In some of these isolated sediments, abnormally high pressure and temperature gradients develop as a result of fluid entrapment (BEG Dodge and Posey, 1981) because high sedimentation rates fed by large river systems in these deltaic deposits prevented the escape of pore water trapped in the shales.

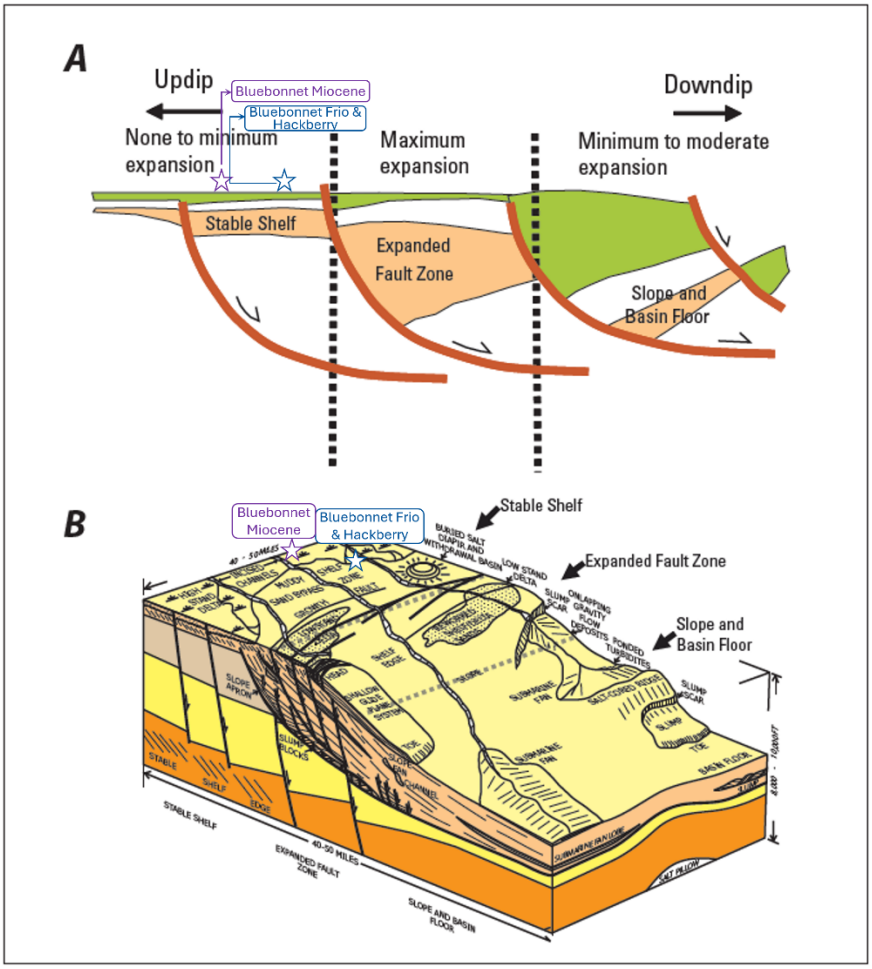


Figure AoR-9: Generalized block diagram showing structural compartments and depositional environments. The Bluebonnet Sequestration Hub is located on the stable shelf at the time of Frio and Miocene deposition. After USGS, 2013.

Beneath the Gulf Coastal Plain of Texas lies the Jurassic Louann salt. Salt displacement occurs from loading by laterally continuous depositional systems. Major rapid diapirism of the salt domes in the Gulf Coast Basin was initiated during the Tertiary period due to sediment loading of the Wilcox and subsequent fluvio-deltaic sediments (Annual report, 1986). By the end of the Oligocene, the salt diapirs had reached the surface and entered the post-diapir development stage. Salt domes are numerous in the Gulf Coastal Plain and may penetrate thousands of feet of sediments. Salt dome development impacts local faulting and sedimentation patterns (BEG Dodge and Posey, 1981). Although the degree of salt intrusion can be very great, disruption of adjacent strata is limited to the vicinity of the dome (USGS, 1996). Salt domes can provide structural and stratigraphic hydrocarbon traps and also affect the groundwater chemistry in their vicinity. No salt domes are present within the proposed Bluebonnet Hub AoR. The closest salt dome is the Hankamer Salt Dome, which is located approximately 2.3 miles to the west.

River systems to the west transported siliciclastic sand and mud to the Gulf Coast throughout the Paleogene and Neogene. Through time, the depositional centers of these rivers shifted in an east-west direction and prograded in a north-south direction. The deposition of these gulfward-prograding depocenters was interrupted repeatedly by transgressions. These flooding events reflect increases in sea level and can be recognized on logs as marine shales. Some of the prominent regional marine shales are the Anahuac Formation, Marginulina, and Amphistegina B shales (Figure AoR-10). During the deposition of these marine shales, the continental platform was submerged over a widespread period. After these cyclical flooding episodes, the sedimentary system prograded over these shales and resulted in the next sandstone-rich depositional event, which prograded steadily basinward (Bump et al., 2021).

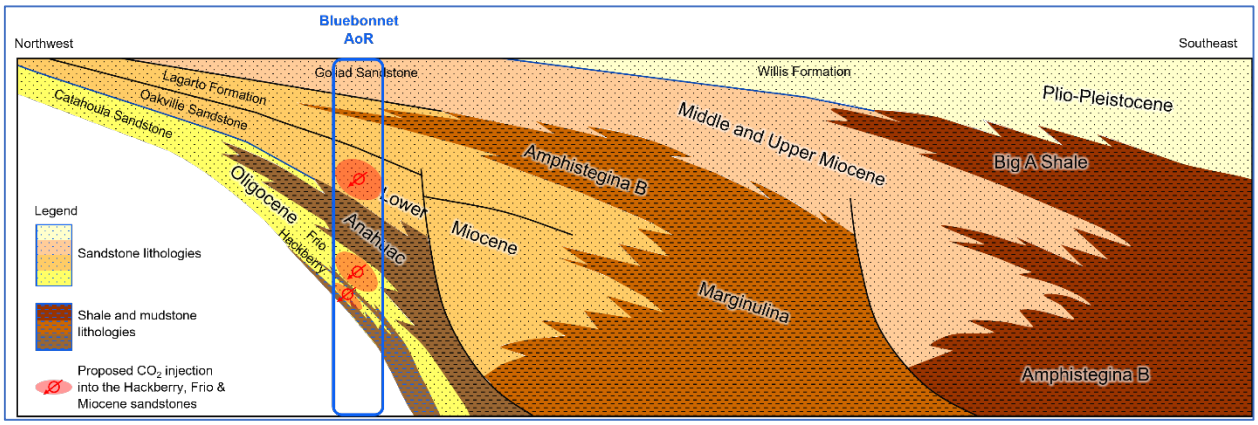


Figure AoR-10: Northwest-southeast schematic cross section of the Oligocene, Lower, Middle and Upper Miocene depositional complexes. Lithostratigraphic features and their correlations are highlighted. After Seni et al., 1997.

On the regional upper Texas Gulf Coast, dip cross sections were published by the BEG in 1981. In the dip section, the main sand depocenter in each unit shifts seaward, which explains the progradational nature of the sand wedges. Within the Bluebonnet Hub, areal Frio, Hackberry, and Miocene sand trends were mapped, providing largescale storage capacity (Figure AoR-11).

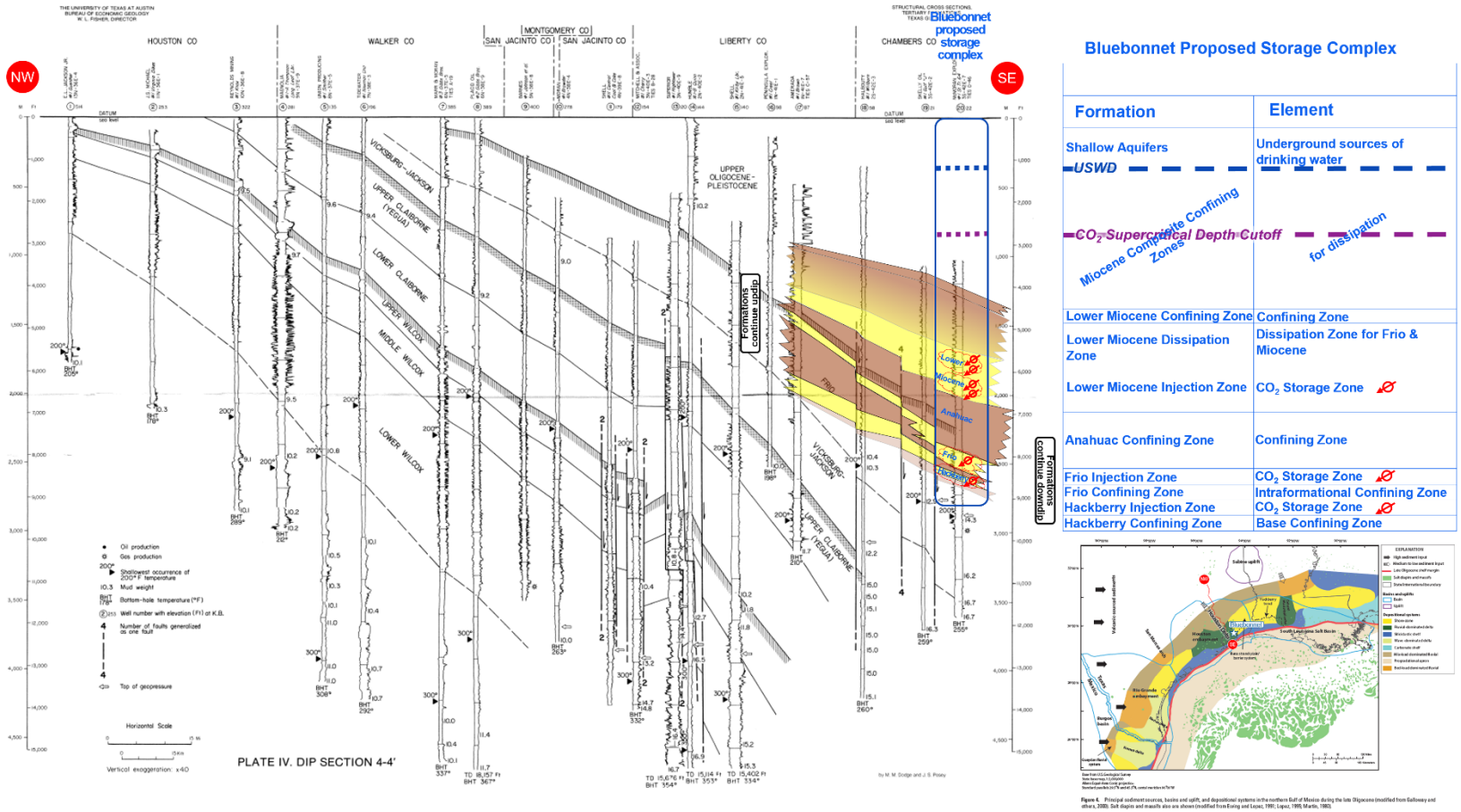


Figure AoR-11: Regional dip cross section, highlighting the proposed storage complex. The planned CO_2 injection zones are the Hackberry, Frio, and Lower Miocene sandstones. The planned confining zones to contain the sequestered CO_2 within the subsurface are the thick marine transgressive Anahuac Confining Zone, the Lower Miocene Confining Zone, and the Miocene Composite Confining Zone acting as a dissipation zone (modified after BEG, 1981).

The Early Miocene was a period of relative paleogeographic stability of the Gulf Basin. Galloway et al. (2000) identified two major supersequences (deposodes) during the Early/Lower Miocene (Figure AoR-12). Although the volumes of the Lower Miocene supersequences are substantially less than that of the Frio section, their shorter durations resulted in comparably high calculated supply rates (Galloway et al. 2011). The rate of continental margin accretion declined but remained high (Figure AoR-12). This is reflected at least in part in the declining volcanic activity and active uplift across western North America (Snedden and Galloway, 2019). The sedimentation pattern in the Miocene–Pliocene was dominated by fluvial systems entering the basin from the north.

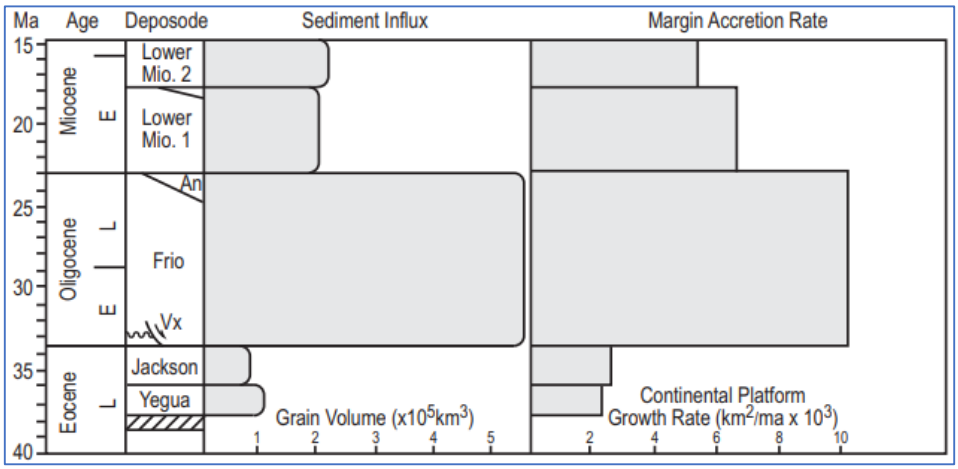


Figure AoR-12: Depositional episodes and chronology of the Middle Cenozoic Geothermal Phase; (A) Northern Gulf (US) margin deposodes, sediment influx, calculated as total grain volume, and continental margin accretion rates. Miocene sediment influx and margin accretion reduced compared to Oligocene, but was still high (GBDS, 2019).

Two major fluvial-dominated delta systems developed during the Lower Miocene (i.e., the paleo Mississippi and paleo Red River). These prograded rapidly across the Anahuac transgressive shelf and onto the central GoM continental margin (Snedden and Galloway, 2019). The main depositional system, Mississippi fluvial–deltaic axis, continued its long history as a major continental river and deltaic depocenter. To the west, the other fluvial axis (paleo Red River fluvial system) traversed the easternmost Texas Miocene coastal plain (Galloway et al. 1986). It supplied the Calcasieu delta system, which was somewhat smaller in area and depocenter volume than the Mississippi delta system (Figure AoR-13). Both delta systems persisted during the Lower Miocene deposodes (Snedden and Galloway, 2019).

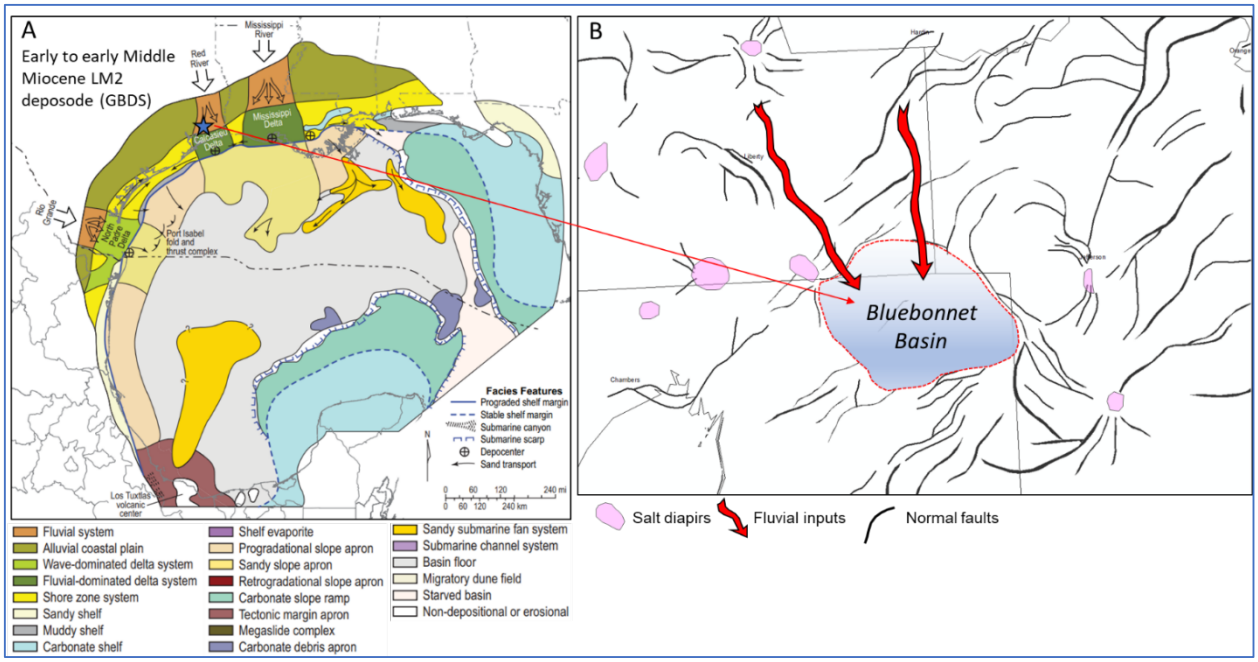


Figure AoR-13: A) Gulf of Mexico regional depositional setting during Lower Miocene and lower part of Middle Miocene (deposode LM2, Snedden and Galloway, 2019). B) Subregional understanding around the AOI (Bluebonnet basin). Also, showing main fluvial fairways into the Bluebonnet basin, normal faults, and salt diapirs.

The Bluebonnet Hub is located in the sediment fairway of the Red River and Calcasieu delta system, and specifically within the Houston embayment (Figure AoR-13). Extensional tectonic affected the larger area, with growth faulting developed parallel to the shelf margin resulting in sediment thickening on the downthrown side of the faults, though mostly seen south of the Bluebonnet site (Figure AoR-10).

A regional structural dip cross section showing the USDW, major aquifers, and proposed storage complex including the confining and injection zones, additional composite confining zones for dissipation and vertical distance between the proposed injection zone, and USDW is shown in Figure AoR-14. The present-day structure of the top of the confining and injection zones dips towards the Gulf Coast in the southeast at varying rates ranging between 2.31 – 3.38° degrees, as observed on 3D seismic data over the project area. This formation dip impacts the CO_2 plume migration, which is driven by buoyancy forces in an updip direction.

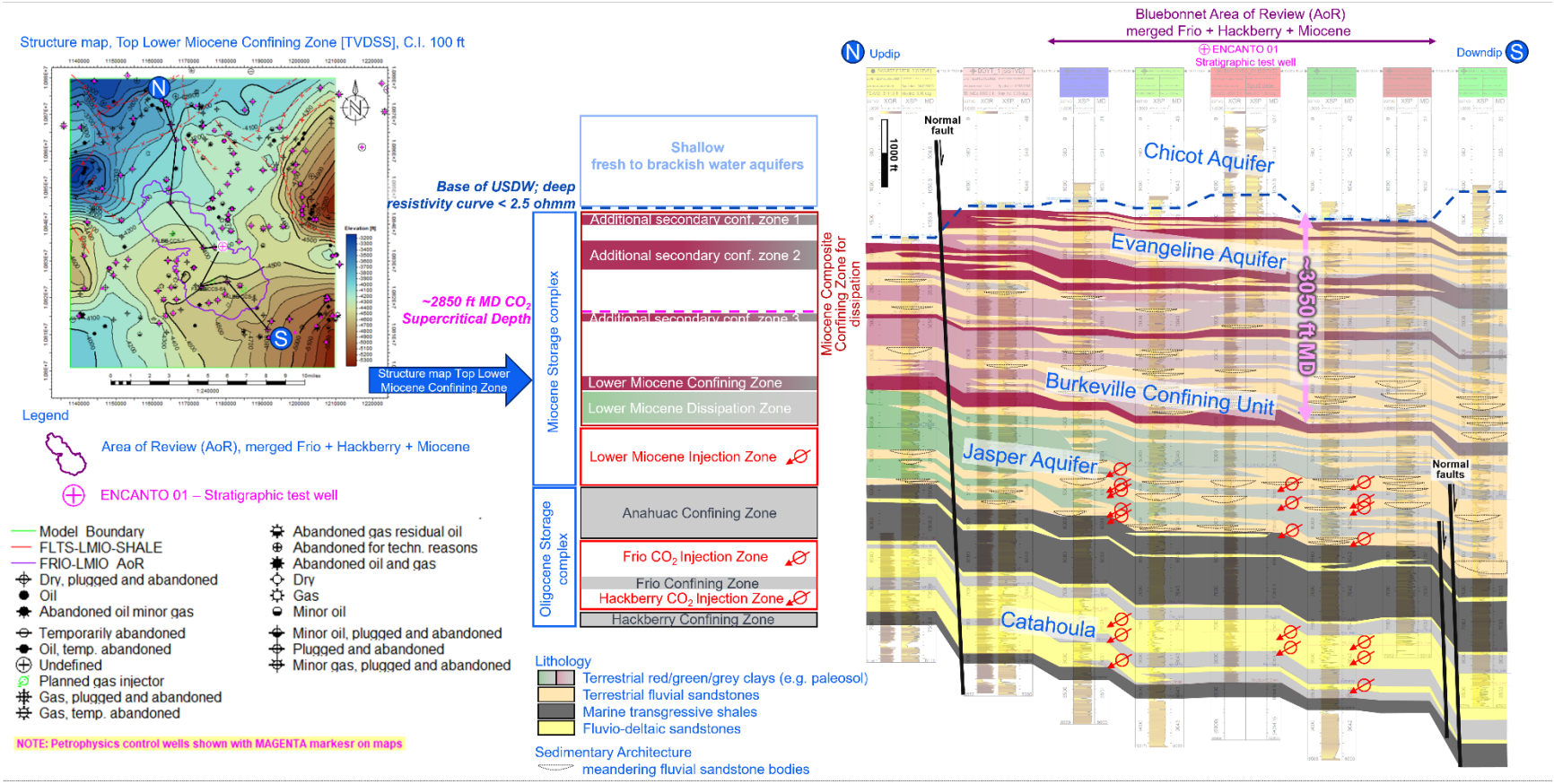


Figure AoR-14: Regional structural dip cross section through the Area of Interest (AOI), highlighting the proposed storage complex; scale 1:8,000. The proposed CO_2 injection zones are the Hackberry, Frio, and Lower Miocene sandstones. The proposed confining zones to contain the sequestered CO_2 within the subsurface are the transgressive marine Hackberry, Frio, and Anahuac shales, as well as the terrestrial Lower Miocene Confining Zone and the Miocene Composite Confining Zones. Major faults are highlighted in black. The base of Underground Sources of Drinking Water (USDW), below which TDS>10,000 mg/L is shown in dashed blue.

3.5 Basin History and Structure

Understanding of the regional structure in the Bluebonnet area was developed from published literature, regional well data, regional 2D seismic owned or licensed by Oxy USA Inc., and 3D seismic licensed by Oxy USA Inc. The result is a structural synthesis that aligns regional structural trends with observations of local structural elements. Numerous structural styles are interpretated within the Bluebonnet 3D seismic region (defined here as the ~200 square mile area covered by licensed 3D seismic used in this evaluation), including salt doming, growth faulting, transtensional faulting, and growth fault reactivation. These various faulting styles were evaluated extensively to select an AoR for the Bluebonnet Sequestration Hub in which any faulting that impacts the integrity of the storage complex is absent. The dominant structural features in the Bluebonnet region are Cenozoic growth faults resulting from sediment loading of progradational sequences on top of older unstable slopes. This progradational loading and resulting growth faulting is observed by mapped growth structures that decrease in age geographically towards the Gulf of Mexico Basin (Figure AoR-15 and Figure AoR-16). Deposition of the Bluebonnet Storage Complex occurred in the Middle Cenozoic Geothermal Phase during periods of Frio-Vicksburg detachment faulting and regional volcanism and uplift.

The Bluebonnet site is located on the paleo Frio Shelf between the Frio maximum transgression and Frio shelf edge, where shelf-parallel listric growth faults detached on the older Wilcox slope below as a result of sediment loading during Frio deposition (Figure AoR-16a). Growth faulting at this time was widespread throughout the Bluebonnet 3D seismic area (Figure AoR-16b). However, observations from 3D seismic demonstrate that significant and widespread movement along these faults ceased prior to the end of Frio deposition and strain resulting from subsequent loading is concentrated more discretely along select zone of weakness, resulting in the more organized and geographically discrete faults that are observed in the map in Figure AoR-17.

Faulting within the 3D survey was interpreted manually with the assistance of various fault enhancement attributes including Landmark's Structure Oriented Filter and Fault Likelihood attributes. All faults were interpreted using fault plane mapping techniques to assure reasonable and proper fault geometries. All interpreted faults were incorporated into the geomodel.

Detailed interpretation of local structures from 3D seismic are shown in the map and cross section views in Figure AoR-17. Fault intercepts are shown in the map view for the top of Vicksburg surface below the storage complex (blue), top of Hackberry Injection zone surface (orange), top of Frio Injection Zone surface (green), and top of Lower Miocene Confining Zone surface above the storage complex (red).

Five faulting styles are identified in the area shown in the map as:

1) Salt doming and associated radial faulting
2) Widespread Vicksburg growth faulting
3) Coast-parallel reactivated growth faulting
4) Coast-sub-parallel reactivated growth faulting, and
5) Minor transtensional faulting.

Cross sections AA', BB', and CC' in Figure AoR-17, and cross section DD' in Figure AoR-18 are interpreted from 3D seismic and show the various faulting styles across the area. The timing of fault movement for each fault style was interpreted from 3D seismic utilizing observations of fault plane terminations, identification of pre-, syn-, and post-depositional seismic reflector cross-fault relationships, and pseudo-structural reconstructions (i.e., flattening on relevant surfaces).

Additional context for a fault included in the model that intersects the top of the Hackberry outside of the AoR boundaries. A map view of the fault intersection with the top of the Hackberry Confining Zone outside of the AoR is visible in Figure AoR-19.

Particular attention was paid to faulting within the Bluebonnet AoR (widespread Vicksburg growth faulting). Manual fault interpretations were cross-checked against Fault Likelihood attribute overlays and surface extractions (see Figures AoR19 and AoR20). All mapping and attribute analyses indicate that movement on widespread Vicksburg growth faulting ceased before the end of Hackberry, Frio, and Lower Miocene deposition. No measurable offset is present within the Hackberry, Frio, and Lower Miocene injection zones or confining zones. The confining and injection zones are free of transecting or transmissive faults within the AoR (see Figure AoR-20). Fault likelihood maps seen in Figure AoR-20 are horizon extractions at the top of the confining zones.

Regional data indicated the presence of faulting south of the AoR outside of the primary interpretation 3D (see Figure AoR-21). Out of an abundance of caution, additional 3D licensed by Oxy USA Inc. was preliminarily evaluated to locate and characterize these faults. These faults, which are located a mile south and down dip of the southern limit of the AoR, are interpreted as Frio Growth Structures. These faults set up the updip trap for the Fig Ridge North and Fig Ridge Frio fields, and thus, are interpreted to be sealing.

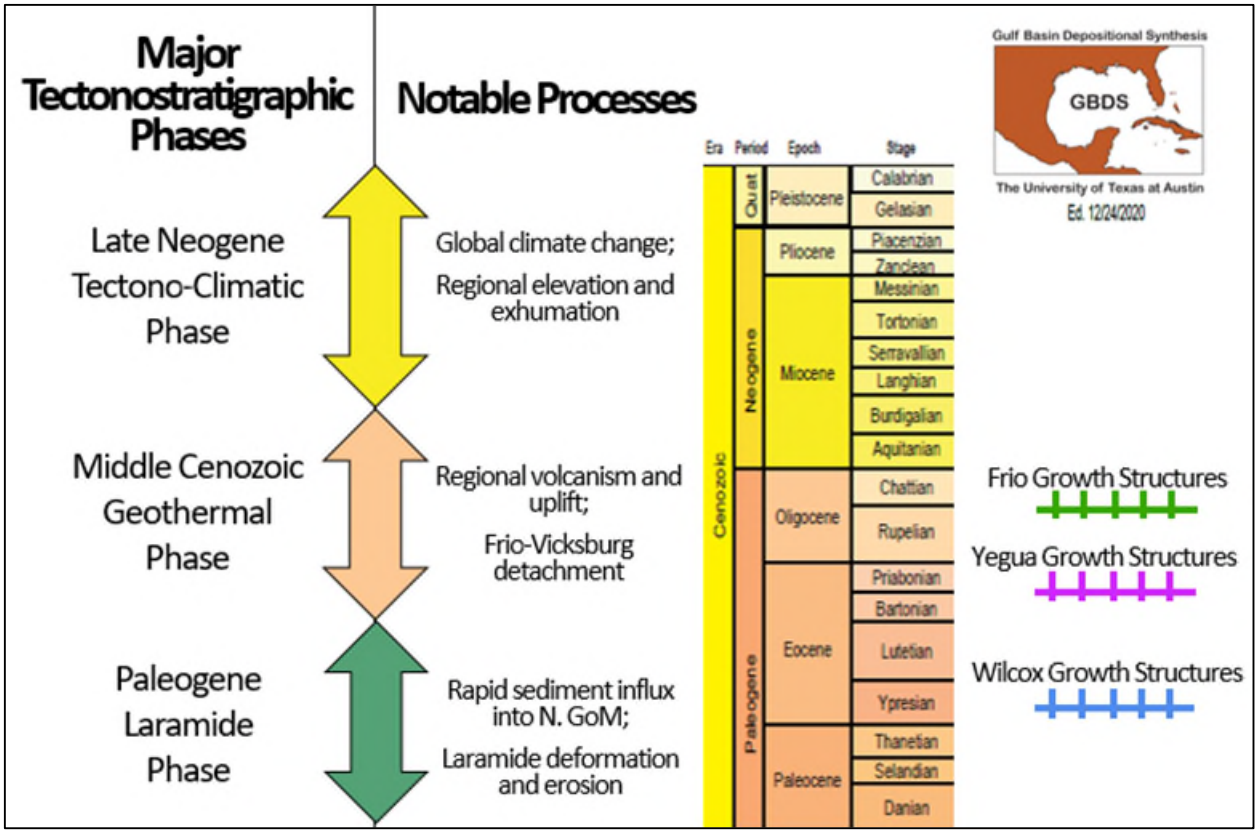


Figure AoR-15: Tectono-stratigraphic chart showing key processes related to structural history of the Gulf Coast Bluebonnet region (modified from the University of Texas at Austin's Gulf Basin Depositional Synthesis).


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3.6 Stratigraphy of the Storage Complex

Two stacked storage complexes have been identified in the Bluebonnet Sequestration Hub (Figure AoR-22). The deeper and older Oligocene storage complex will be developed first and comprises the Hackberry and Frio Injection Zones, as well as the Hackberry, Frio, and Anahuac Confining Zones. The shallower and younger Miocene storage complex comprises the Lower Miocene Injection Zone, Lower Miocene Confining Zone, and Miocene Composite Confining Zones. Both storage complexes are vertically stacked and described in the following from oldest to youngest.

Frio and Hackberry Injection Zone

This storage complex is composed of 284 ft Frio and 52 ft Hackberry net sand thickness, totaling 335 ft net sand thickness, as the storage reservoir for CO_2 and 1,074 ft of overlying Anahuac Confining Zone as the confining unit.

Lower Miocene Injection Zone

The Miocene section of this storage complex is composed of 1,004 ft sand thickness as the storage reservoir for CO_2 and 168 ft of overlying confining zone as the confining unit. The base confining zone for the Miocene storage section is represented by the Anahuac confining zone, which it is 1,074 ft in average at the site. Figure AoR-22 show the stratigraphic column of the hydrologic units within the storage complex.

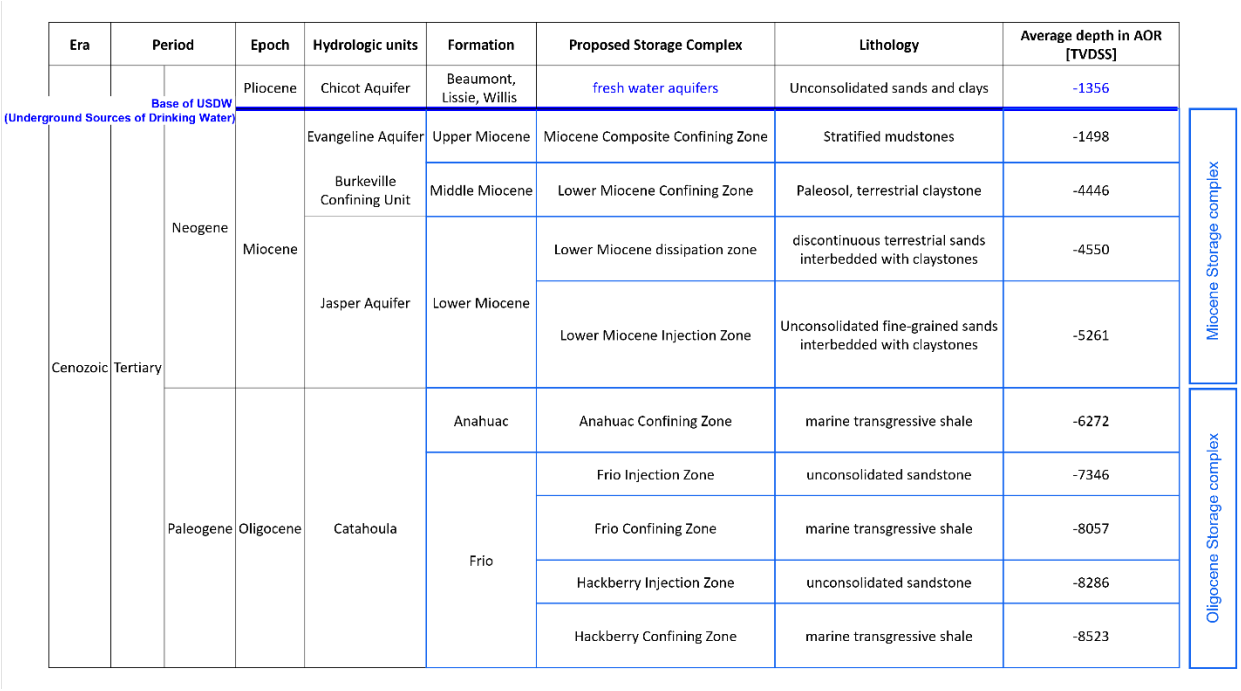


Figure AoR-22: Stratigraphic column of the hydrologic units and geologic formations and their lithologies. The average subsea depths over the proposed AoR are shown for the proposed Oligocene storage complex.

The stratigraphy of the storage complex is described from older and deeper to younger and shallower strata.

The **Hackberry Confining Zone** is the base confining zone for the proposed storage complex. The Hackberry Confining Zone is a low-permeability confining zone that is regionally contiguous in both the north-south dip direction and in the east-west strike direction. This third-order marine transgressive shale represents a time in the Oligocene when the Gulf Coast was submerged under water due to rising sea levels, which explains the lateral continuity. Transgressive shales offer good to excellent seal potential depending on their fabric and petrophysical properties.

Above this base confining zone, is the lower CO_2 injection zone within the **Hackberry Injection Zone**. These sandstones were likely deposited in a proximal delta front and are better developed

in the northern updip part of the acreage and thin toward the south and downdip, which drives the completion strategy of the proposed CO_2 injection wells. The Hackberry sandstones exhibit high porosity and permeability, both of which are critical parameters for input in the storage capacity and injectivity estimations.

The **Frio Confining Zone**, which caps the proposed Hackberry Injection Zone, is a laterally continuous and intraformational marine shale reflecting another flooding event in the Oligocene. This also serves as the base confining zone for the Frio Injection Zone above and represents a lower third-order, shale-prone transgressive system tract (TST).

The upper CO_2 injection zone within the Oligocene storage complex is the **Frio formation**. The **Frio Injection Zone** is composed of a series of deltaic and marginal-marine to nonmarine sandstones and shales (USGS, 2013). On regional and local cross sections, the Frio was subdivided and mapped in three units: the Top, Mid, and Low Frio. These Frio subunits expand basinward and are characterized by thick, undifferentiated sandstone bodies, which were deposited within the lobes of a slowly prograding delta system called the Houston Delta (refer to Section 3.5 Basin History and Structure). The internal architecture of the Frio Injection Zone reservoir sandstone is interpreted as an assemblage of a stacked, high-constructive, and lobate delta (Bebout 1976). The collected Frio core from the stratigraphic test well Encanto 01 and log data from surrounding wells within the AoR confirmed this interpretation and documented both fluvial and subaqueous environments within a deltaic setting, as well as nonmarine to marginal-marine deposited sequences based on biostratigraphic analyses. The Frio sandstones exhibit high porosity and permeability, both are critical parameters for input in the storage capacity and injectivity estimations.

In a sequence stratigraphic interpretation performed on a cross section through the Encanto 01 stratigraphic test well logs and surrounding wells, the Frio Formation is characterized by a fluvial/deltaic signature with numerous trough cross beddings and minor carbonaceous plant debris. The third-order sequence stratigraphic framework comprises a lower third-order, shale-prone TST, which is the Frio Confining Zone and an overlying sand-prone third-order highstand system tract (HST). The third-order highstand can be split into fourth-order sequences, each of those made up of thin TST and a thicker sand-prone HST, which are the Top, Mid, and Low Frio sandstones (i.e., the Frio Injection Zone).

The **Frio Injection Zone** is regionally overlain by an onlapping transgressive marine shale wedge, the **Anahuac Formation** (Galloway, 1982). This is an excellent stratigraphic marker and the upper confining zone for the proposed Frio Injection Zone.

The Anahuac Confining Zone is mostly composed of dense marine shale, but also contains deltaic and carbonaceous sediments. During the Late Oligocene transgressive flooding was a time of carbonate deposition and associated decrease in clastic supply on the shelf platform. The resulting Heterostegina carbonates (Het Lime) occur as far west as Houston (Galloway 2000). The Anahuac does not crop out within the state of Texas and caps the stacked Hackberry and Frio Injection Zones. The Anahuac shale is a major seal that separates two regional pressure

compartments (i.e., the Frio and Miocene sands). It represents the lower confining zone for the Miocene storage complex and is a good base seal for the proposed CO_2 injection into the Lower Miocene sands.

The Anahuac transgression was terminated by a renewed progradation of siliciclastic sediments of the **Lower Miocene Injection Zone**, which was a period of relative paleogeographic stability in the Gulf Basin. These Lower Miocene sandstones were deposited in a transitional to terrestrial setting. It is common to observe nonmarine, stacked meandering fluvial channel complexes of variable thickness, especially in the upper part of the reservoir section. The lower part of the reservoir section contains predominantly delta-front sands interbedded with distributary channels of variable thickness and continuity.

In the sequence stratigraphic context, deltaic progradation resumed in the Lower Miocene, with delta front sands prevailing in the Bluebonnet area at the initial progradation. This deltaic progradation occurred as part of a highstand system tract (HST), which developed uninterrupted during the Lower Miocene. The Bluebonnet basin in the Lower Miocene was initially infilled with marginal marine sediments, and later fluvio-deltaic sediments (see Section 3.7 Depositional Environment). Then, the Miocene storage section and corresponding confining zone (mostly composed of coastal plain and related deposits) would correspond to a third-order highstand system tract (HST). The transgressive episode above this HST should correspond to the Amphistegina B shale, though it is not well observed at the Bluebonnet site.

The **Lower Miocene Confining Zone** acts as the confining zone for the Lower Miocene Injection target and as a secondary confining zone for the Frio and Hackberry Injection Zones below. The Lower Miocene Confining Zone is mostly composed of terrestrial sediments, including paleosols and reddish mudrocks, which were deposited in a coastal marsh along the northern Gulf Coast.

This paleosol is overlain by additional mudrock intervals interbedded with sandstones in the shallower Miocene section, collectively called the **Miocene Composite Confining Zones.** The Miocene Composite Confining Zone represents the upper most confining system for the Lower Miocene Injection Zone, Frio Injection Zone, and Hackberry Injection Zone. The Miocene Composite Confining zone includes as minimum three lateral continuous seals mapped across the AoR, intercalated with intervals of sands. The low permeability of the seals combined with the permeability contrast within this stratified sequence of interbedded sandstones and mudrock will act as a composite confining system (Bump et al, 2023) by imposing a highly tortuous path for any CO_2 migrating upward, and would therefore, attenuate any CO_2 and/or pressure in case of a leak through the Lower Miocene Confining Zone.

On top of the **Miocene Composite Confining Zone** is the base of the Underground Source of Drinking Water (USDW). The described base Hackberry, intraformational Frio, Anahuac, and Lower Miocene Confining Zones as well as the upper most Miocene Composite Confining Zones (five confining zones altogether) are in place to prevent any fluid migration from the permitted Hackberry, Frio, and Miocene Injection Zones into the USDW.

All described zones are laterally continuous in a north-south dip and west-east strike direction within and beyond the AoR. Figure AoR-23 shows a generalized stratigraphic column and Figure AoR-24 shows a cross-sectional view of the proposed storage complex.

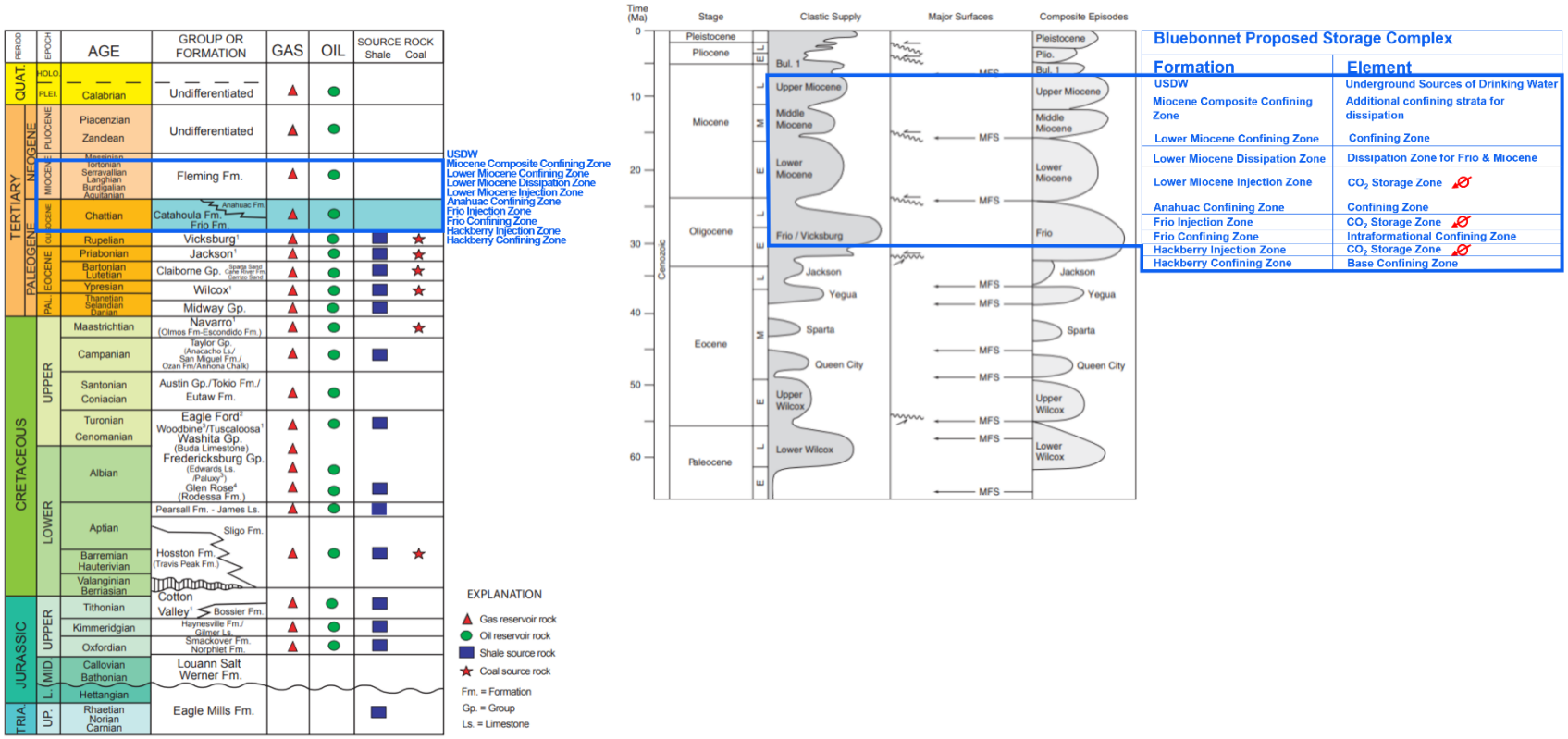


Figure AoR-23: Generalized stratigraphic column of the northern Gulf of Mexico coastal plain, highlighting the proposed storage complex in blue (modified after Swanson et al., 2013 and Galloway, 2008).

Proposed Storage Complex	
Formation	**Element**
Shallow Aquifers	Underground Sources of Drinking Water
USDW	
Miocene Composite Confining Zones	CO_2 Supercritical Depth Cutoff for dissipation
Lower Miocene Confining Zone	Confining Zone
Lower Miocene Dissipation Zone	Dissipation Zone for Frio & Miocene
Lower Miocene Injection Zone	CO_2 Storage Zone
Anahuac Confining Zone	Confining Zone
Frio Injection Zone	CO_2 Storage Zone
Frio Confining Zone	Intraformational Confining Zone
Hackberry Injection Zone	CO_2 Storage Zone
Hackberry Confining Zone	Base Confining Zone

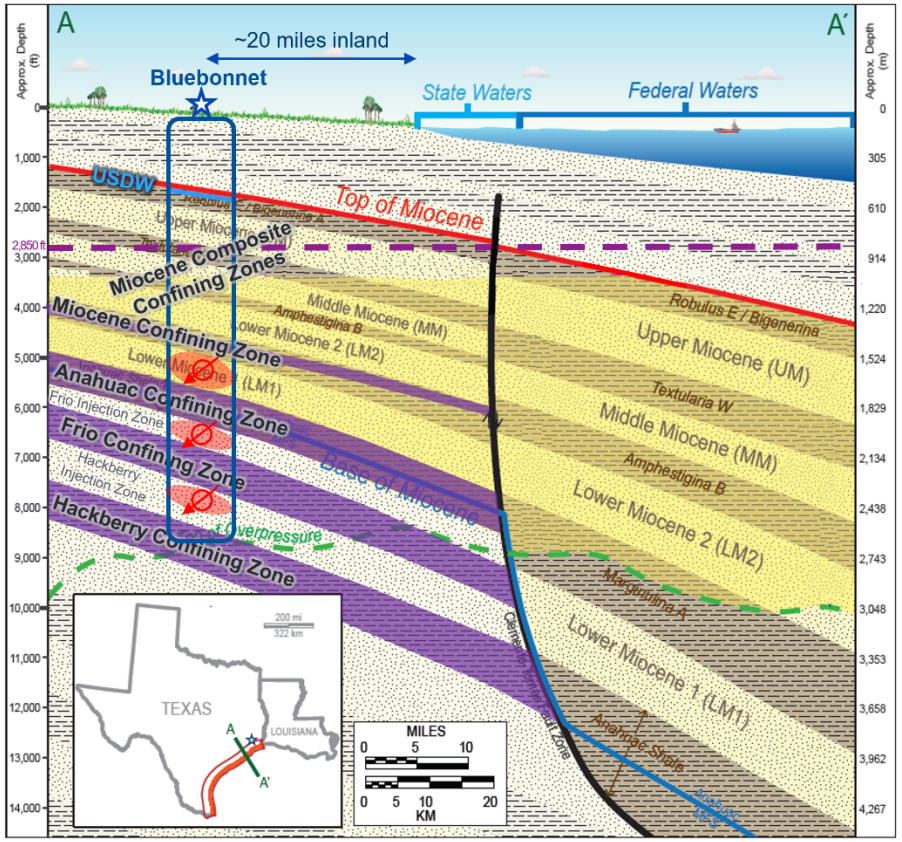


Figure AoR-24: Proposed storage complex at Bluebonnet, identifying formations and elements of the storage complex. This permit requests approval for CO_2 injection into the Hackberry, Frio, and Lower Miocene sandstones, utilizing the Anahuac shale, the Lower Miocene Confining Zone and the Miocene Composite Confining Zone as confining systems. After BEG, 2017.

3.7 Depositional Environment

The Oligocene was a time of massive sediment influx, primarily from the southwest United States (Galloway et al., 2000). The response in the Gulf was the sediment-supply dominated Frio depositional episode, which built out the coast in the form of a regionally extensive wedge of sand and shale deposited along the northern margin of the Gulf of Mexico (BEG, 1997).

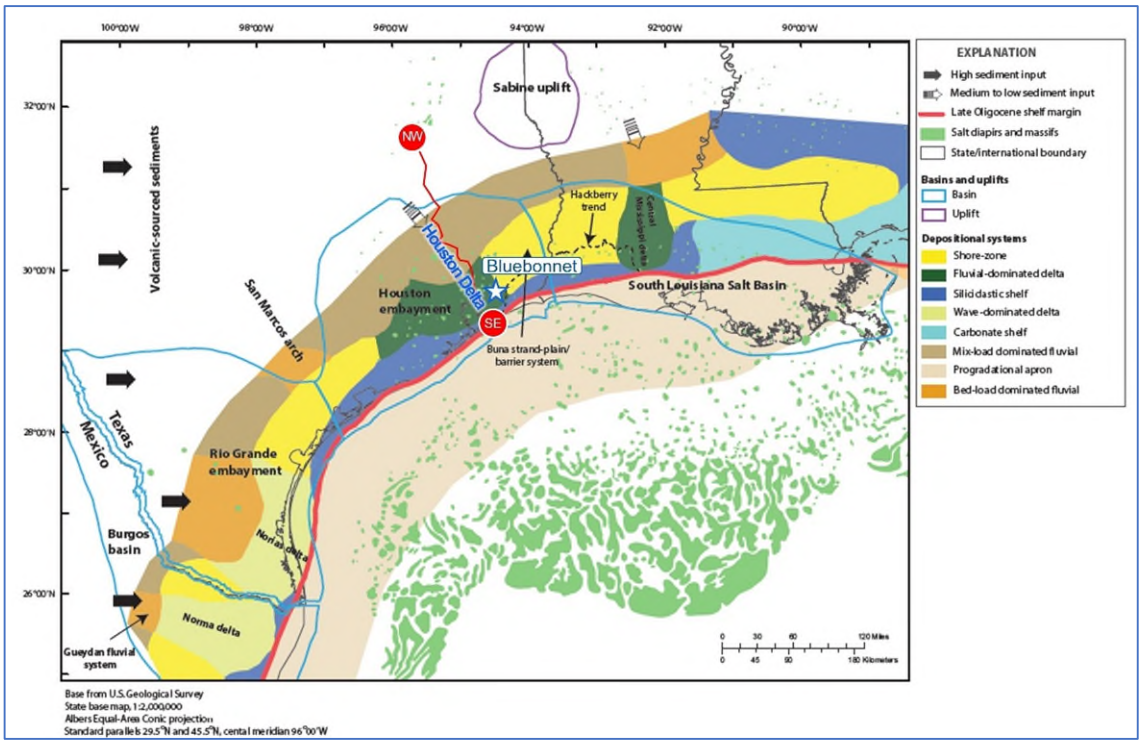


Figure AoR-25: Late Oligocene sediment sources in the northern Gulf of Mexico. Highlighted are the fluvial-dominated Houston Delta, cross section from Figure AoR-10 in red and proposed Bluebonnet Sequestration Hub with the blue star. After Swanson, USGS 2013.

The geometry of these sands impacts injectivity and plume migration. The Frio Formation is composed of a series of fluvial/deltaic and marginal-marine sandstones and shales that are the downdip equivalent of the continental Catahoula Formation (Swanson, 2013). Frio sediments were deposited along the northern margin of the Gulf of Mexico in a major fluvio-deltaic depocenter, which accumulated in the Houston Embayment (Figures AoR-25). The Houston Delta formed multiple lobes, which were fed by numerous smaller fluvial tributaries. These multiple deltaic lobes coalesced to produce a broad expanse of sediment across the continental shelf and onto the continental margin (Seni, 1997). The Oligocene and all younger sequences thin rapidly as they approach their outcrop towards the north (Galloway, 2008).

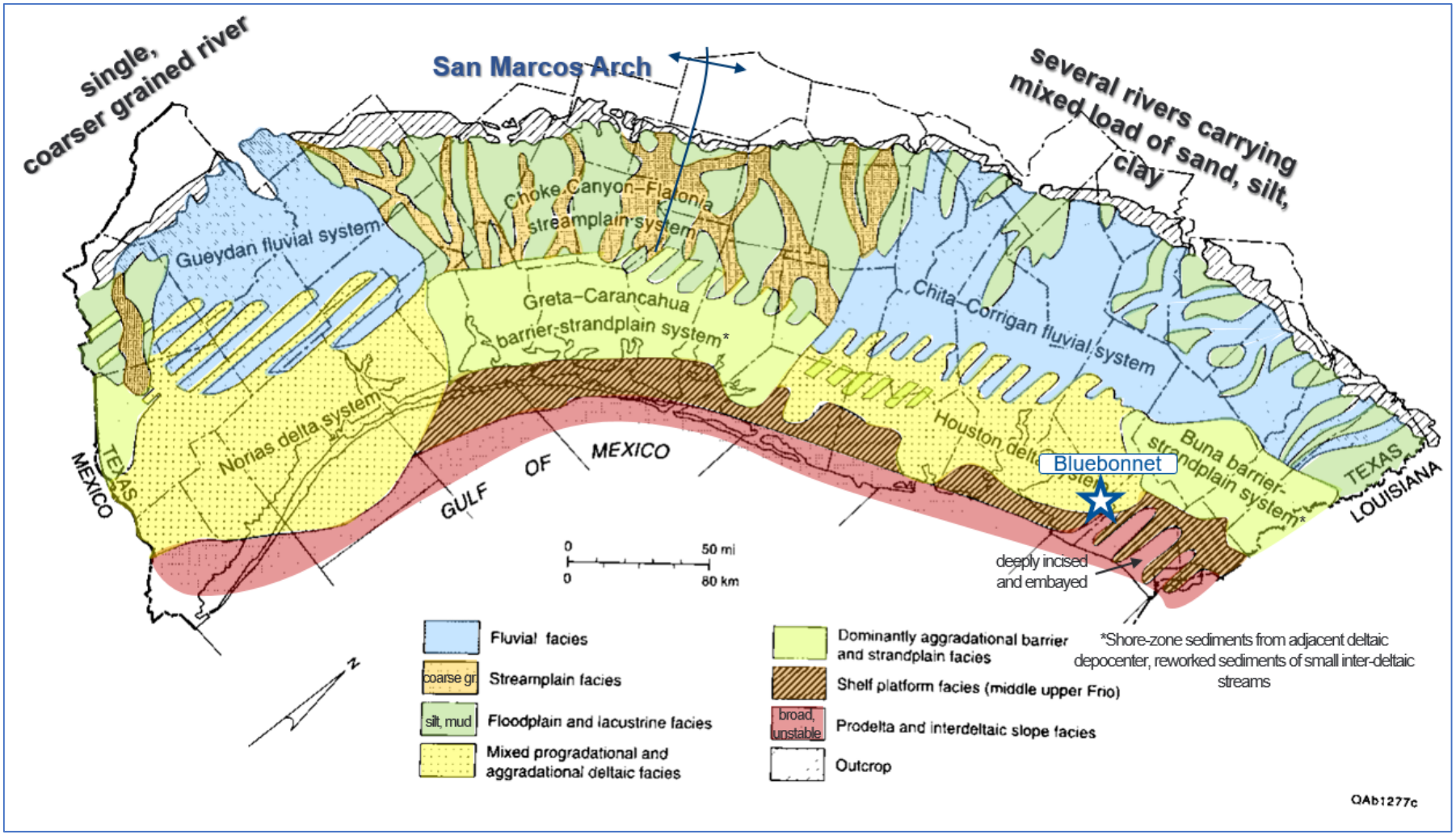


Figure AoR-26: Oligocene-aged Frio depositional system along the northern Gulf Coast. The Bluebonnet Sequestration Hub is in mixed progradational and aggradational deltaic facies (modified after Seni, 1997).

Depositional styles of the Oligocene are classified in retrogradational (shelf facies), progradational (distal deltaic facies), and aggradational (proximal deltaic and fluvial facies) based on well log responses Figure AoR-26 (Seni,1997). At the Bluebonnet Sequestration Hub, the Frio Formation consists of a terminal distributary channel, an interdistributary bay, and a proximal delta front. A schematic representation of the depositional setting for the Frio Formation is shown in Figure AoR-27.

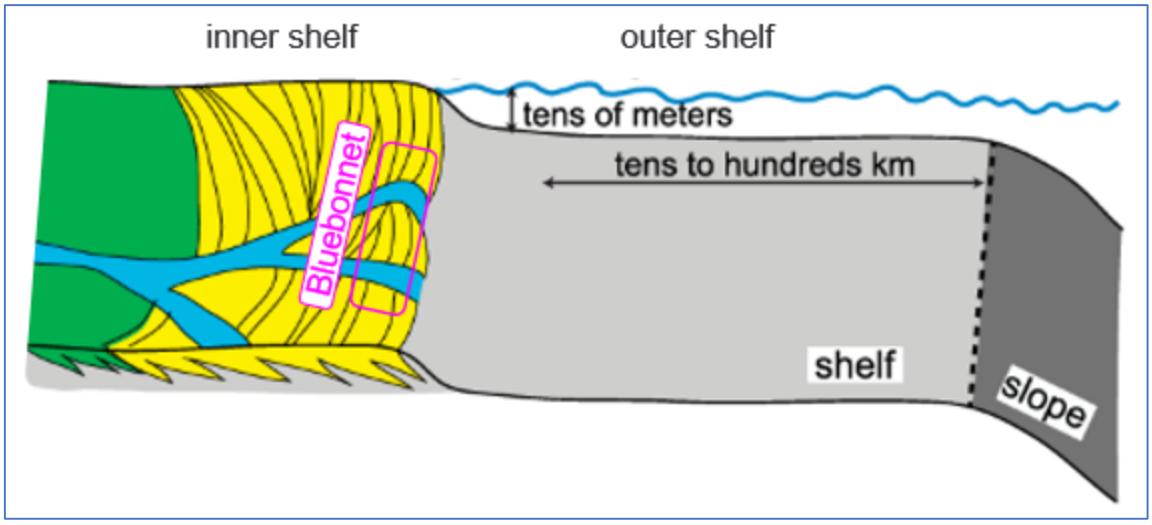


Figure AoR-27: Oligocene-aged Frio delta along the northern Gulf Coast showing a deltaic progradation across a stable shelf. The delta on the inner shelf is dominated by fluvial rivers (blue) discharging sediments (yellow) towards a coast where wave processes dominate the deltaic progradation into deeper water of the outer shelf (modified after Olariu, 2015).

Both facies are overlain by successions of transgressive or back-stepping coastal and marine shelf-facies (Galloway, 2008). Galloway defined multiple maximum flooding surfaces based on these patterns of transgressions related to glacioeustatic sea-level rise events. The overlying Anahuac Shale – a regionally extensive marine transgressive shale – was deposited because of such a eustatic rise in sea level.

In this proposed storage complex, the Anahuac Formation constitutes the primary confining layer for the injected CO_2. This is an excellent stratigraphic marker and many cuttings and whole core were acquired in the stratigraphic test well Encanto 01. This late Oligocene Anahuac shale represents a major marine transgression over the Gulf of Mexico shelf. The transgression occurred during a period of climate warming, which also explains the presence of carbonate building organisms in the Het Lime (see 3.6 Stratigraphy of the Storage Complex).

Upon the Anahuac transgression, an extended phase of high sedimentation rates and building the continental margin followed (Galloway, 2008). The Lower Miocene of the northwestern Gulf of Mexico Basin evolved from a Paleogene (Paleocene–Oligocene) pattern of sediment supply dominated by northwestern fluvial systems to a Neogene (Miocene–Pliocene) pattern dominated by fluvial systems entering the basin from the north. (BEG, 2017). In eastern Texas, where the

Bluebonnet site is located, there was an important sediment input represented by the Newton fluvial system (paleo Red River) and Calcasieu delta system (Figure AoR-28). Within the Lower Miocene, there are multiple stacking patterns of depositional styles, a result of many temporary transgressions in an overall regressive environment (USGS, 1996). Sands of the Newton fluvial system are fine to medium grained and present themselves with blocky and/or fining-upward log signatures. Outcrop features and detailed sand-body geometry indicate meandering channel patterns, which can also be mapped on seismic in various azimuths. Meanderbelt, storm washover, and crevasse splay deposits constitute the sandstone facies of this mixed load fluvial system. Basinward, the system may become increasingly suspended-load dominated (Galloway et al. 1986). The Newton/Red River fluvial system supplied the Calcasieu delta, which extended beneath the Texas coastal plain and adjacent offshore area (Figure AoR-29).

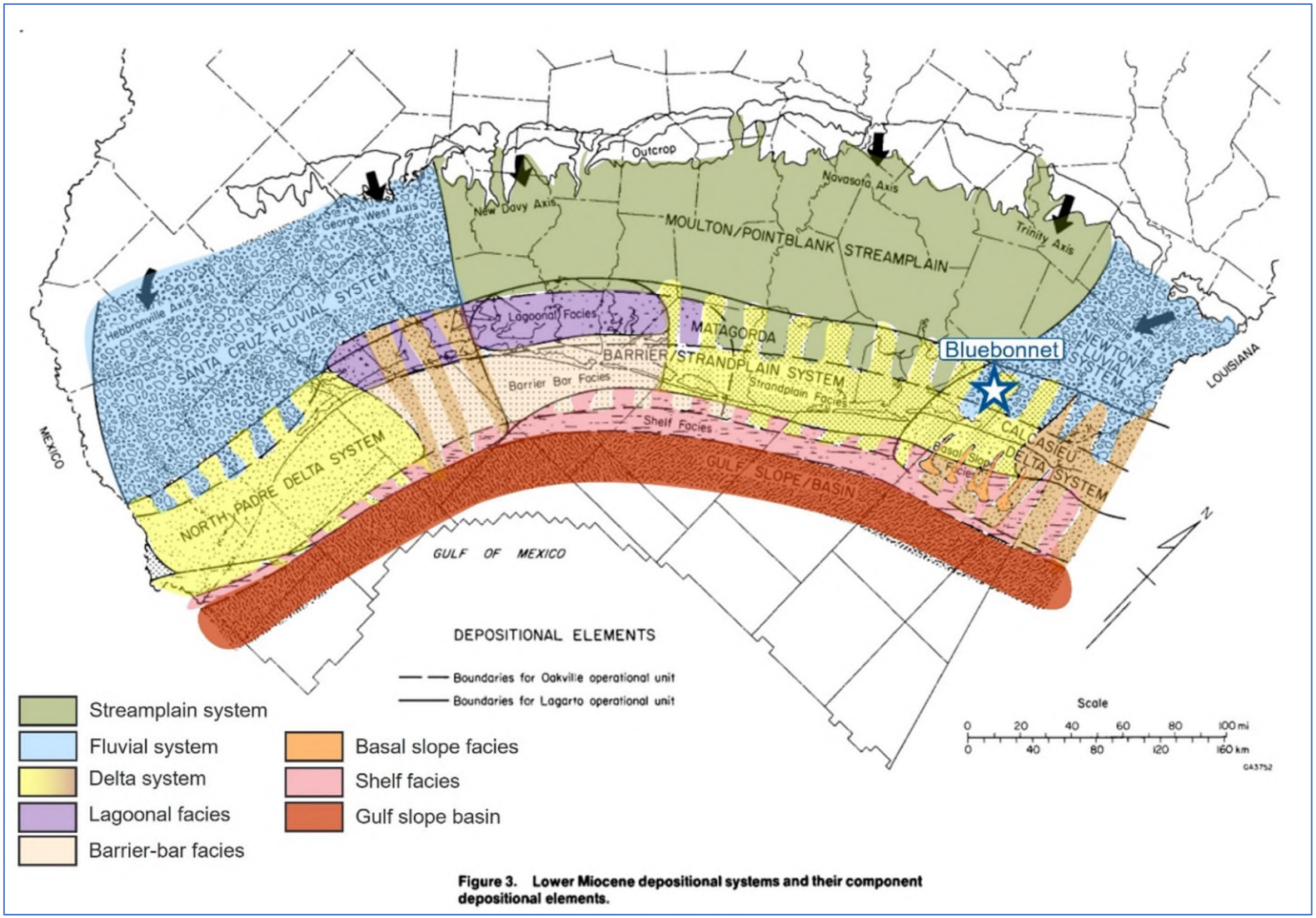


Figure AoR-28: Lower Miocene depositional system along the northern Gulf Coast (modified after Galloway, 1985).

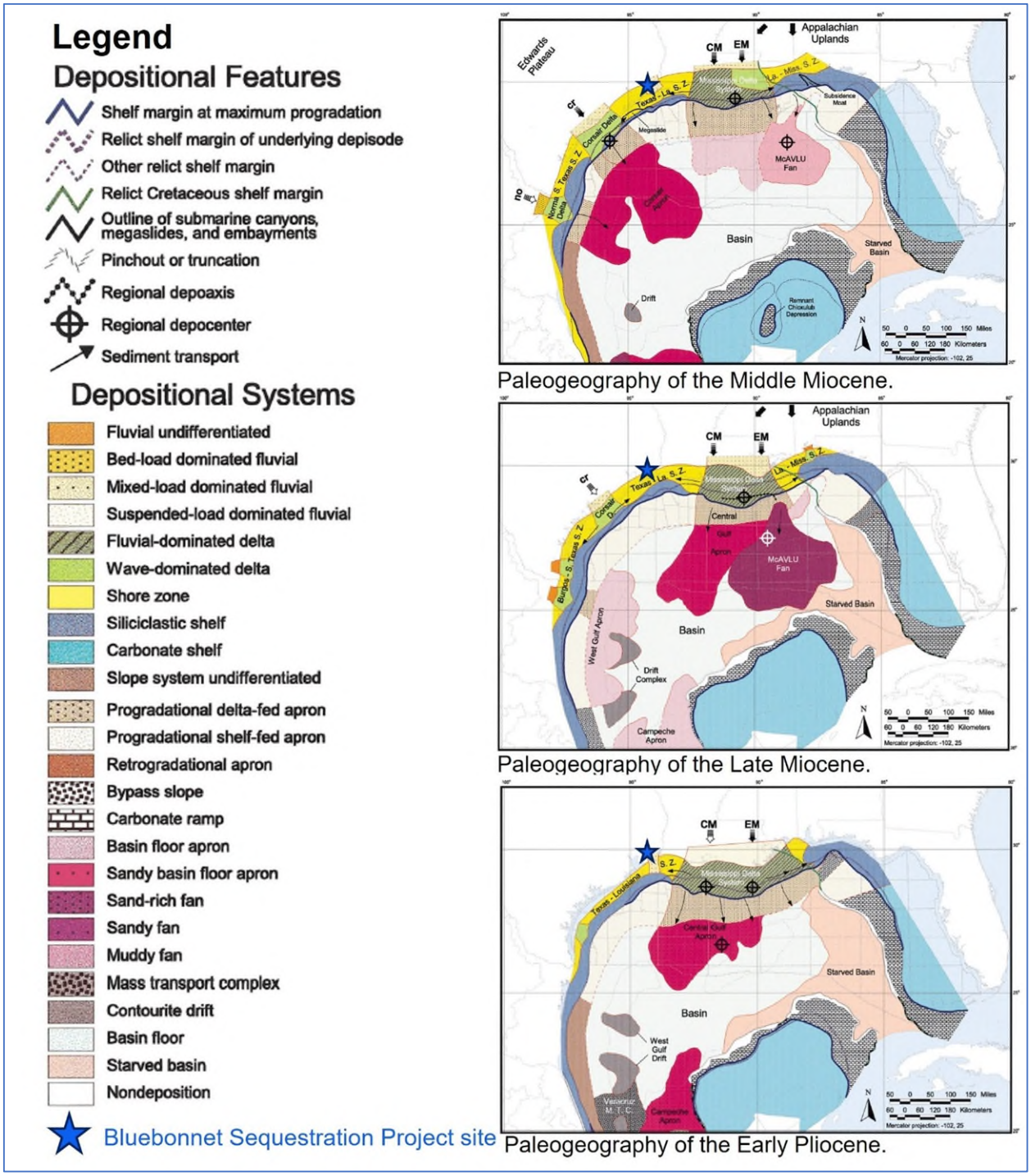


Figure AoR-29: Paleogeographic reconstruction of the Gulf of Mexico Basin from Middle through Late Miocene and Pliocene, after Galloway et al., 2000. The blue star identifies the location of the Bluebonnet Sequestration Project site on a shore zone with mixed-load dominated fluvial input across a coastal plain.

The depositional environment interpretation is based on whole cores from the stratigraphic test well Encanto 01, taken at 5415’-5445’ and 4370’-4430’. The lower cored section is part of the LMIO_INJ_5 injection zone, and it is interpreted as a stacking of fluvial channels mostly composed of cross-bedded fine-grained sandstones with some mud clasts and soft-sediment deformation (Figure AoR-30). The upper cored section is part of the Lower Miocene Confining Zone. It comprises a section of reddish calcareous mudstones, mostly mottled, with some rooting and bioturbation (Figure AoR-31). Some layers of silty sandstones with some bioturbation, climbing ripples, soft-sediment deformation, and occasional mud clasts are interbedded with the mudrocks. This upper section was deposited within a coastal plain/floodplain setting, with some paleosols involved. The sandy levels probably correspond to channel margin, storm washover, or crevasse splay deposits where the soft-sediment deformed sandstones might imply sediment instability at the channel margin The climbing ripples indicate rapid deposition from suspension and can be associated with in crevasse splays and channel levees.





To reconstruct the depositional history of the basin, many types of data sets from the stratigraphic well Encanto 01 well were integrated (cores, biostratigraphy, image logs, etc.). The observations from this well were combined with log data from approximately 149 wells and a 3D reprocessed seismic survey. Extensive well-log correlation, RMS amplitude, and spectral decomposition seismic attributes, as well as paleoenvironments from biostratigraphy, were integrated to understand the spatial evolution of the depositional environments within the Bluebonnet basin. From bottom to top, the depositional history can be summarized in Figure AoR-32 to Figure AoR-37, and described as follow.

Above the transgressive Anahuac interval, delta progradation resumed in the Bluebonnet area with delta front facies mostly towards the south of the Bluebonnet basin (i.e., LMIO_INJ2 zone, Figure AoR-32). Moving up in the section (i.e., LMIO_INJ6 zone), the southern portion of the basin was still dominated by delta-front facies, but channel facies prevailed in the north (Figure AoR-33). A mud-filled channel is identified within the LMIO_INJ6 zone, which might represent a flow barrier between sandstones in the north and south (see Figure AoR-33). This mud-filled channel is better observed within unit LMIO_INJ3 (Figure AoR-34). Up in the Miocene section, and within the LMIO_INJ5 zone, two clear meandering channel systems entered the Bluebonnet basin from the

NW and NE (see Figure AoR-35). The core in Encanto 01 well confirms that these meandering channels are fluvial in origin.




Claimed as PBI


Claimed as PBI



The confining (for dissipation) zones for the Miocene storage section (L_MIO_A, L_MIO_B, and L_MIO_C) are not completely muddy, but contain thick mudstone intervals that are continuous across the Bluebonnet area (i.e., Figure AoR-36). According to the biostratigraphy from Encanto 01 well, these muddy intervals are not fully marine, but correspond to transitional and nonmarine mudstones and should have enough sealing capacity to prevent or retard the vertical movement of CO_2. Interbedded with these thick mudstone intervals, there are sandy intervals of variable thickness and continuity that are interpreted as likely channels and crevasse splays or storm washover deposits. Figure AoR-37 shows a cross-section with a proposed reconstruction of the depositional environments in a transect through the Encanto 01 well.


Claimed as PBI

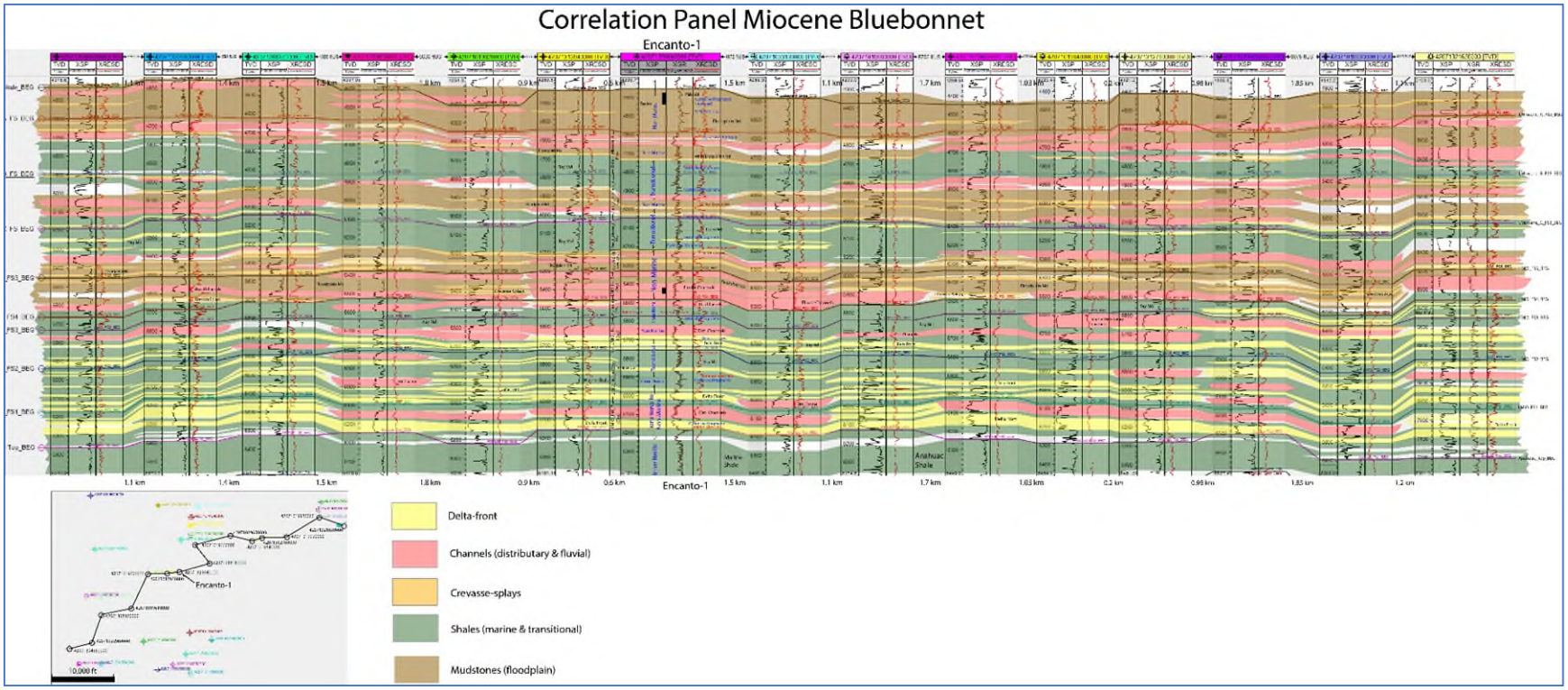


Figure AoR-37: Correlation panel Miocene section in Bluebonnet area. Interpretation of depositional environments based on cores and biostratigraphy from Encanto 01 well, and well data from neighboring wells. Depositional environments from well data also confirm interpretation from seismic facies.

During the Middle and Late Miocene through **Pliocene** (Figure AoR-29), the depositional axes of the rivers shifted towards the east, resulting in a change of depositional system from fluvial-deltaic to coastal plain to shore-zone (BEG, 2017). In these shore-zone systems, the sediment was transported along strike between the adjacent deltas to the east and west. Within the Bluebonnet Sequestration Project site, mixed-load dominated fluvial sediment supply across a coastal plain persisted.

3.8 Characterization of Injection and Confining Zones

The proposed AoR was selected in a location where the average reservoir and confining zone properties meet the criteria needed for permanent CO_2 storage and protection of the USDW(s). All zones were characterized by interpreting well log data and reservoir property maps derived from the geomodel, which also includes the structural interpretation based on seismic.

3.8.1 AoR Injection Zone Characteristics

This section describes in detail the information related to the proposed injection targets, Lower Miocene, Frio, and Hackberry sandstones. It describes depths, areal extents, thicknesses, mineralogy, porosity, permeability, and capillary pressure of the injection zones, including geology changes and facies based on geological cores, well logs, names, and lithology description according to 40 CFR § 1476.82 (3)(iii).

The following set of four cross sections consists of a structural dip cross section (Figure AoR-38), stratigraphic dip cross section (Figure AoR-39), structural strike cross section (Figure AoR-40), and stratigraphic strike cross section (Figure AoR-41). Those are presented over the proposed storage complex and include the strata from the Hackberry Confining Zone at the base through the Lower Miocene Confining Zone at the top. These structural cross sections indicate where the strata are downdip and where the strata are updip, indicating potential flow direction based on buoyancy forces of the injected supercritical CO_2 towards an updip direction. The accompanying stratigraphic cross sections indicate reservoir continuity, lateral facies changes based on log signatures, and thickness trends. Specific trends that can be observed on these cross sections are described in the following paragraphs by zone.

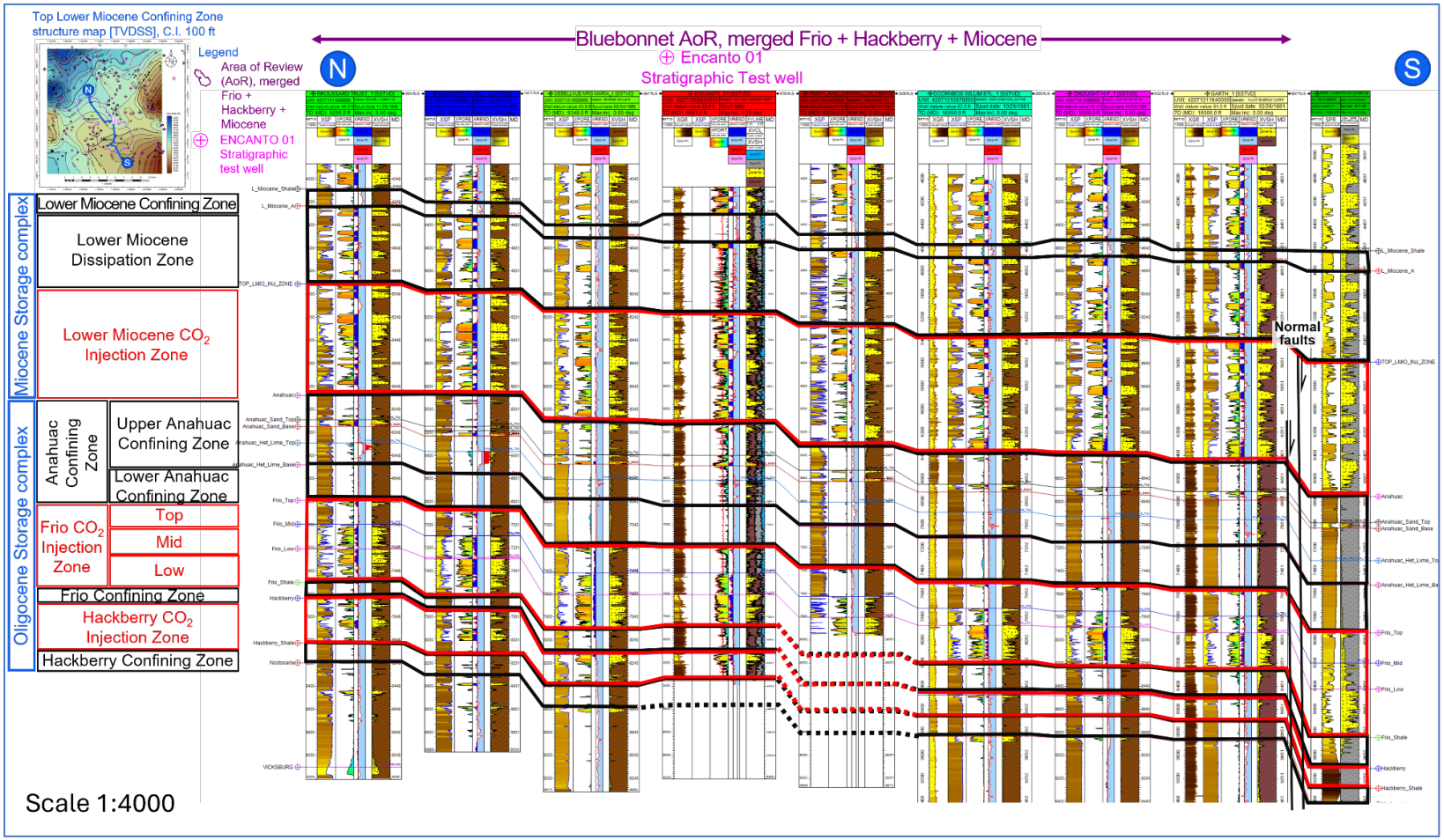


Figure AoR-38: Structural dip cross section, north-south through the AoR, scale 1:4000. Tracks shown are GR, SP, Porosity, Resistivity and VShale. The Hackberry, Frio, and Lower Miocene Injection Zones, as well as the Hackberry, Frio, Anahuac and Lower Miocene Confining Zones are laterally continuous along the structural dip within the AoR. The Hackberry Injection Zone shales out towards the south and downdip and is better developed towards the northern part of the AoR. The porosity over the Mid Frio and the Hackberry Injection Zones increases toward the northern part, which is also reflected in the net sand thickness increase towards the north. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

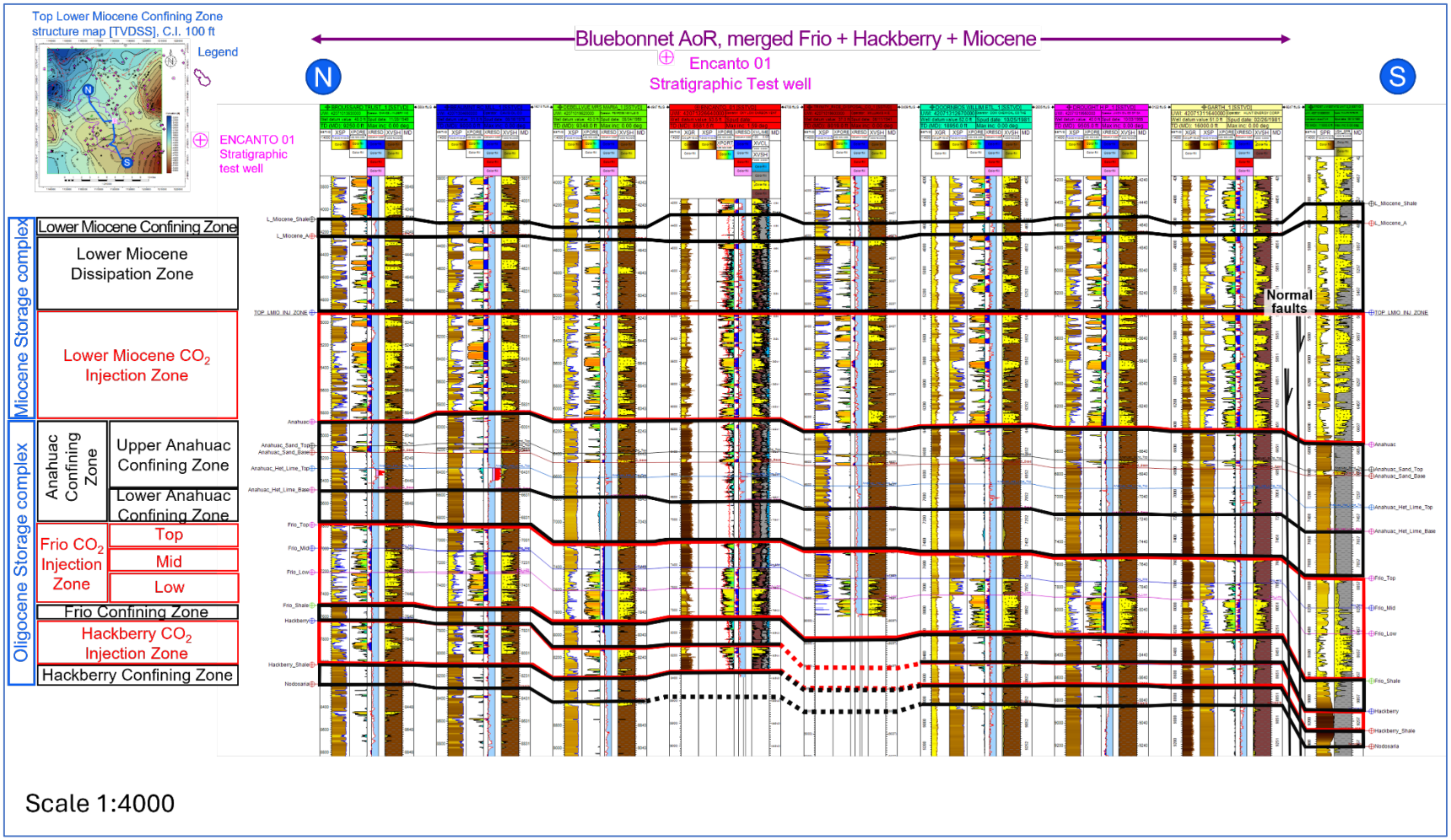


Figure AoR-39: Stratigraphic dip cross section, north-south through the AoR, scale 1:4000. The datum on which this cross section is hung on on the Top Lower Miocene Injection Zone. Tracks shown are GR, SP, Porosity, Resistivity and VShale. The Hackberry, Frio, Anahuac, and Lower Miocene Confining Zones are laterally continuous within the AoR. The Hackberry and Frio log signatures are correlative among the offset wells, which indicates preferred connectivity of reservoir properties in a dip direction and might influence plume migration pathways together with structural formation dip. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

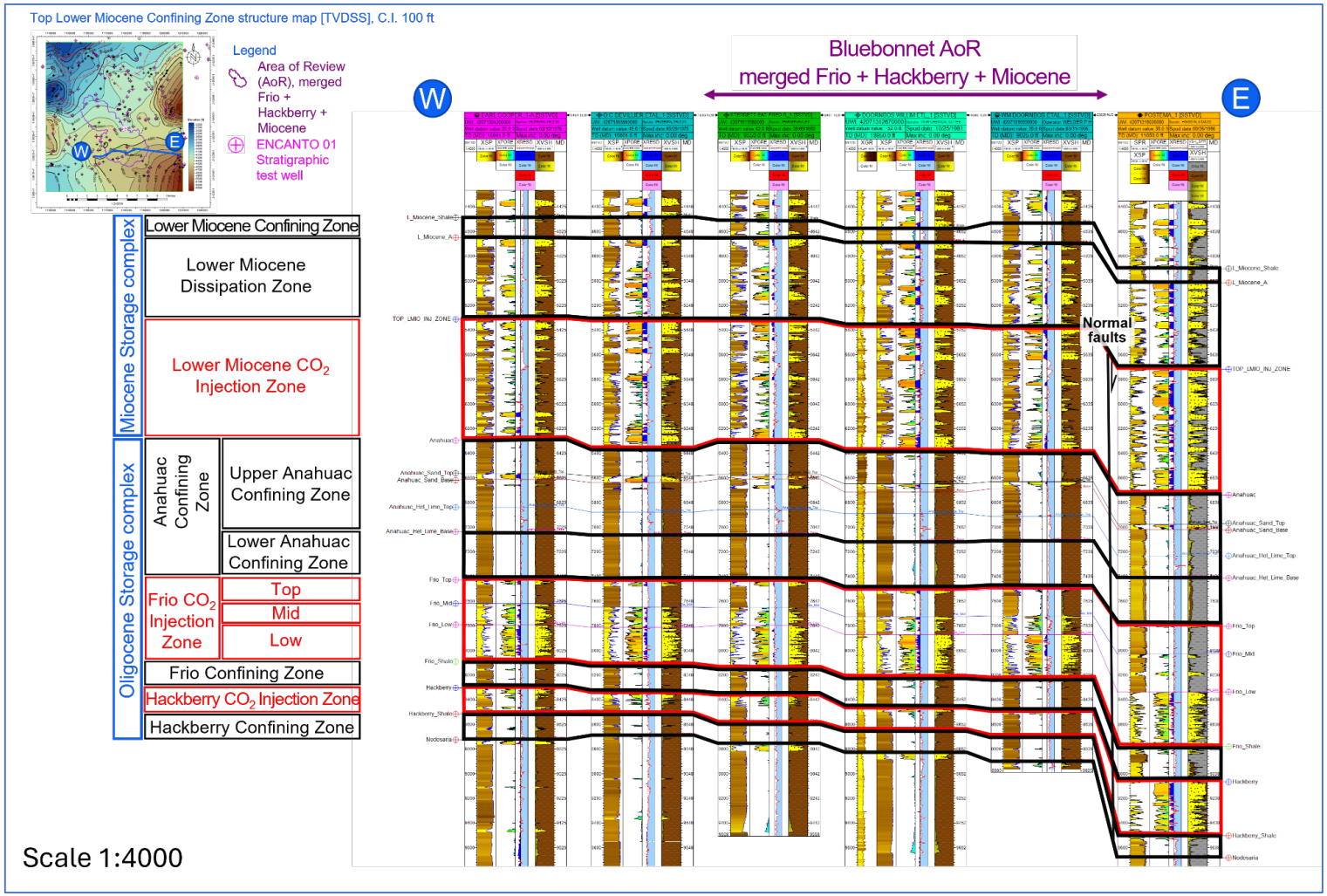


Figure AoR-40: Structural strike cross section, west-east through the southern AoR, scale 1:4000. Tracks shown are GR, SP, Porosity, Resistivity and VShale. The Hackberry, Frio, Anahuac and Lower Miocene Confining Zones are laterally continuous along strike within the AoR. The west side of the AoR is slightly more updip than the east side. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

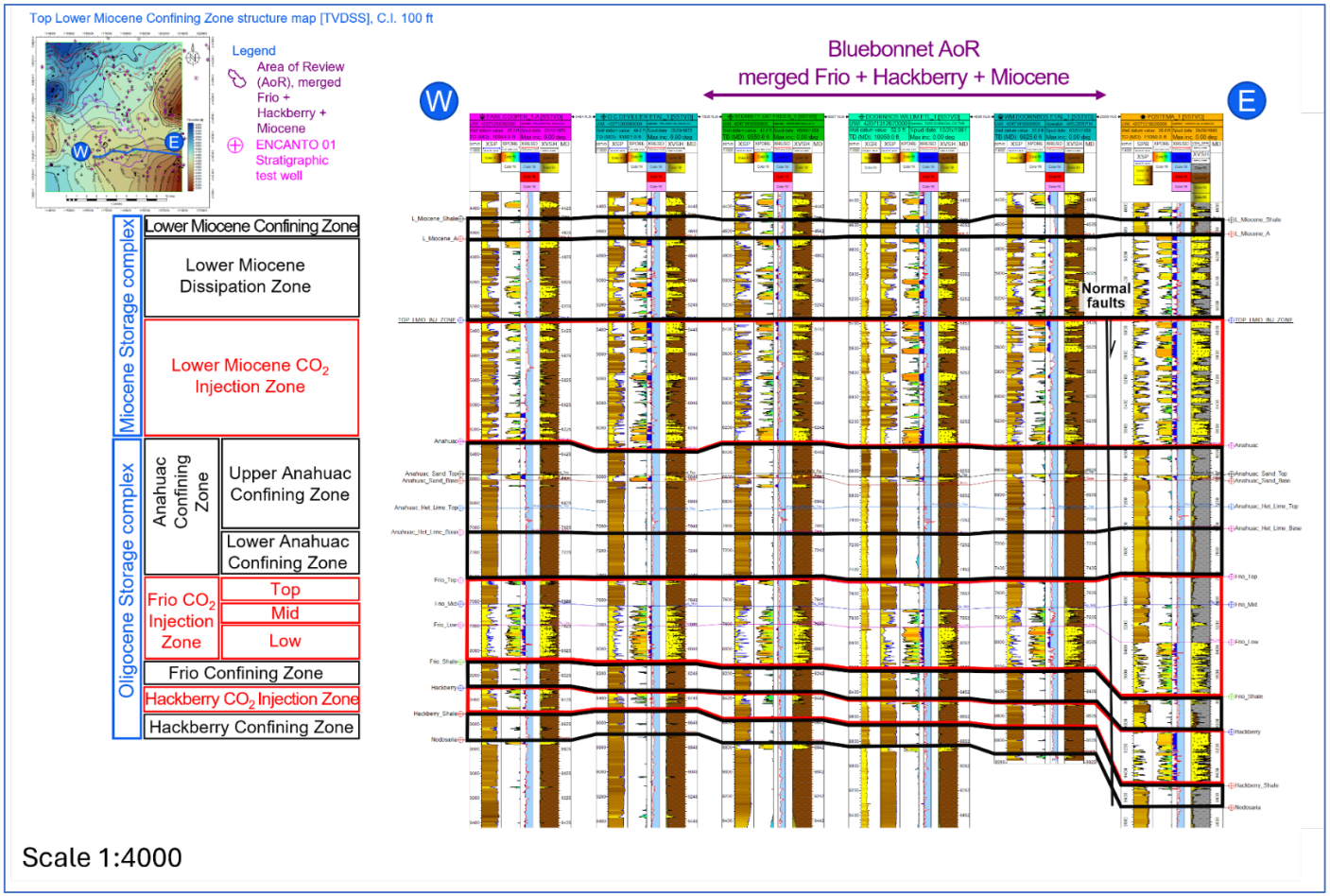


Figure AoR-41: Stratigraphic strike cross section, west-east through the southern AoR, scale 1:4000. The datum on which this cross section is hung on the Top Lower Miocene Injection Zone. Tracks shown are GR, SP, Porosity, Resistivity, and VShale. The Hackberry, Frio, Anahuac and Lower Miocene Confining Zones are laterally continuous within the AoR. The Hackberry Injection Zone sand thickness increases towards the west and decreases towards the east (in addition to the thickening towards the north and shaling out towards the south), which is also displayed in the net sand thickness map. The Top, Mid, and Low Frio are correlative in a strike direction as well. In the Low Frio lateral facies changes on a local well-to-well scale can be observed. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

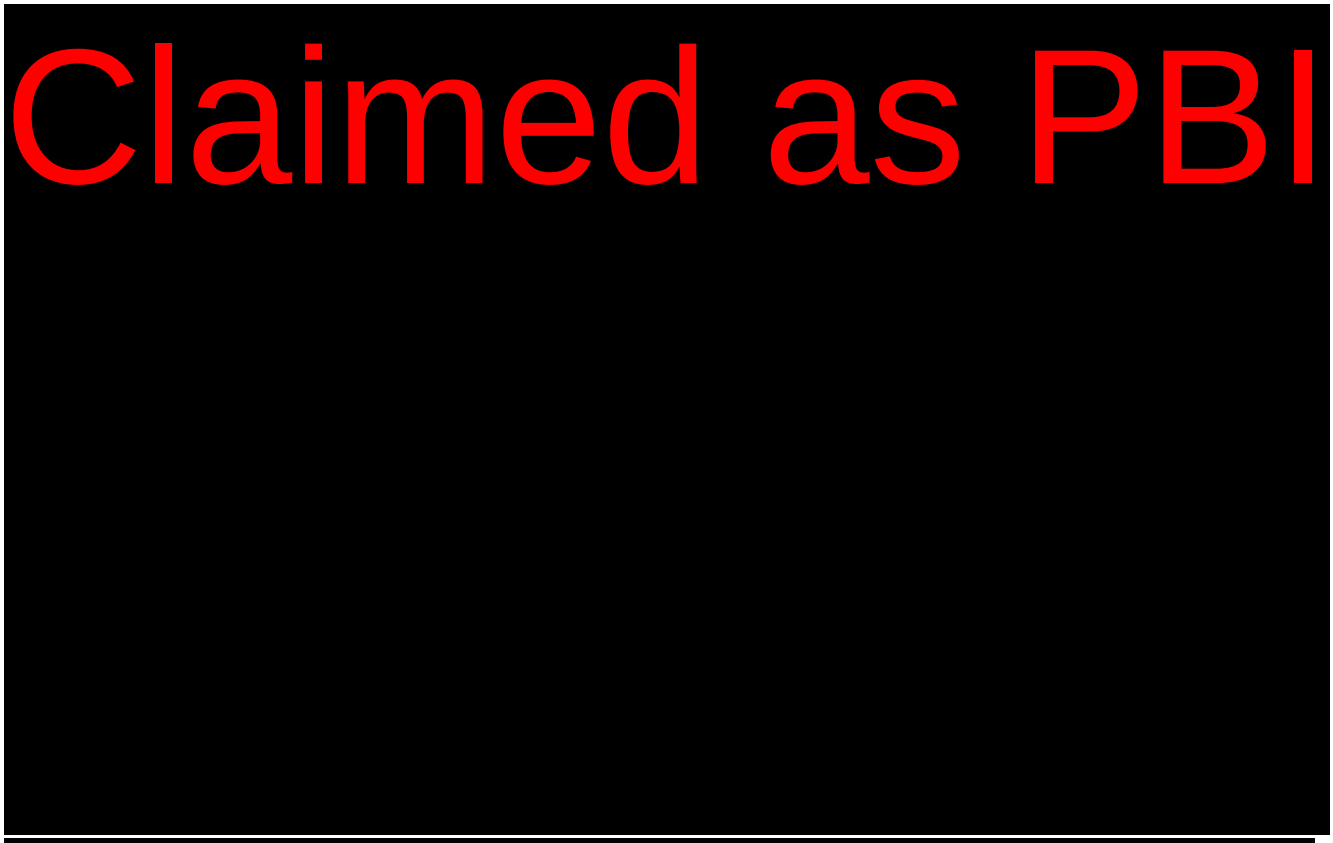
3.8.1.1 Hackberry Injection Zone

The Hackberry sandstones at the Bluebonnet Sequestration Project site were likely deposited in a proximal delta front and are better developed in the northern updip part of the acreage and thin toward the south and downdip. The net sand thickness of the Hackberry Injection Zone is 52 ft and only drill cuttings from the stratigraphic test well Encanto 01 exist in this zone along with the log data. The Hackberry Injection Zone shales out towards the south and downdip (i.e., is thinner), and is better developed towards the north and updip (i.e., is thicker), which is why the average net sand thickness is somewhat misleading.

The Hackberry Injection Zone is laterally continuous in a north-south dip and east-west strike direction within and beyond the AoR (Figure AoR-38 through Figure AoR-41). However, along the stratigraphic west-east strike cross section (Figure AoR-41), the Hackberry Injection Zone sand thickness increases towards the west and decreases towards the east (in addition to the thickening towards the north and shaling out towards the south), which is also displayed in the net sand thickness map (Figure AoR-46). Further to the east, approximately 3 miles beyond the AoR, the Hackberry was likely deposited in a different environment or affected by faulting.

3.8.1.1.1 Petrologic description

Petrological characterization of the Hackberry thin sections made from cuttings indicate that the sands are typically unconsolidated quartz-rich sands dominated by quartz, minor K-feldspar, and plagioclase grains, along with a few volcanic rock fragments, chert, and minor coarse siltstone. Additionally, minor argillaceous rock fragments are noted. Typically, a few quartz grains also have Böhm lamellae indicating tectonized quartz. Additionally, a quartz with inherited quartz overgrowths can be observed. The pores are well connected.


Claimed as PBI


Claimed as PBI

3.8.1.1.2 Hackberry Injection Zone maps

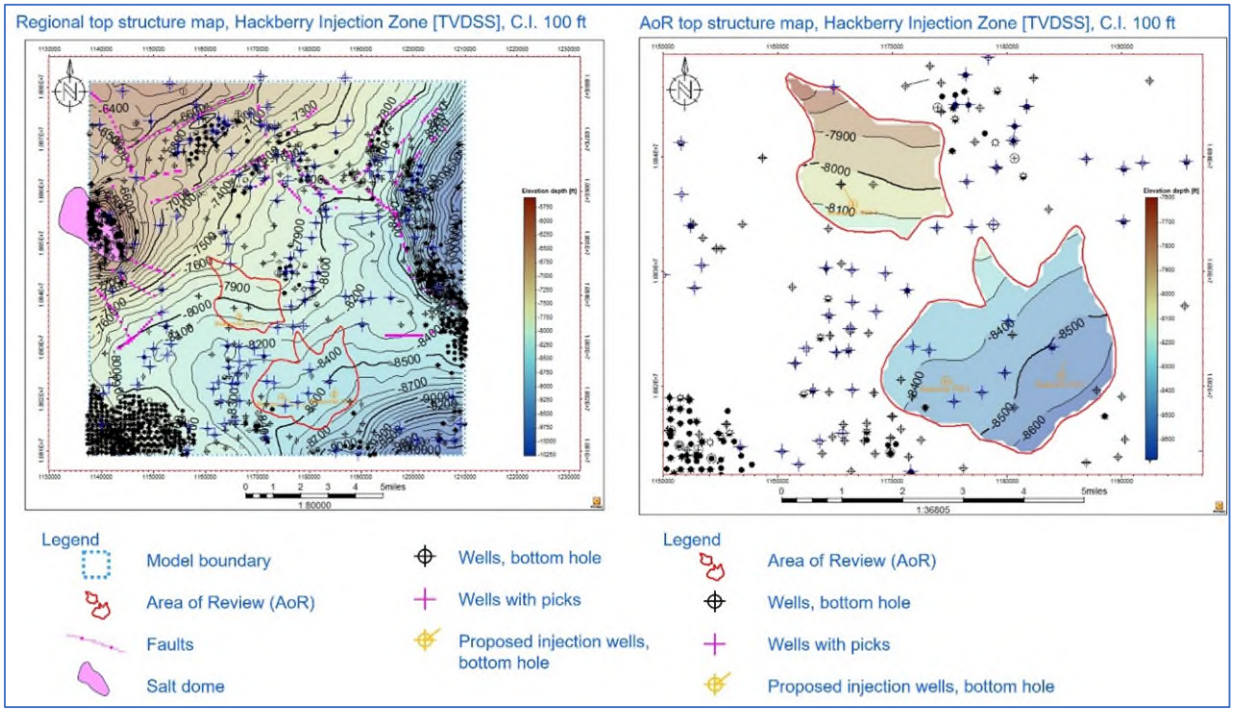


Figure AoR-44: Regional and AoR top structure map of the Hackberry Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

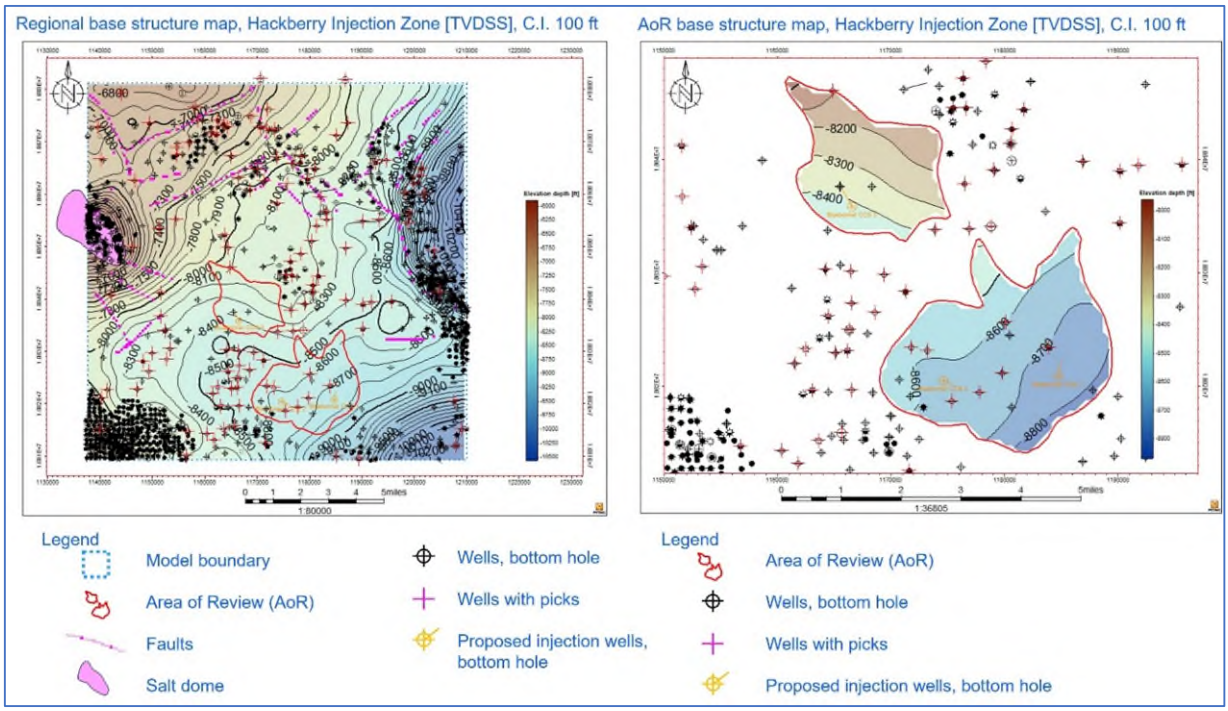


Figure AoR-45: Regional and AoR base structure map of the Hackberry Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

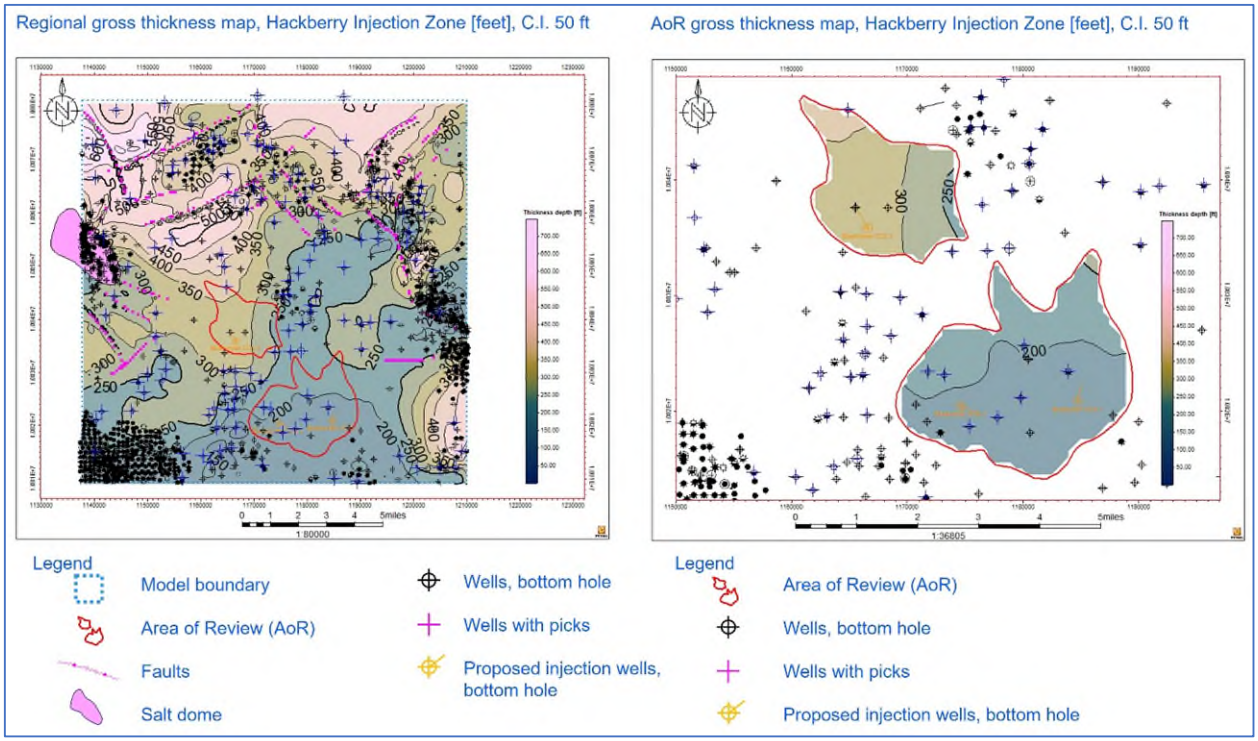


Figure AoR-46: Regional and AoR gross thickness map of the Hackberry Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

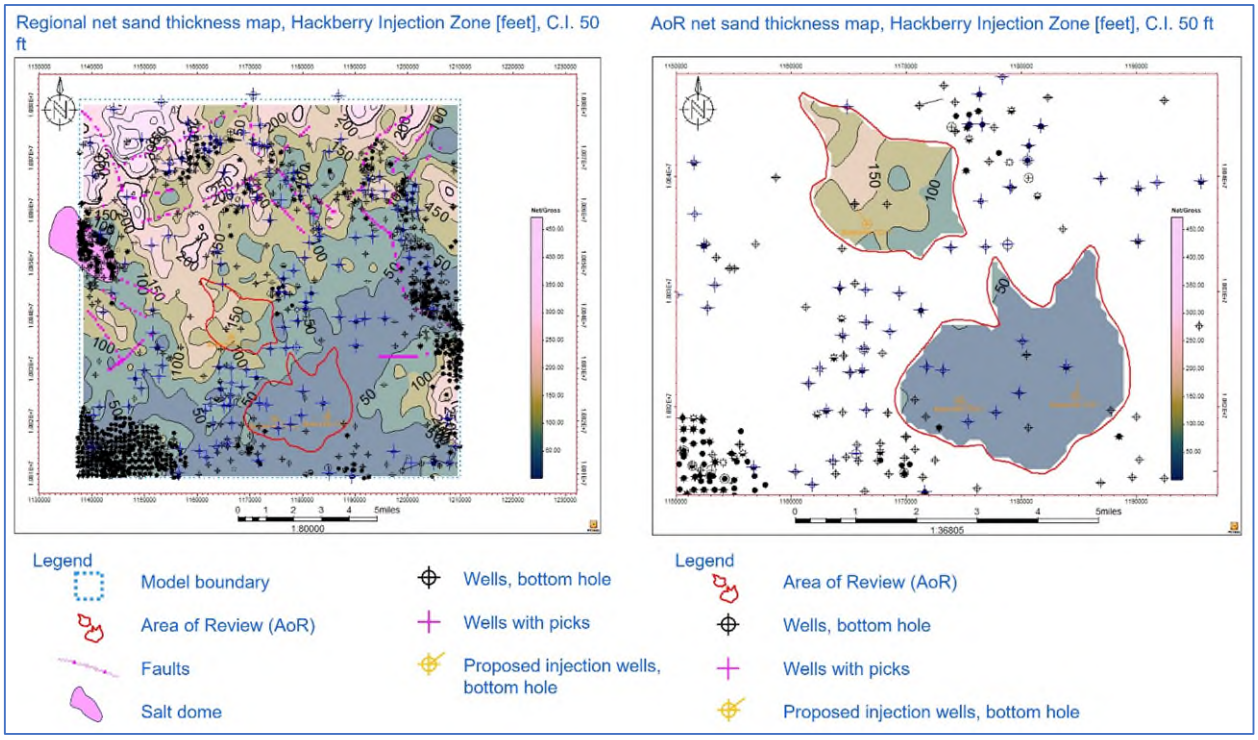


Figure AoR-47: Regional and AoR net sand thickness map of the Hackberry Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

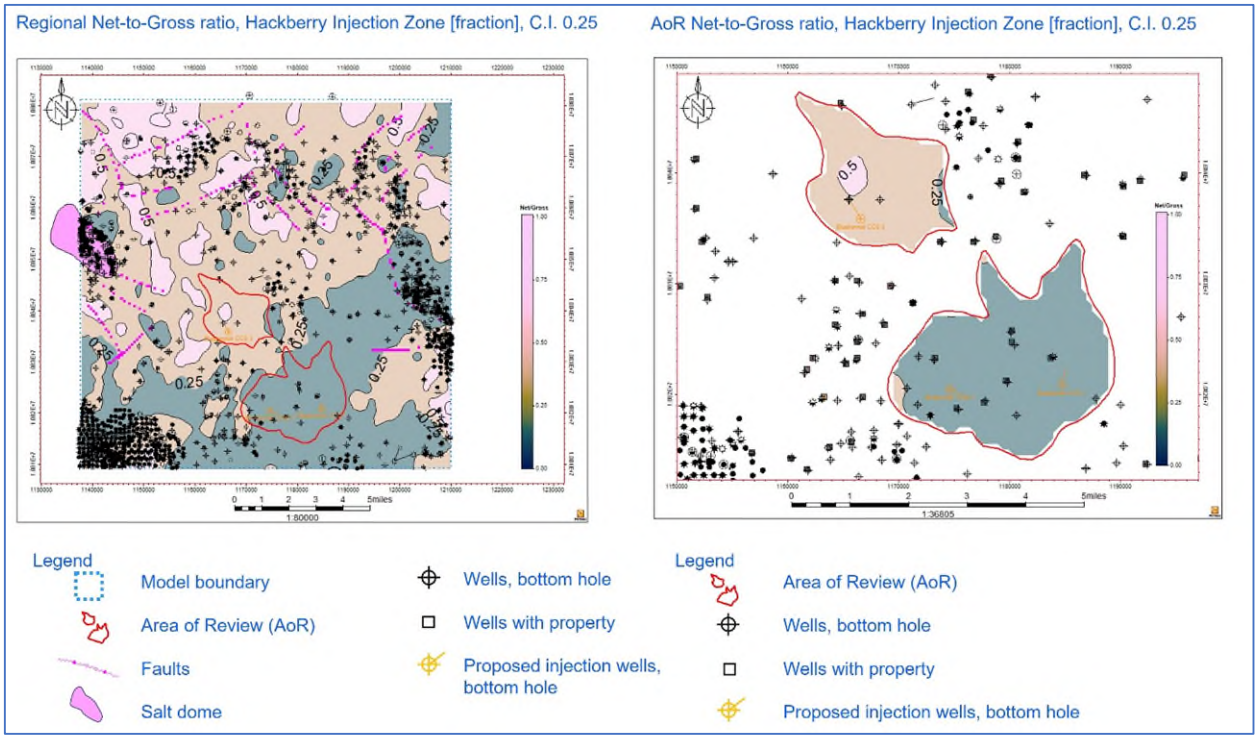


Figure AoR-48: Regional and AoR Net-to-Gross (NTG) ratio map of the Hackberry Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

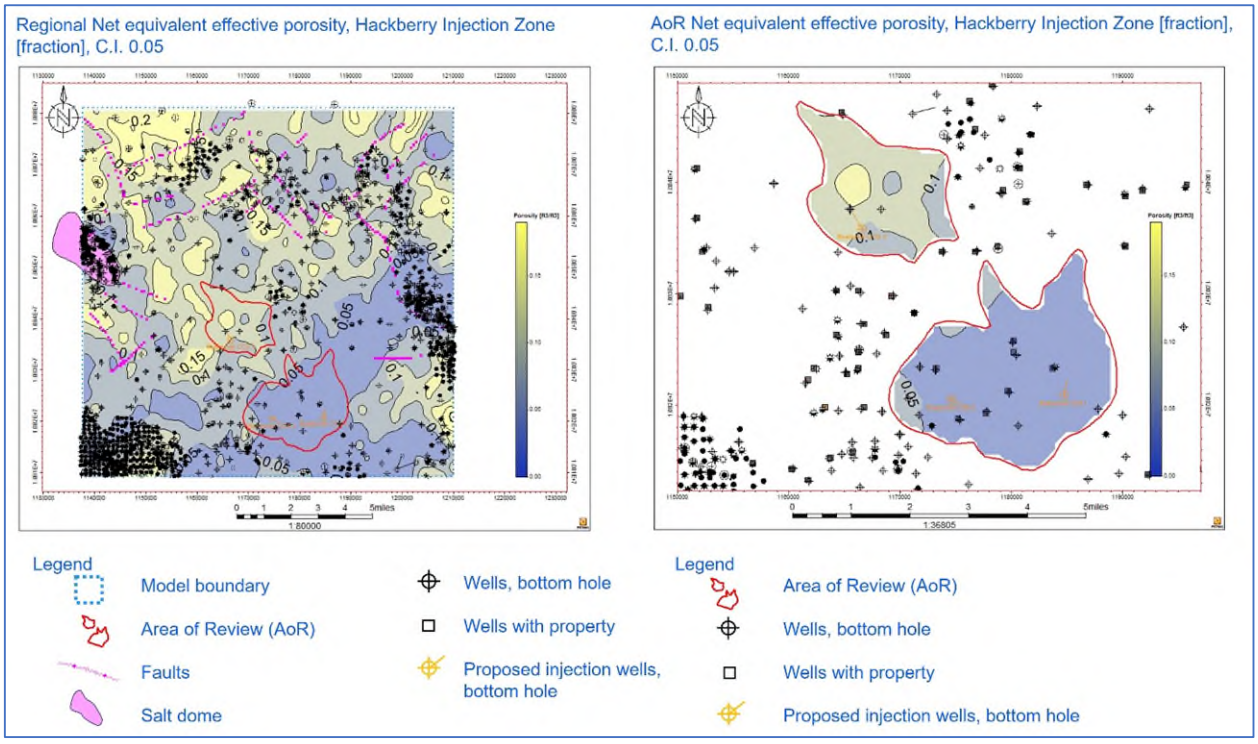


Figure AoR-49: Regional and AoR net equivalent effective porosity map of the Hackberry Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

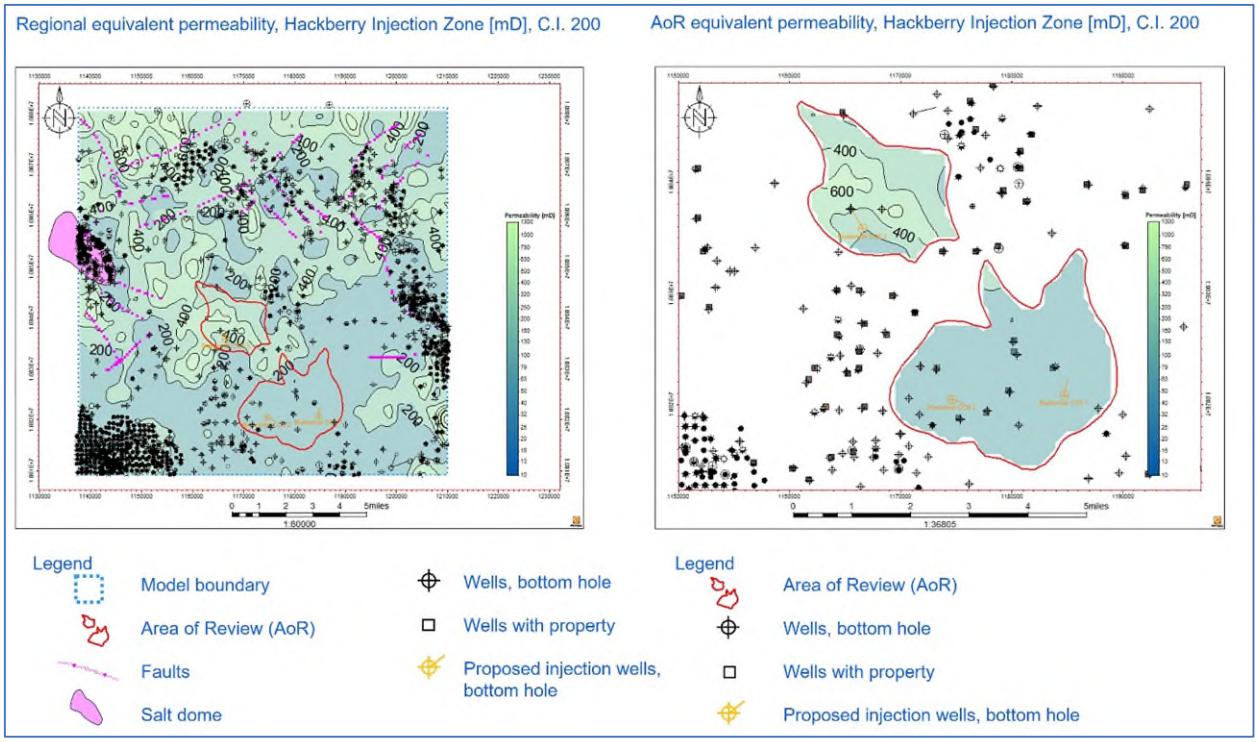


Figure AoR-50: Regional and AoR equivalent permeability map of the Hackberry Injection Zone in millidarcy (md), contour interval 200 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-1 represent map-based average numbers extracted from the geomodel over the AoR.

Table AoR-1: Reservoir properties for the Hackberry Injection Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Injection Zone
Top depth [TVDSS]	Claimed as PBI	
Base depth [TVDSS]		
Gross Thickness [ft]		

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Injection Zone
Net Sand Thickness [ft]	Claimed as PBI	
NtG Ratio [fraction]		
Porosity [fraction] EQI, net eff. porosity * NTG		
Permeability [md]		

Figures AoR-44 through Figure AoR-50 show the associated maps for each of the discussed formations.

3.8.1.2 Frio Injection Zone

The upper CO_2 injection zone within the Oligocene storage complex is the Frio formation as described in previous sections. The Frio formation is characterized by numerous trough cross beddings and minor carbonaceous plant debris.

The net sand thickness of the Frio Injection Zone is 284 ft. A 30-ft core in the Mid Frio was collected in the stratigraphic test well Encanto 01, which is reported under Appendix A, Coring and RSWC section.

As described under 3.7 Depositional Environment, the Frio sediments were deposited in the fluvial-dominated Houston Delta. Based on the log signatures, different depositional environments within that system can be interpreted. The Low Frio, with its coarsening upward trend (i.e., sandy at the top), has a deltaic character often found at terminal distributary channels. The Mid and Top Frio can be interpreted as variable, mixed-load fluvial deposits. Along the north-south stratigraphic dip cross section the Top, Mid, and Low Frio log signatures are correlative among the offset wells, which indicates preferred connectivity of reservoir properties in a dip direction and might influence plume migration pathways together with structural formation dip.

On an east-west strike cross section some wells are sandy at base of the Low Frio interval compared to other wells, which are sandier at the top of the Low Frio. This could be explained by deltaic lobe shifting, resulting in lateral facies changes on a local well-to-well scale. Altogether,

the Top, Mid, and Low Frio are correlative in a strike direction as well; however, small scale well-to-well lateral facies changes are expected, affecting the injectivity within the multiple stacked flow units of the Frio Injection Zone due to sedimentary distribution patterns, which are oriented perpendicular to the coastline.

The lithologic composition of the Frio Injection Zone is described below based on mud cuttings acquired during drilling operations of the stratigraphic test well Encanto 01 and mudlogs from two legacy wells nearby.

The Frio Injection Zone lithology shows 70 – 100 % milky white to clear transparent to light grey sand, frosted grains in places, very fine-to medium to coarse-grained sand, predominantly friable, loose and unconsolidated to moderately cemented quartz grains, poorly to moderately sorted sandstone, rounded to angular and subrounded elongated grains, silty argillaceous to slightly calcareous matrix in places, arkosic in places, light red chert in places, glauconitic slightly silty, and interbedded with 10 – 30%: soft to firm green-grey shaly interbeds. These clays are pyritic and contain feldspar shreds and earthy textures. Traces of white amorphous blocky soft limestone were also observed. No visible hydrocarbon cut, hydrocarbon, or mineral fluorescence were observed during mudlogging the Frio injection interval.

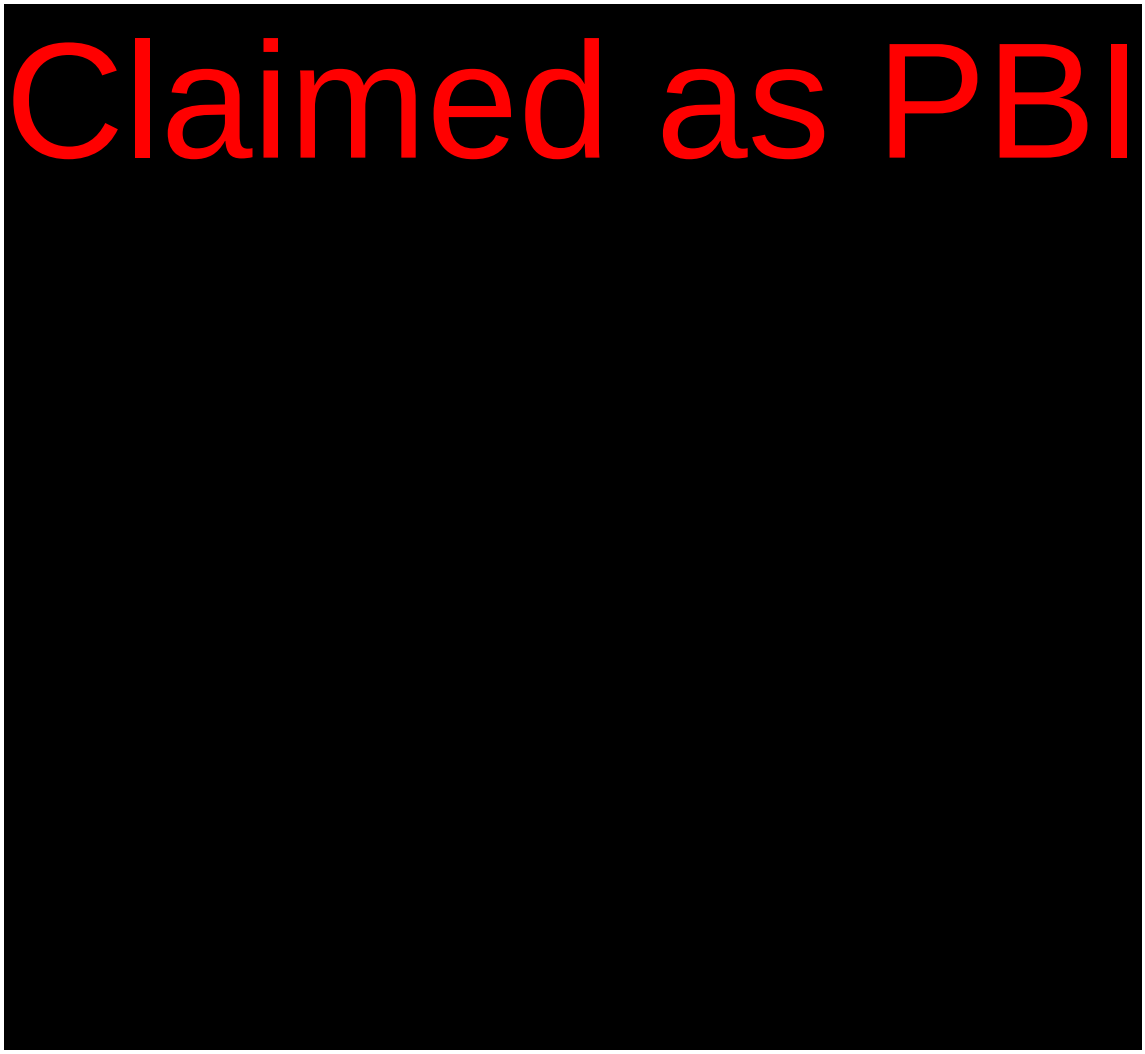
3.8.1.2.1 Petrologic Description

The Frio Injection Zone is characterized by quartz-rich sandstones. For the three subdivisions of Low, Mid, and Top, thin sections were made, characterized, and point counted to decipher the modal composition of the sandstone, diagenetic minerals, and any effects of diagenesis on reservoir quality. In addition, key framework grains were examined for provenance.

Generally, in the Low Frio, quartz grains are the most abundant mineral, followed by feldspar grains and plagioclase. Rock fragments are more abundant and are mostly volcanics containing mixtures of K-feldspar, plagioclase, and lesser quartz. Other grains are minor argillaceous rock fragments. Intergranular pores are commonly abundant and well interconnected. Some grains have authigenic titanium oxide and pyrite framboids attached.

The Mid Frio sands are commonly massive (structureless) with quartz grains, which are abundant, some of which are polycrystalline. Common K-feldspar and plagioclase grains are observed. Additionally, moderate volcanic rock fragments (vrf) are mostly rich in K-feldspar, but also contain variable amounts of plagioclase and sometimes quartz. Other rock fragments include chert, argillaceous, and plutonic varieties. Intergranular pores are abundant and well interconnected. Grain-coating authigenic minerals such as pyrite framboids, incipient K-feldspar and quartz overgrowths, and titanium oxide are rare. One of the selected sandstones had nodules of zeolite still with ample intergranular pores. SEM analysis indicated that the zeolite is sodium-rich analcime, which consists of hydrated sodium aluminum silicate in crystalline form $NaAlSi_2O_6 \cdot H_2O$ (Figure AoR-56 and Figure AoR-57). The sandstones are virtually unconsolidated.

The plot of sandstone compositional diagram for all the Frio and Miocene sandstones is shown below in Figure AoR-51, based on thin section 300-point count conventional analysis:




Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI

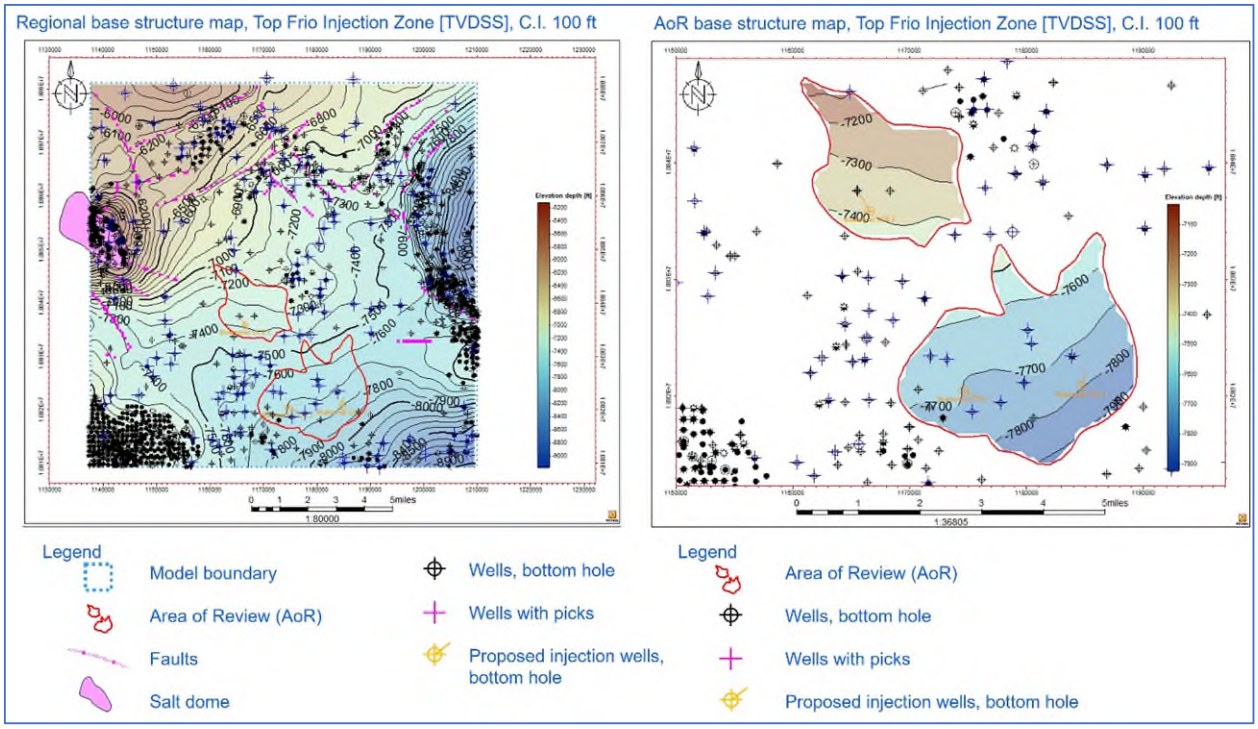


Figure AoR-60: Regional and AoR top base map of the Top Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

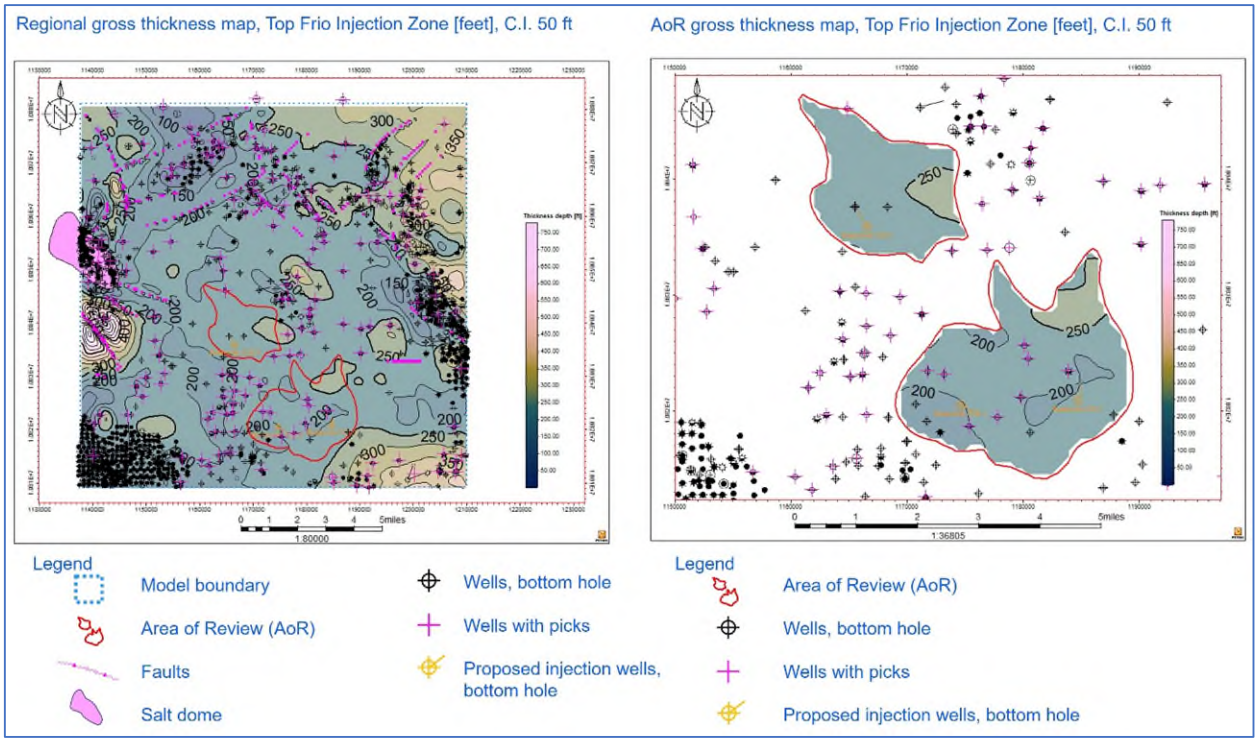


Figure AoR-61: Regional and AoR gross thickness map of the Top Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

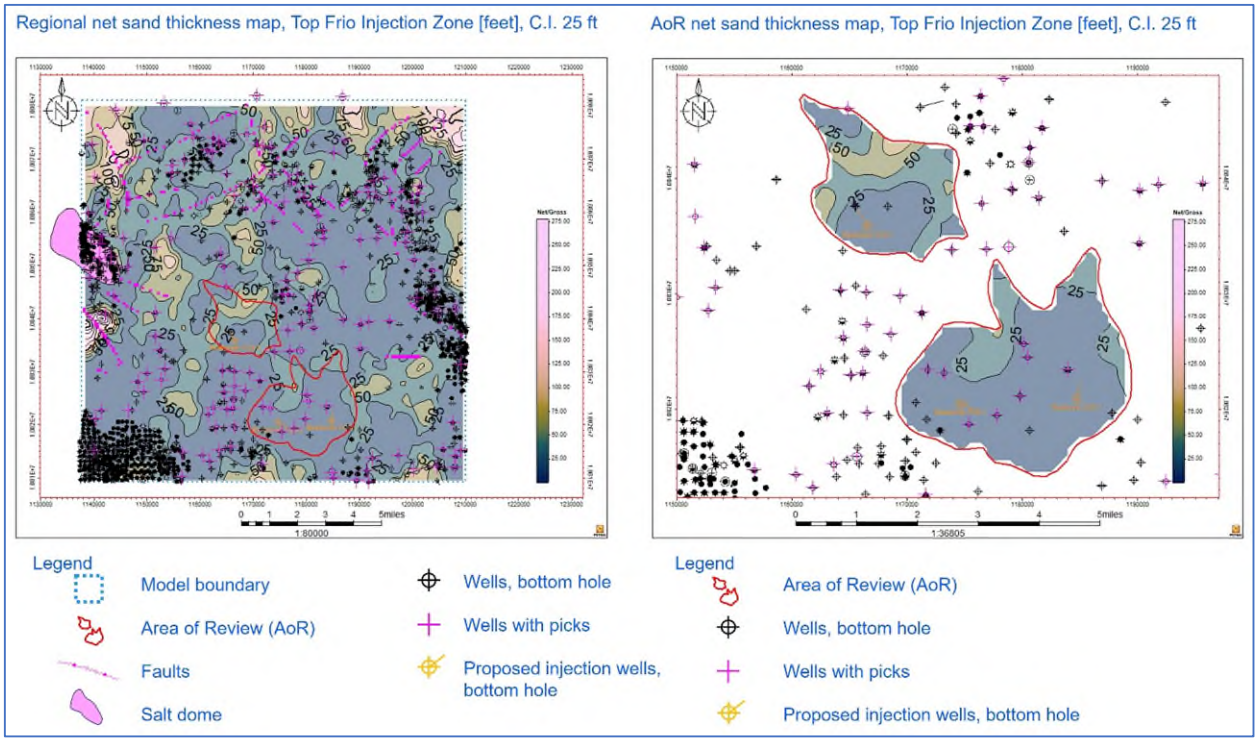


Figure AoR-62: Regional and AoR net thickness map of the Top Frio Injection Zone in feet, contour interval 25 ft. This map was generated from the Oligocene Model described under 4.0.

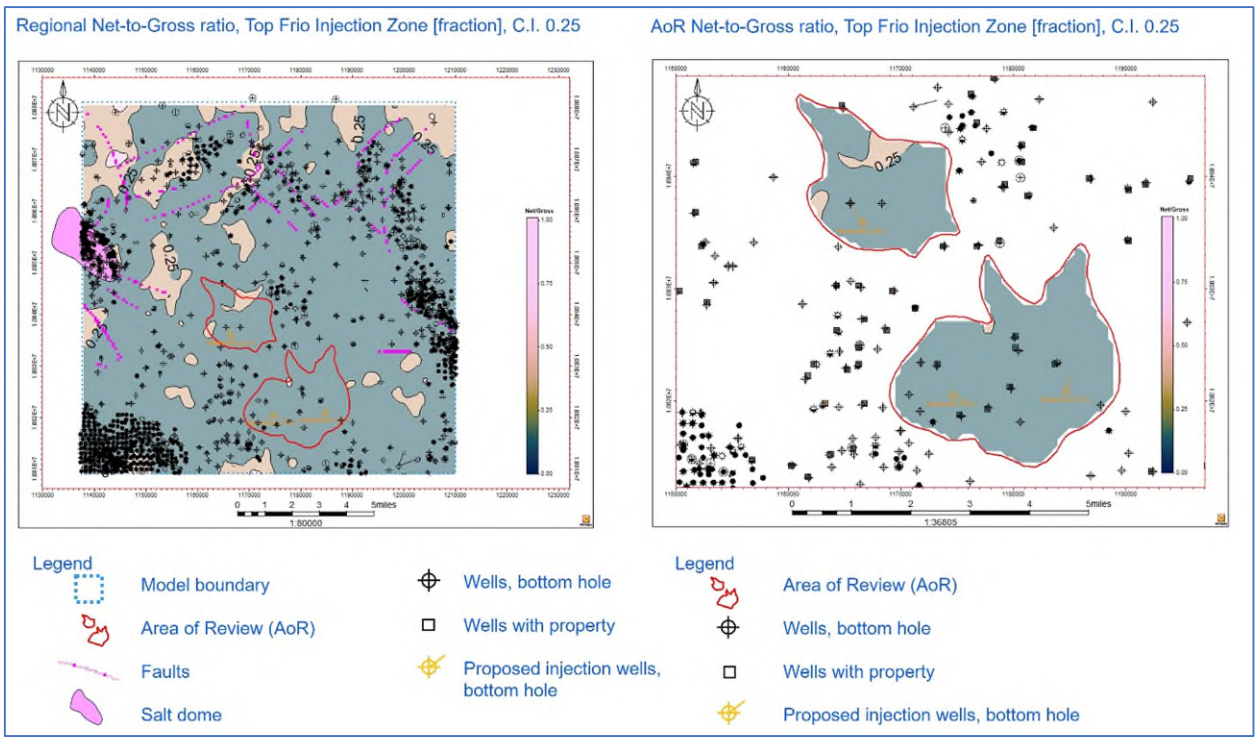


Figure AoR-63: Regional and AoR Net-to-Gross (NTG) ratio map of the Top Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

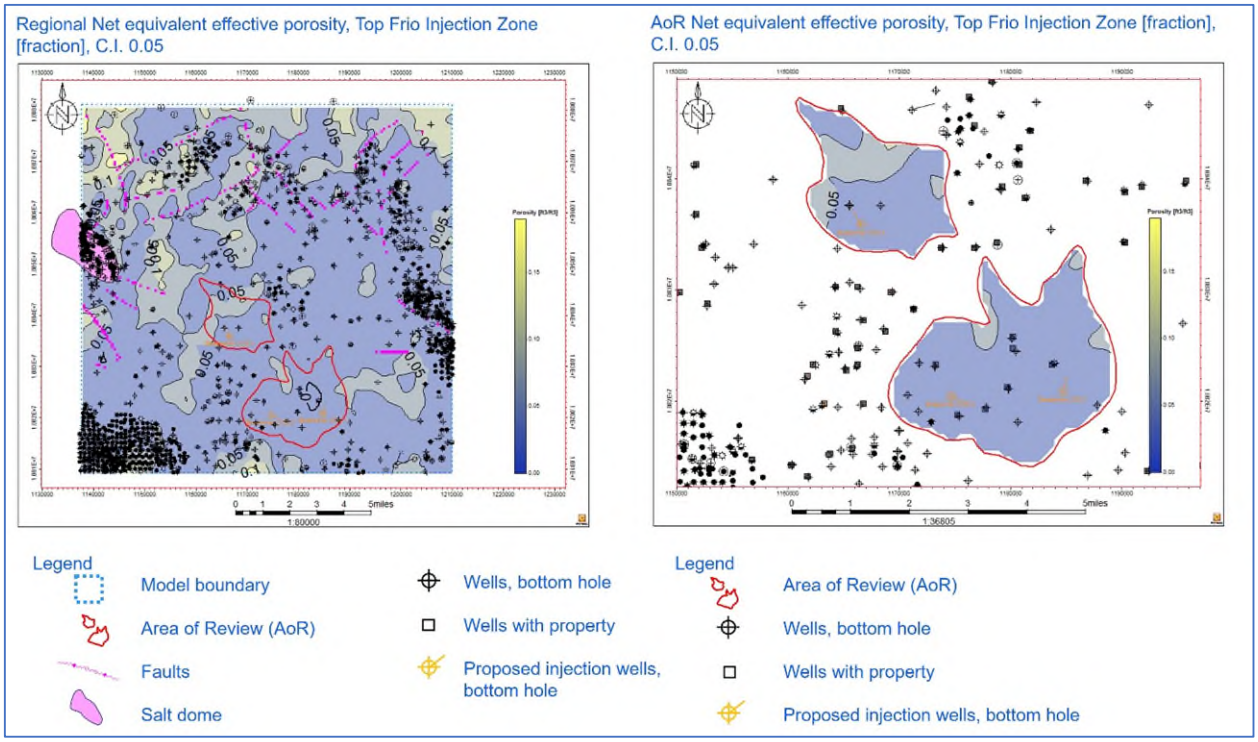


Figure AoR-64: Regional and AoR net equivalent effective porosity map of the Top Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

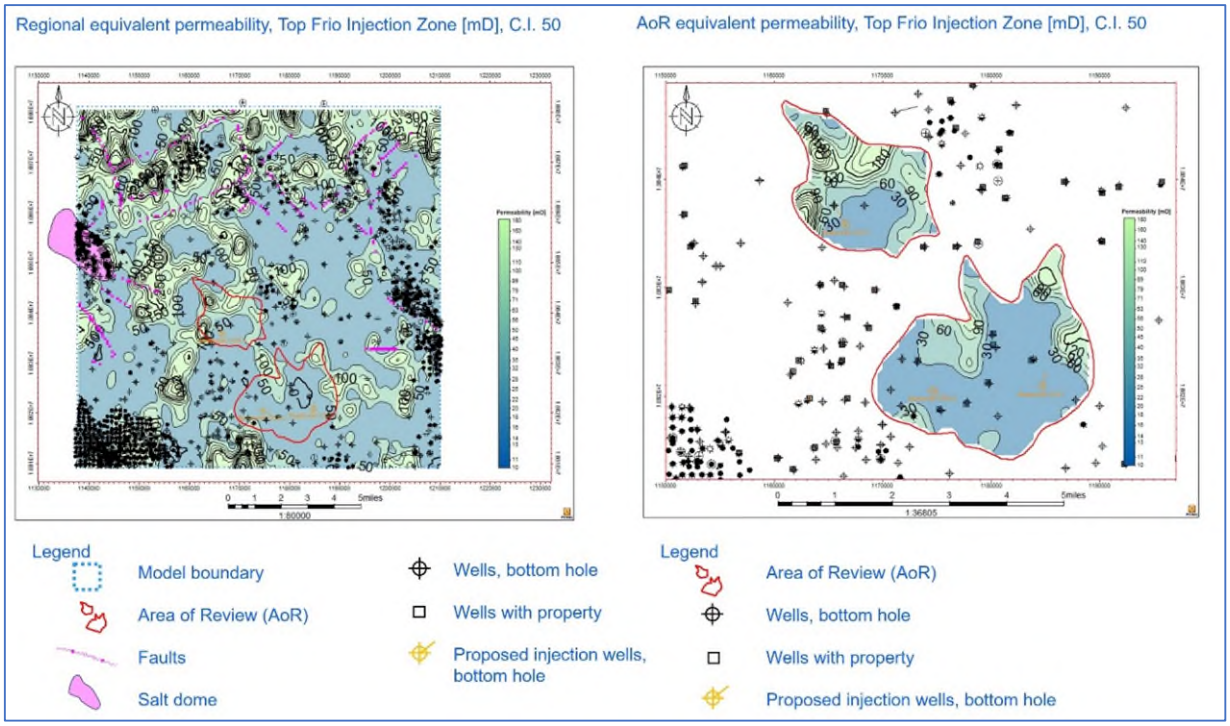


Figure AoR-65: Regional and AoR equivalent permeability map of the Top Frio Injection Zone in millidarcy (md), contour interval 50 md. This map was generated from the Oligocene Model described under 4.0.

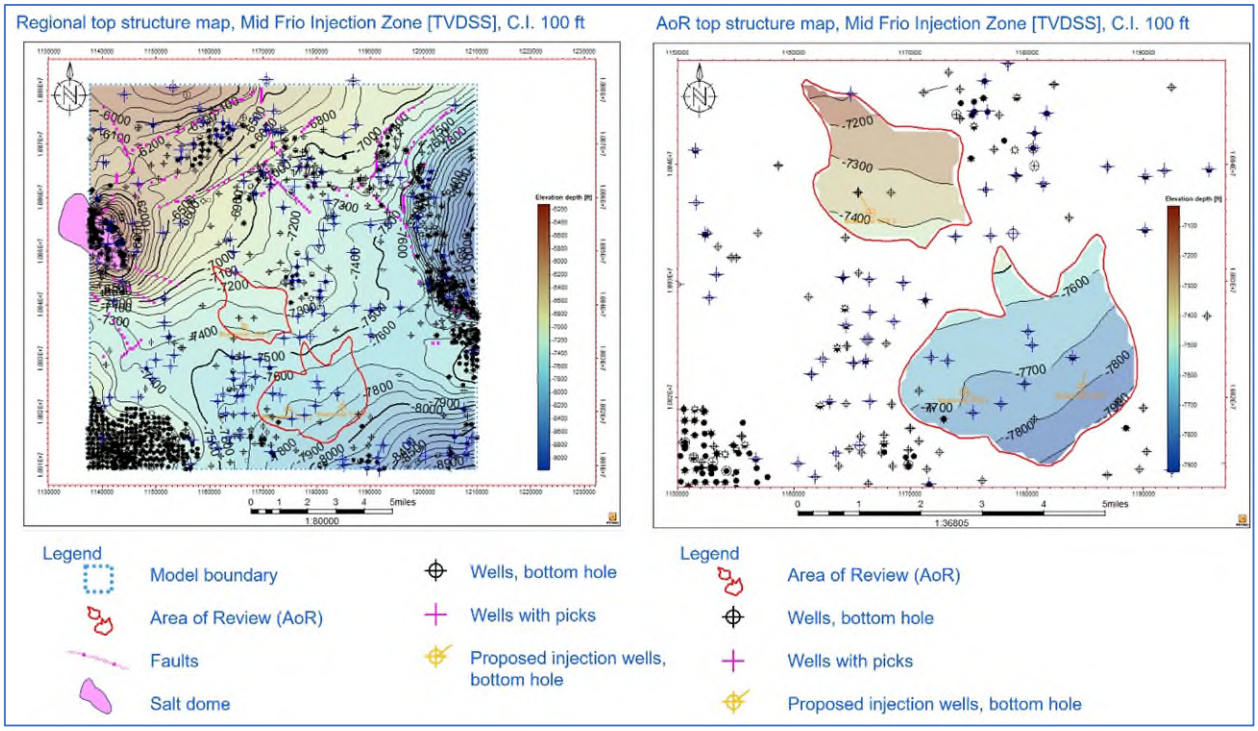


Figure AoR-66: Regional and AoR top structure map of the Mid Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

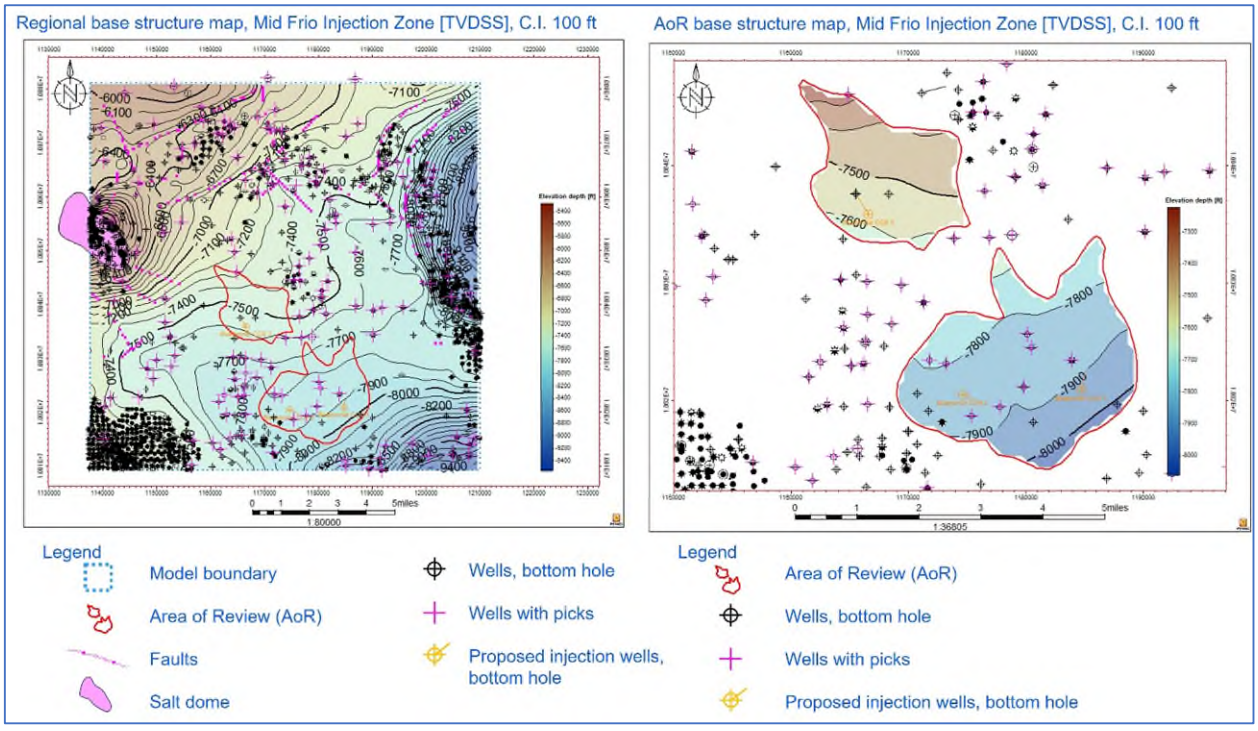


Figure AoR-67: Regional and AoR base structure map of the Mid Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

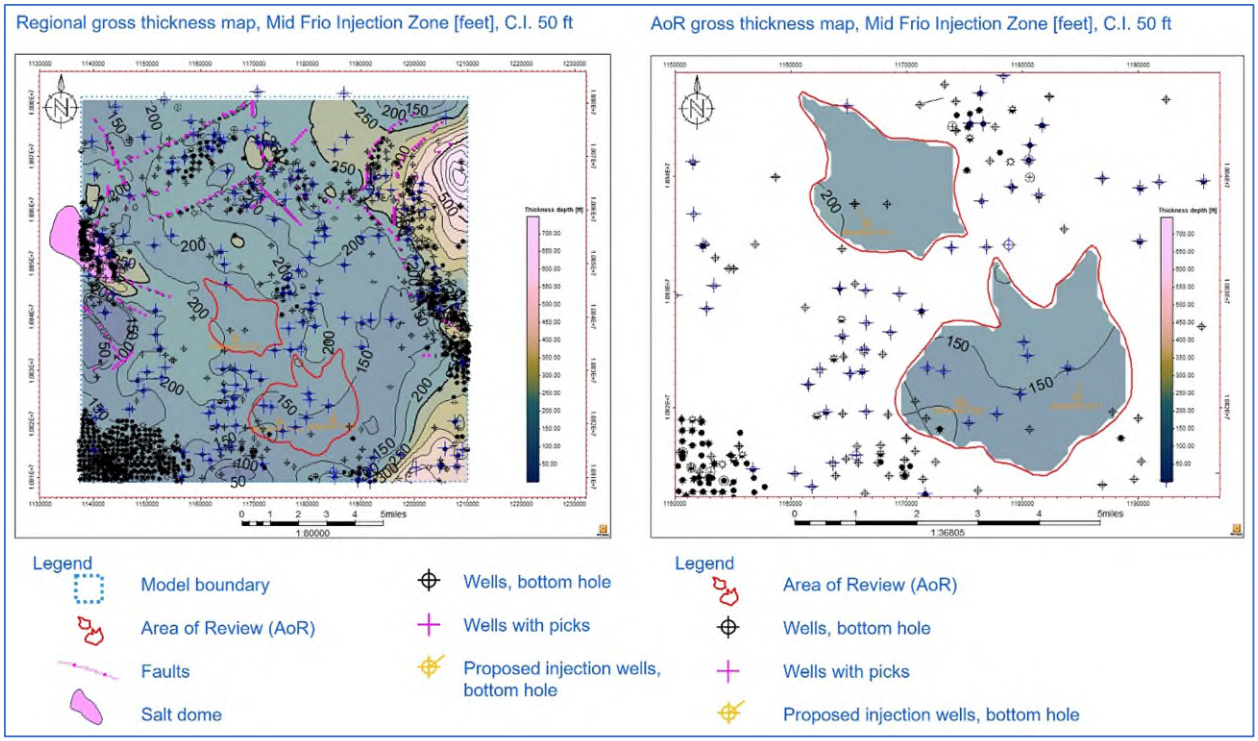


Figure AoR-68: Regional and AoR gross thickness map of the Mid Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

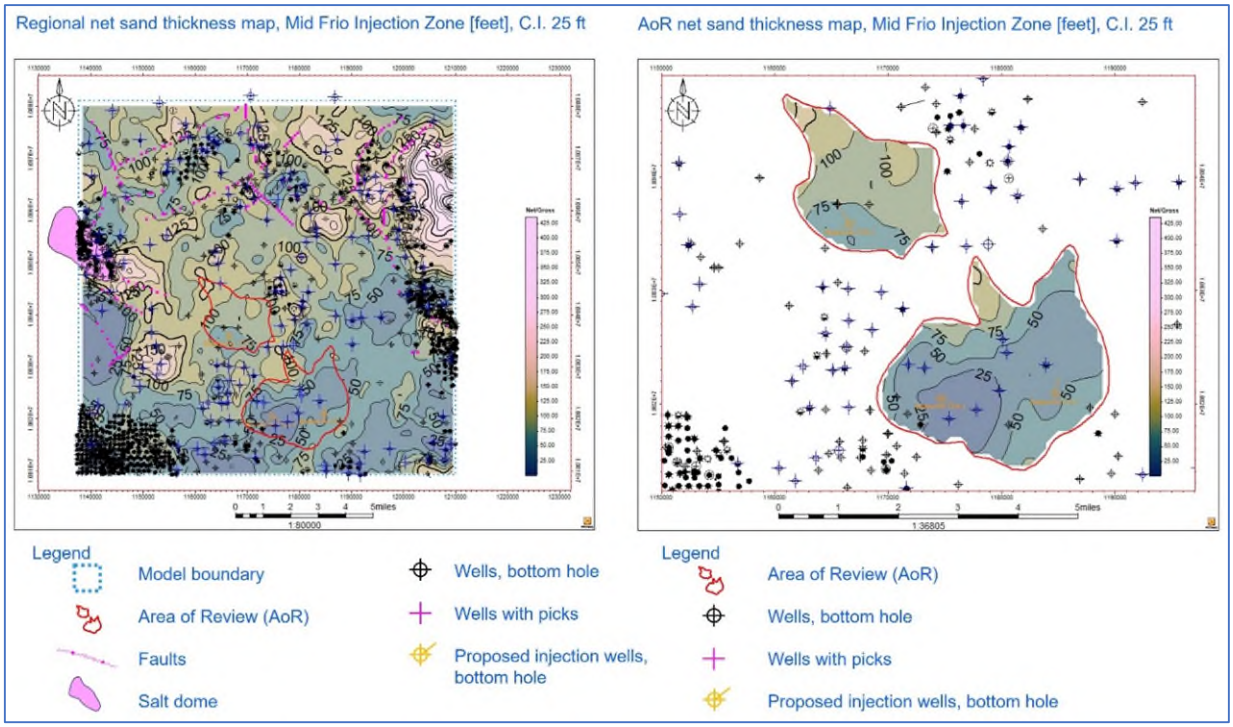


Figure AoR-69: Regional and AoR net thickness map of the Mid Frio Injection Zone in feet, contour interval 25 ft. This map was generated from the Oligocene Model described under 4.0.

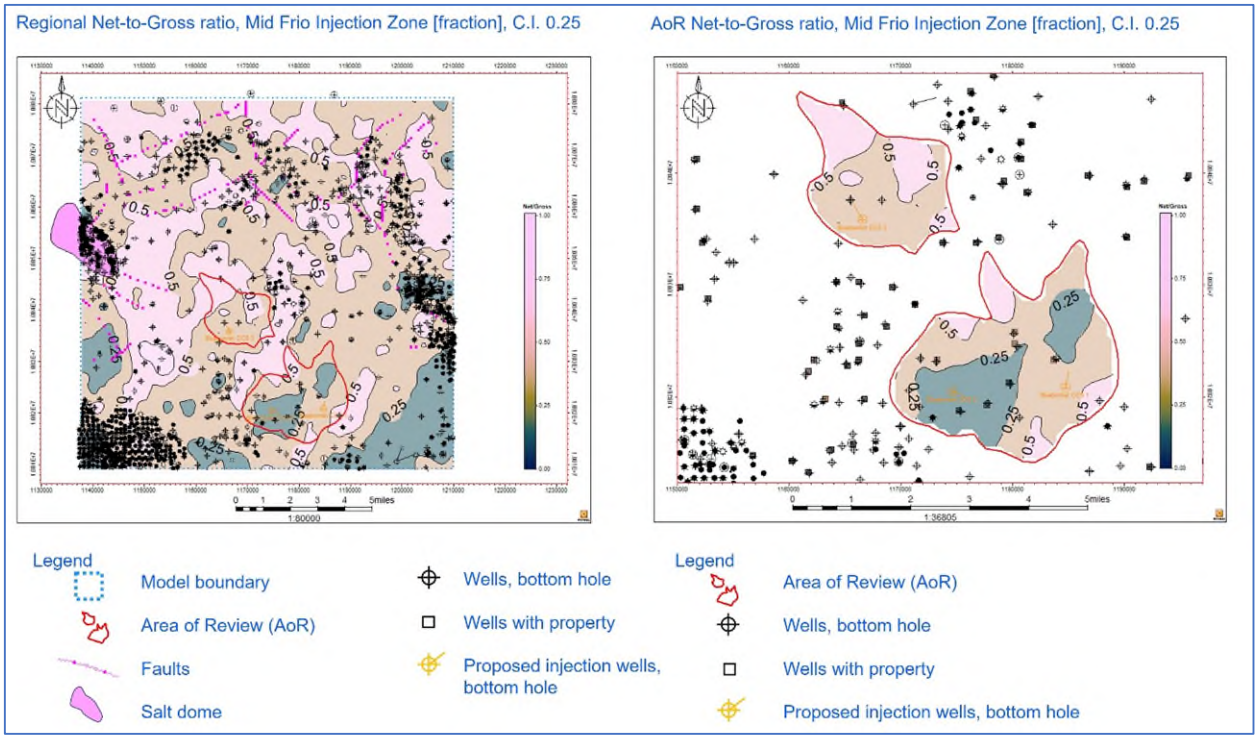


Figure AoR-70: Regional and AoR Net-to-Gross (NTG) ratio map of the Mid Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

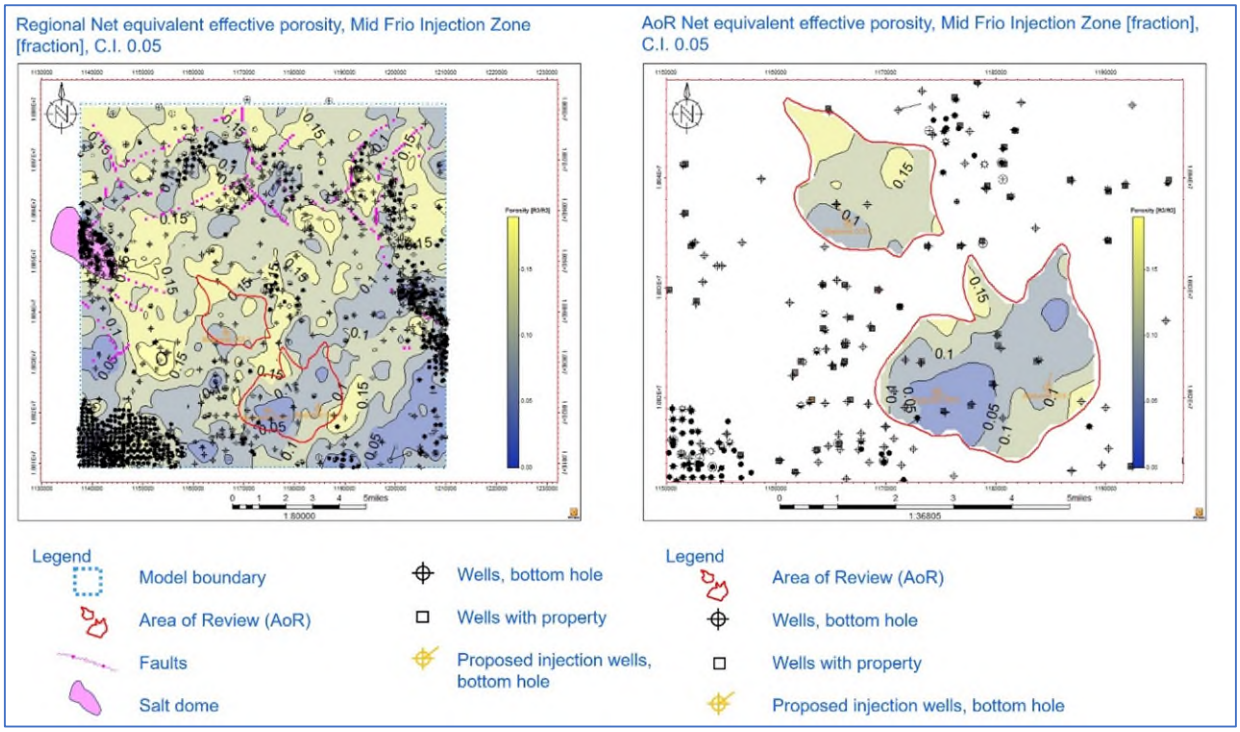


Figure AoR-71: Regional and AoR net equivalent effective porosity map of the Mid Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

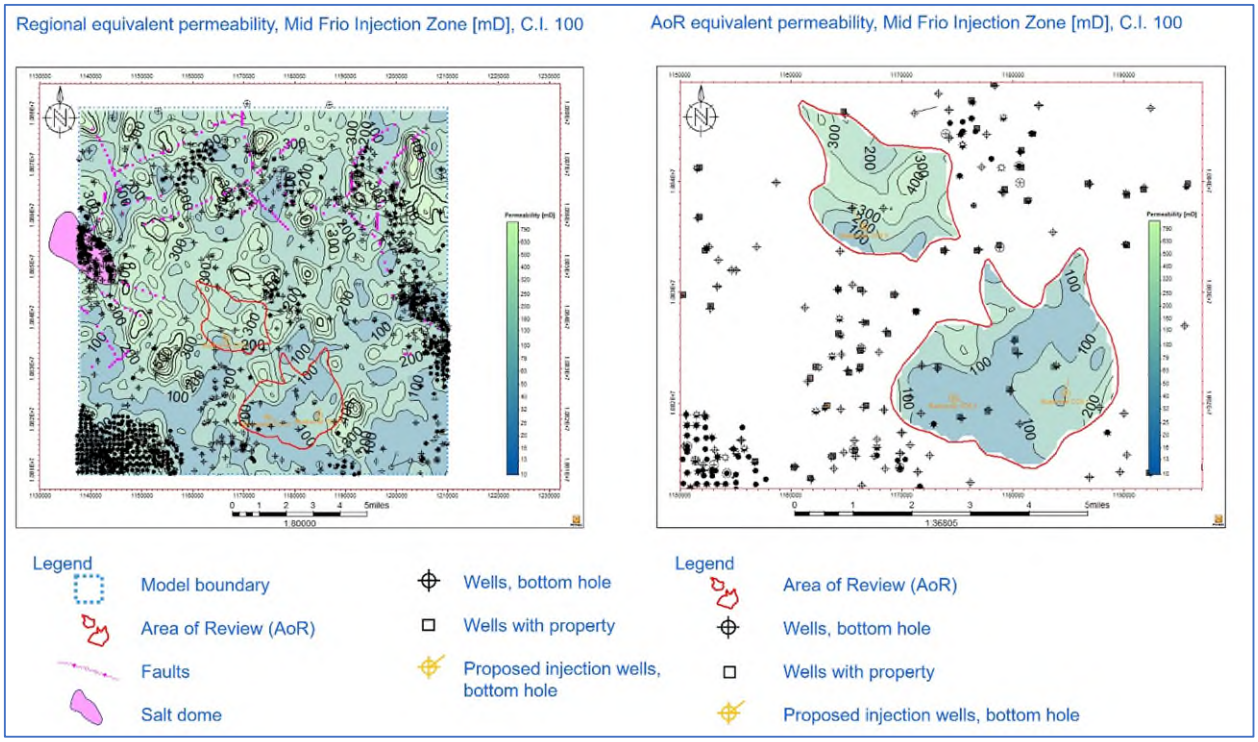


Figure AoR-72: Regional and AoR equivalent permeability map of the Mid Frio Injection Zone in millidarcy (md), contour interval 100 md. This map was generated from the Oligocene Model described under 4.0.

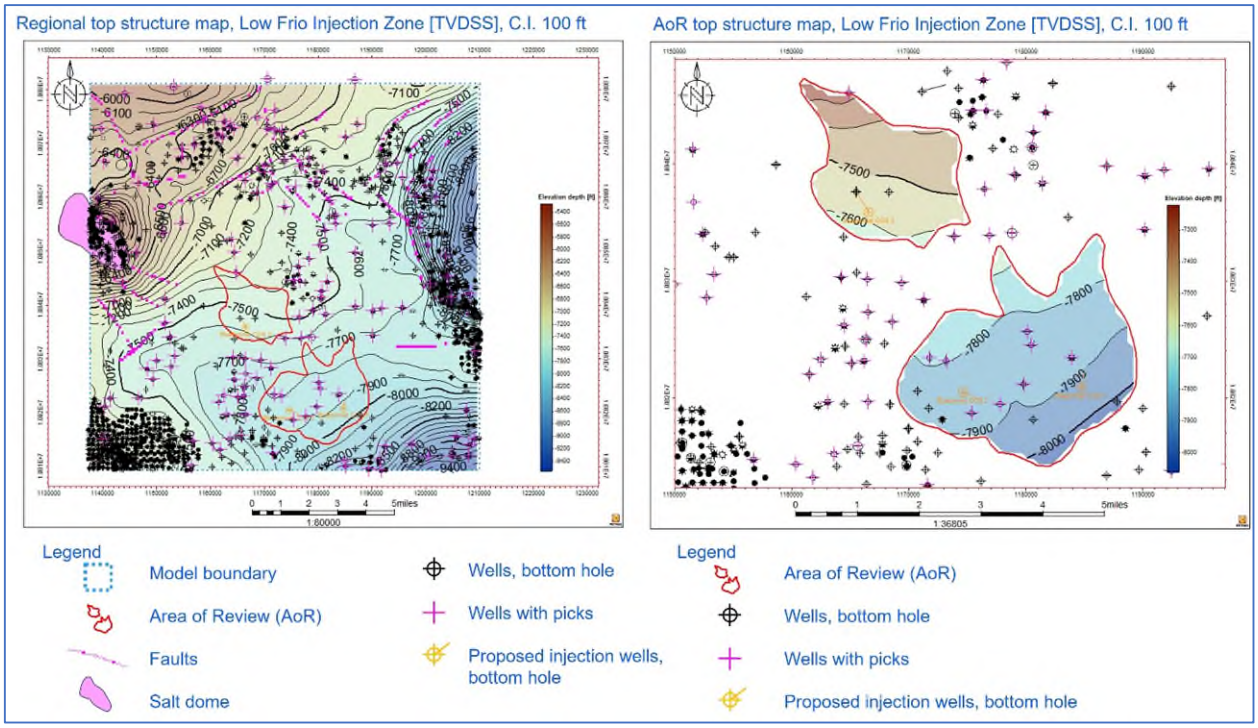


Figure AoR-73: Regional and AoR top map of the Low Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

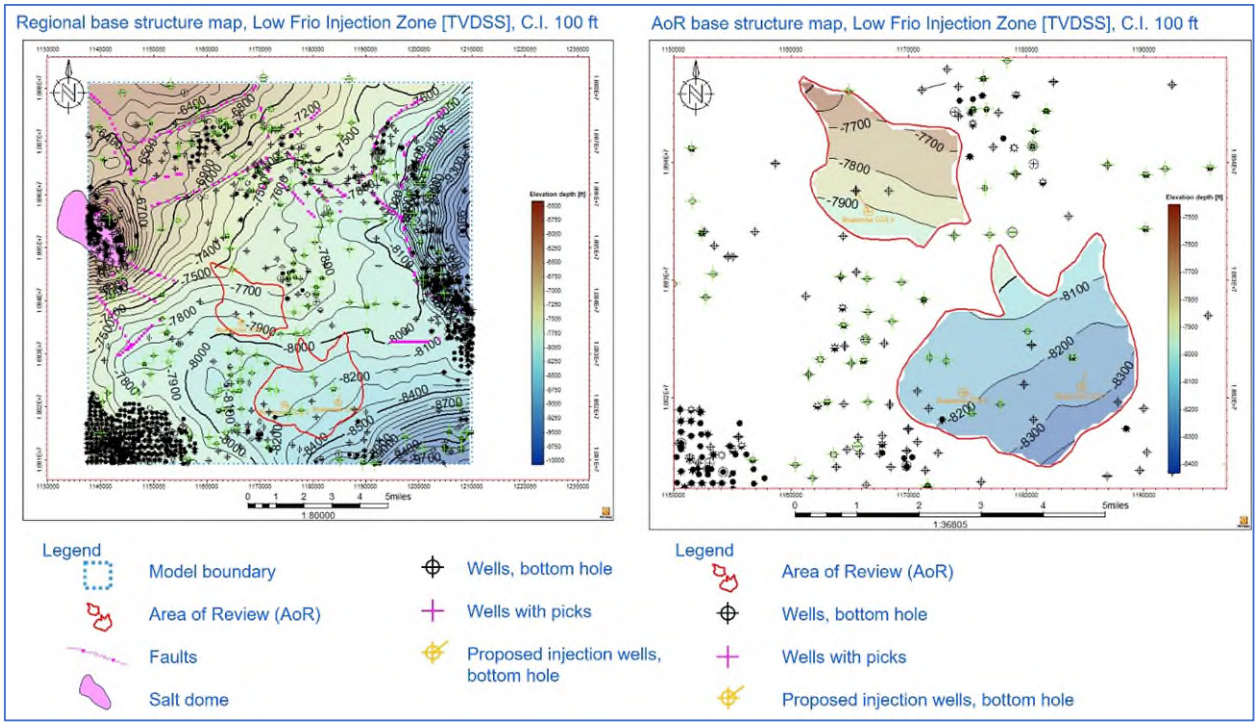


Figure AoR-74: Regional and AoR base structure map of the Low Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

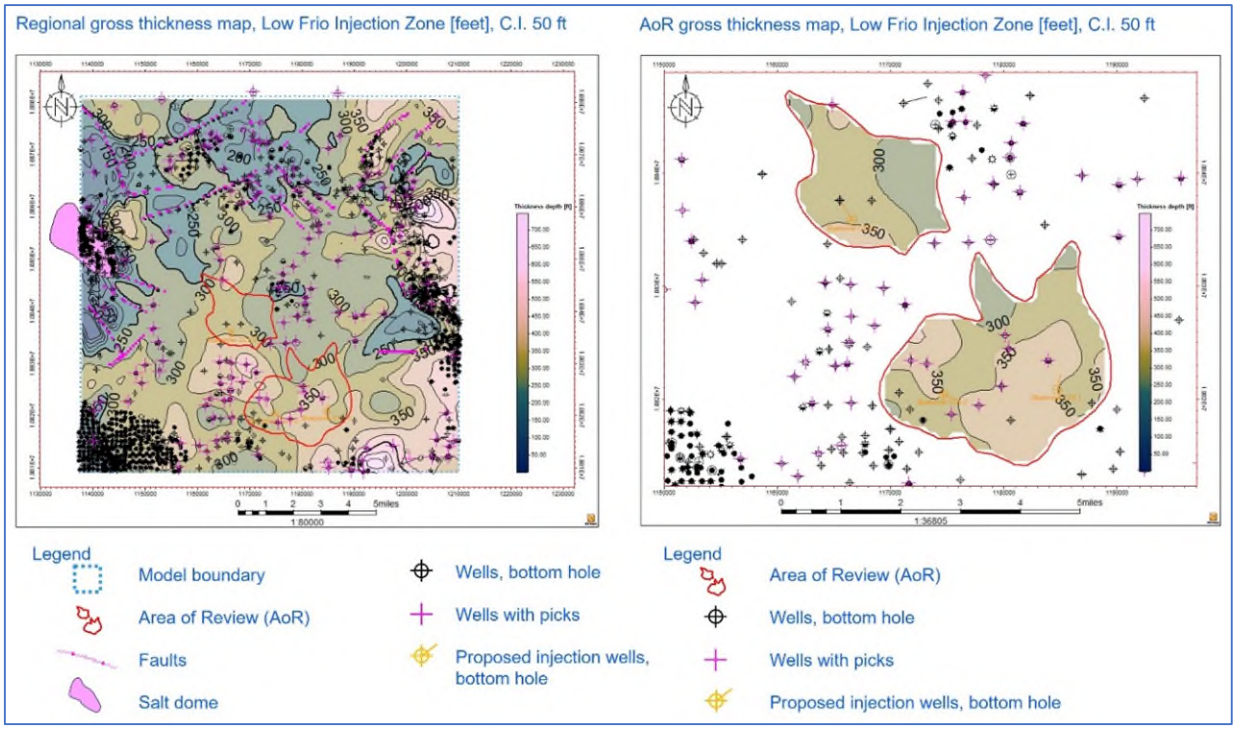


Figure AoR-75: Regional and AoR gross thickness map of the Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

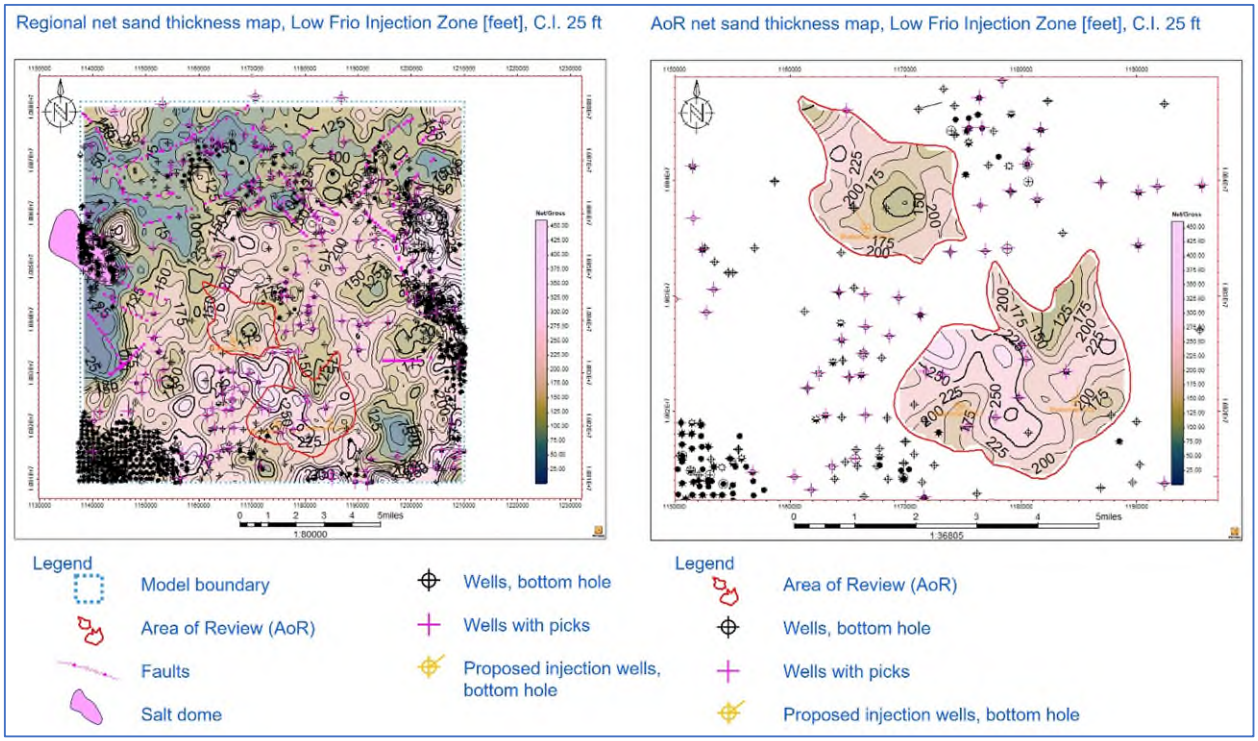


Figure AoR-76: Regional and AoR net sand thickness map of the Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

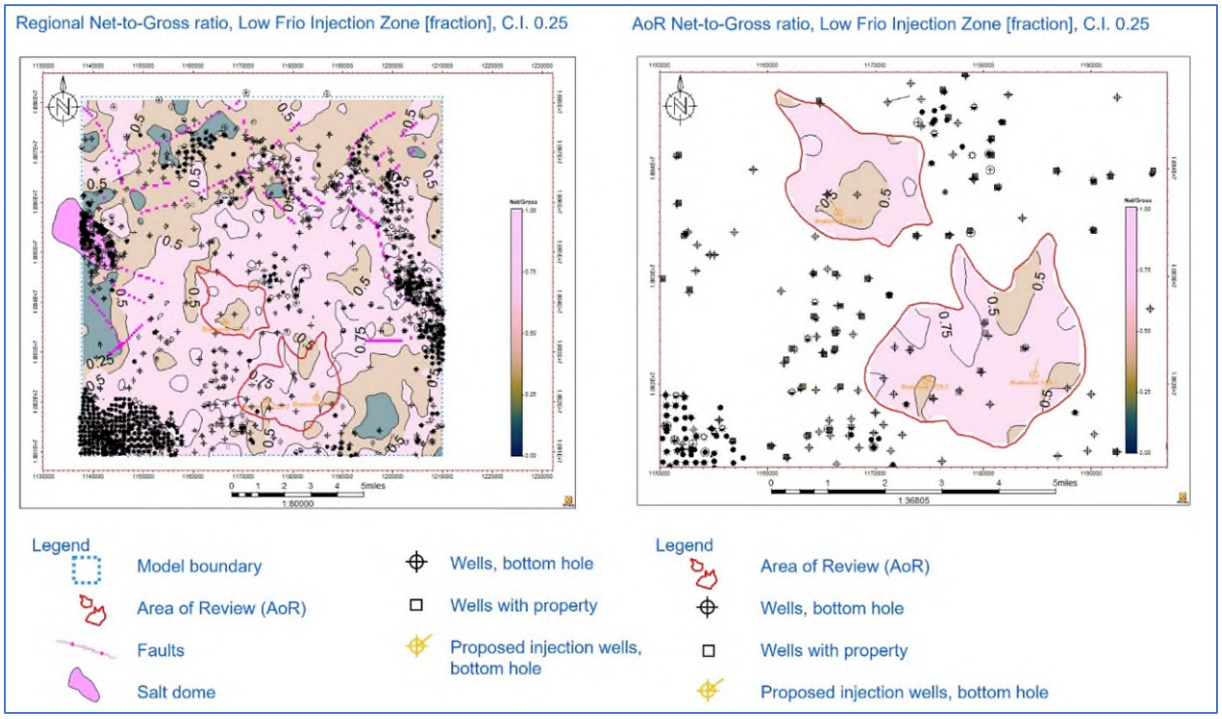


Figure AoR-77: Regional and AoR Net-to-Gross (NTG) ratio map of the Low Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

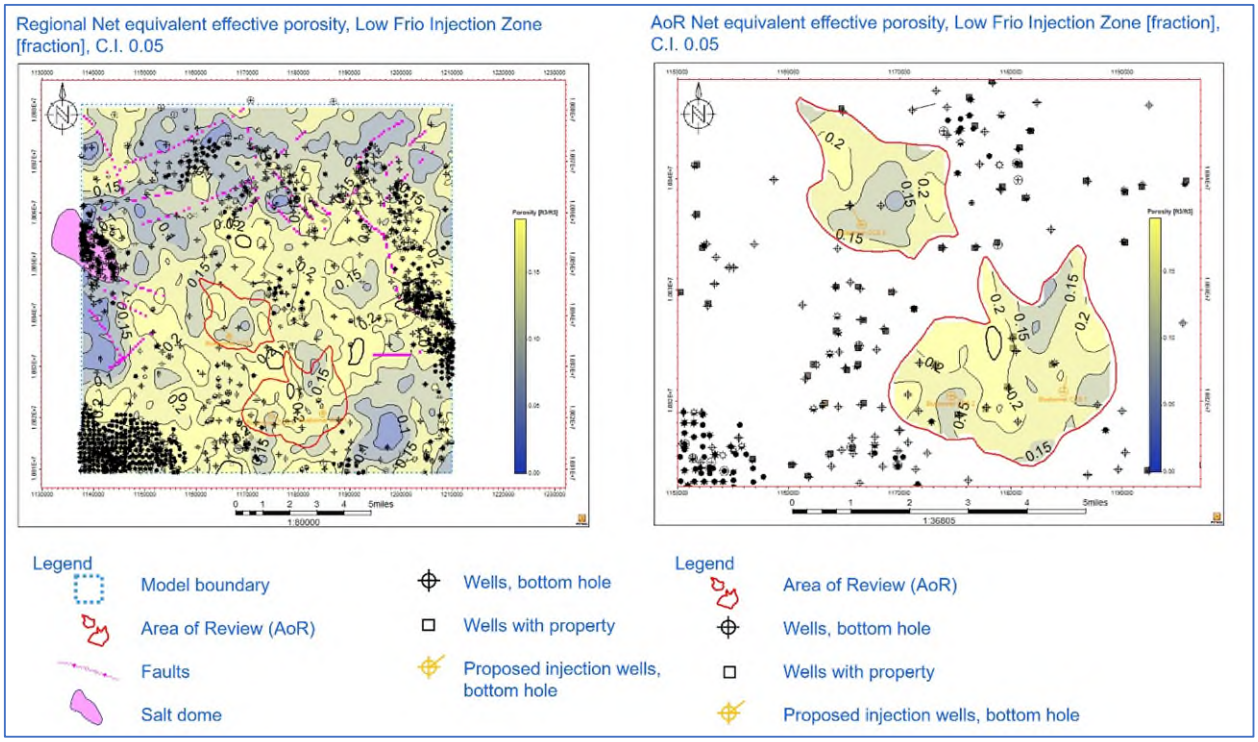


Figure AoR-78: Regional and AoR net equivalent effective porosity map of the Low Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

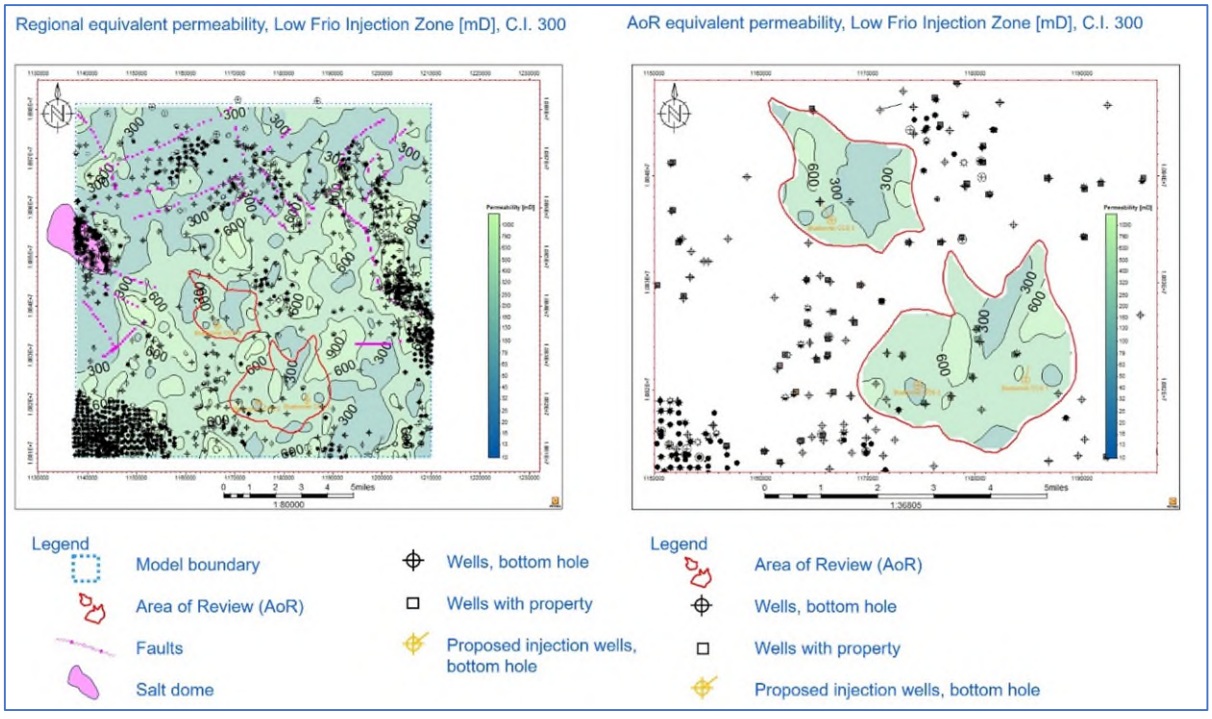


Figure AoR-79: Regional and AoR equivalent permeability map of the Low Frio Injection Zone in millidarcy (md), contour interval 300 md. This map was generated from the Oligocene Model described under 4.0.

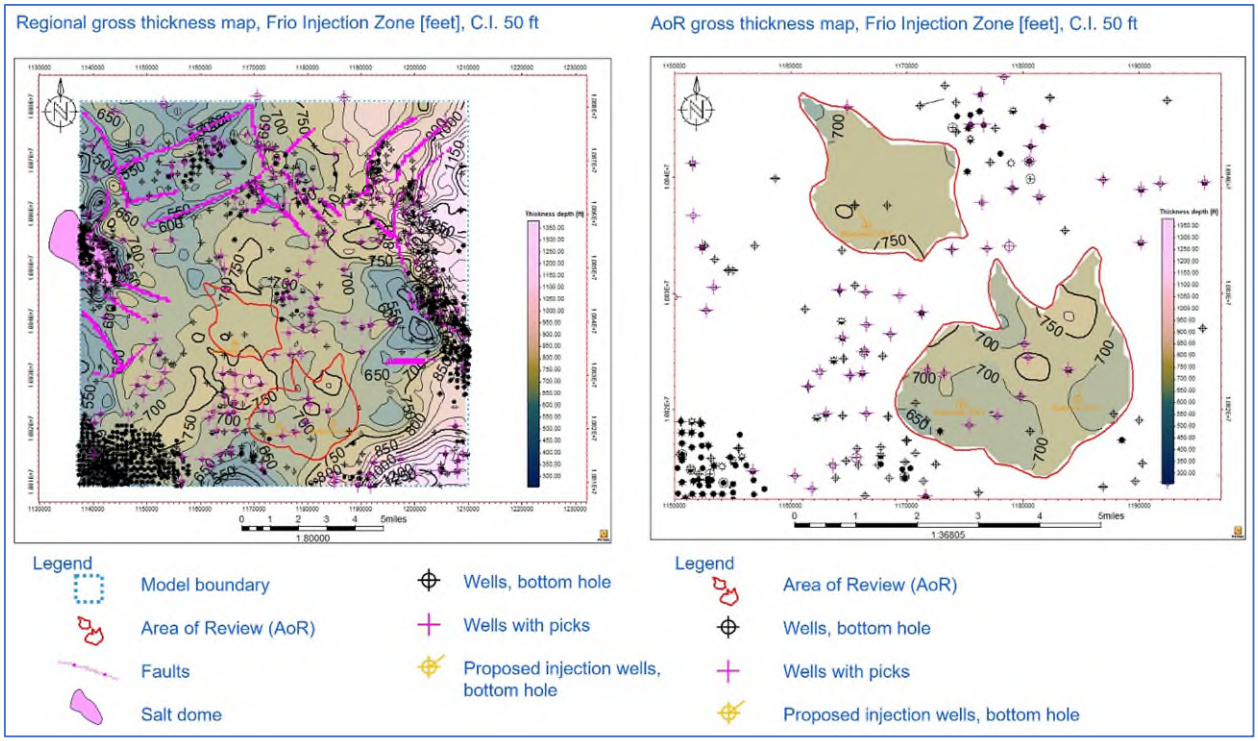


Figure AoR-80: Regional and AoR gross thickness map of the combined Top, Mid, and Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

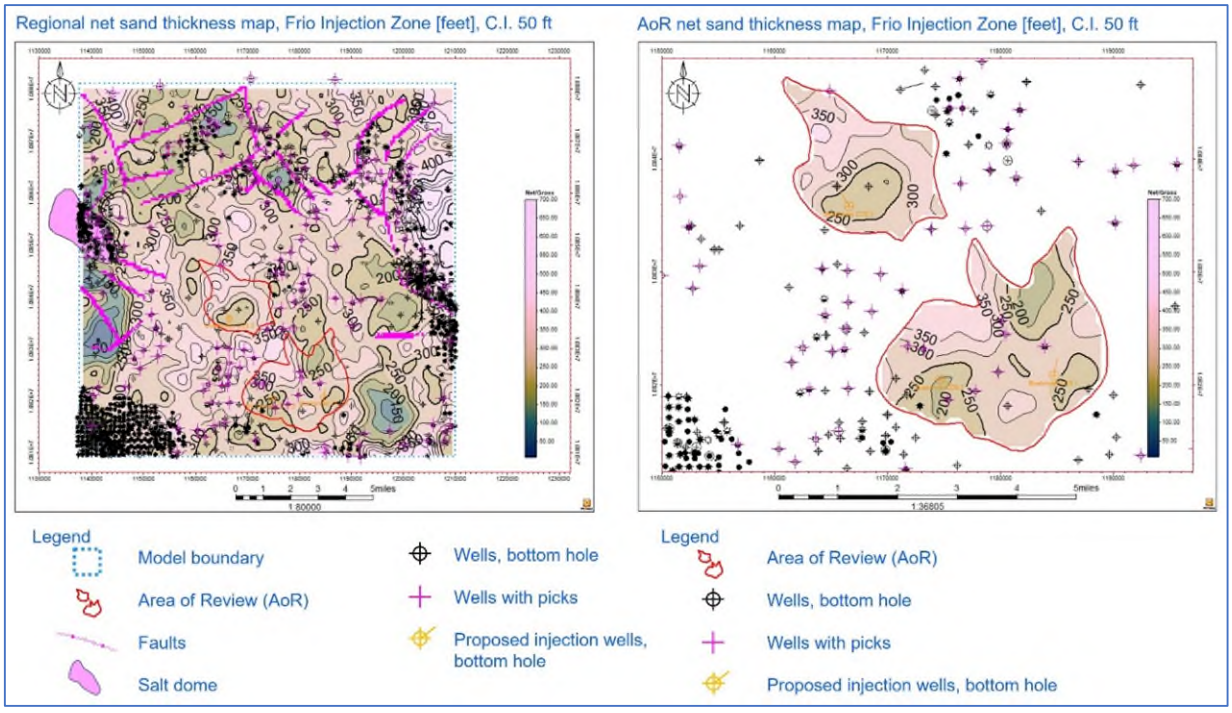


Figure AoR-81: Regional and AoR net thickness map of the combined Top, Mid, and Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

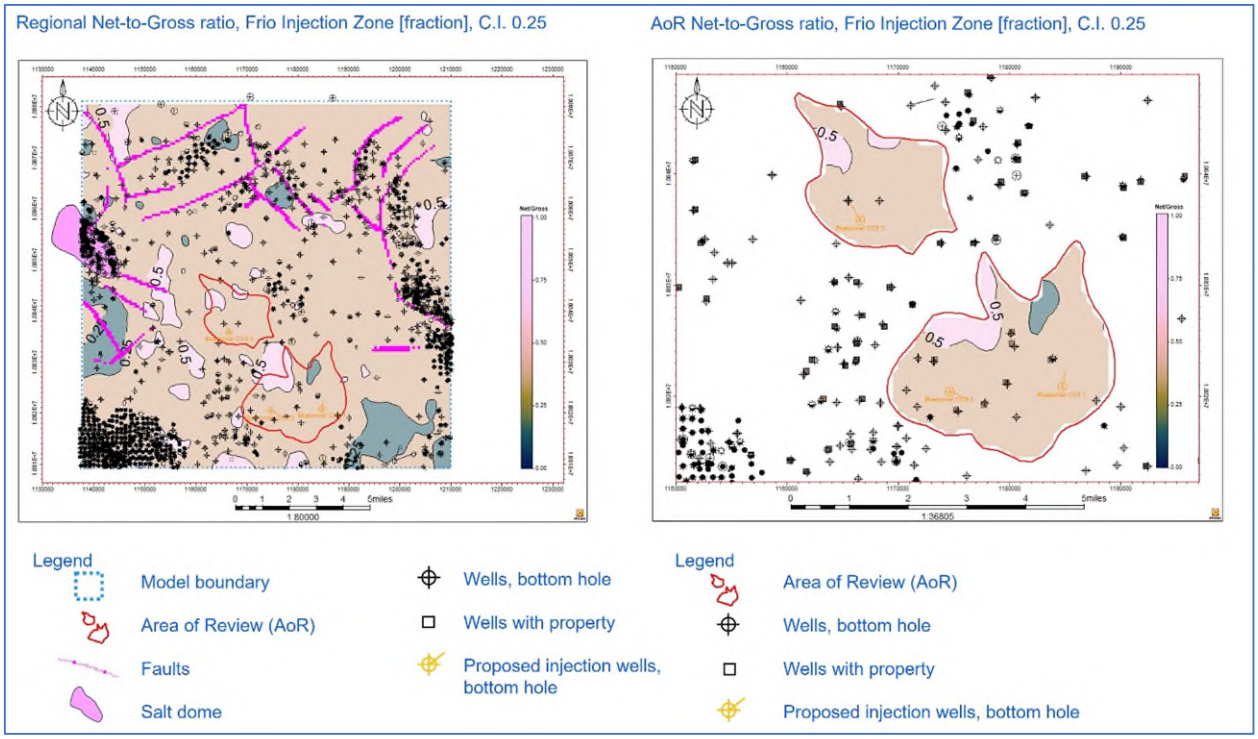


Figure AoR-82: Regional and AoR Net-to-Gross (NTG) ratio map of the combined Top, Mid, and Low Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

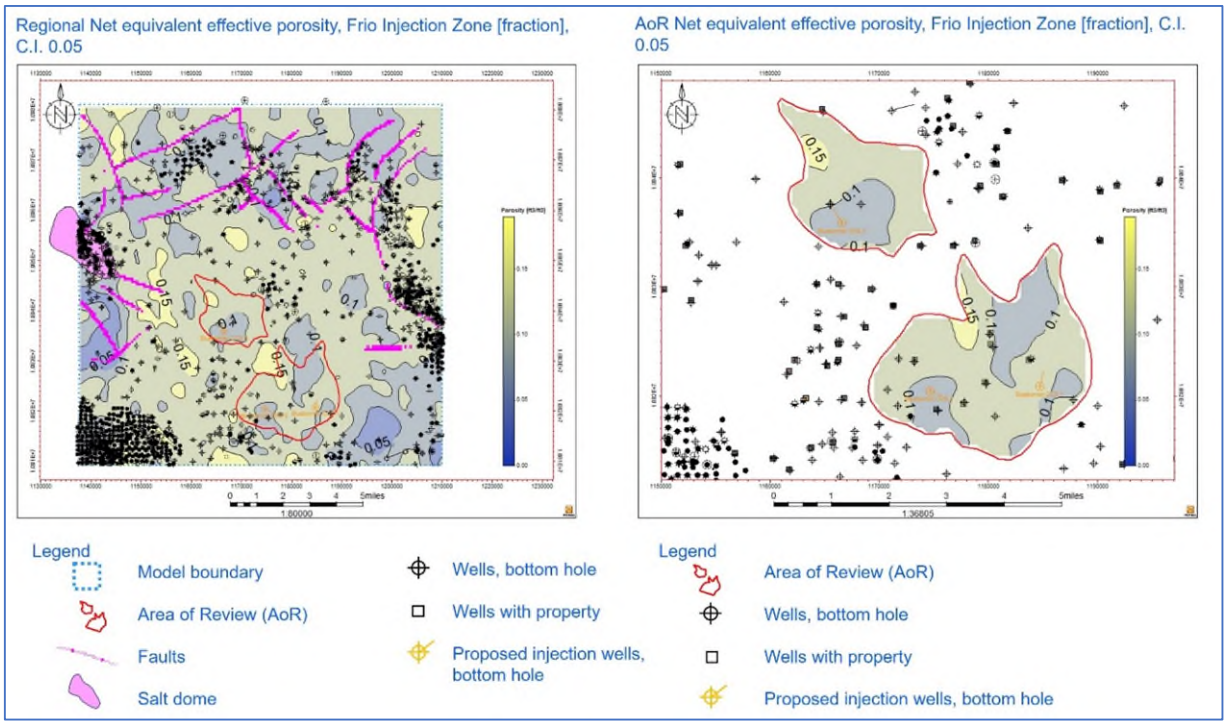


Figure AoR-83: Regional and AoR net equivalent effective porosity map of the combined Top, Mid, and Low Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

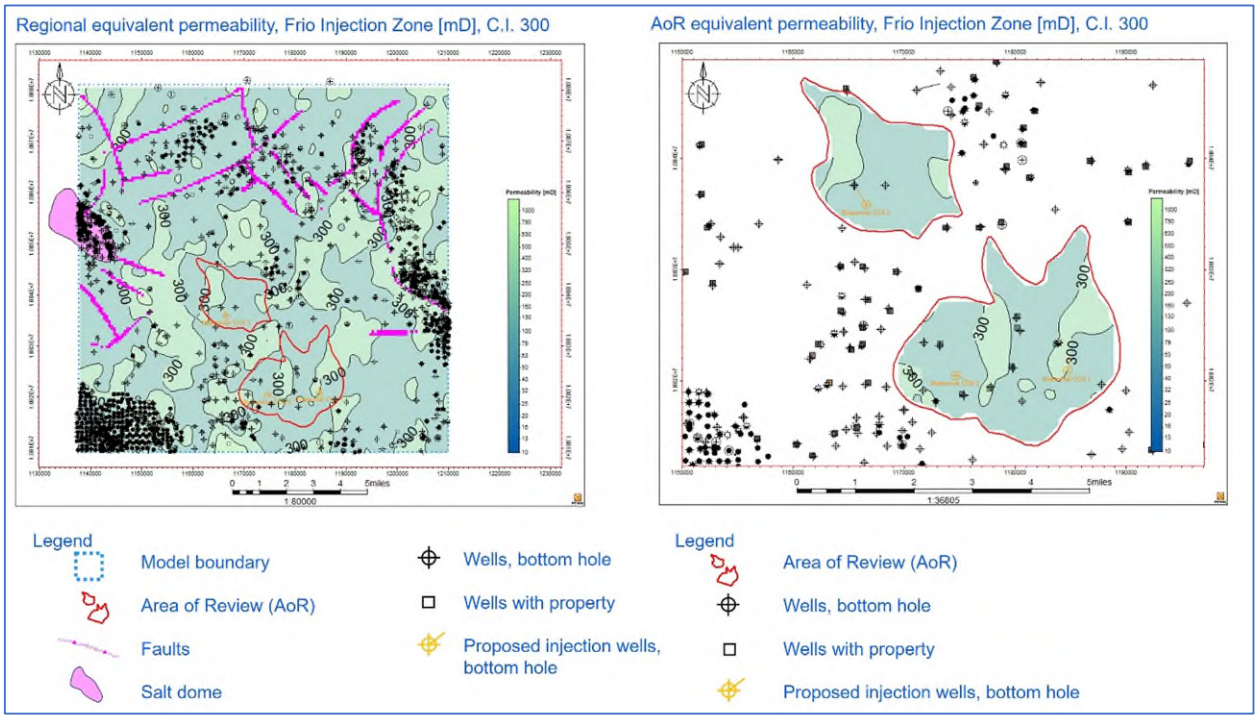


Figure AoR-84: Regional and AoR equivalent permeability map of the combined Top, Mid, and Low Frio Injection Zone in millidarcy (md), contour interval 300 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-2 represent map based average numbers extracted from the geomodel over the AoR.

Table AoR-2: Reservoir properties for the Frio Injection Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Frio injection zone			
		Top Frio	Mid Frio	Low Frio	Combined
Top depth [TVDSS]		Claimed as PBI			
Base depth [TVDSS]					
Gross Thickness [ft]					
Net Sand Thickness [ft]					

Reservoir properties in AoR	Extracted map values from geomodel	Frio injection zone			
		Top Frio	Mid Frio	Low Frio	Combined
	Claimed as PBI				
NtG Ratio [fraction]					
Porosity [fraction] EQI, net eff. porosity * NTG					
Permeability [md]					

Figures AoR-59 to AoR-84 show the associated maps for each of the discussed formations.

3.8.1.3 Miocene Injection Zone

The Miocene Injection Zone is characterized by moderately to well sorted, fine- to medium-grained sandstones, which are virtually unconsolidated. These sandstones are fluvial in origin. Sedimentary structures contain massive sands, trough cross-bedding, low- to high-angle cross stratifications, and contorted bedding. These sands also contain angular and amalgamated mudclasts. The mineral composition is rich in quartz with moderate amounts of K-feldspar and plagioclase, containing various kinds of (un)altered volcanic and metamorphic rock fragments and limestone fragments. Cementing and grain-coating authigenic minerals such as pyrite framboids and incipient K-feldspar overgrowths are very rare. Intergranular pores are abundant and are well interconnected, resulting in large pore throats and high porosity and permeability measurements.

3.8.1.3.1 Petrologic Description

The selected sandstones have abundant quartz grains with common feldspar grains including plagioclase and K-feldspar. Moderate volcanic rock fragments are often rich in K-feldspar (stained yellow for ease of recognition), although a few are plagioclase-rich and altered. Additionally, some have pink-stained limestone rock fragments. Intergranular pores are commonly abundant and are well interconnected. A few sandstones have microfossils including foraminifera with the chambers that are commonly filled with Fe-calcite.

The Miocene sandstone compositional diagrams are shown in the following figures in the top left and are based on thin section 300-point count conventional analysis.


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI

Claimed as PBI

Claimed as PBI



3.8.1.3.2 Miocene Injection Zone Maps

Petrophysically calculated porosity and permeability was calibrated to core. Average gross porosity from the petrophysical analysis performed in Encanto 01 in the Miocene Injection Zone is [redacted] sand porosity is [redacted], average gross permeability is [redacted] and sand permeability is [redacted] For more detail about the petrophysical workflow, please refer to the petrophysical Appendix A.

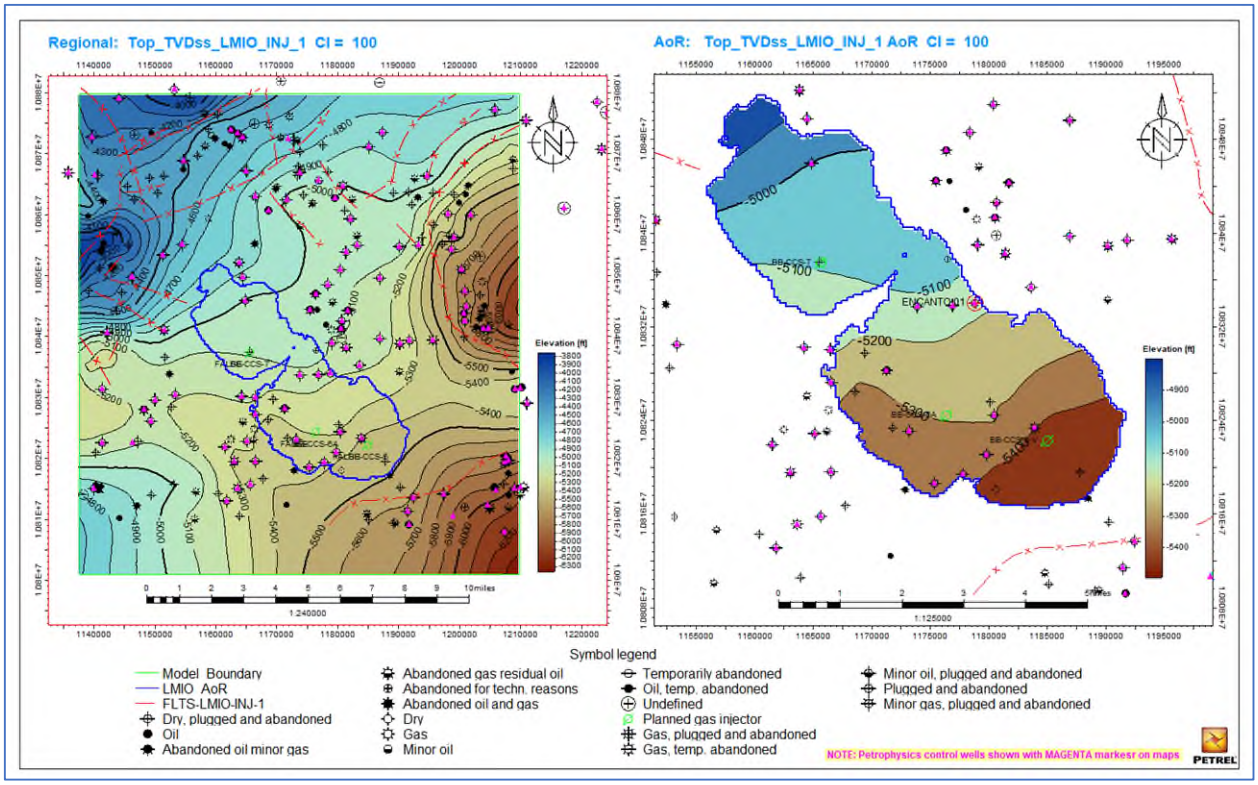


Figure AoR-92: Regional and AoR top structure maps of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

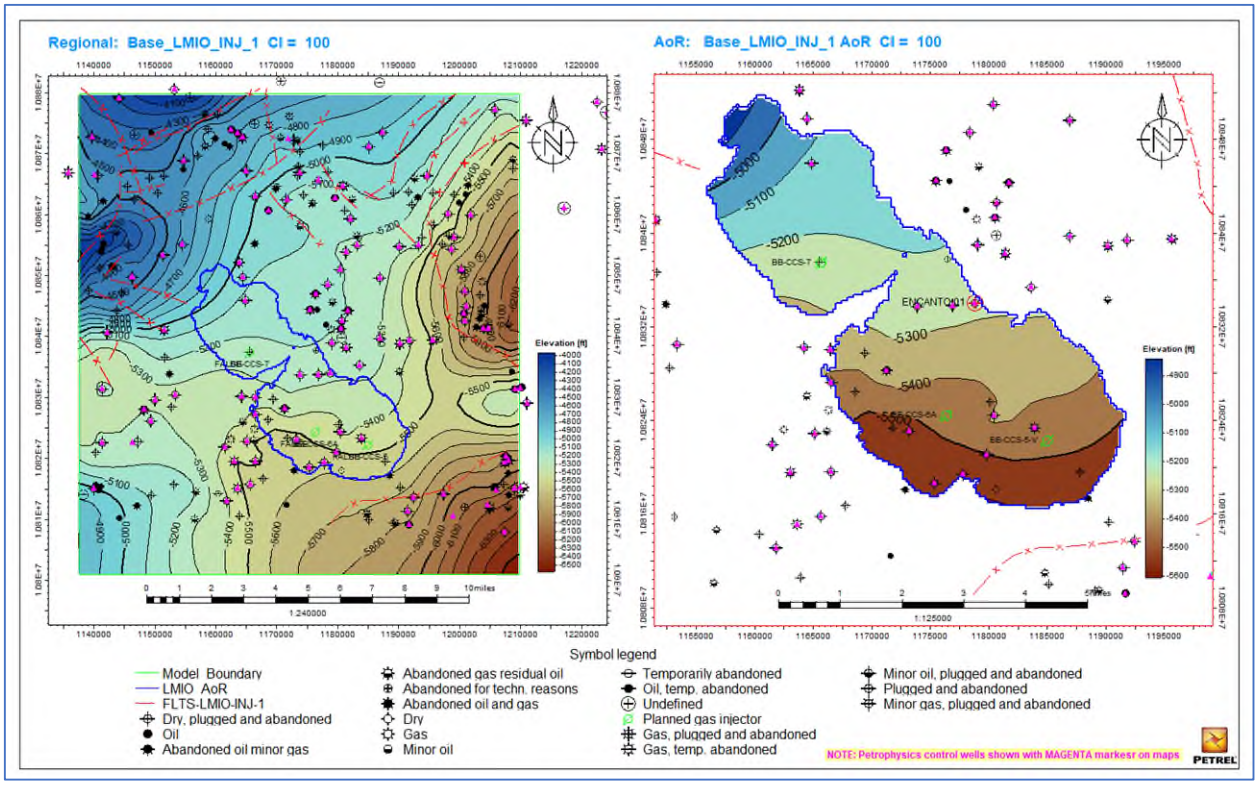


Figure AoR-93: Regional and AoR base structure maps of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

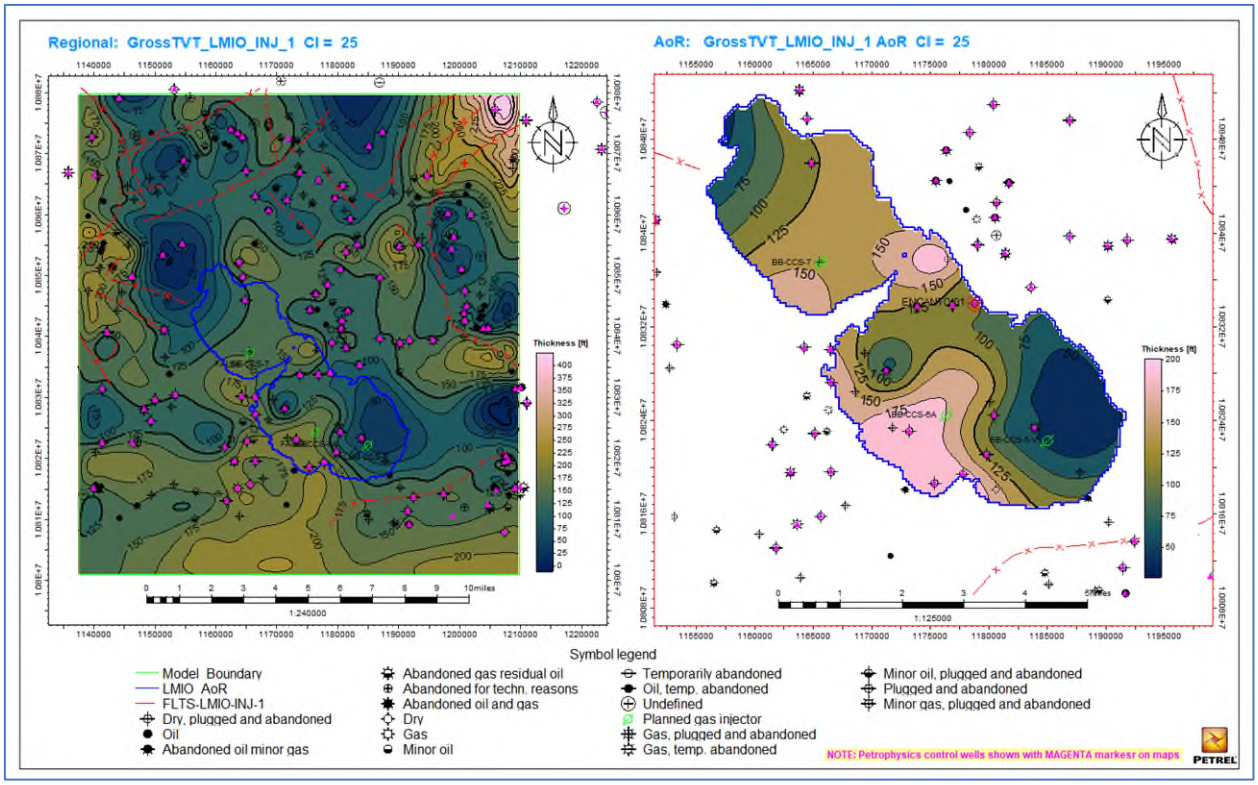


Figure AoR-94: Regional and AoR gross thickness maps of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0

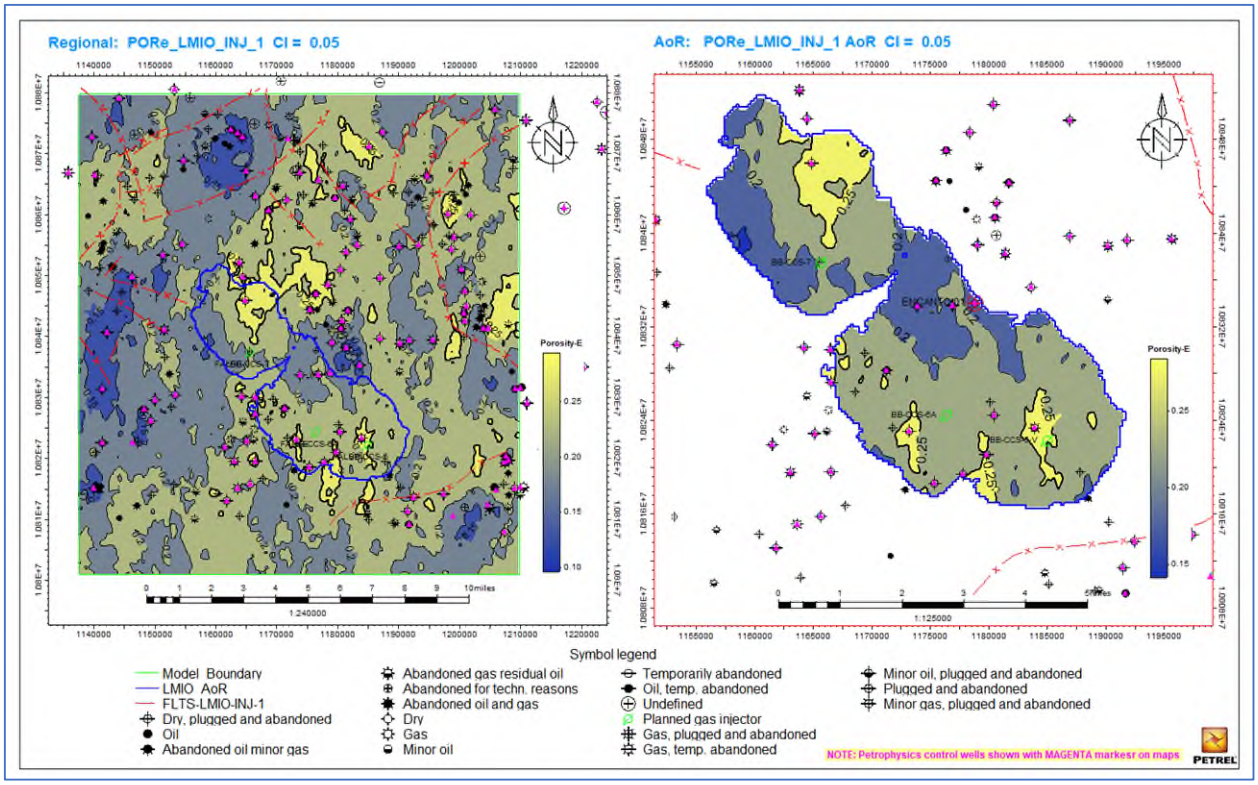


Figure AoR-95: Regional and AoR average effective porosity of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

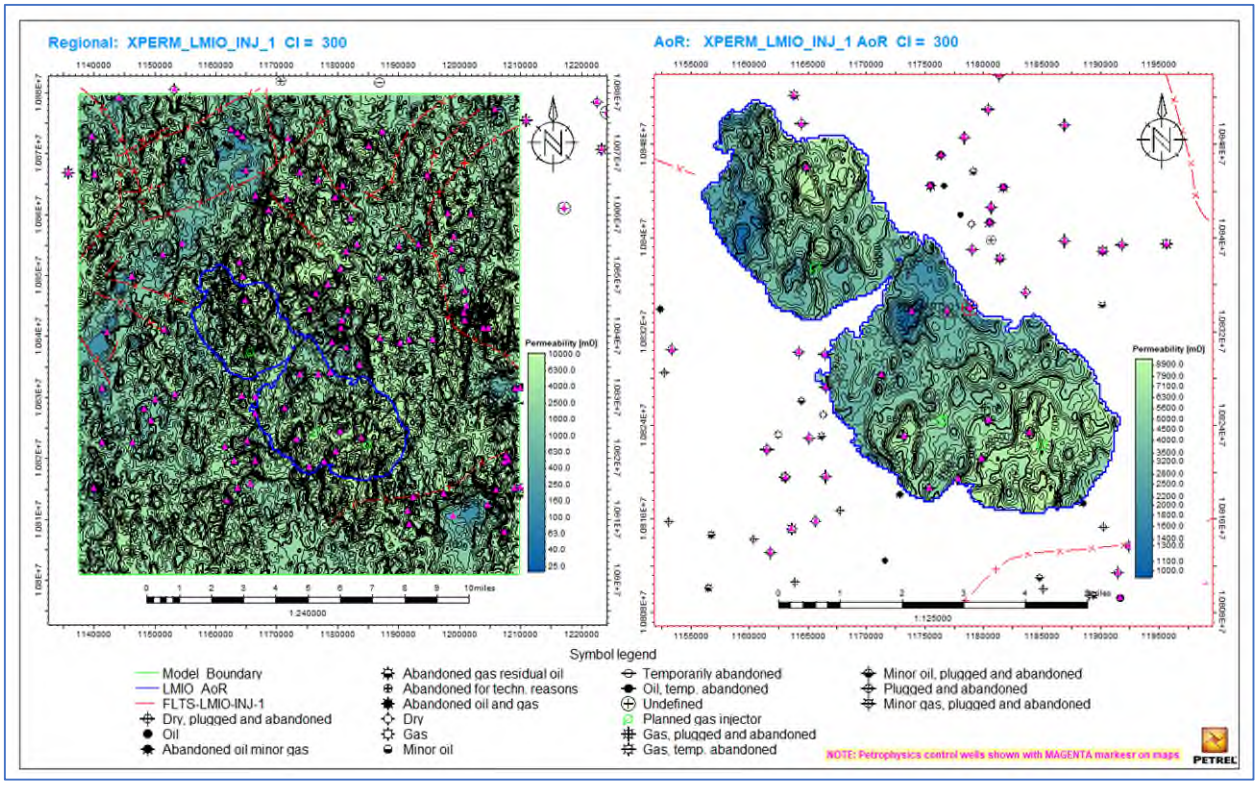


Figure AoR-96: Regional and AoR average permeability of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers in Table AoR-3 represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-3: Reservoir properties for the LMIO_INJ_1 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_1 Injection Zone
Top Depth (TVDss)	Claimed as PBI	
Base Depth (TVDss)		
Gross Thickness (ft.)		

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_1 Injection Zone
Effective Porosity (fraction)	Minimum	Claimed as PBI
	Maximum	
Permeability (md)	Average	
	Minimum	
	Maximum	

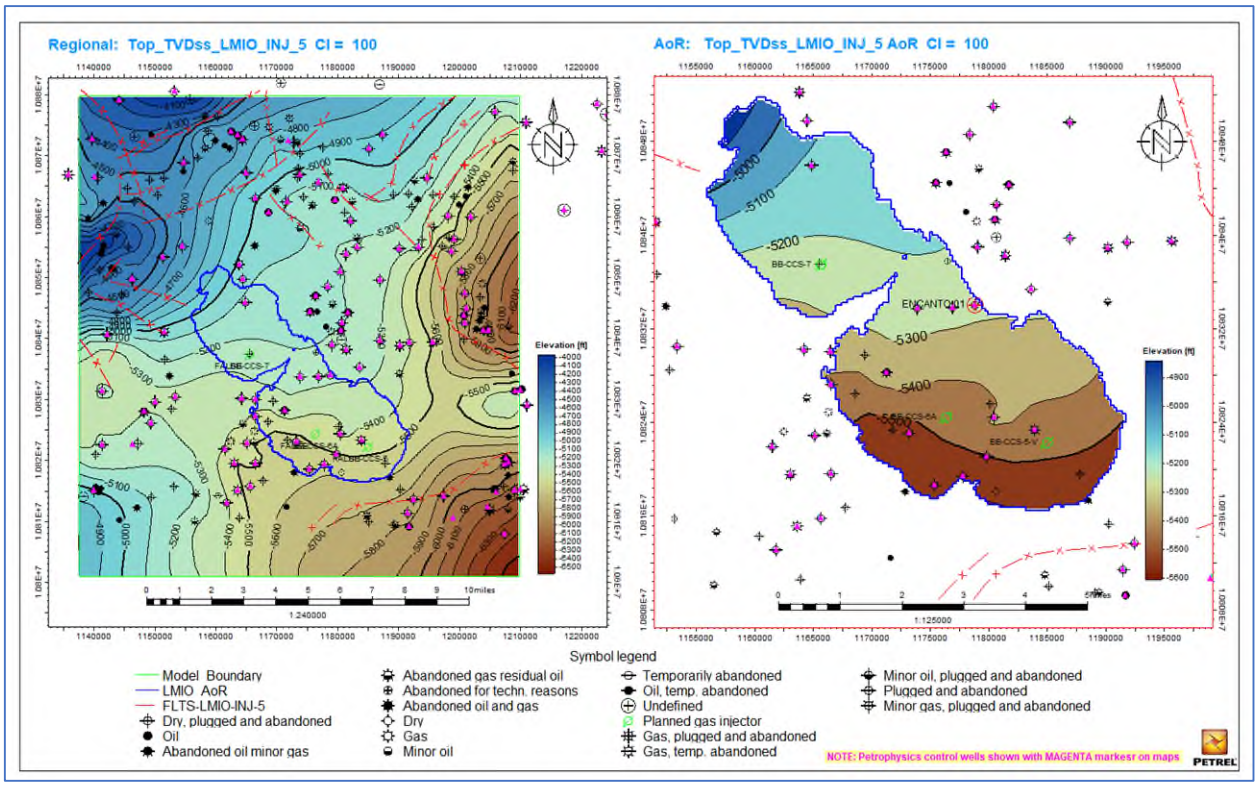


Figure AoR-97: Regional and AoR top structure maps of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

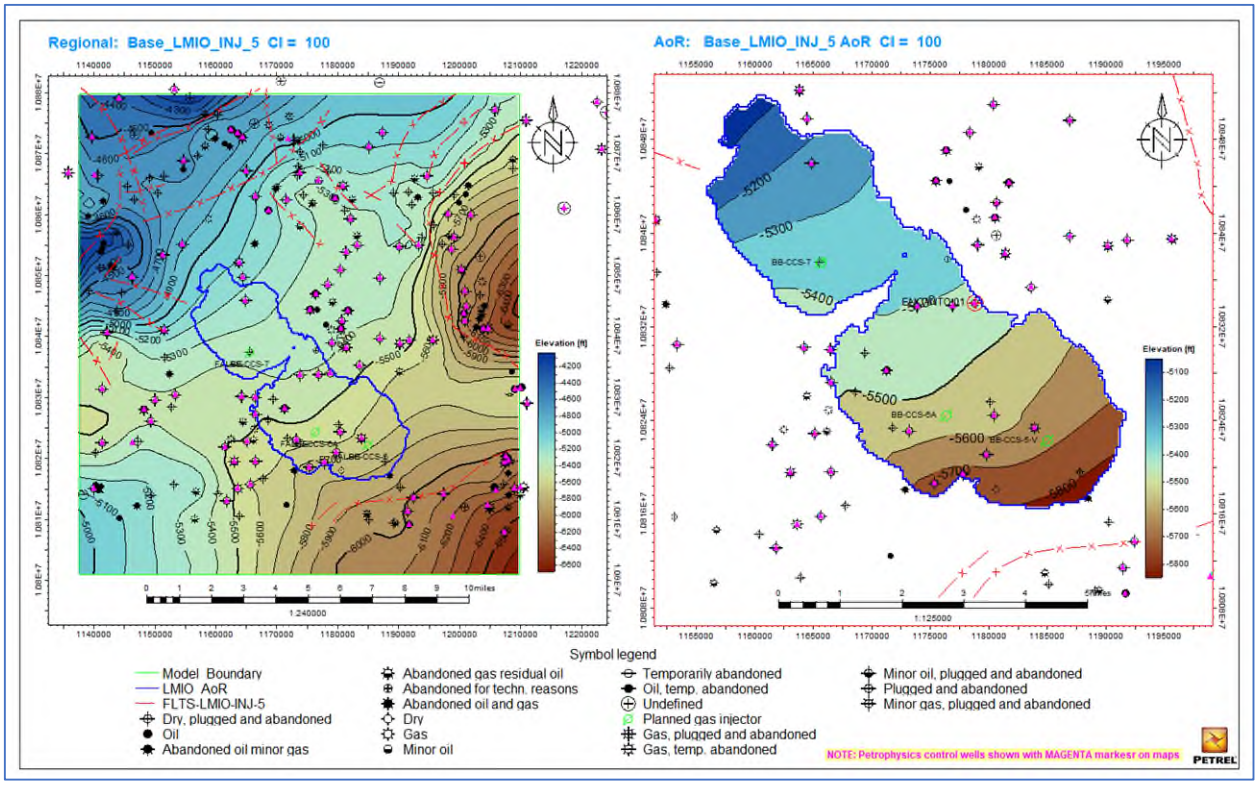


Figure AoR-98: Regional and AoR base structure maps of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

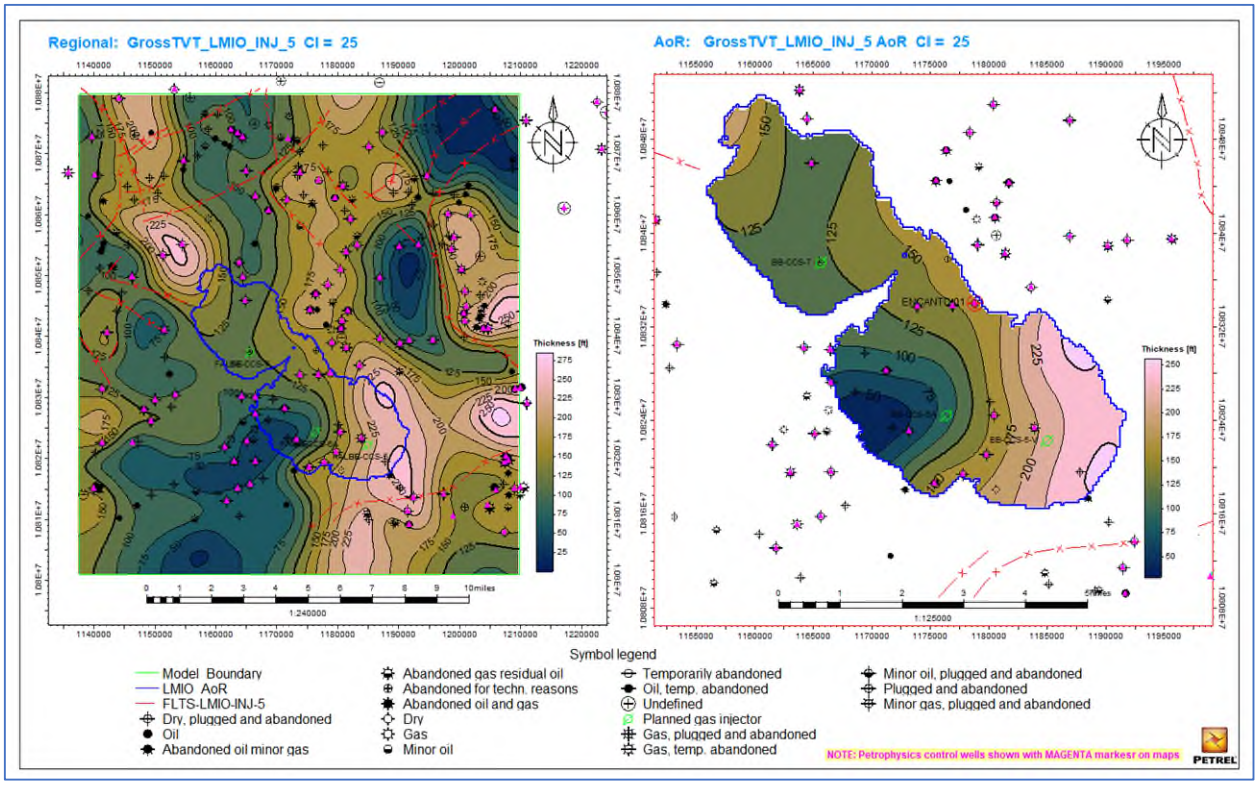


Figure AoR-99: Regional and AoR gross thickness maps of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

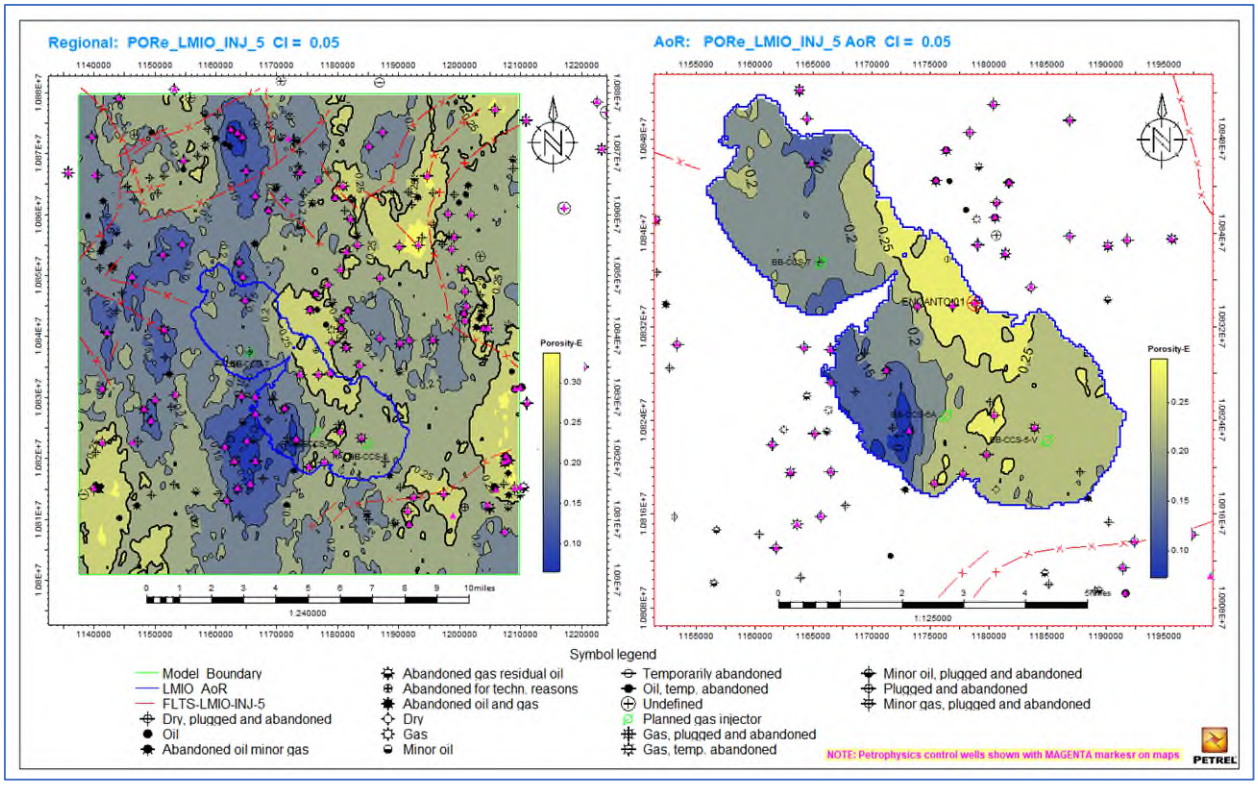


Figure AoR-100: Regional and AoR average effective porosity of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

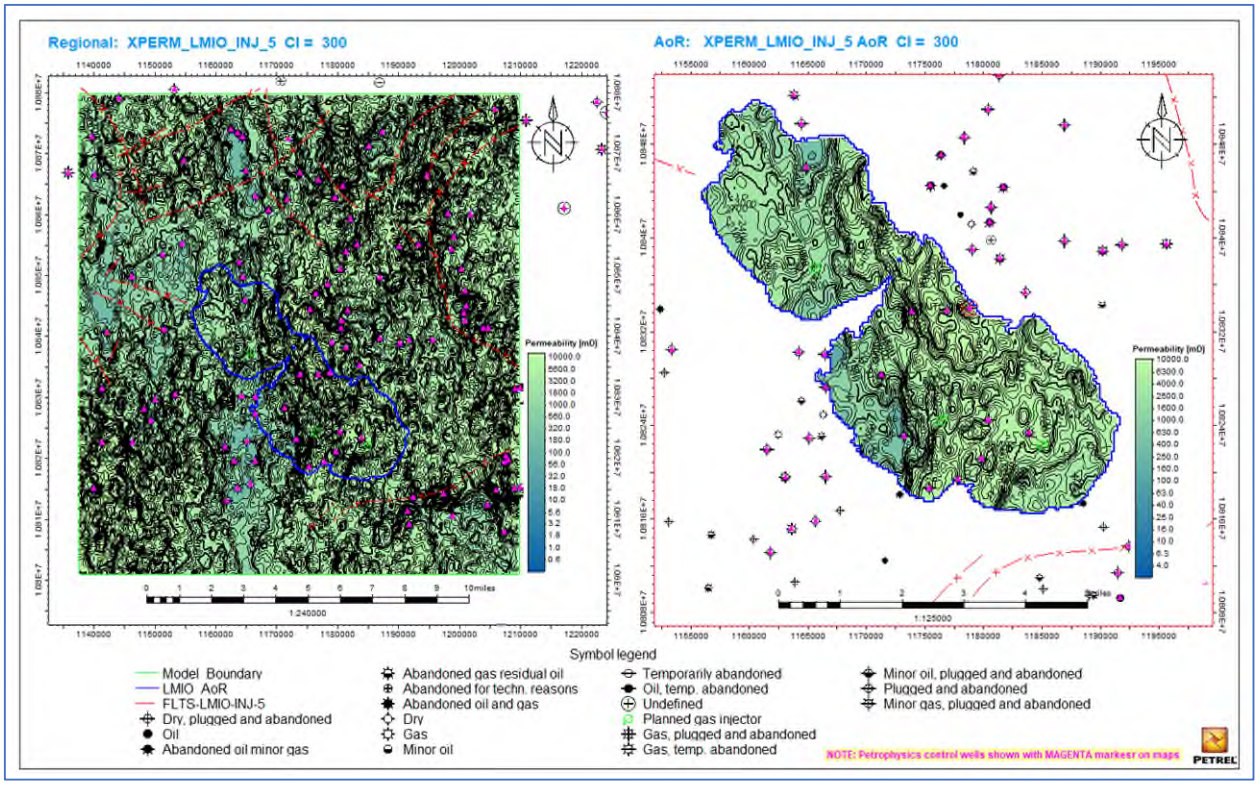


Figure AoR-101: Regional and AoR average permeability of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-4: Reservoir properties for the LMIO_INJ_5 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_5 Injection Zone
Top Depth (TVDss)	Claimed as PBI	
Base Depth (TVDss)		
Gross Thickness (ft.)		
Effective Porosity (fraction)		
Permeability (md)		

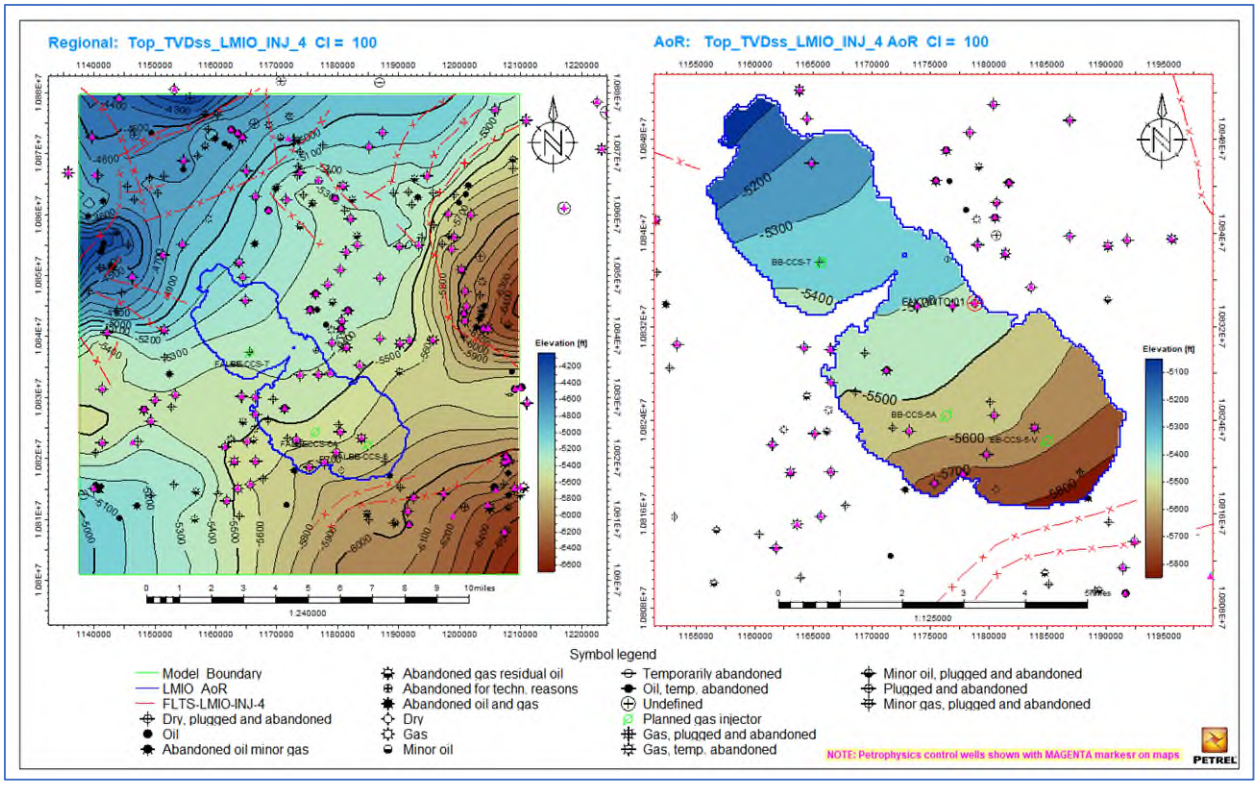


Figure AoR-102: Regional and AoR top structure maps of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

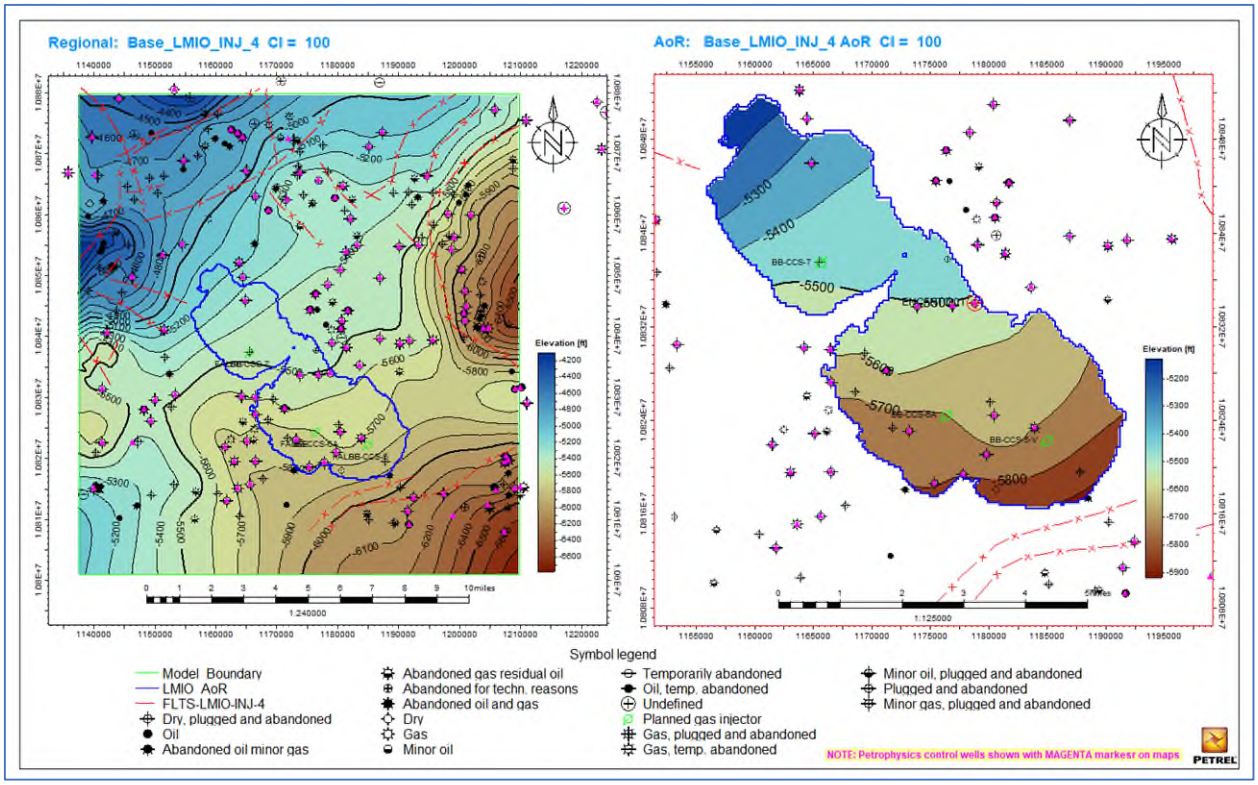


Figure AoR-103: Regional and AoR base structure maps of the LMIO_INJ_4 Injection Zone, in feet. Contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

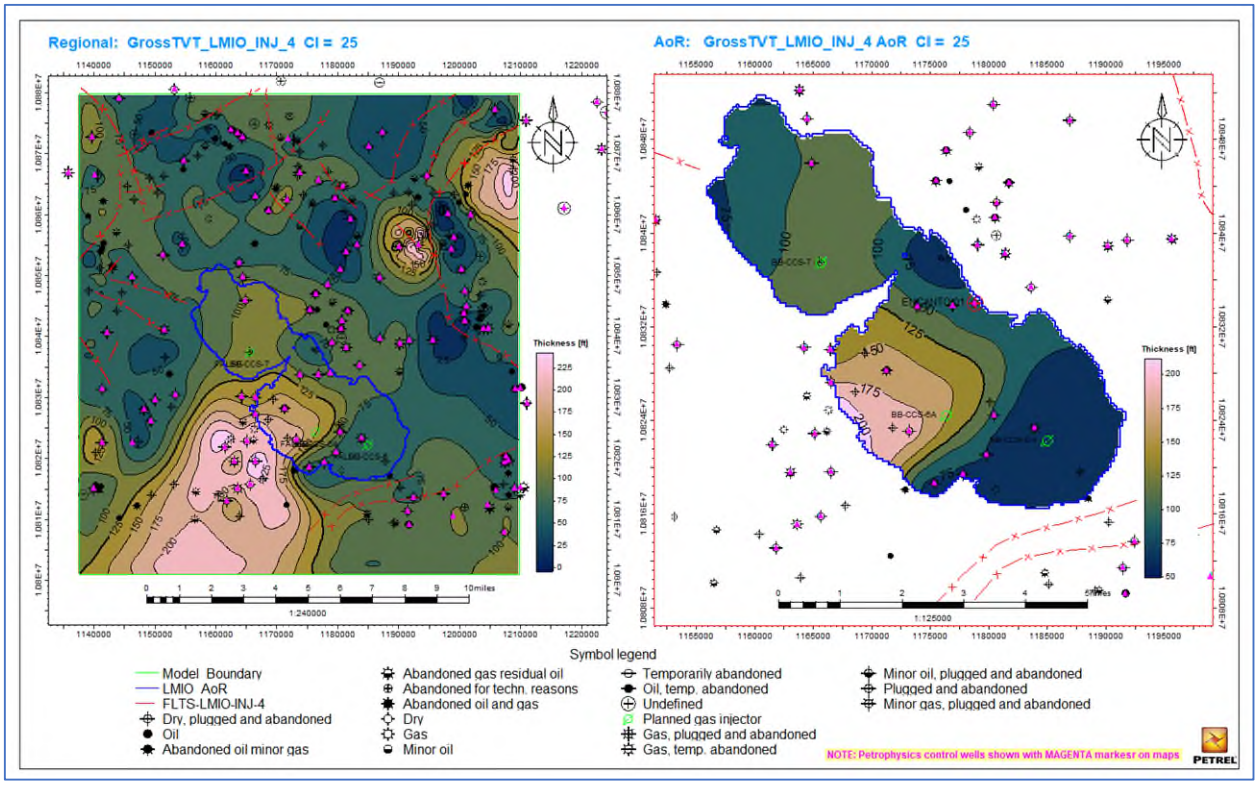


Figure AoR-104: Regional and AoR gross thickness maps of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

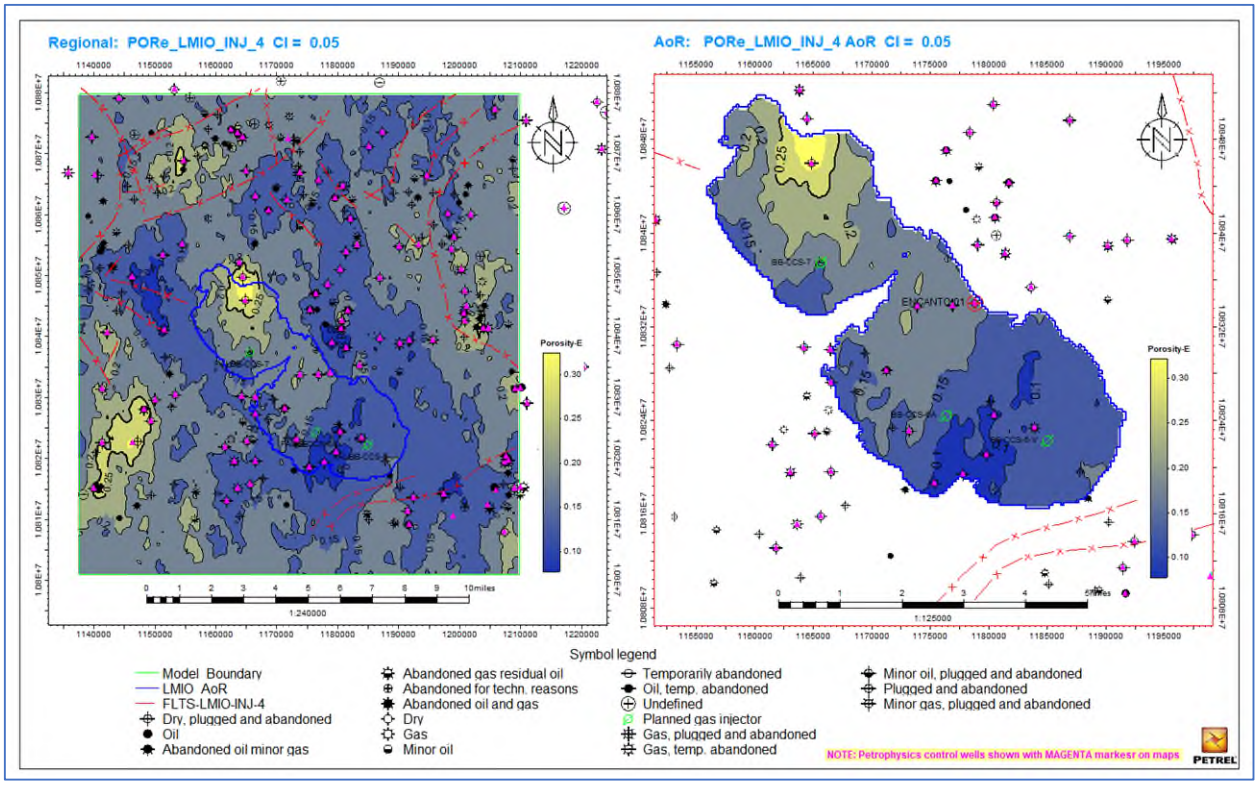


Figure AoR-105: Regional and AoR average effective porosity of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

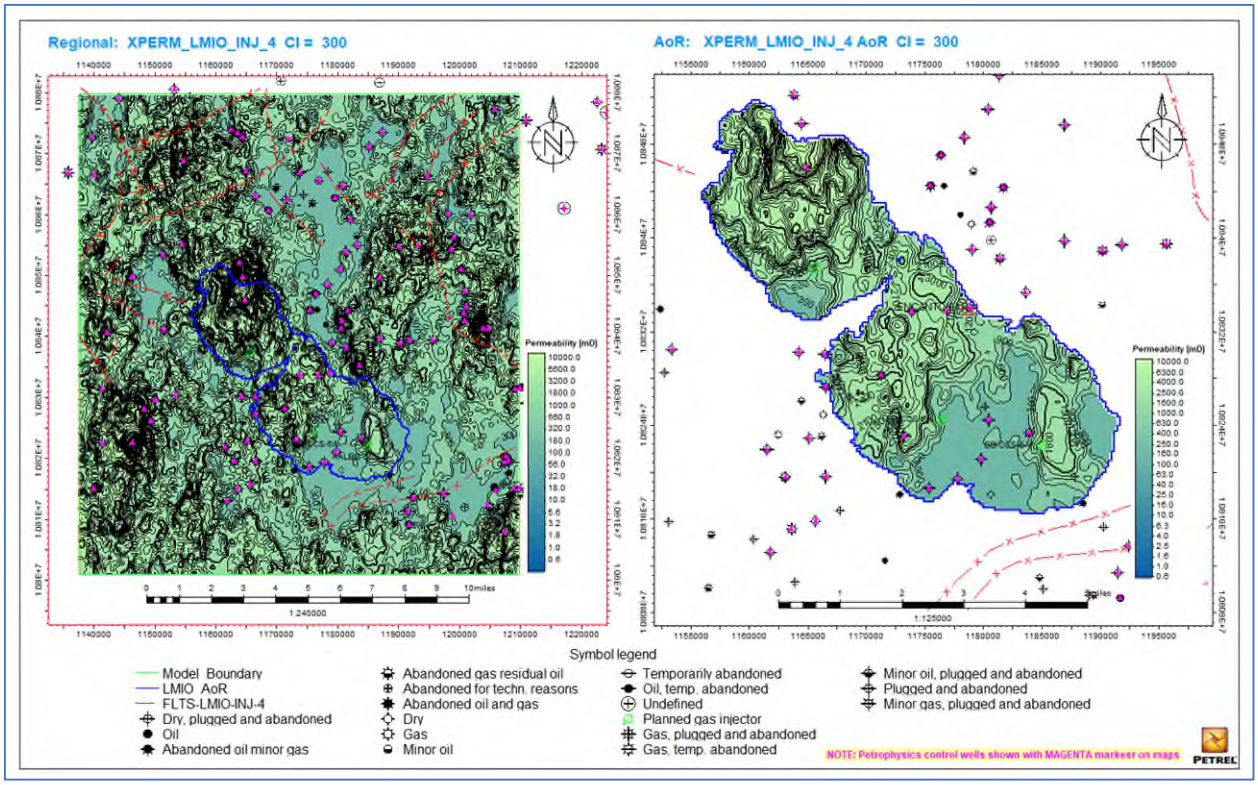


Figure AoR-106: Regional and AoR average permeability of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 300250 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-5: Reservoir properties for the LMIO_INJ_4 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_4 Injection Zone
Top Depth (TVDss)	Claimed as PBI	
Base Depth (TVDss)		
Gross Thickness (ft.)		
Effective Porosity (fraction)		
Permeability (md)		

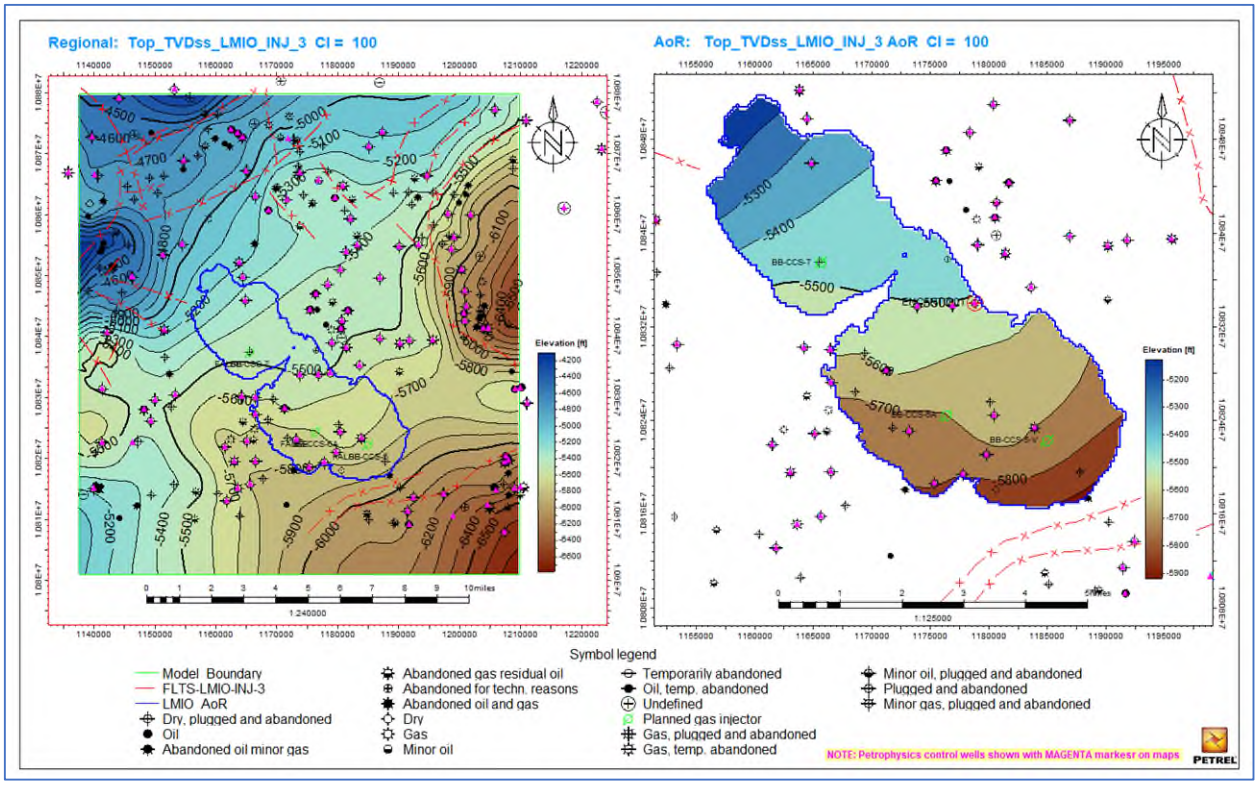


Figure AoR-107: Regional and AoR top structure maps of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

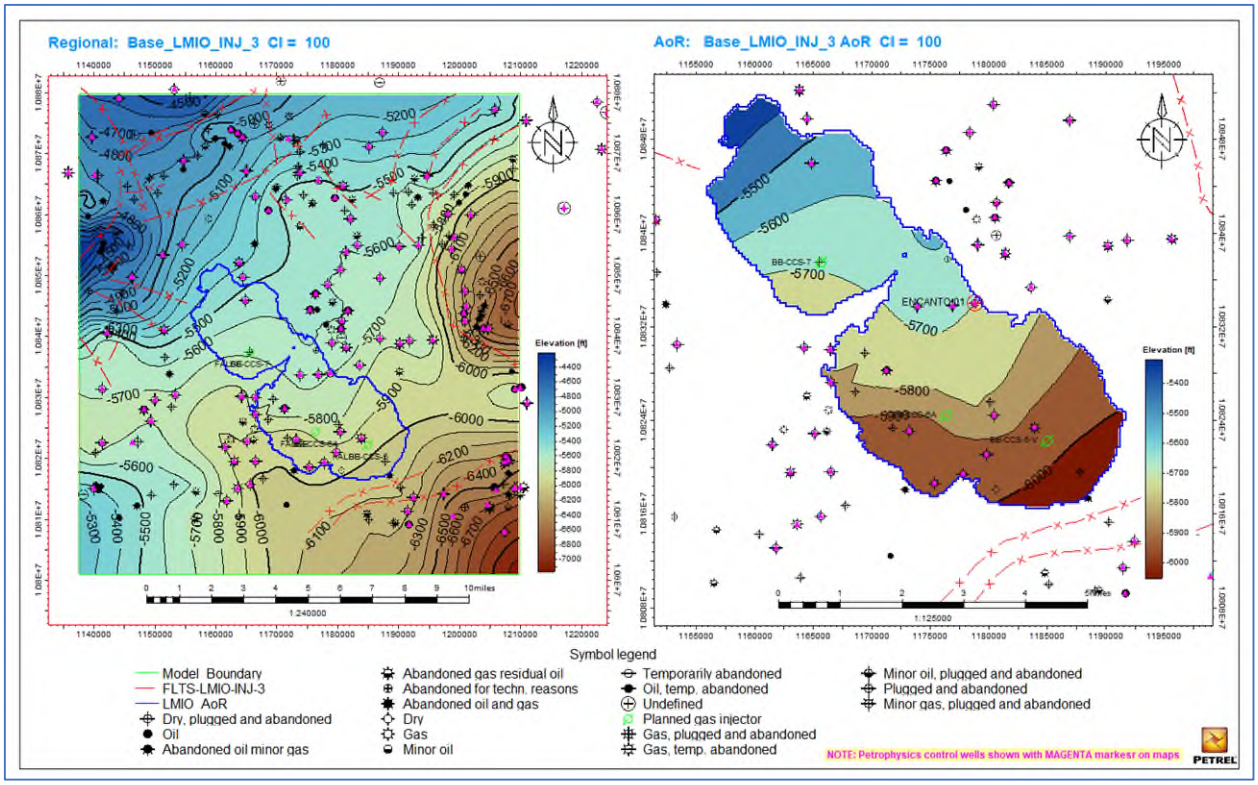


Figure AoR-108: Regional and AoR base structure maps of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

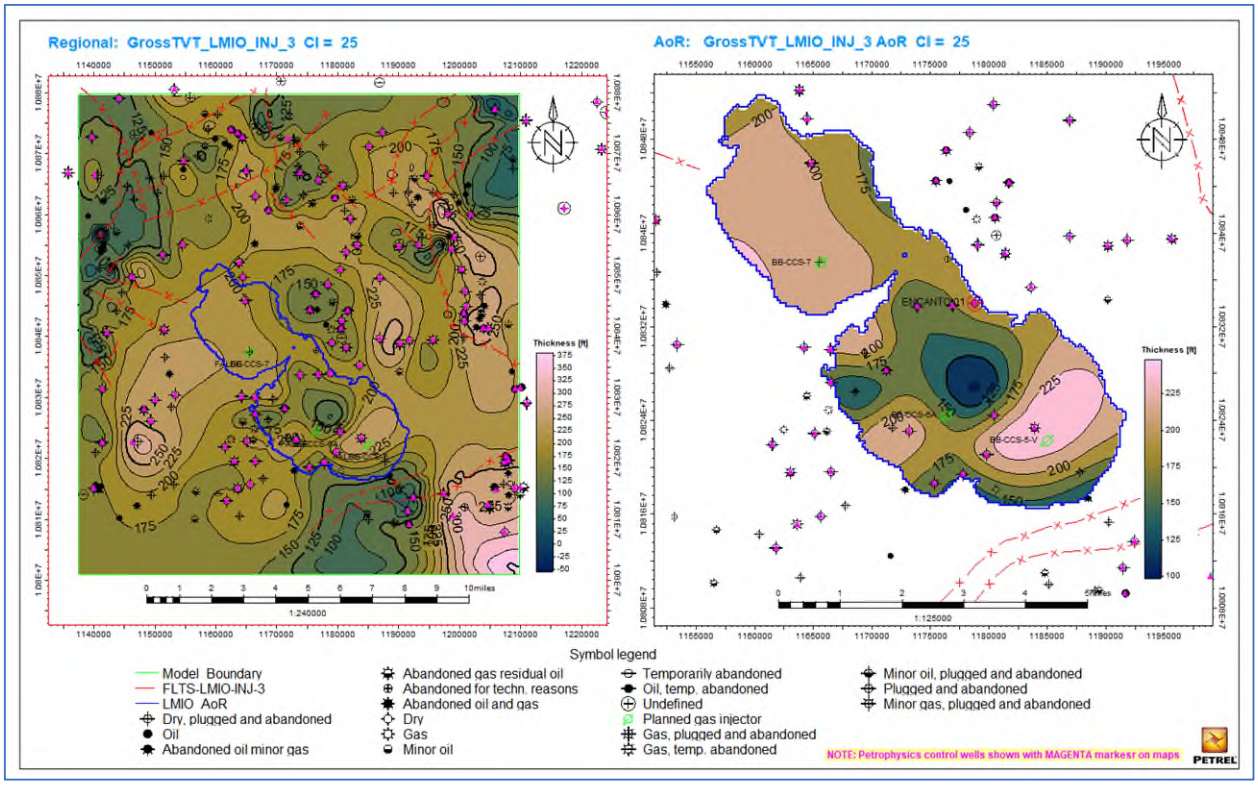


Figure AoR-109: Regional and AoR gross thickness maps of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

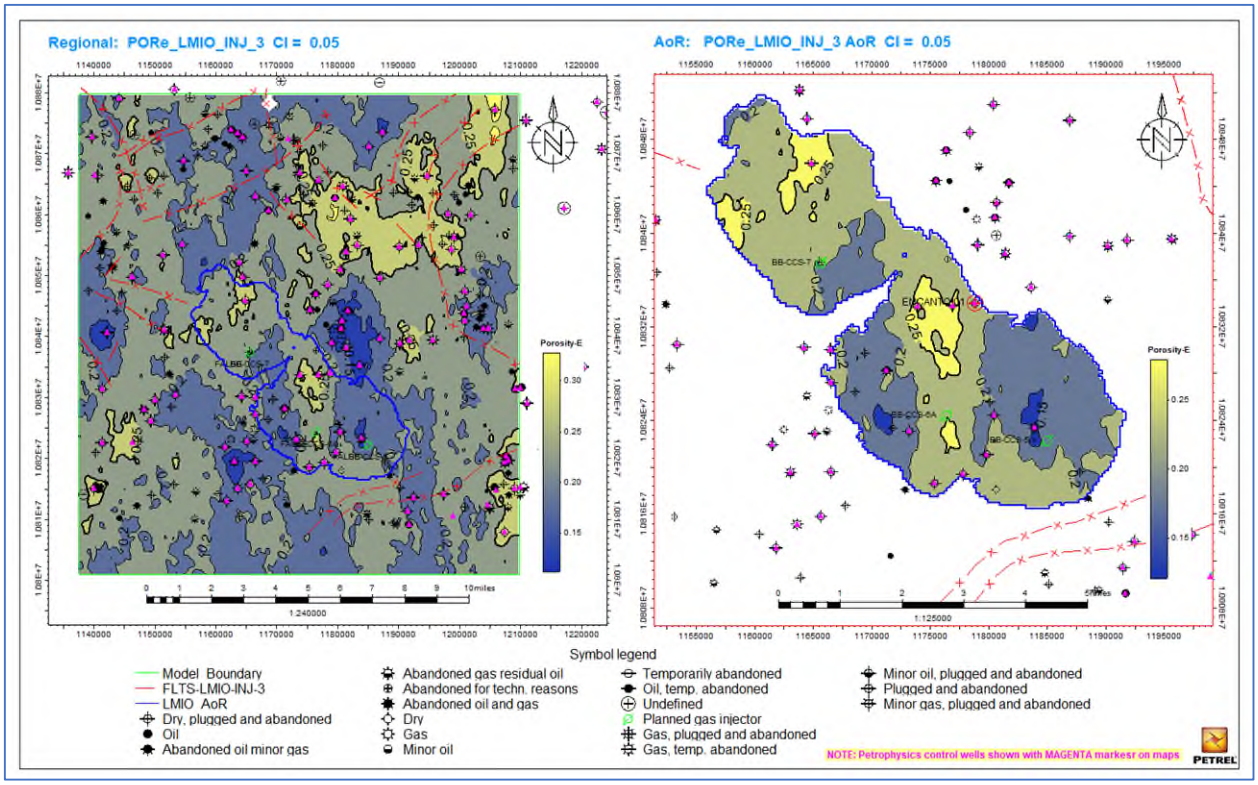


Figure AoR-110: Regional and AoR average effective porosity of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

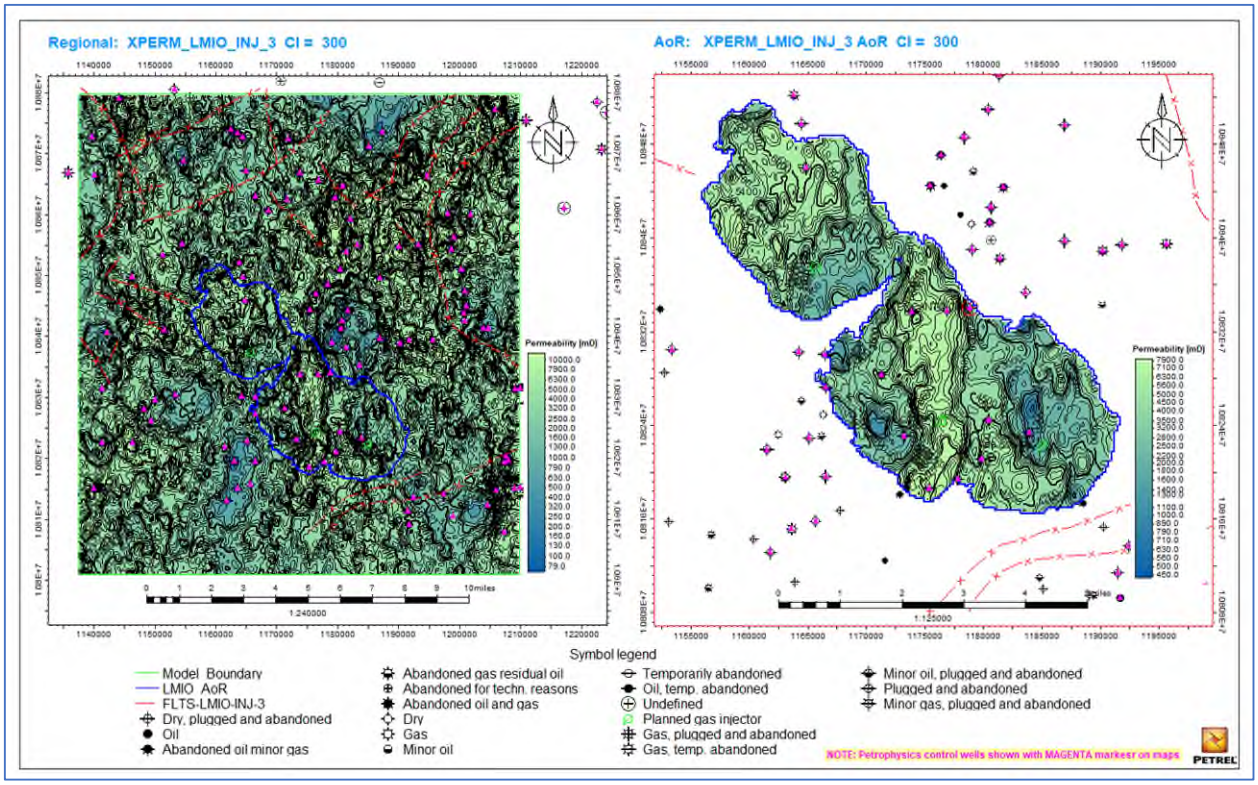


Figure AoR-111: Regional and AoR average permeability of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-6: Reservoir properties for the LMIO_INJ_3 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_3 Injection Zone
Top Depth (TVDss)	Claimed as PBI	
Base Depth (TVDss)		
Gross Thickness (ft.)		
Effective Porosity (fraction)		
Permeability (md)		

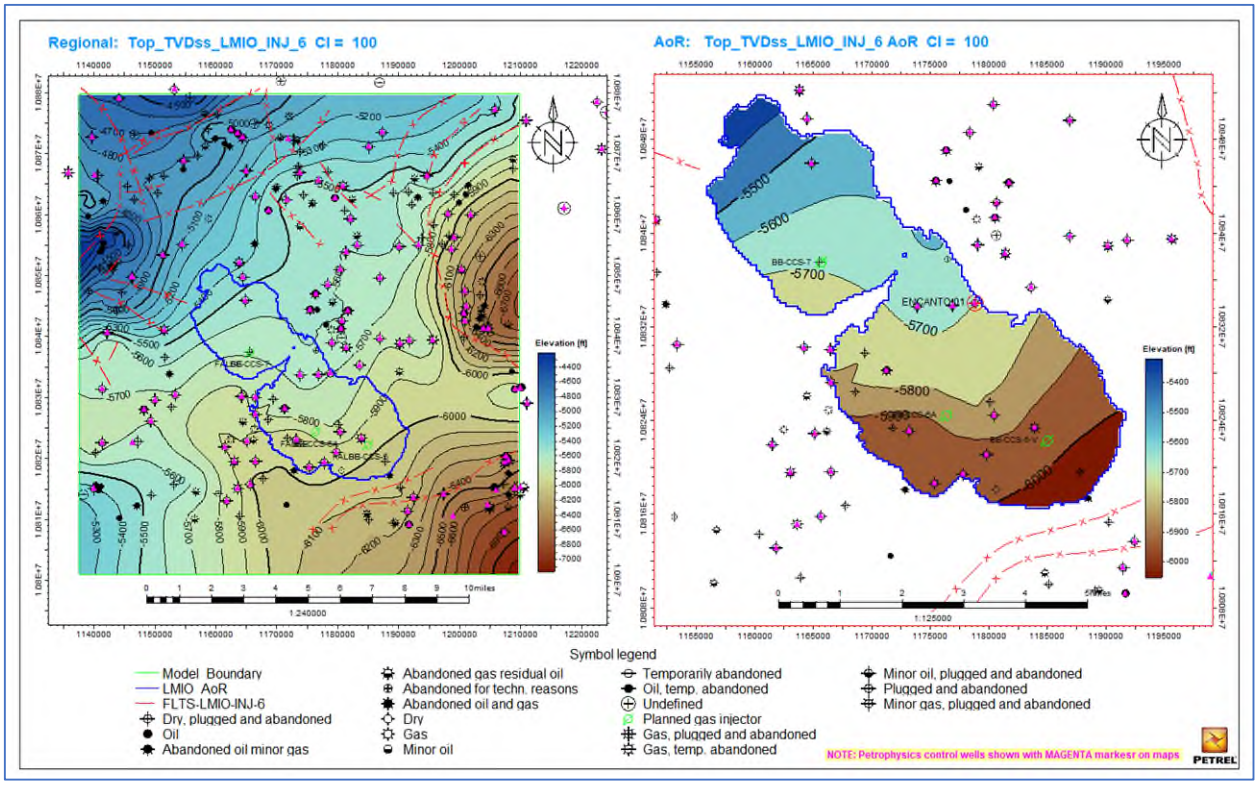


Figure AoR-112: Regional and AoR top structure maps of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

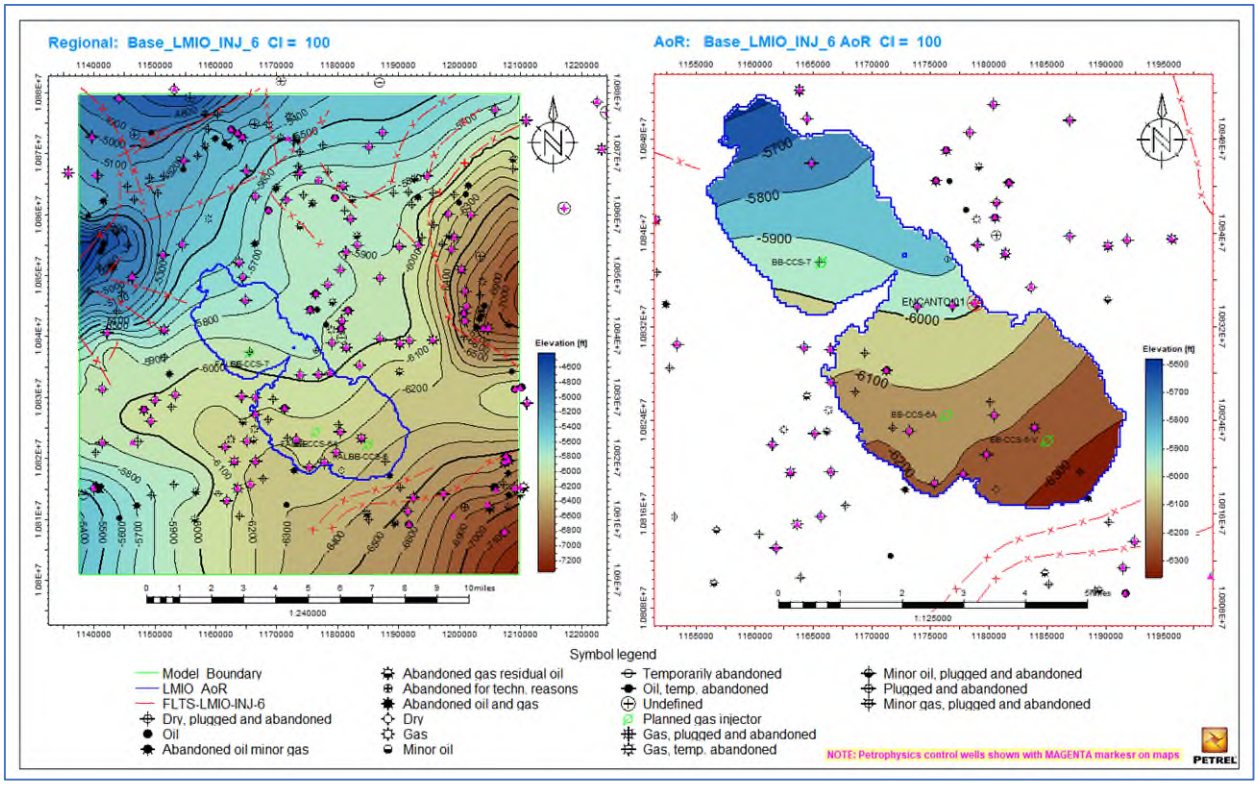


Figure AoR-113: Regional and AoR base structure maps of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

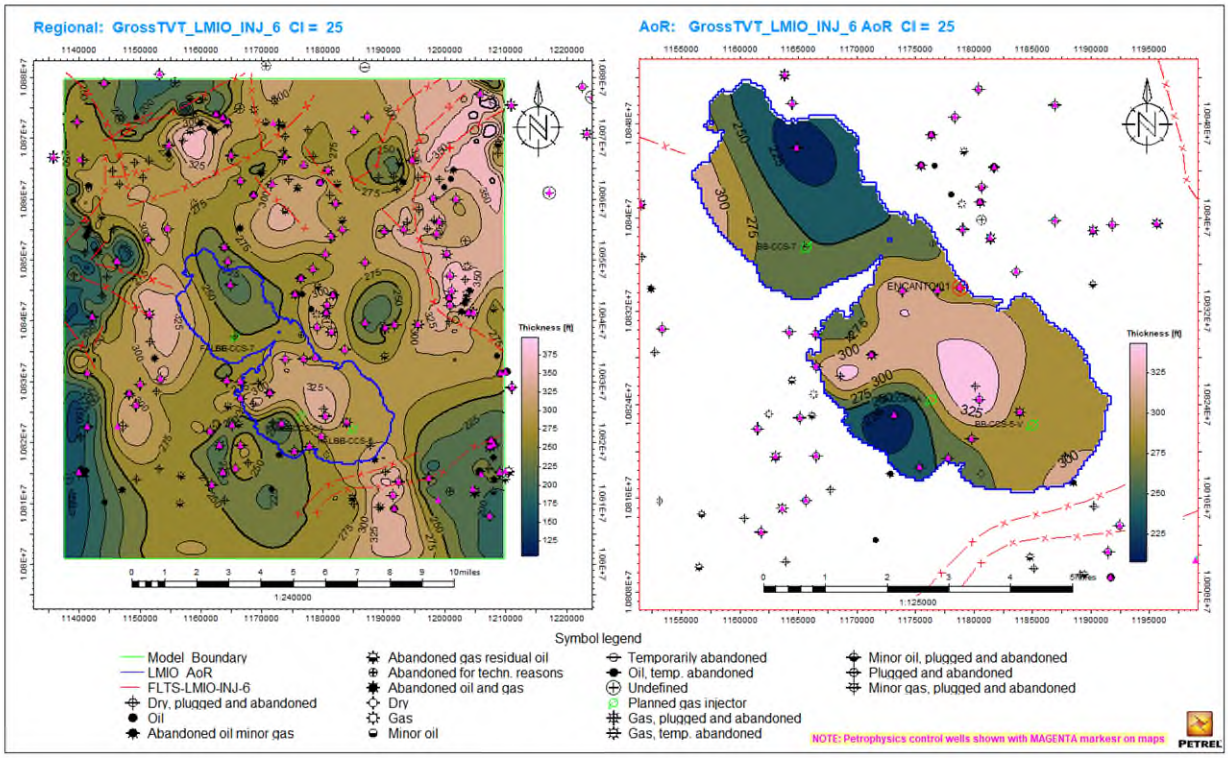


Figure AoR-114: Regional and AoR gross thickness maps of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

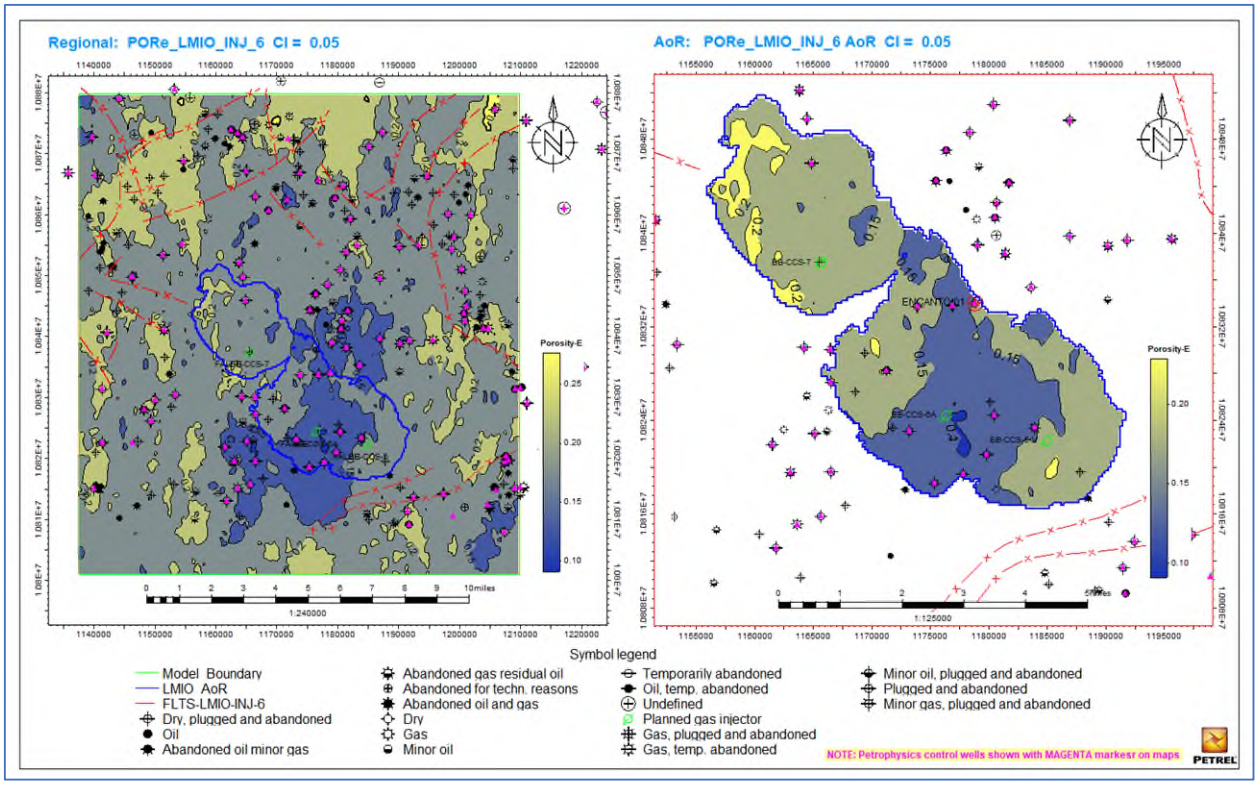


Figure AoR-115: Regional and AoR average effective porosity of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

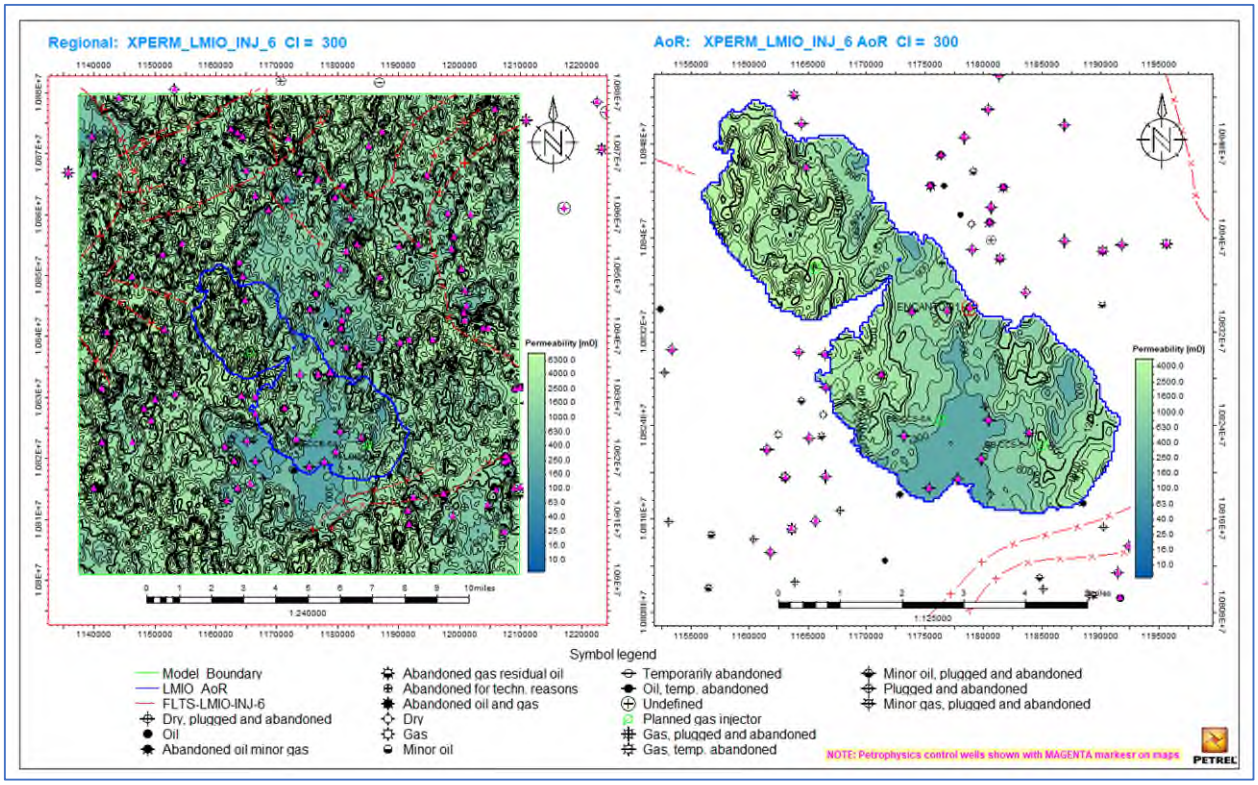


Figure AoR-116: Regional and AoR average permeability of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 250 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-7: Reservoir properties for the LMIO_INJ_6 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_6 Injection Zone
Top Depth (TVDss)	Claimed as PBI	
Base Depth (TVDss)		
Gross Thickness (ft.)		
Effective Porosity (fraction)		
Permeability (md)		

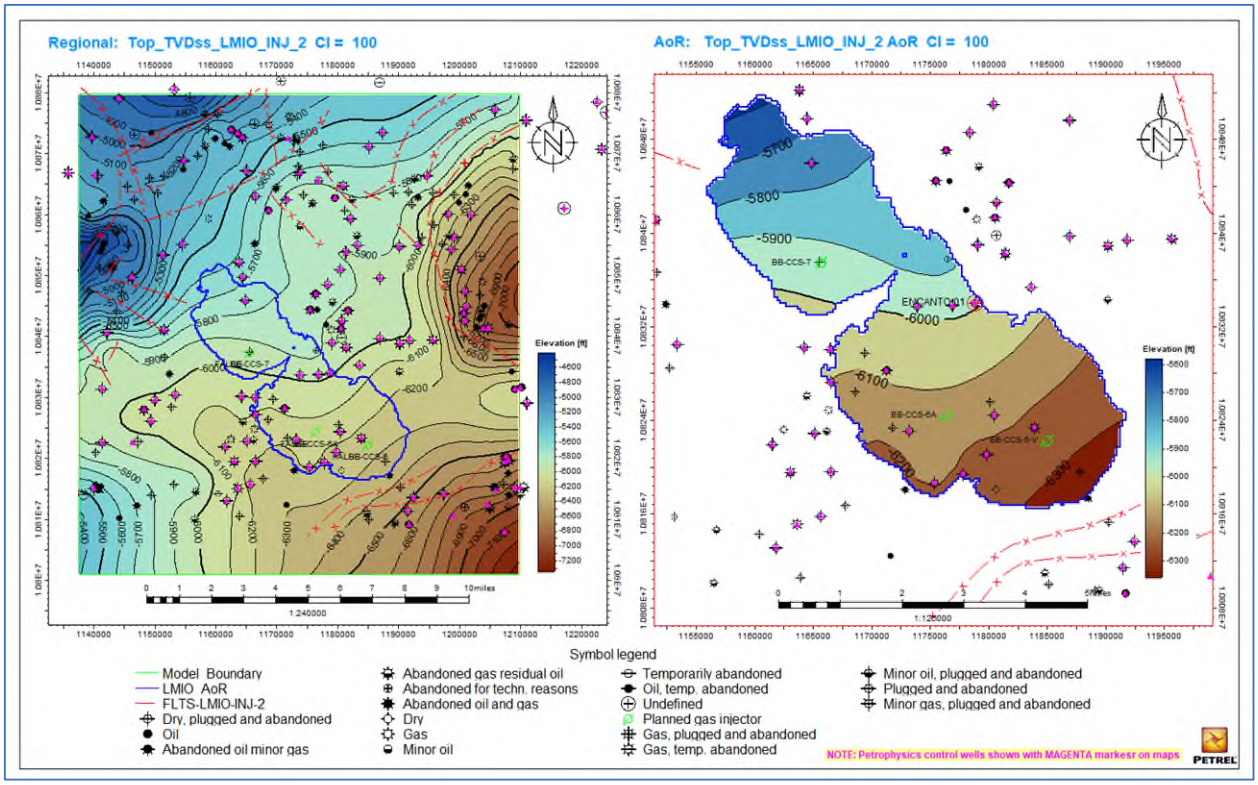


Figure AoR-117: Regional and AoR top structure maps of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

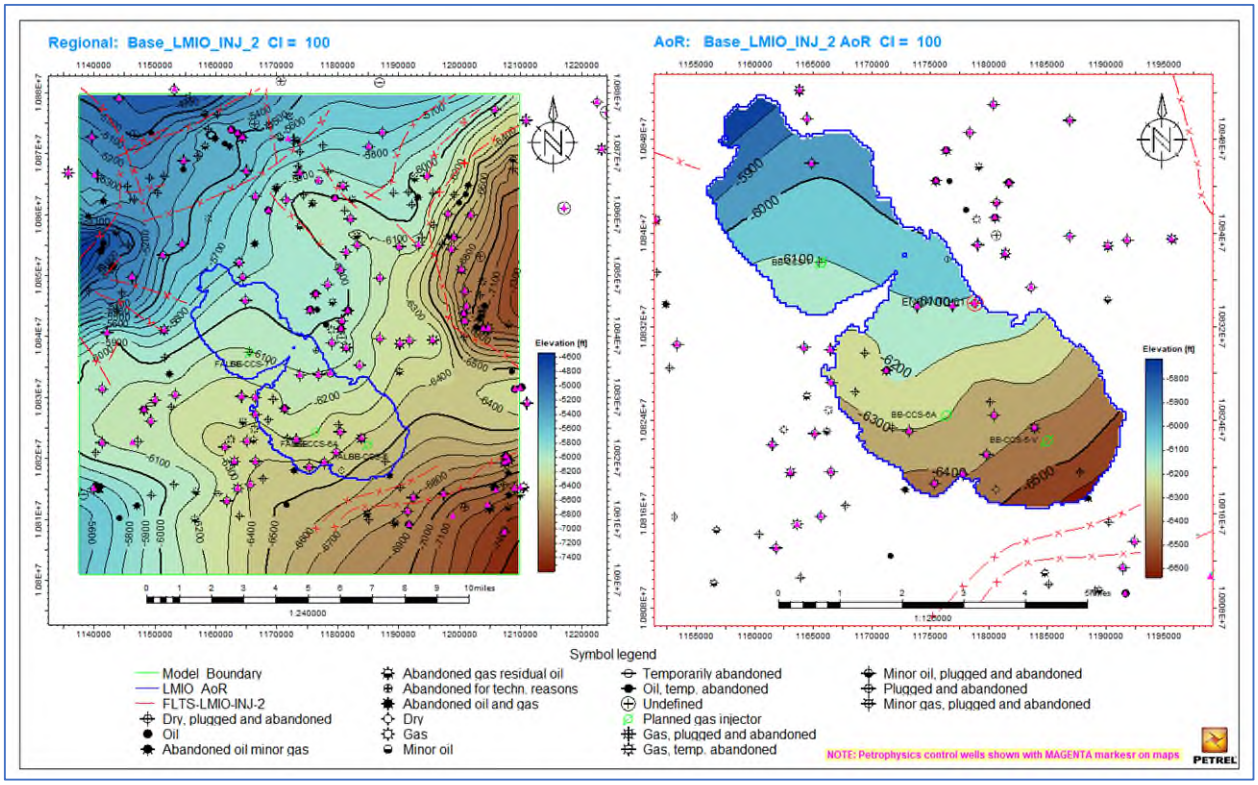


Figure AoR-118: Regional and AoR base structure maps of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

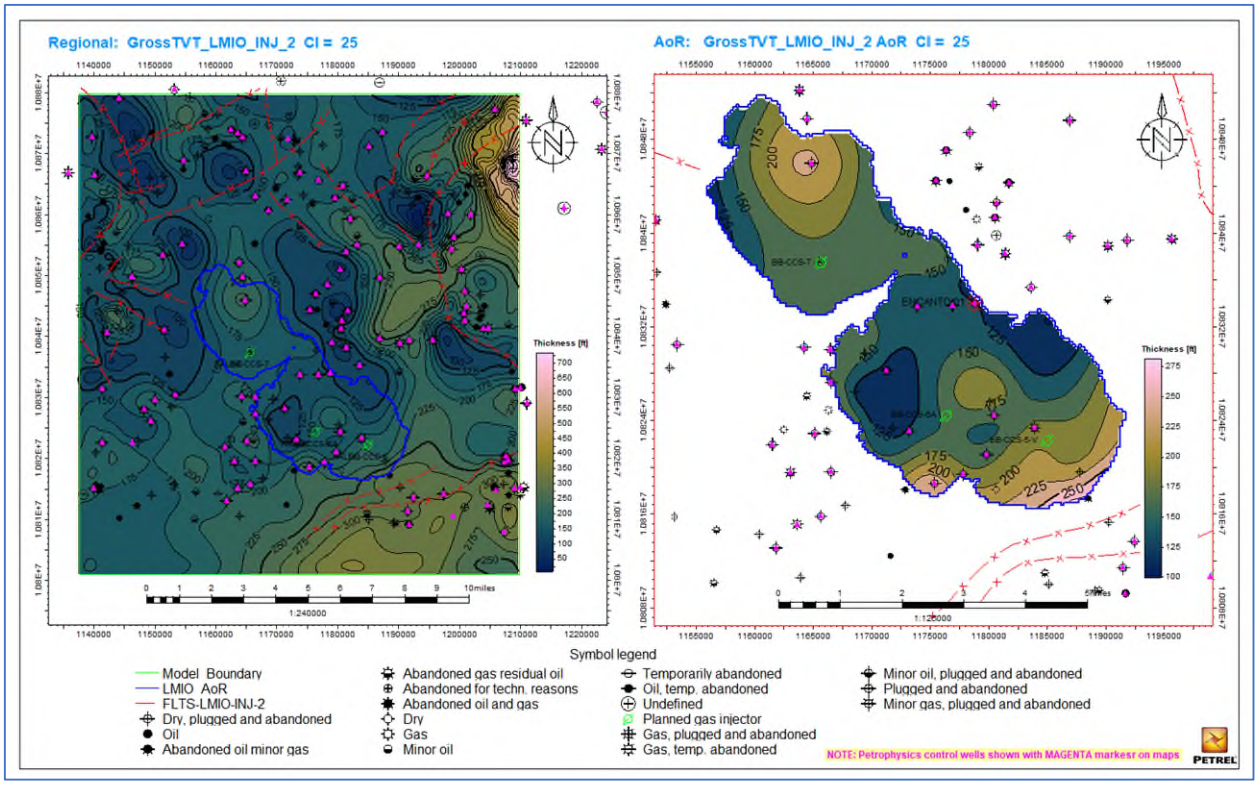


Figure AoR-119: Regional and AoR gross thickness maps of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

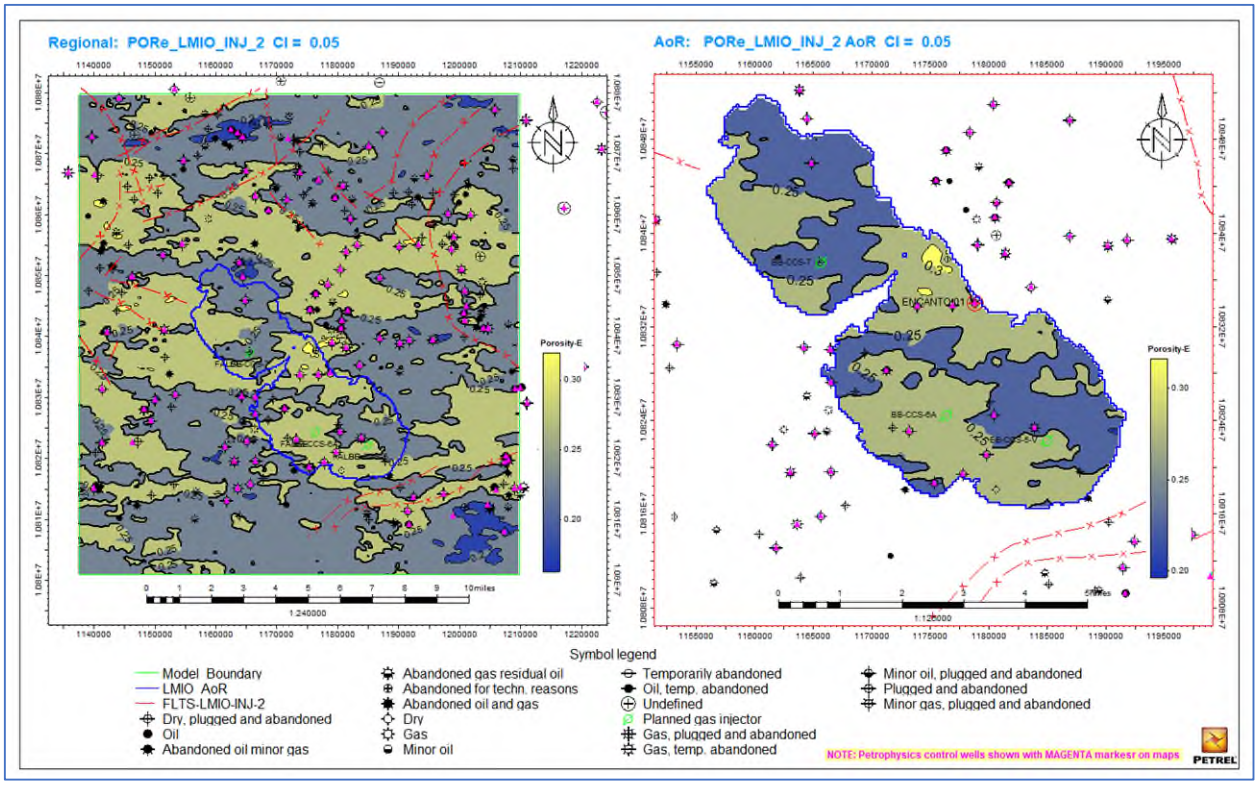


Figure AoR-120: Regional and AoR average effective porosity of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

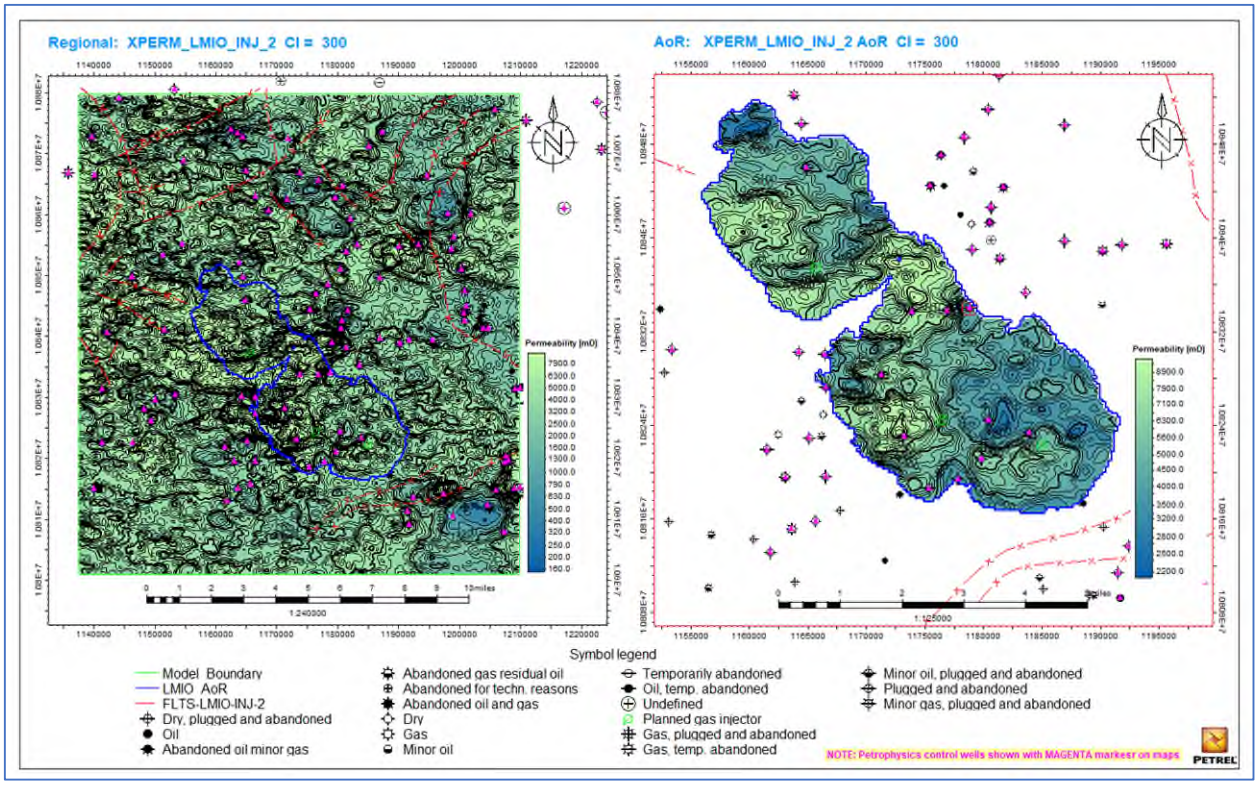


Figure AoR-121: Regional and AoR average permeability of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-8: Reservoir properties for the LMIO_INJ_2 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_2 Injection Zone
Top Depth (TVDss)	Claimed as PBI	
Base Depth (TVDss)		
Gross Thickness (ft.)		
Effective Porosity (fraction)		
Permeability (md)		

3.8.2 AoR Confining Zone Characteristics

This section describes in detail the information related to the proposed confining zones. It describes the depths, areal extents, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection zones, including geology changes and facies based on geological cores, well logs, names, and lithology description according to 40 CFR § 1476.82 (3)(iii).

3.8.2.1 Hackberry Confining Zone

The Hackberry Confining Zone is the base confining zone for the proposed storage complex. Based on the slabbed whole core description (Appendix A core panel 7), this is dominantly a bioturbated argillaceous siltstone to silty mudstone, which was deposited in an offshore transition inner neritic depositional environment. Within the cored interval, several feet are argillaceous, very fine-grained sandstones with varying textures ranging from bioturbated or massive to horizontally laminated to low-angle cross stratified. The burrows represent a time hiatus when organisms had time to burrow into the sediment; those burrows were subsequently filled with the fine-grained

sands. Trace fossils were observed, specifically trace fossils from a lower energy setting. The clay rich shales are good baffles that compartmentalize this confining zone.

The Hackberry Confining Zone is a low-permeability (confirm with MICP and whole core, average air permeability from core is [redacted] Claimed as PBI) confining zone that is regionally contiguous in both the north-south dip direction, as well as in the east-west strike direction. This third-order marine transgressive shale represents a time in the Oligocene when the Gulf Coast was submerged under water due to rising sea levels, which explains the lateral continuity.

3.8.2.1.*1 Petrologic description*

The associated Hackberry silty mudstones and shales were analyzed for composition, nature of the clay species, and presence of structural alignment for anisotropy evaluation. Examples are shown in Figures AoR-122 and AoR-126, which describe a silica-rich argillaceous mudstone with quartz, feldspars, rock fragments, and mica and sandy mudstone with quartz, feldspars, and volcanic rock fragments, respectively. The quartz richness in this confining unit may impact the sealing capacity because of larger pore throats 0.055 to ~ 0.4 microns in the fine sands and laminations, but the mudstone intervals with small pore throat radii between 0.001 to ~0.025 microns can act as a seal, and the combination of pore throats, will act as a confining system.

There is in general a weak alignment (anisotropy). Most clays are smectite and smectite-illite based on XRD and SEM analyses. The nature of pores including assessment of kerogen pores, if any, clay species, and structural alignment were the key objectives of SEM analysis. The intrinsic anisotropy due to clay orientation is high. The extrinsic anisotropy due to textural and mineralogical alignment is low to insignificant. Two mudstone samples were ion-milled; based on the SEM examination, sample 8455.3 ft shows no structural alignment, and 8463.70 ft displays slight textural anisotropy at thin section scale.

Claimed as PBI

Claimed as PBI


Claimed as PBI


Claimed as PBI



If the mudstone was silty, thin section grain sizes were measured in addition to laser particle size distribution analysis (LPSA). As is common, 200 grains were analyzed. The MICP data were supplemented as well. An example is shown in Figure AoR-127.



3.8.2.1.2 Organic petrography, maturity evaluation, and extraction for presence of oil

Based on the organic petrography and thermal alteration index (Chevron) study that Stratochem Services conducted, the Encanto 01 Hackberry shale samples selected below the injection zone are immature to marginally mature. The average %VRo =0.39%, Min=0.31%, Max=0.49%. Vitrinite Reflectance Equivalent Vre from Bitumen Reflectance: Average=0.43%, Min=0.40%, Max=0.44%. In the samples examined, both bitumen and kerogen are present. Additionally, the sample's position in the oil generation zone arrived at from Chevron TAI indicates that the kerogen is currently immature to marginally mature.


Claimed as PBI



The hydrocarbon potential of the samples for oil is fair to good. Furthermore, the kerogen type is dominantly II/III, but the zones examined are too immature to have generated any oil or gas. It should be noted that the section was drilled with synthetic oil-based mud (OBM), precluding pyrolytic analysis on any free *in-situ* hydrocarbons. Mud extract gas chromatograms are shown depicting the OBM contamination, which is also shown to be present in the cuttings and core samples.

3.8.2.1.3 Contamination of the rock by synthetic oil-based mud

However, if there was oil in the zone, it would be noticed even with the OBM. In order to confirm that any "oil" in the cuttings was due to the synthetic oil-based mud, four cutting samples were quantitatively extracted with dichloromethane to remove all soluble organic matter, and the extracted material was analyzed by gas chromatography (GC). The four extract GCs are shown below and are identical to the synthetic oil added to the drilling mud (refer to Appendix E); the OBM contaminants tower above any indigenous hydrocarbons. This proves that there was no indigenous oil-like material in the cuttings. Therefore, indigenous "oil" in this zone is not present in measurable quantities. Given the low thermal maturity, this is not surprising.



3.8.2.1.4 Seal Analysis

There are six samples with MICP (Mercury Injection Capillary Pressure) in the Hackberry Confining Zone; three from vertical and three horizontals whole core plugs. Following a conservative approach (please see Appendix A for a more detailed analysis), the displacement pressure criteria will need an injection height of ~[redacted] feet before breaking in the confining zone. These results will be corroborated/calibrated to TEP (Threshold Entry Pressure) test results.

3.8.2.1.5 Hackberry Confining Zone Maps

The Hackberry confining zone maps are shown below.

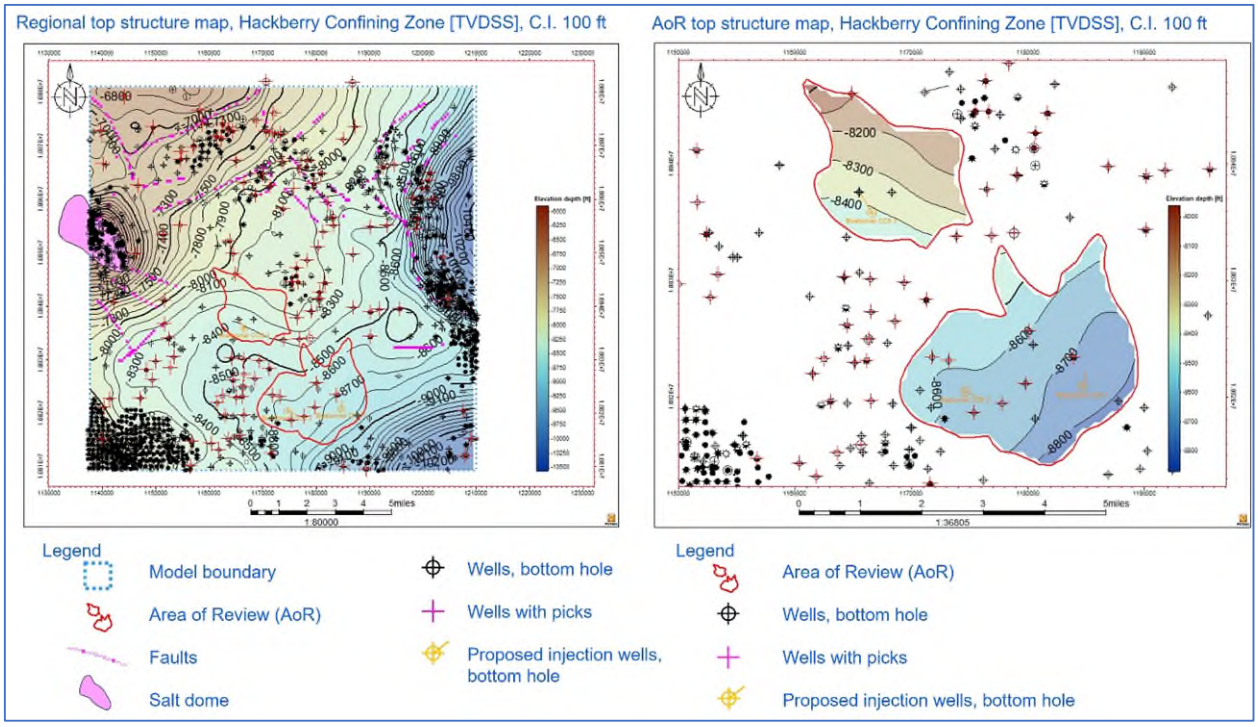


Figure AoR-132: Regional and AoR top structure map of the Hackberry Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

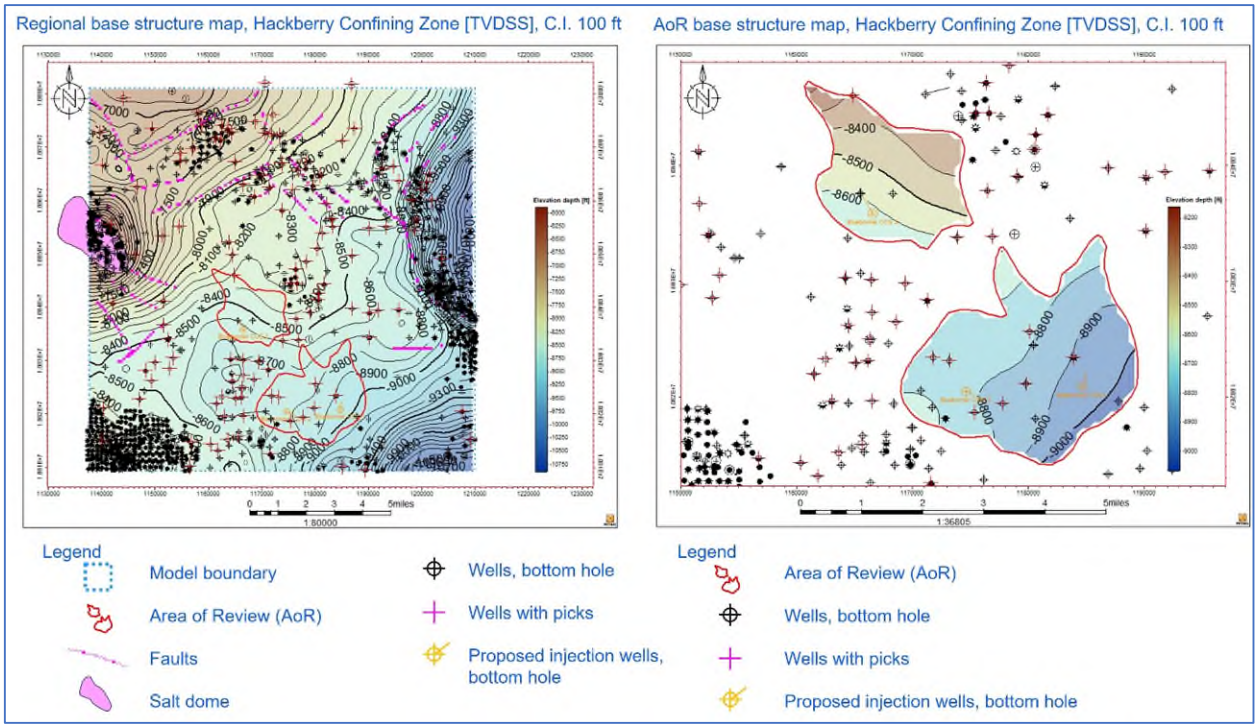


Figure AoR-133: Regional and AoR base structure map of the Hackberry Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

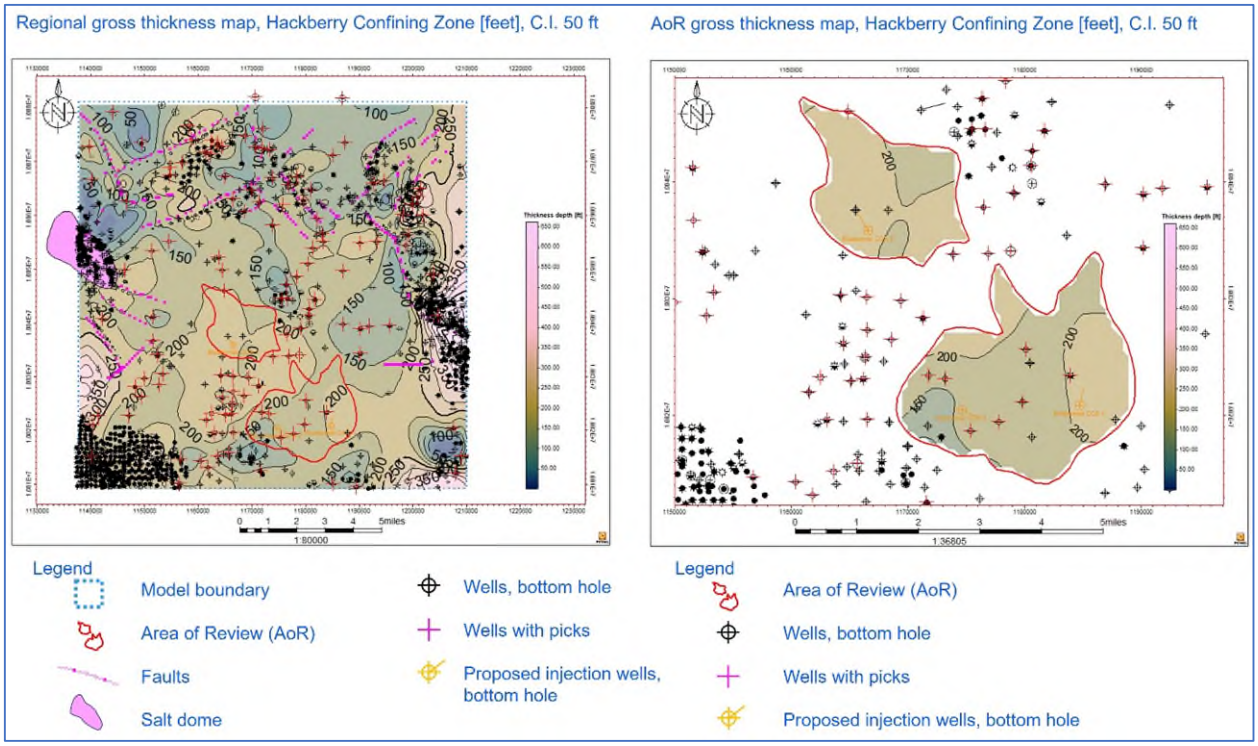


Figure AoR-134: Regional and AoR gross thickness map of the Hackberry Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

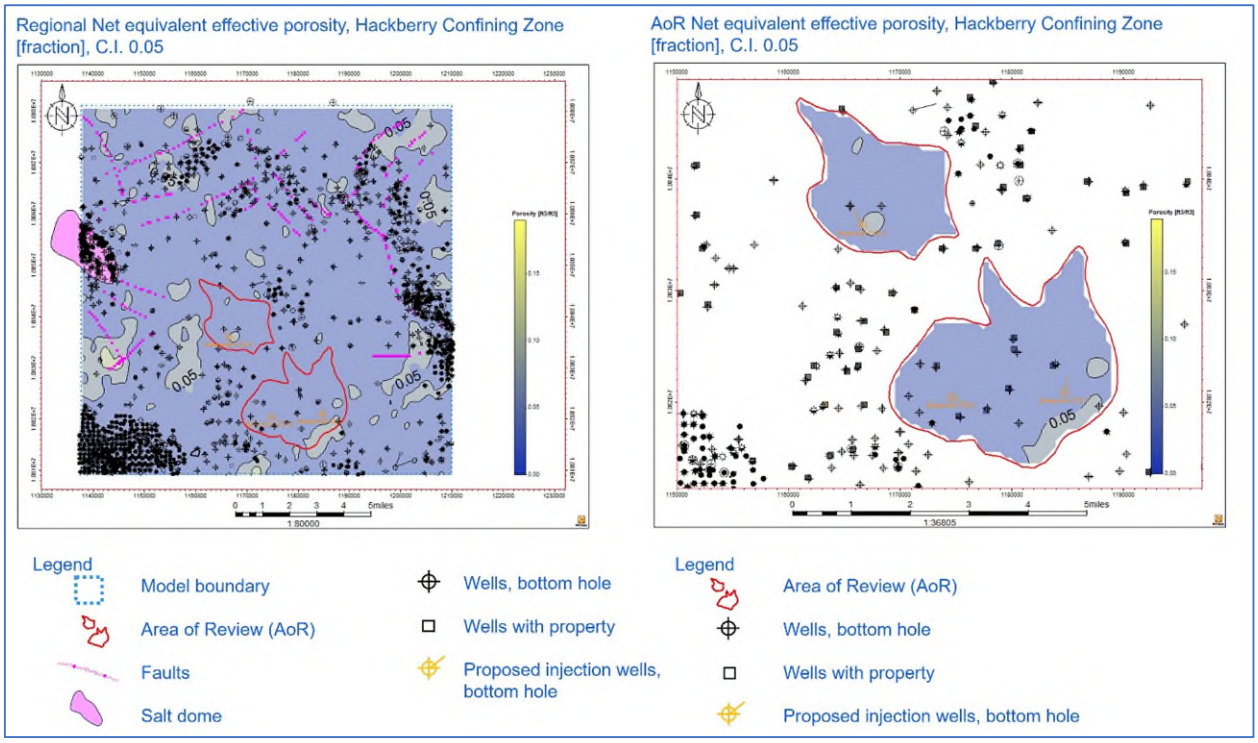


Figure AoR-135: Regional and AoR net equivalent effective porosity map of the Hackberry Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

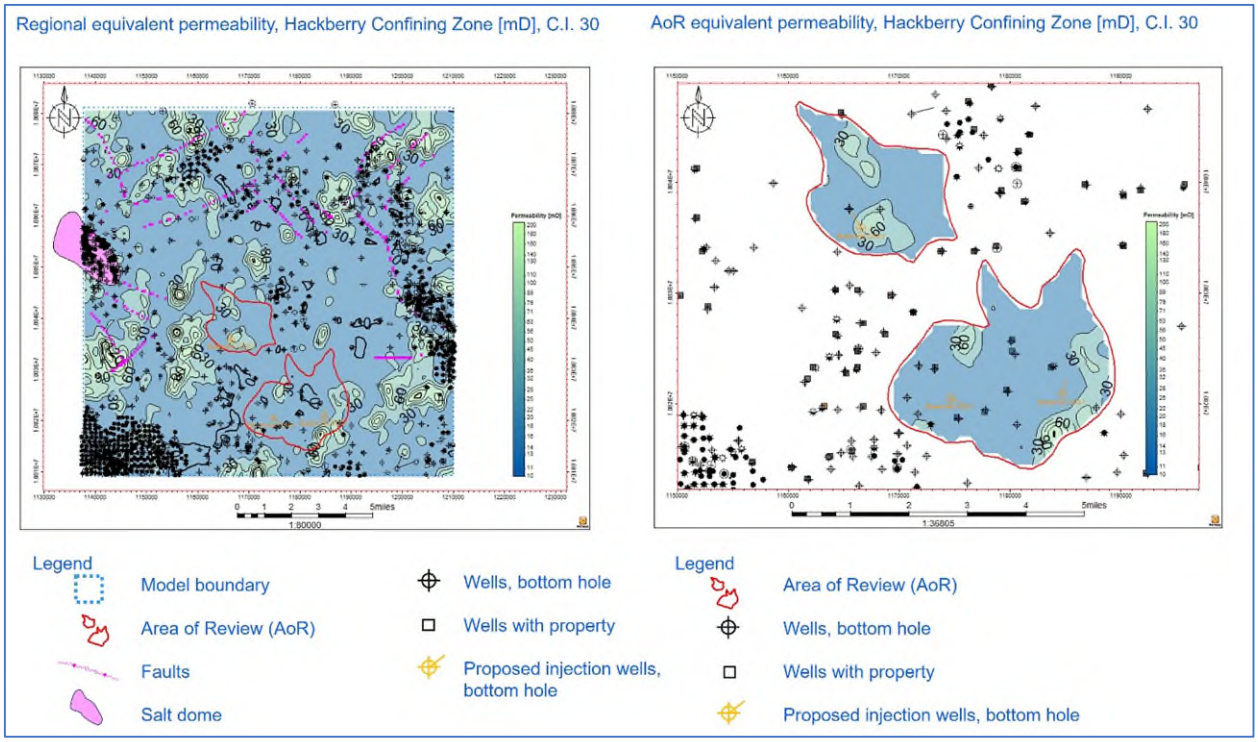


Figure AoR-136: Regional and AoR equivalent permeability map of the Hackberry Confining Zone in millidarcy (md), contour interval 30 md. The average permeability in the Hackberry Confining Zone across the AoR is driven by a lack of data points and can be misleading. This map was generated from the Oligocene Model described under 4.0.

The following numbers represent map-based average numbers extracted from the geomodel over the AoR. The localized permeability bullseyes in the Hackberry Confining Zone across the AoR are driven by a lack of data points, where the model predicts porosity and estimates permeability but has no actual control points. Therefore, the resulting permeability maps look patchy in this zone, which is not substantiated with well control and not accurate. The permeability map, however, does show low permeability values where data points do exist, which correlates with permeability measurements from core.

Table AoR-9: Reservoir properties for the Hackberry Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Confining Zone
Top depth [TVDSS]	Minimum	Claimed as PBI
	Maximum	
	Average	
Base depth [TVDSS]	Minimum	
	Maximum	
	Average	

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Confining Zone
Gross Thickness [ft]	Claimed as PBI	
Porosity [fraction] EQI, net eff. Porosity * NTG		
Permeability [md]		

3.8.2.2 Frio Confining Zone

After the sandstones of the Hackberry Injection Zone were deposited, another sea level rise followed that flooded the northern Gulf Coast of Texas and resulted in another laterally contiguous shale called the Frio Confining Zone. This shale provides the top confining zone for the Hackberry Injection Zone below as well as the base confining zone for the Frio Injection Zone above. As such, it is an intraformational confining zone in between two vertically stacked injection zones of the Hackberry and Frio.

The Frio Confining Zone can be mapped laterally in both the north-south dip and east-west strike direction. The SP log character stands out as a blocky shale in between the Hackberry sandstones below and Frio sandstones above. The gross thickness map shows shale thickening towards the south and downdip along with a decrease in thickness towards the north and updip which is a function of water depth during a marine transgression of the gently dipping Gulf Coast. Based on a sequence stratigraphic approach, the Frio Confining Zone represents a third-order shale-prone transgressive system tract (TST), which is overlain by the sand-prone third order highstand system tract (HST) fluvio-deltaic Frio Injection Zone.

The lithologic composition of the Frio Confining Zone is described below based on mud cuttings acquired during drilling operations of the stratigraphic test well Encanto 01 and mudlogs from two legacy wells nearby:

The Frio Confining Zone lithology shows 80-100% light to dark grey and blue to green shale, soft to poorly-moderately firm and brittle, subblocky to subplaty and splintery, massive, dull, predominantly very clay-rich with traces of brown red to purple minerals, traces of calcite containing 0-20% minor soft and ashy intervals, light to dark grey and translucent clear silty sand, very fine-grained, poorly consolidated to moderately cemented with silty argillaceous matrix, very poorly sorted, traces of calcite, limestone, and glauconite. No visible hydrocarbon cut, hydrocarbon, or mineral fluorescence were observed during mudlogging this interval.

3.8.2.2.1 Petrologic Description

Based on cuttings and XRD (see Appendix A), these are clay-rich mudstones with components of quartz, plagioclase, calcite, and K-feldspar with traces of pyrite, siderite, and anatase. XRD on the clay fraction determined that the clays are dominantly illite-smectite and minor kaolinite, illite+mica, and chlorite. The quartz weight percent varies and is reflective of isolated thin, approximately 2 ft thick, siltier stringers within the Frio Confining Zone, which can also be recognized on SP logs. Those intervals contain porosity but are surrounded by hundreds of feet of clay-rich transgressive muds.

3.8.2.2.3 Frio Confining Zone Maps

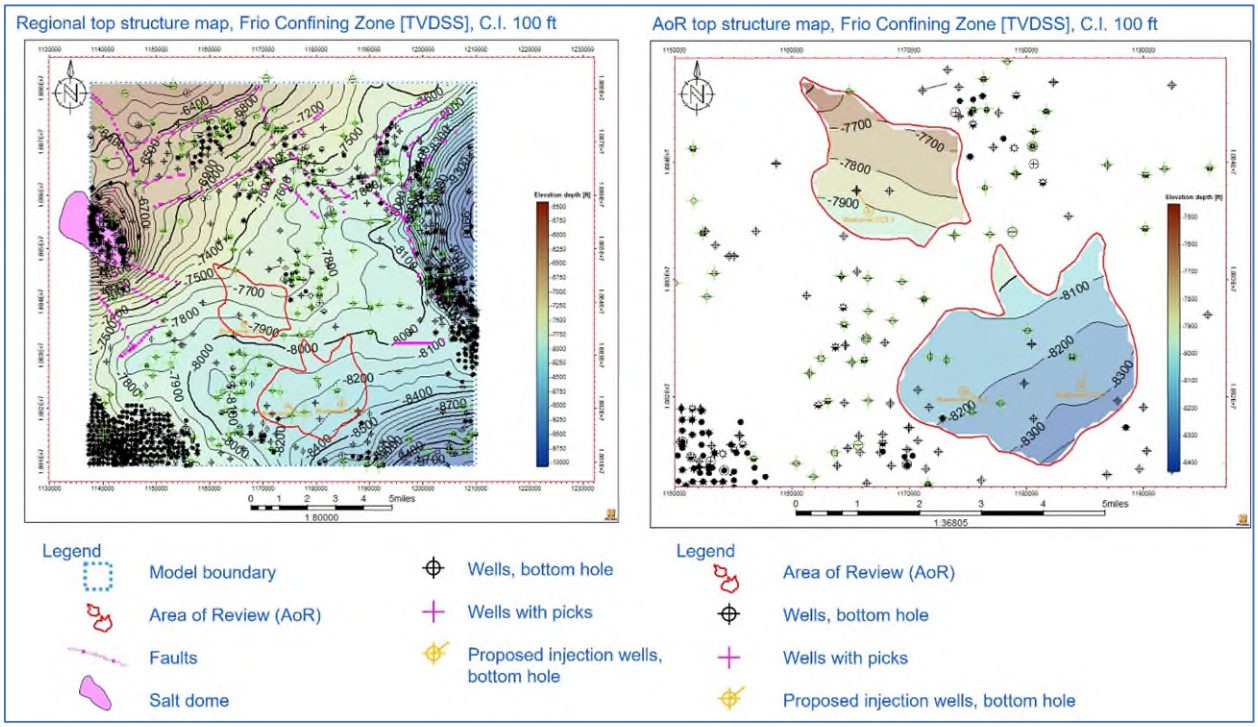


Figure AoR-137: Regional and AoR top structure map of the Frio Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

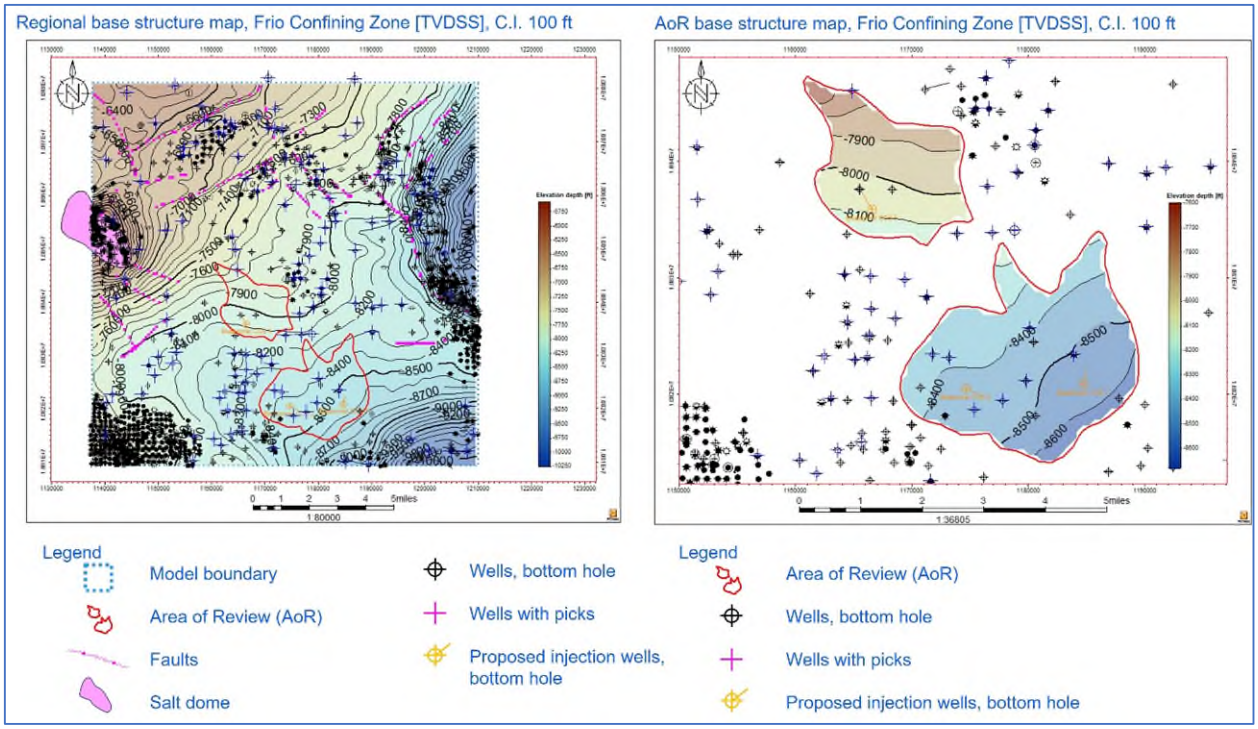


Figure AoR-138: Regional and AoR base structure map of the Frio Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

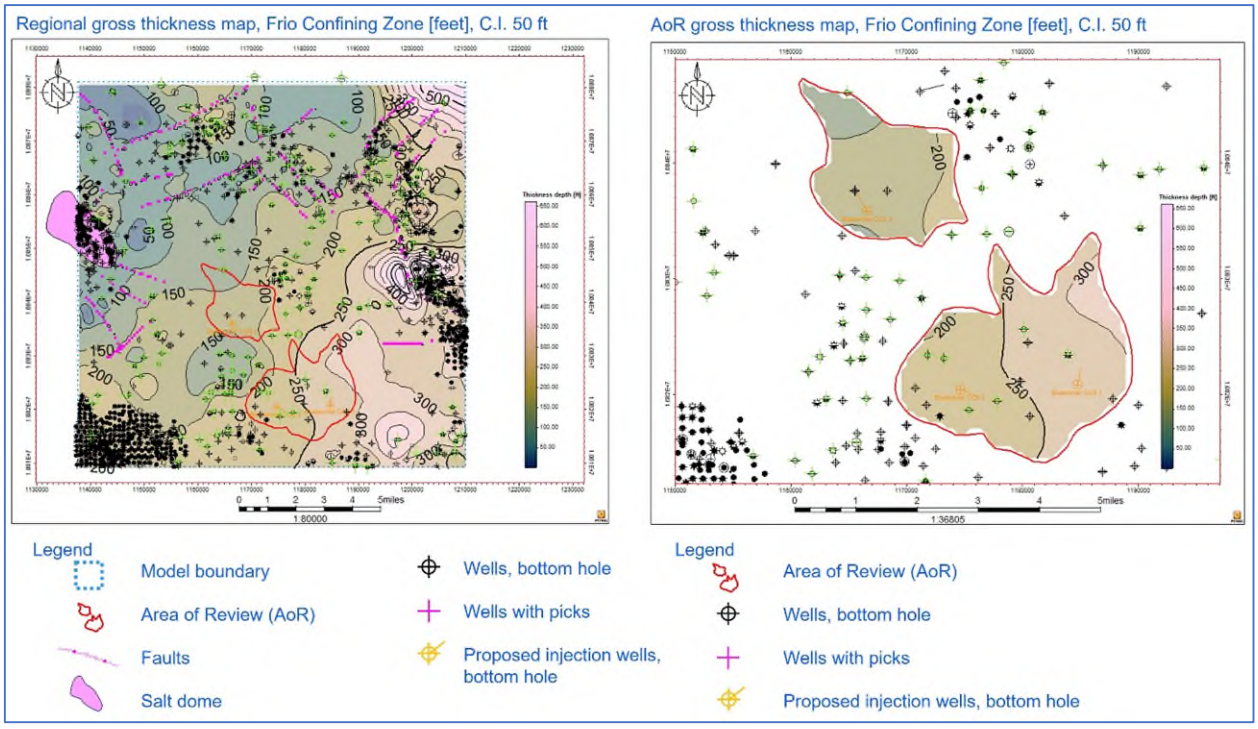


Figure AoR-139: Regional and AoR gross thickness map of the Frio Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

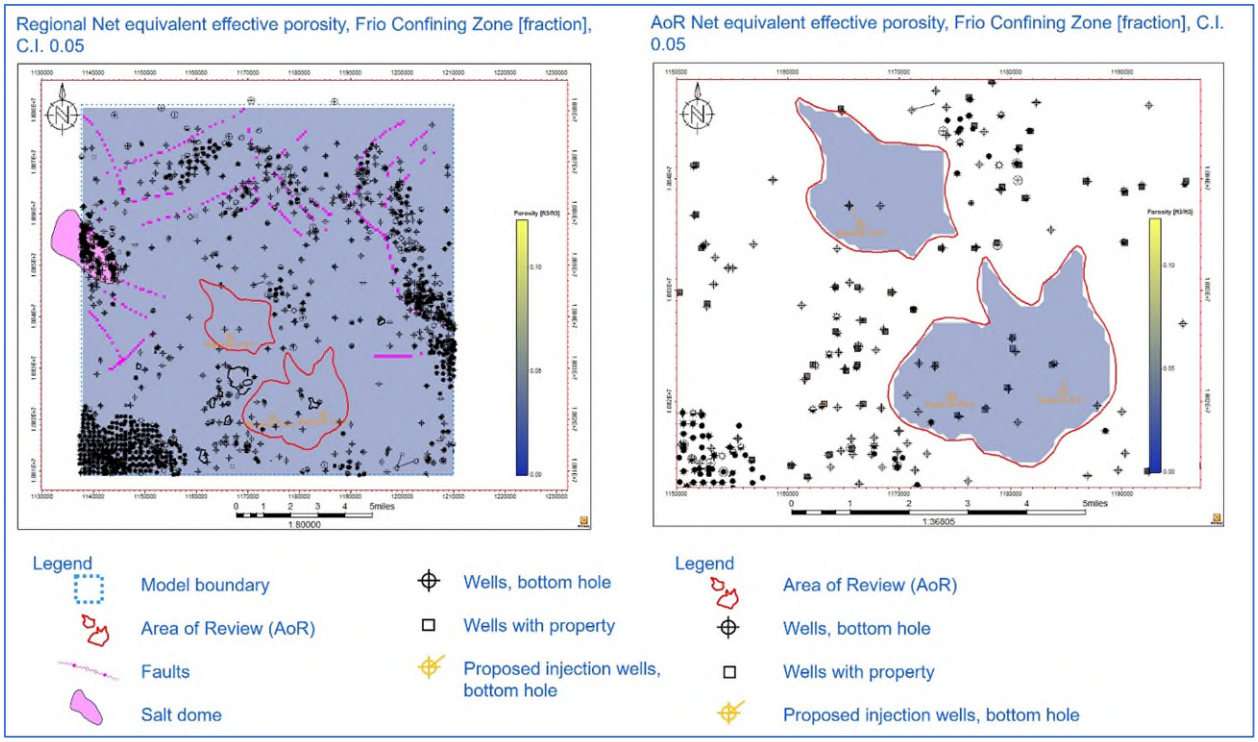


Figure AoR-140: Regional and AoR net equivalent effective porosity map of the Frio Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

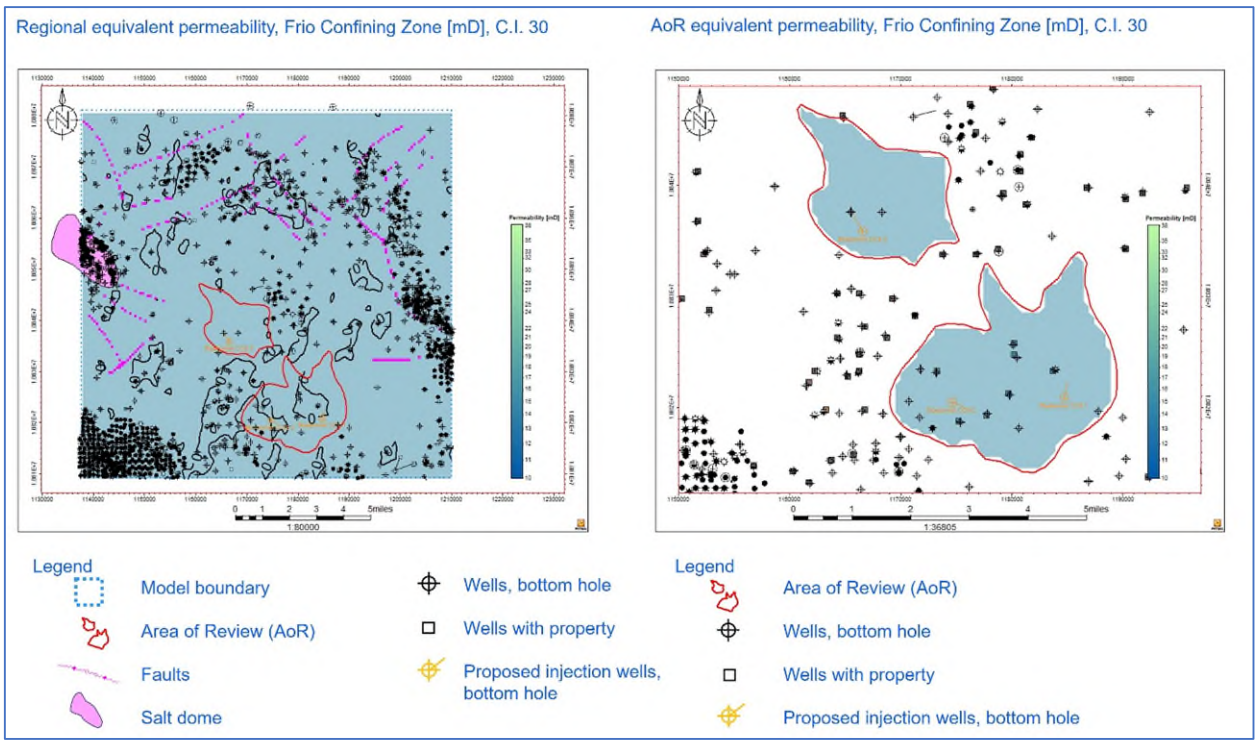


Figure AoR-141: Regional and AoR equivalent permeability map of the Frio Confining Zone in millidarcy (md), contour interval 30 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-10 represent map based average numbers extracted from the geomodel over the AoR.

Table AoR-10: Reservoir properties for the Frio Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Frio Confining Zone
Top Depth [TVDSS]	Claimed as PBI	
Base Depth [TVDSS]		
Gross Thickness [ft]		
Porosity [fraction] EQI, net eff. Porosity * NTG		
Permeability [md]		

3.8.2.3 Anahuac Confining Zone

The Anahuac Confining Zone is a low-permeability primary confining zone that is regionally contiguous in both the north-south dip direction as well as in the east-west strike direction beyond the limits of the AoR. This is due to the nature of a major marine transgression on a passive continental margin, where sea level changes affect large areas. As mentioned under Section 3.6, the Anahuac Confining Zone is a well-known stratigraphic seal along the northern Texas Gulf Coast that is interbedded with calcareous and siliciclastic strata.

The Anahuac Confining Zone is Claimed as PBI thick inside the proposed AoR and two 30-ft cores were collected in the stratigraphic test well Encanto 01 well (Appendix A).

The Anahuac Confining Zone is composed of a Lower Anahuac Confining Zone with a better sealing capacity Claimed as PBI and an Upper Anahuac Confining Zone Claimed as PBI. The properties measured in the lab seem to be correlated to the depositional environment.

The Lower Anahuac Confining Zone consists mostly of shales deposited offshore in a middle neritic environment. The whole core acquired in this interval is a bioturbated, calcareous, and silty mudstone interbedded with bioturbated, calcareous, and argillaceous siltstone. Trace fossils were identified as Asterosoma, which are temporary stationary burrows where marine animals probe deeply into substrate to search for deposited food, Arenicolites, and vertical feeding tube traces from Teichichnius. Minor thin-walled mollusk shells, e.g., pelecypod fragments, occur throughout the interval, indicating a starved and stressed environment where oxygen and nutrient levels were probably low, which is expected in a middle neritic environment. Some calcareous siltstone laminae have been preserved, while other laminae have been destroyed due to bioturbation. The preserved laminae are typically ripple-laminated, have sharp bases, and some are normally graded. One interpretation could be that those laminae represent tempestites. One conjugate set of induced fractures was identified.

The Upper Anahuac Confining Zone consists mostly of shales deposited offshore in an inner neritic environment. Because the water depth when this zone was deposited was shallower, sunlight was more pervasive and nutrient supply and oxygen levels were higher, there is overall a higher percentage of silt and bioturbation within the Upper Anahuac Confining Zone. The base of the whole core is a non- to slightly calcareous, silty mudstone with textures varying from faintly laminated to massive to bioturbated. Vertical feeding traces produced by a Teichichnus trace fossil were identified. Sedimentary structures are laminations to thin beds of ripple-laminated, argillaceous siltstone. An isolated zone with soft sediment deformation was identified. Three normal shear fractures (microfaults) and several coring induced fractures occur in the lower part of the whole core. The upper part of the whole core is described as a bioturbated, slightly calcareous to calcareous, and silty mudstone interbedded with bioturbated, slightly calcareous, and argillaceous siltstone. At the boundary is a basal bed of a bioturbated, non-calcareous, argillaceous, and very fine-grained sandstone. Those thin sands can be seen as bright features on the CT scan. Trace fossils are identified as Asterosoma. The primary sedimentary structures are still apparent on a few siltstone beds and include ripple and parallel lamination. Only one coring-induced fracture was identified in this top part of the core.

Overall, the Anahuac Confining Zone transitions from middle neritic offshore silty mudstone in the Lower Anahuac Confining Zone to an inner neritic more argillaceous siltstone in the overlying Upper Anahuac Confining Zone.

The lithologic composition of the Anahuac Confining Zone is described below based on mud cuttings acquired during drilling operations of the stratigraphic test well Encanto 01 and mudlogs from two legacy wells nearby.

The Anahuac Confining Zone lithology shows 80 – 100 % light to dark green to grey and blue shale, light to medium to dark and bright red, soft to moderately firm, poorly to moderately consolidated, subfissile to subplaty and splintery, predominantly clay, massive and dull, predominantly clay with laminations, traces of cream clear fossils, traces of lignite and pyrite, and trace white cream crystalline limestone with earthy texture in the Het Lime interval. It is interbedded with 10 – 20%: very finely laminated silts and light to dark-grey, off-white to translucent very fine-grained sandy layers, which are predominantly loose and unconsolidated and

have a silty/argillaceous/calcareous matrix, poorly sorted. Trace mineral fluorescence has been observed, but no hydrocarbon fluorescence or hydrocarbon cut has been observed during mudlogging the Anahuac Confining Zone.

3.8.2.3.1 Petrologic Description

The Lower Anahuac Confining Zone is an argillaceous siliceous mudstone/mixed siliceous mudstone, as shown in the mudstone compositional diagram (Figure AoR-144). Coarse silt and very fine sands are present in burrows, along with fine clays, pyrite and calcite, and intergranular pores when bioturbated (Figure AoR-142). Quartz, plagioclase, and K-feldspars are present. The fine silt made up of laminations and bioturbation is present as well. Pyrite and minor amounts of titanium oxide TiO_2 and calcite are present as a pore-filling cement. Mineral and textural alignment was identified. Microporosity is present.

SEM analysis shows that clays appear to be compacted and structurally aligned, also clay wrapping around grains was observed. Microfossil fragments, e.g., foraminifers and fine-grained material associated with this rock, was also observed. Backscattered Electron (BSE) images on ion-milled samples show presence of organic particles, but those lack pores associated with organics, which possibly indicates the immature nature of these organics. A few desiccation pores (Figure AoR-146) and possibly some small natural pores can also be seen. Based on the general lack of both intergranular and kerogen pores, and structural alignment, the rock could be a competent baffle. The clay speciation is dominantly illite/smectite. Further thin section description, petrologic analysis, and seal capacity analysis confirm the confining potential of the Lower Anahuac Confining Zone depending on rock fabric, mineralogy, porosity, permeability, and capillary pressure measurements. The sequence stratigraphic analysis confirms the continuity of this confining zone.


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI

The Upper Anahuac Confining Zone cored interval is composed of an argillaceous siliceous pyritic and burrowed mudstone. The silt and fine sand fraction, along with porosity, is concentrated in the burrows. The mudstone rock is represented by pore throat radii between 0.001 to ~0.024 microns, this rock will act as a confining system. The sandy burrows are represented by larger pore throat radii 0.03 to ~0.9 microns, which likely reduce the seal capacity due to the bi-modal pore throat system.

Another rock type is silty/sandy faintly laminated mudstone. Small pore throat radii between 0.001 to ~0.03 microns possibly represent the mudrock, which may act as a baffle. Slightly larger pore throat radii, 0.03 to ~ 0.3 microns, possibly represent sandy burrows or faint laminations. Framboidal pyrite was observed. The clay speciation derived from XRD displays that the clay is dominantly illite-smectite.

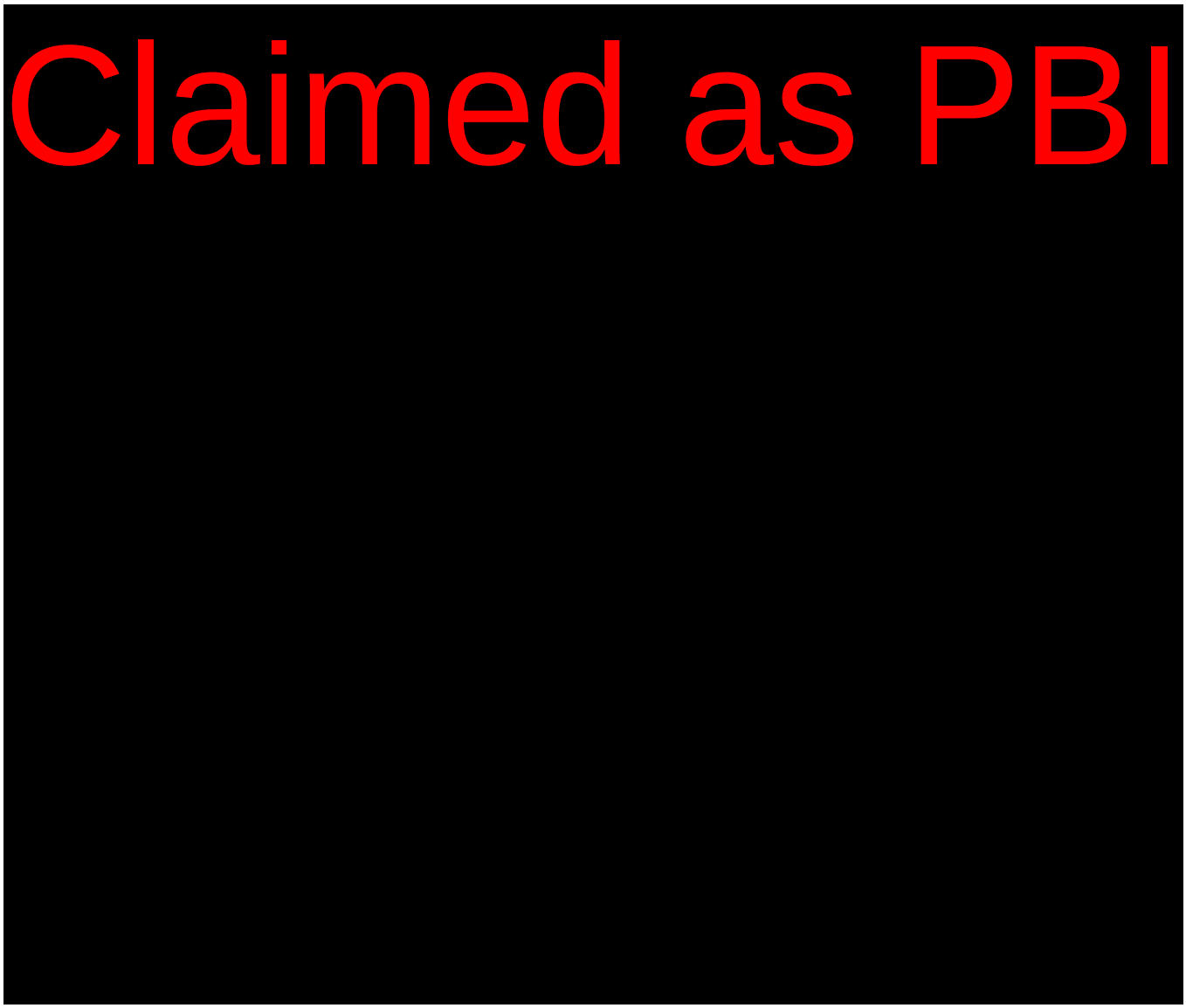



Claimed as PBI



Figur


Claimed as PBI



3.8.2.3.2 Seal Analysis

There are five samples with MICP data in the Lower Anahuac Confining Zone, two verticals and three horizontal plugs from whole core. Following a conservative approach (please see Appendix A for more detail analysis), the displacement pressure criteria will need an injection height of Claimed as PBI before breaking into the confining zone. These results will be corroborated / calibrated to TEP (Threshold Entry Pressure) test results.

In the Upper Anahuac Confining Zone, there are five plugs, three vertical and two horizontals plugs, from whole core. Three plugs present a bi-modal pore system and will not be considered for seal analysis. Following a conservative approach (please see Appendix A for more detail analysis), the displacement pressure criteria will need an injection height of Claimed as PBIeet before breaking into the confining zone. These results will be corroborated / calibrated to TEP (Threshold Entry Pressure) test results.

3.9.2.3.3 Anahuac Confining Zone Maps

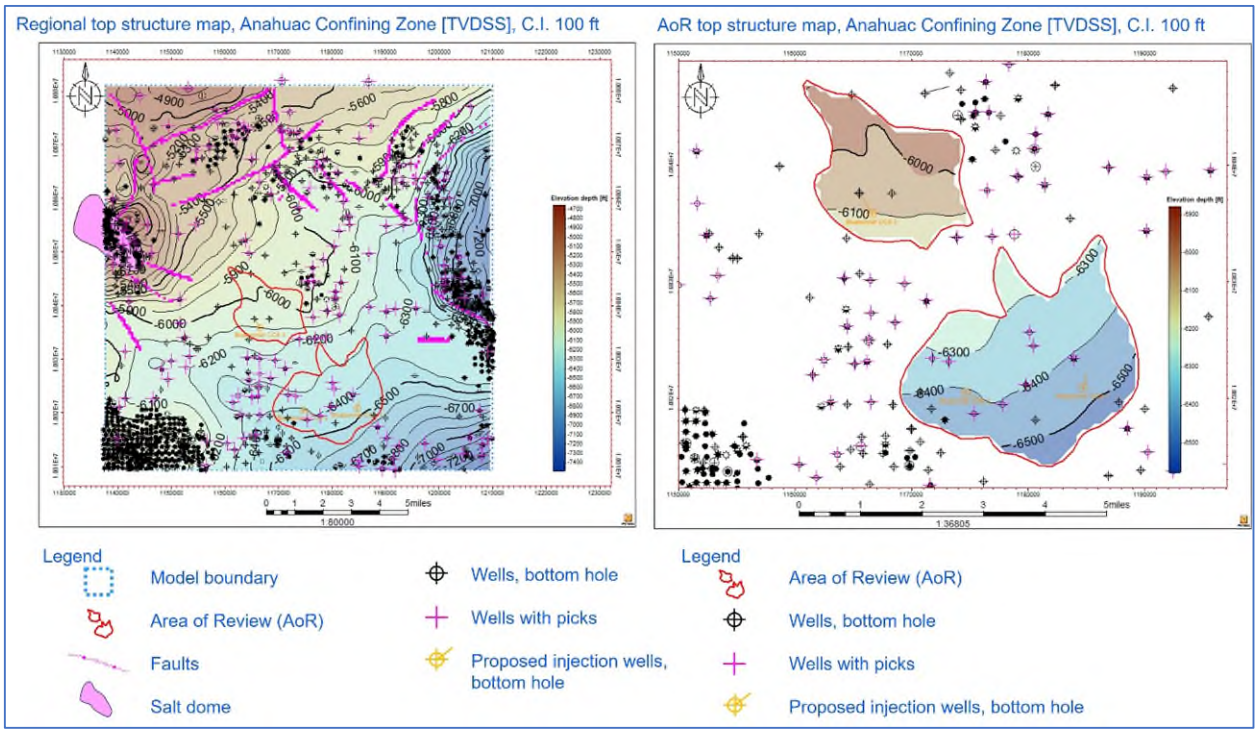


Figure AoR-154: Regional and AoR top structure map of the Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

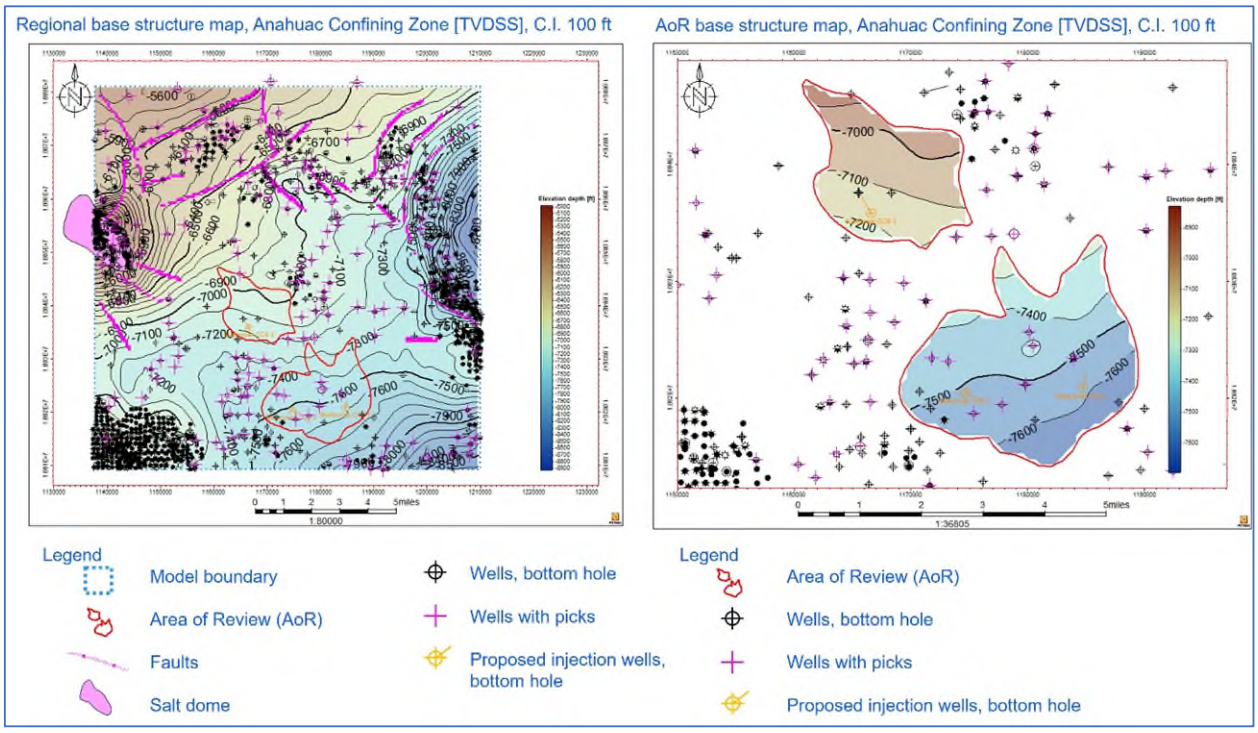


Figure AoR-155: Regional and AoR base structure map of the Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

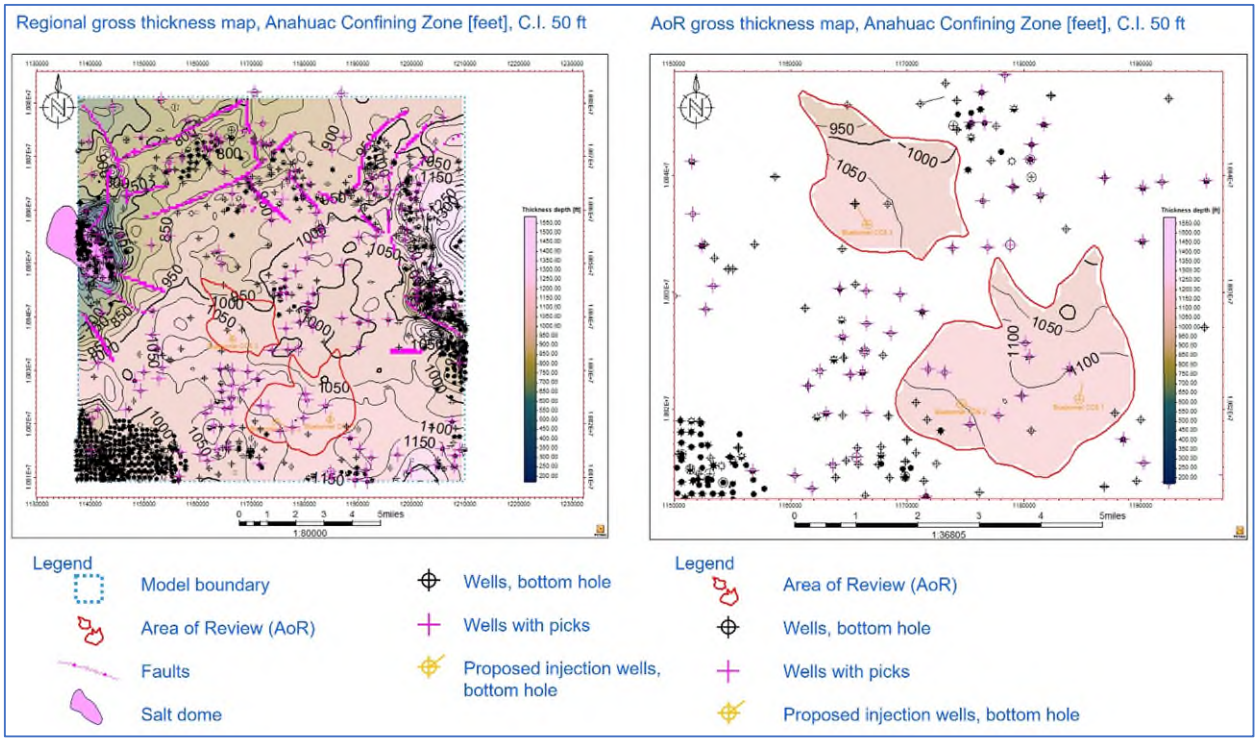


Figure AoR-156: Regional and AoR gross thickness map of the Anahuac Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

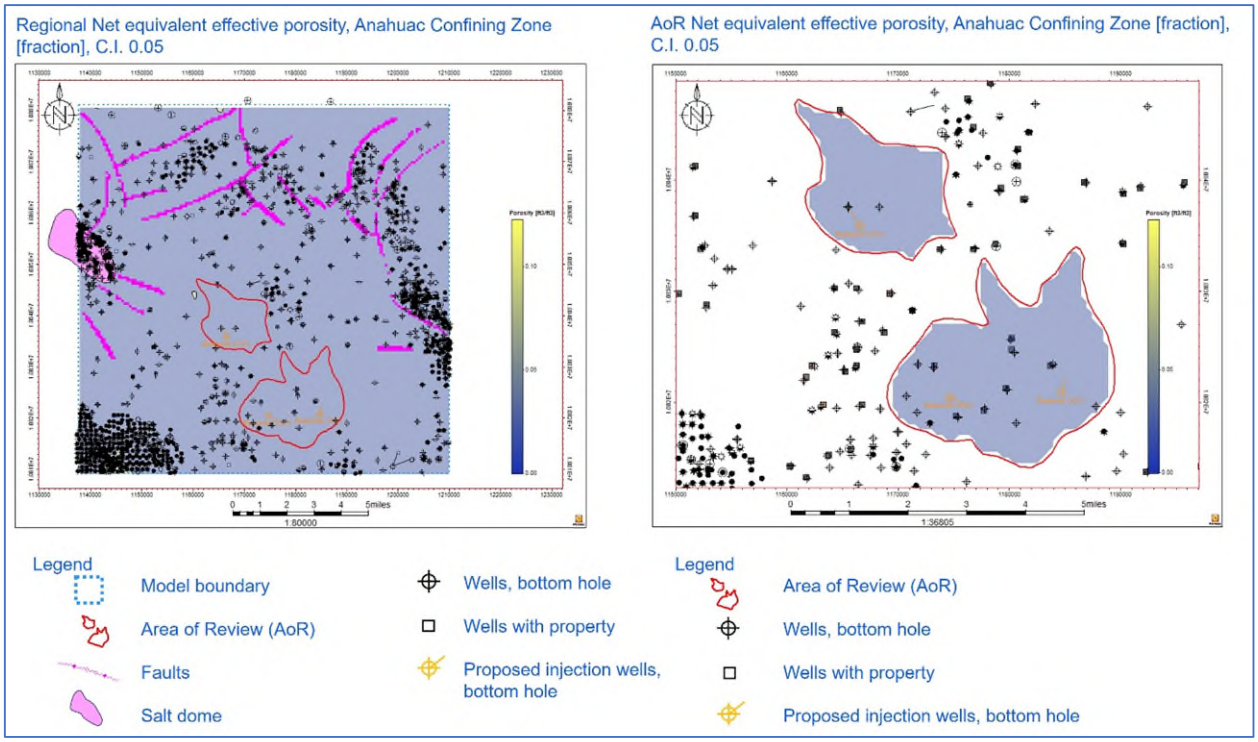


Figure AoR-157: Regional and AoR net equivalent effective porosity map of the Anahuac Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

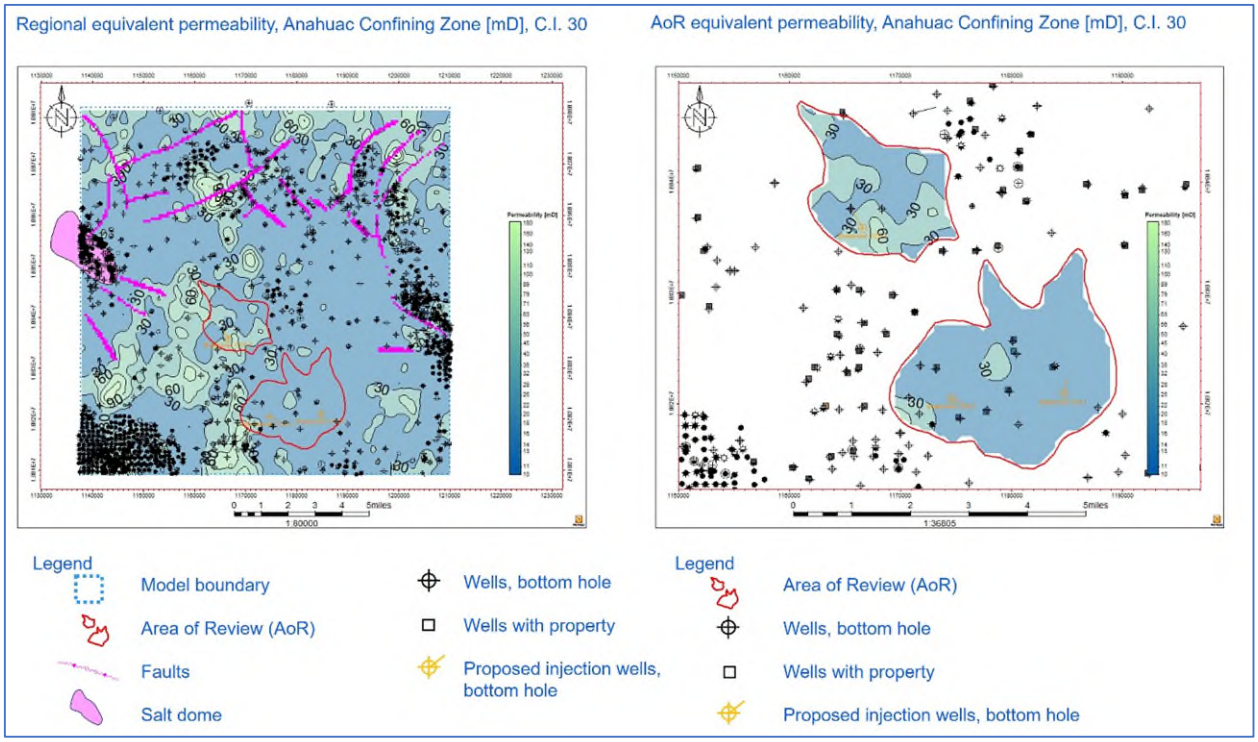


Figure AoR-158: Regional and AoR equivalent permeability map of the Anahuac Confining Zone in millidarcy (md), contour interval 30 md. This map was generated from the Oligocene Model described under 4.0.

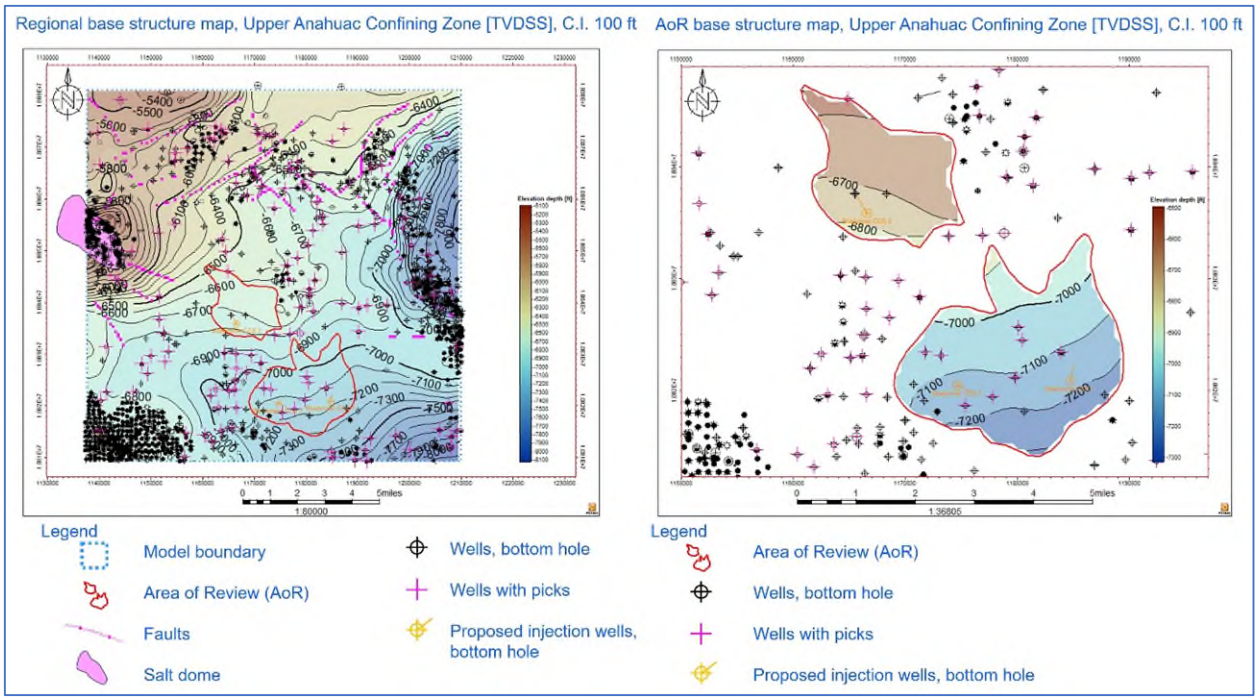


Figure AoR-159: Regional and AoR base structure map of the Upper Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

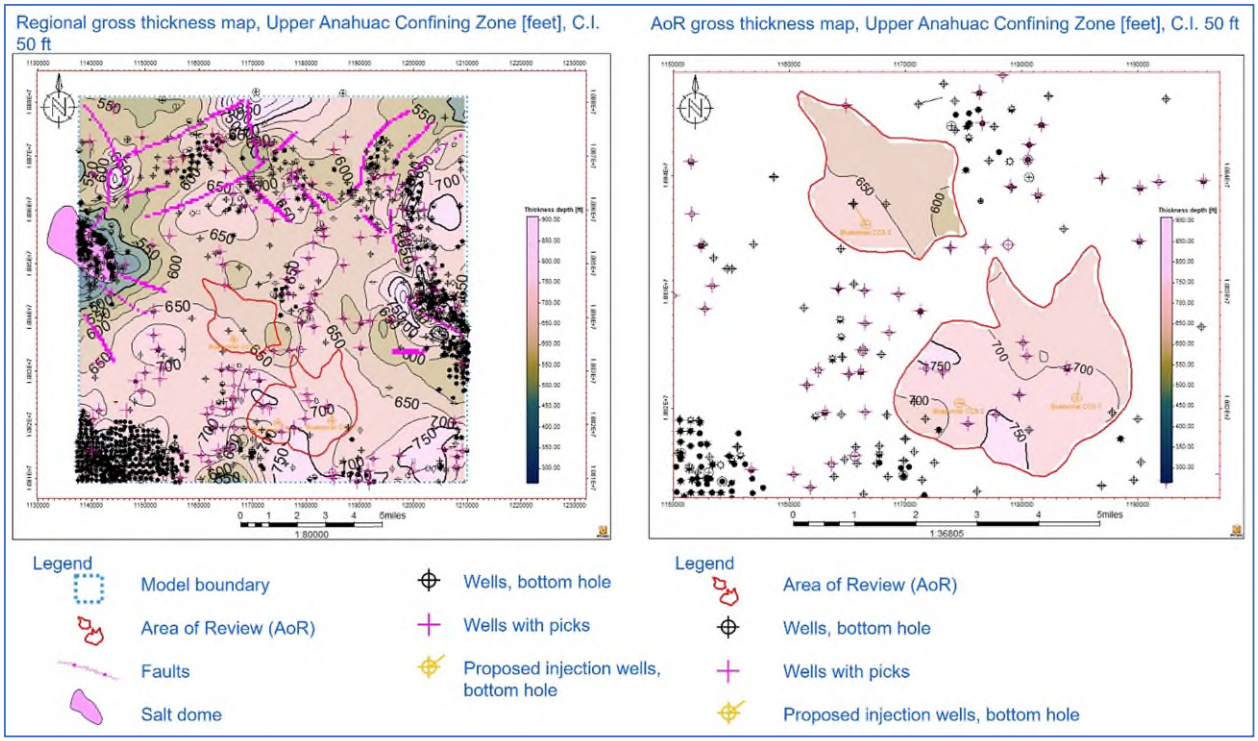


Figure AoR-160: Regional and AoR gross thickness map of the Upper Anahuac Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

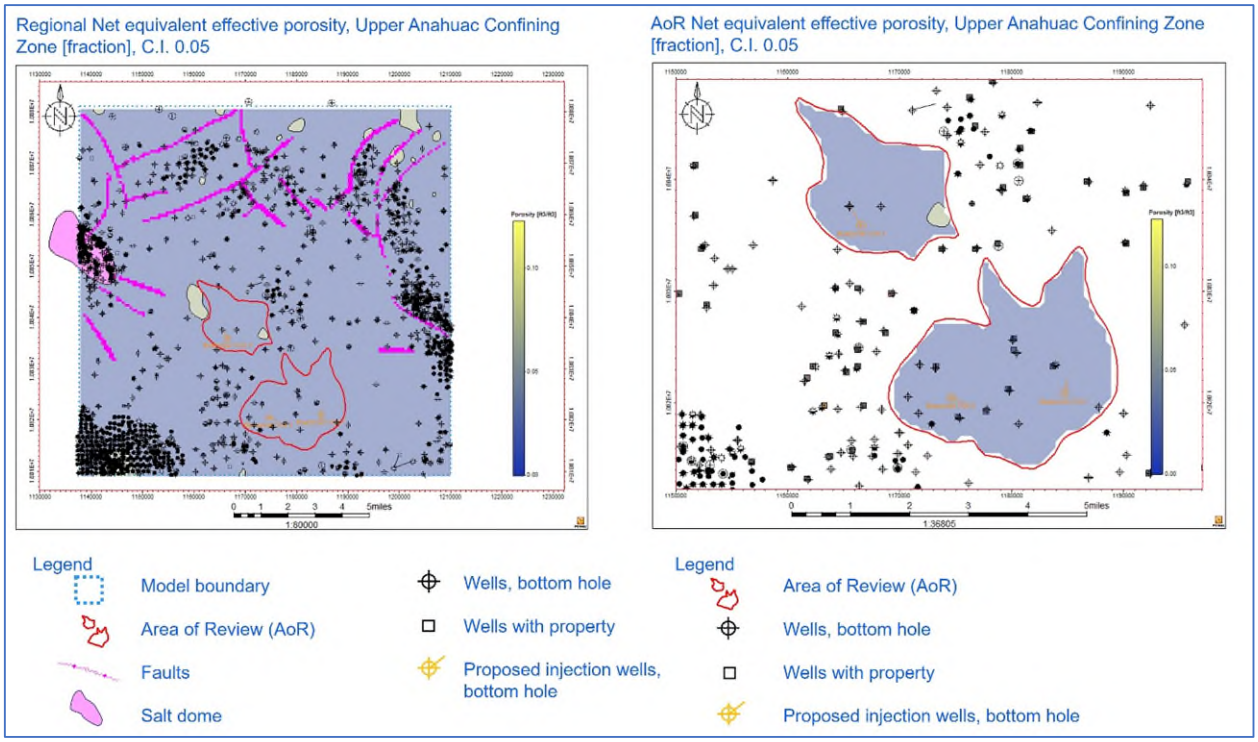


Figure AoR-161: Regional and AoR net equivalent effective porosity map of the Upper Anahuac Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

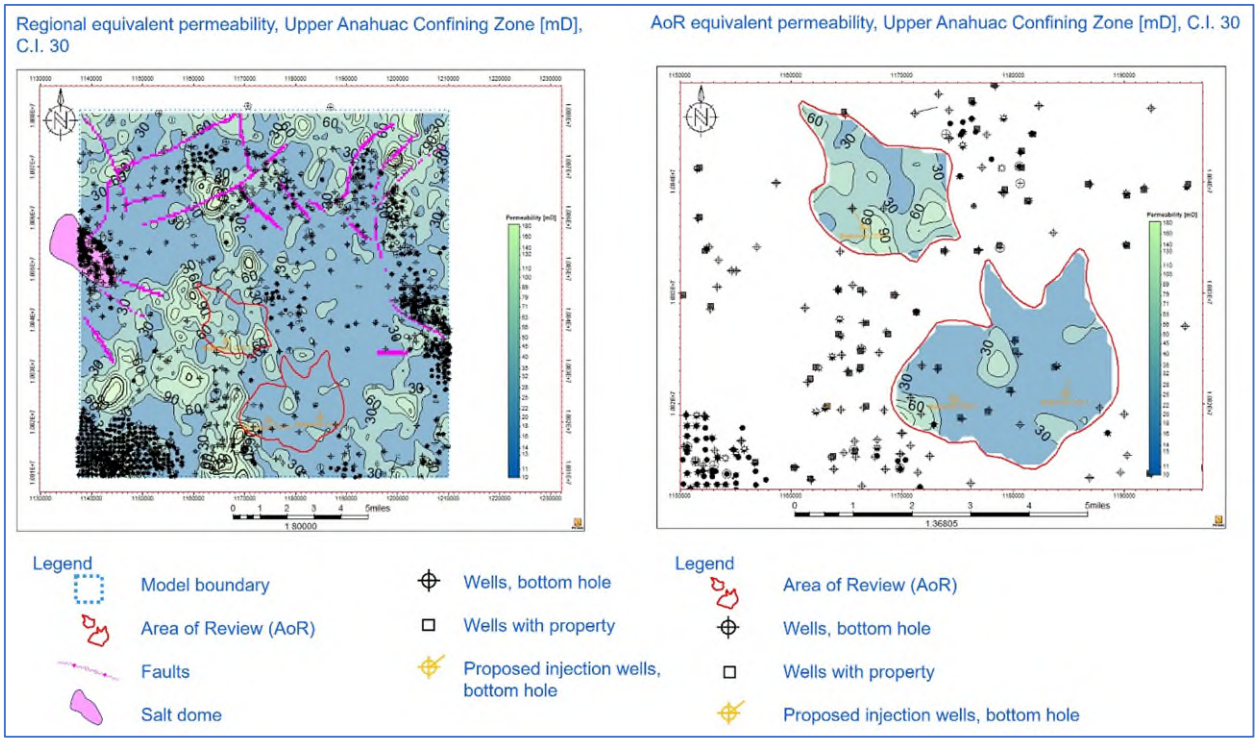


Figure AoR-162: Regional and AoR equivalent permeability map of the Upper Anahuac Confining Zone in millidarcy (md), contour interval 30 md. This map was generated from the Oligocene Model described under 4.0.

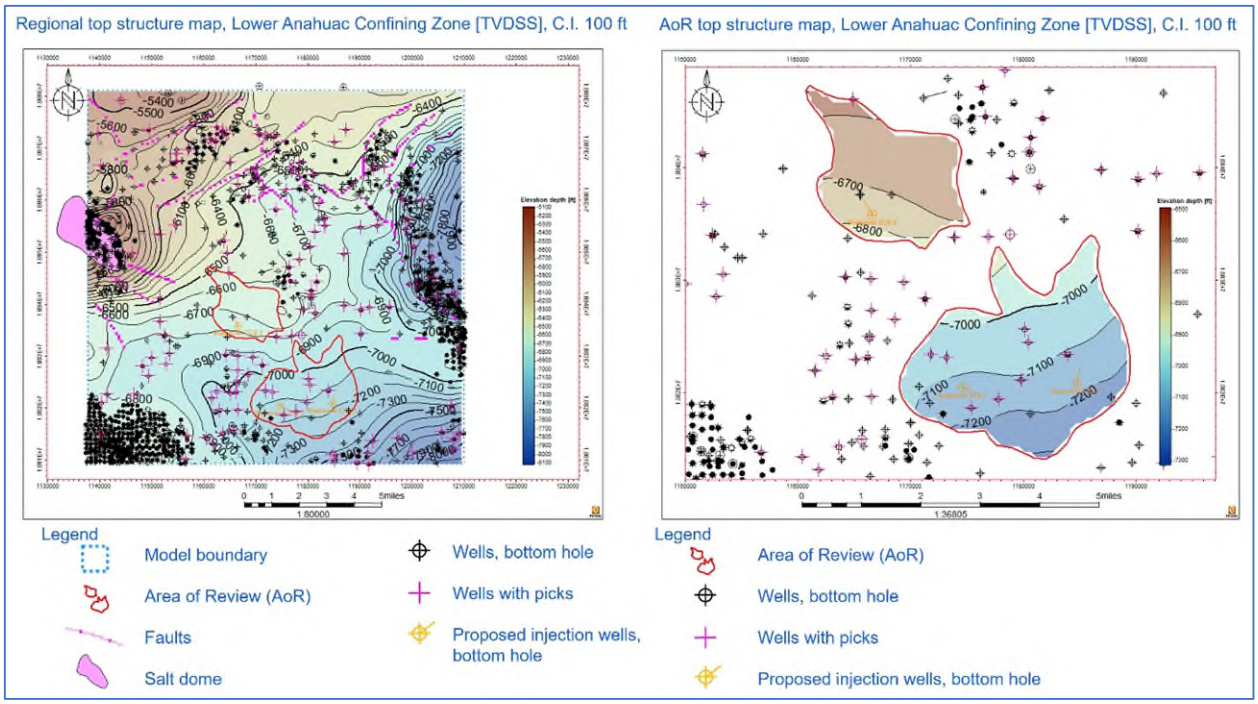


Figure AoR-163: Regional and AoR top structure map of the Lower Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

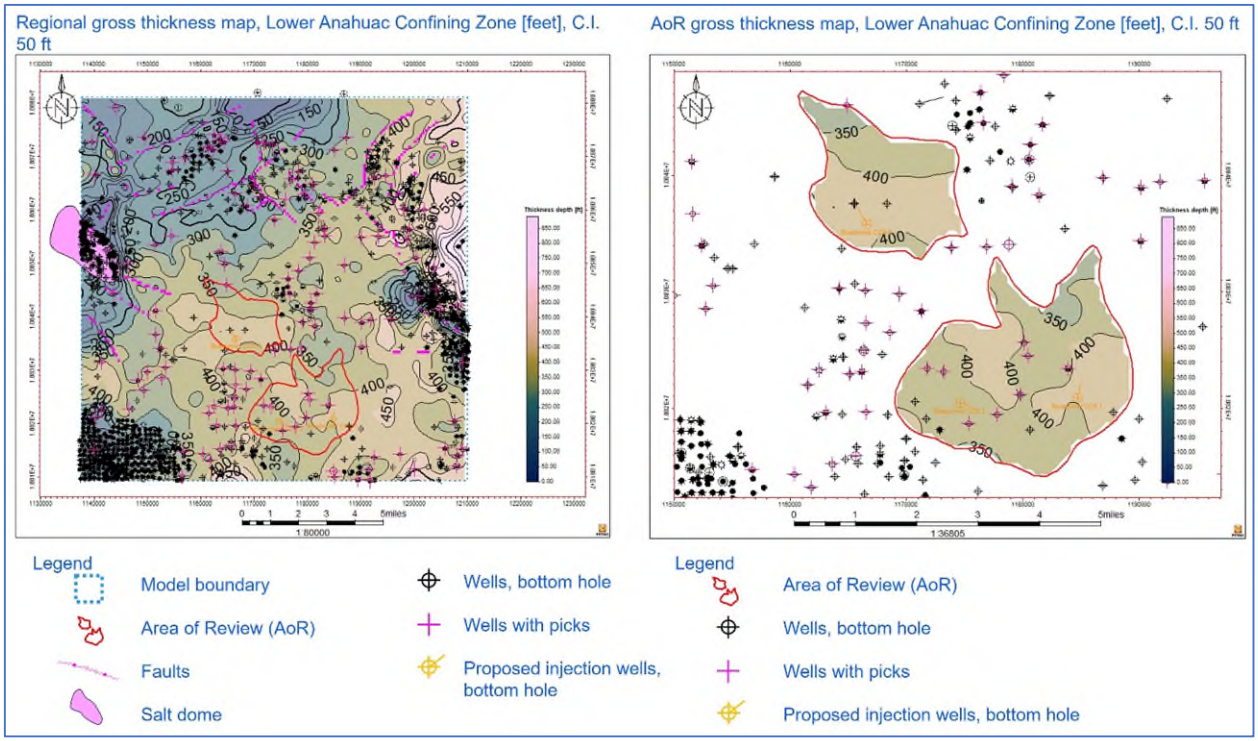


Figure AoR-164: Regional and AoR gross thickness map of the Lower Anahuac Confining Zone in feet, contour interval 50 ft. The gross thickness is drawn to the base structure map of the Anahuac Confining Zone, Figure AoR-213. This map was generated from the Oligocene Model described under 4.0.

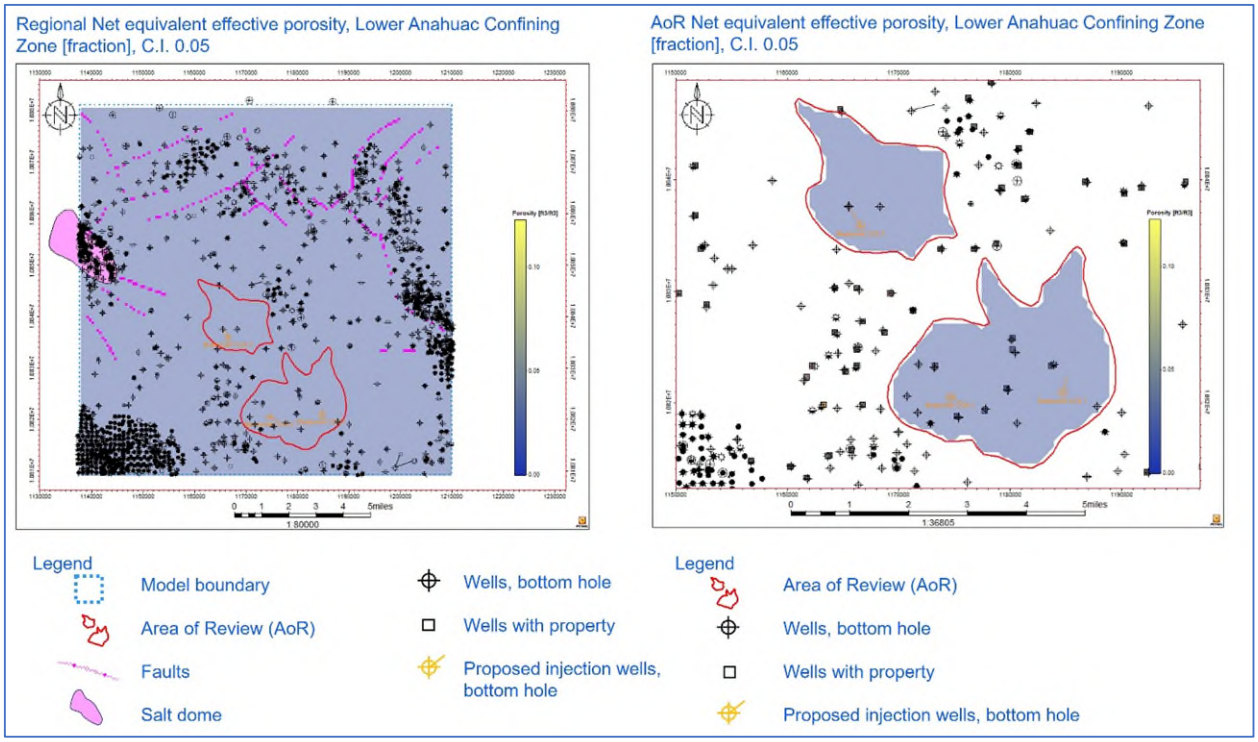


Figure AoR-165: Regional and AoR net equivalent effective porosity map of the Lower Anahuac Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

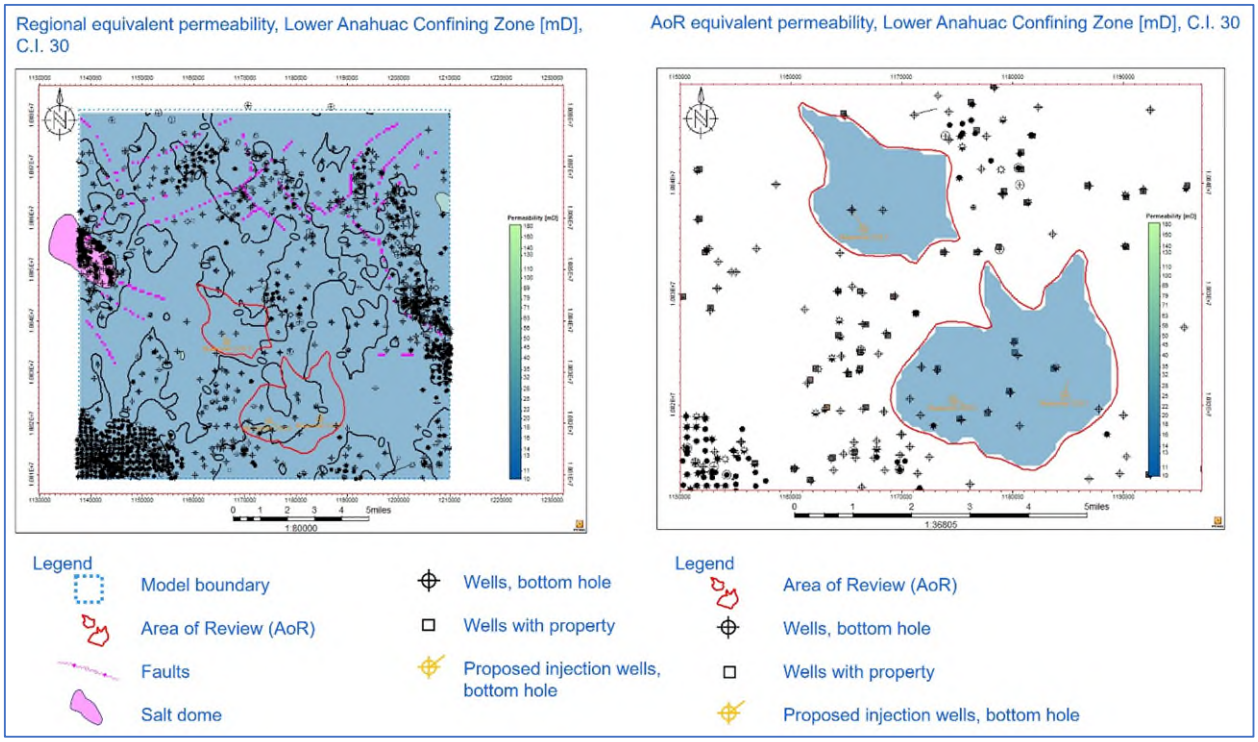


Figure AoR-166: Regional and AoR equivalent permeability map of the Lower Anahuac Confining Zone in millidarcy (md), contour interval 300 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-11 represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-11: Reservoir properties for the Anahuac Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Anahuac Confining Zone		
		Upper Anahuac	Lower Anahuac	Combined
Top Depth [TVDSS]	[redacted]			
Base Depth [TVDSS]				
Gross Thickness [ft]				

Claimed as PBI

Reservoir properties in AoR	Extracted map values from geomodel	Anahuac Confining Zone		
		Upper Anahuac	Lower Anahuac	Combined
Porosity [fraction] EQI, net eff. porosity * NTG	Claimed as PBI			
Permeability [md]				

3.8.2.4 Lower Miocene Confining Zone = Secondary Confining Zone for Frio Injection

The Lower Miocene Confining Zone is characterized as a paleosol, silty calcareous mudstone, and non-silty lime-mudstone. The paleosol was deposited in a coastal marsh/floodplain. On the mudlog as well as the slabbed whole core, two main colors were observed: green mudstone intervals are the result of reduced iron and red mudstone intervals are the result of oxidized iron, those red soils are hematitic. In the third-order sequence stratigraphic framework, the paleosol is a weathering surface, which is a sequence boundary (S.B.) that caps the Miocene sand-prone third-order highstand.

The formation of a paleosol on a coastal marsh was influenced by changing salinity and fluid migration over long time periods. The changing salinity is the reason why there are syneresis cracks: the clays expand in fresh water and shrink in saline water. Slickensides are local to common, have striation, and contain high clay content, and thus, are natural structures and planes of weakness. Some of the paleosol exhibits root traces with a fine organic core with the apparent porphyroskelic fabric (see Figure AoR-172). Below the reddish paleosol, most samples are limey mudstone. There are also non-silty lime-mudstones.

Mottled textures in the calcareous red mudstone are common and may be caused by rooting. Very fine-grained interbedded sandstones may represent storm washover deposits or crevasse splays, ranging from massive to mottled to ripple-laminated. In between the sand laminations, occur mudstone intervals with silt-filled desiccation cracks. Two sand injectites occur at the base of the first core. Burrows are present in both the mudstones and interbedded sandstones. Many small calcareous nodules occur and are recognized as bright white features on the CT scan. Local brecciation was observed.

3.8.2.4.1 Petrologic Description

An argillaceous sandy marly mudstone with calcite (stained red) and quartz grains (white) is shown in Figure AoR-167.

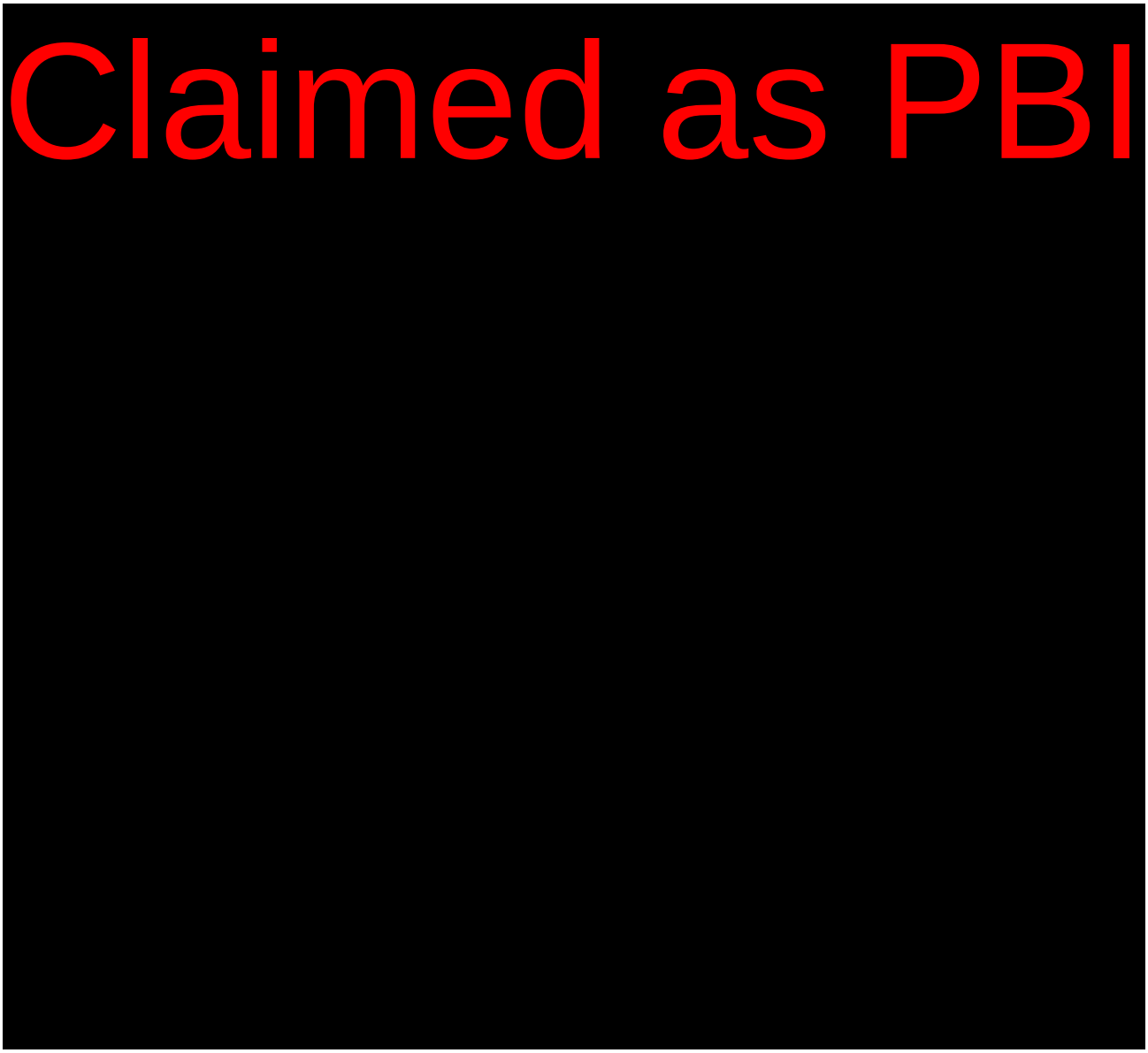

Claimed as PBI



Figu

Figure AoR-170 shows a uniform non-silty limey mudstone. Based on the fabric and MICP data, these non-silty lime-mudstones have a competent sealing capacity.


Claimed as PBI


Claimed as PBI



3.8.2.4.2 Seal Analysis

There are eight samples with MICP data in the Lower Miocene Confining Zone, three from vertical plugs and five from horizontals whole core plugs. With results from the Threshold Entry Pressure (TEP), the conservative approach was changed to a more aggressive approach to tie in with TEP results. Following this update, the displacement pressure criteria will need an average injection height of Claimed as PBI see Table AoR-11, in appendix A) feet before breaking into the confining zone. The comparison and calibration of the MICP with TEP results is explained in the Appendix A.

3.8.2.4.3 Lower Miocene Confining Zone maps

The Lower Miocene Confining Zone maps are shown below.

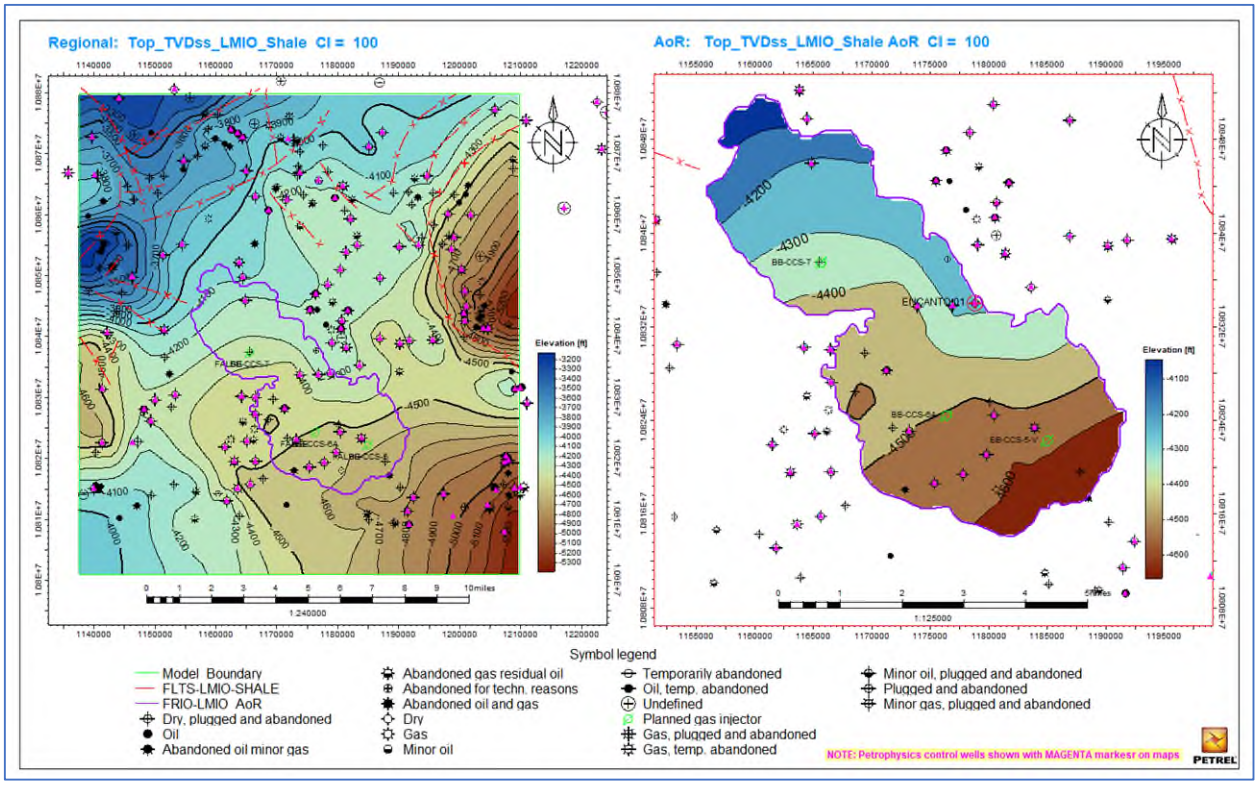


Figure AoR-173: Regional and AoR top structure maps of the Lower Miocene Shale Confining Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

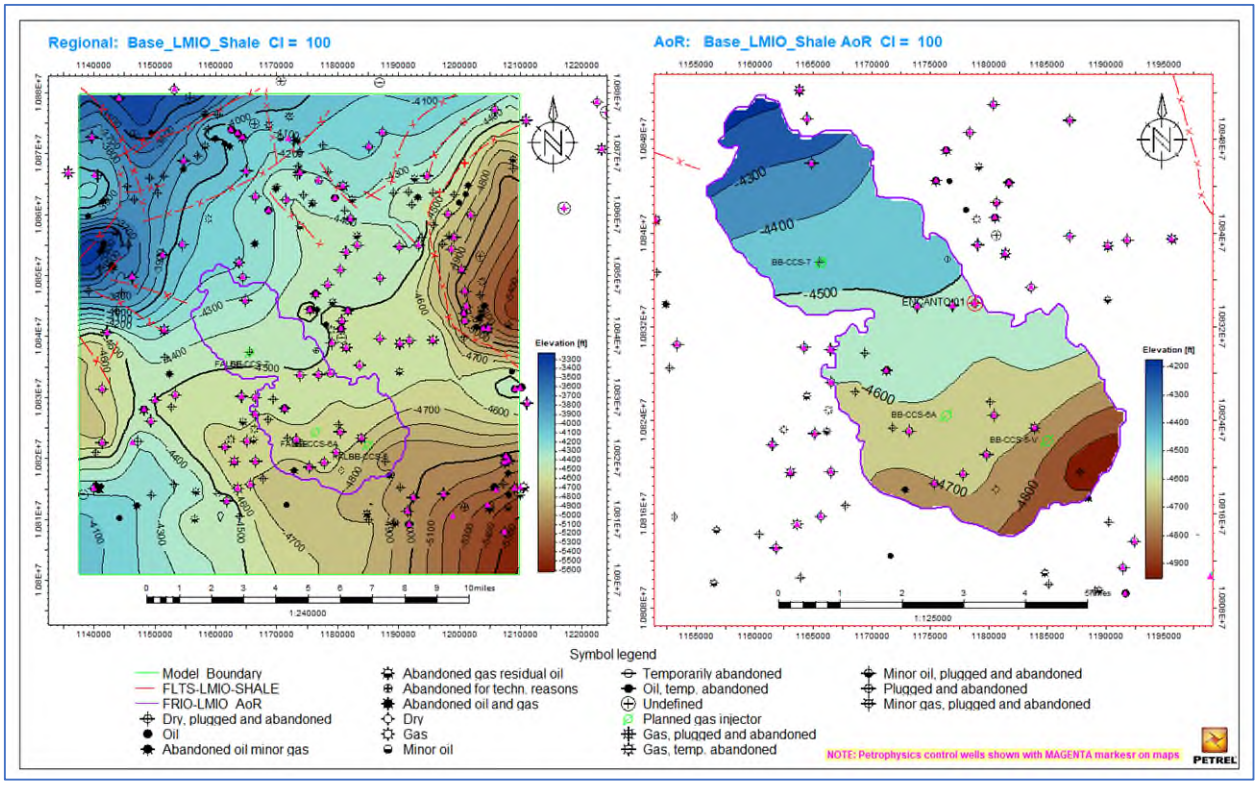


Figure AoR-174: Regional and AoR base structure maps of the Lower Miocene Shale Confining Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

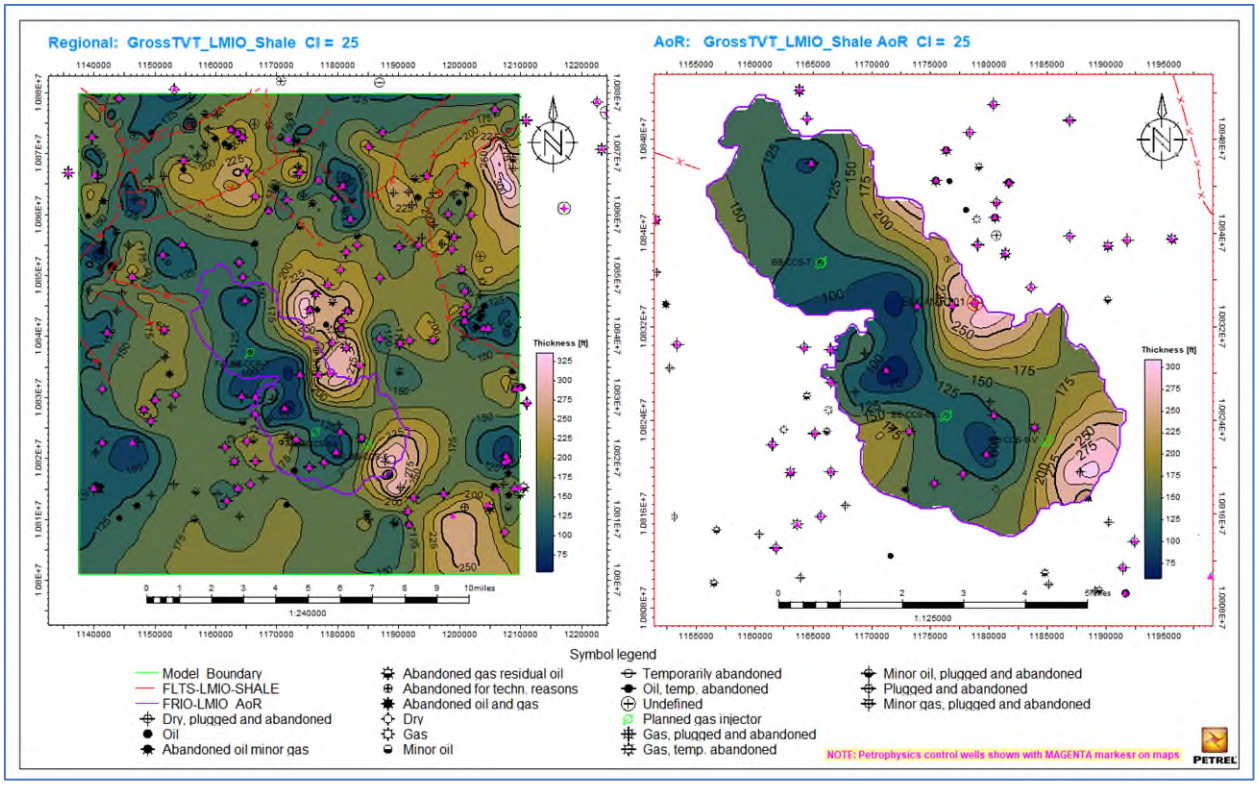


Figure AoR-175: Regional and AoR gross thickness maps of the Lower Miocene Shale Confining Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

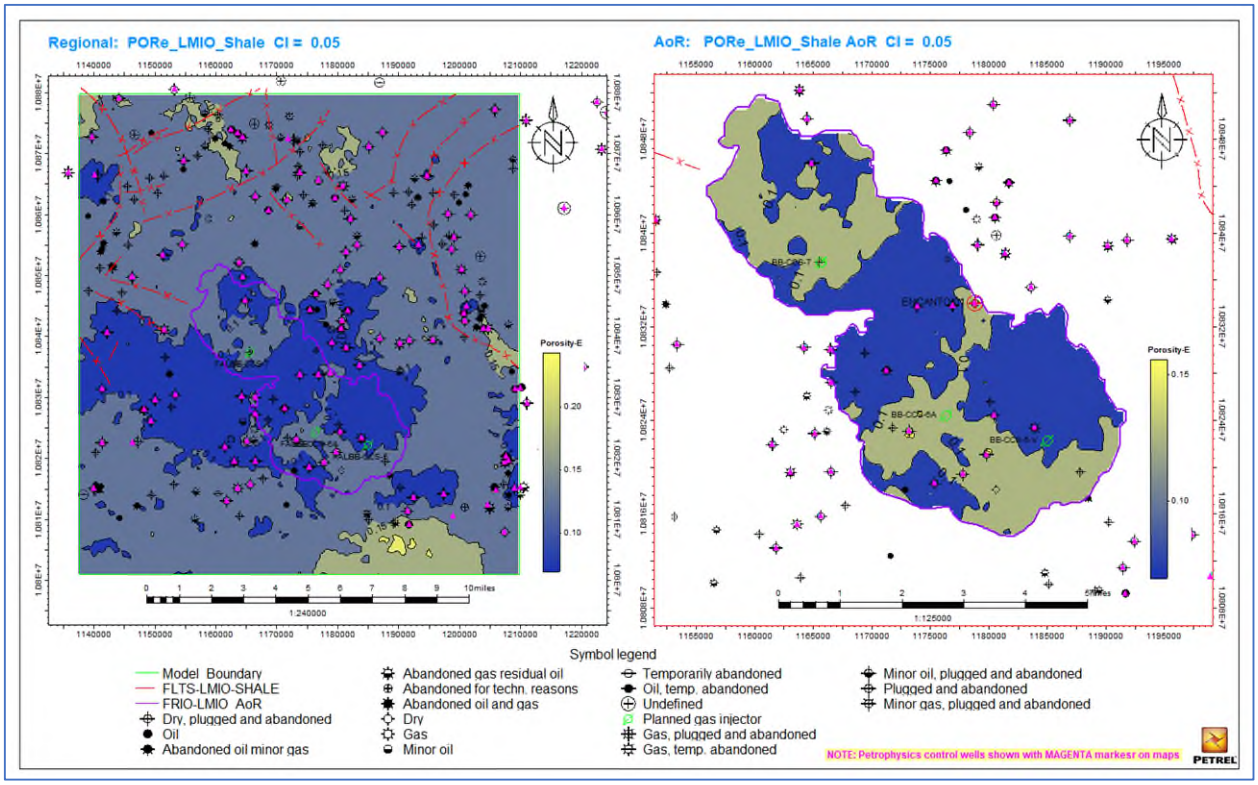


Figure AoR-176: Regional and AoR average effective porosity of the Lower Miocene Shale Confining Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

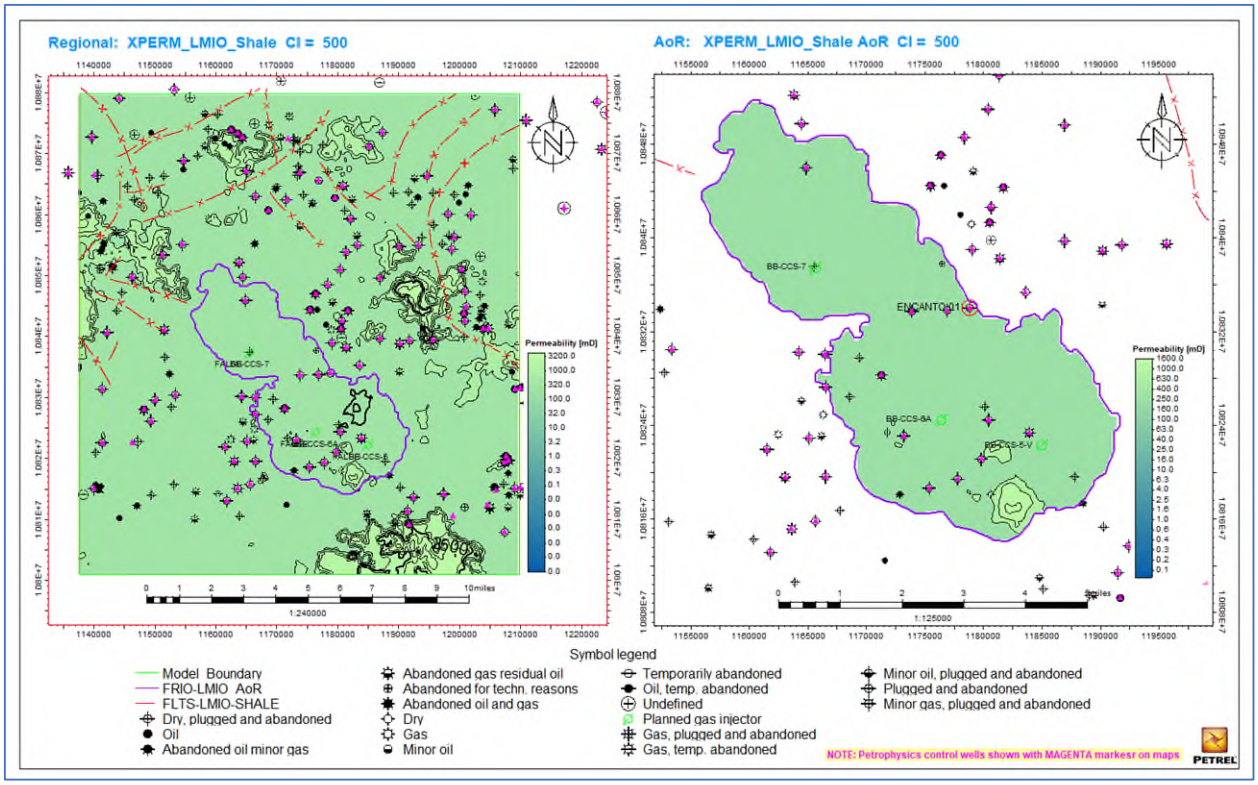


Figure AoR-177: Regional and AoR average permeability of the Lower Miocene Shale Confining Zone, in feet, contour interval = 500 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-12: Reservoir properties for the Lower Miocene Shale Confining Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	Lower Miocene Confining Zone
Top Depth (TVDss)	Claimed as PBI	
Base Depth (TVDss)		
Gross Thickness (ft.)		
Effective Porosity (fraction)		
Permeability (md)		

3.8.2.5 Miocene Composite Confining Zone = Dissipation Zone

Miocene Composite Confining Zones were mapped based on integrating petrophysical well logs with completion and injection depths of seven permitted saltwater disposal wells in and around the greater Area of Interest (AOI) (see Table AoR-13).

Table AoR-13: Seven saltwater disposal wells that were integrated in the mapping of the Miocene Composite Confining Zone for dissipation.

Relative location	UWI	Well Name	Injection interval [MD]	
			top	base
inside area of interest (AoR)	42-071-31590	Dugat 1	3,050	4,400
	42-071-32453	Dugat SWD_3	2,500	4,500
	42-071-31663	Epler John L_2	1,960	2,020
	42-071-30370	O C Devillier_3	2,550	4,050
in neighboring producing fields	42-291-04582	Dan Harrison Fee 19-A	2,288	2,312
	42-071-01554	Wilcox SWD 17	1,400	2,100
	42-071-31968	Syphrettdw 13	1,790	2,029

Three individual confining zones were chosen because they were located immediately above discrete permitted and approved injection zones in those seven SWDs and correlative on Spontaneous Potential and deep resistivity logs in the dip and strike directions within the Bluebonnet model boundary. The fact that shallow saltwater disposal wells were permitted and allowed to inject at shallow depths ranging from 1400 ft to 4,500 ft measured depth, implies that regional fluid-migration barriers exist on top of the approved disposal zones.

To characterize these three confining zones within the Miocene Composite Confining Zone, wireline logs (spontaneous potential and deep resistivity curves) from 45 to 120 wells were used to make structure and gross thickness maps within the Bluebonnet model boundary. The well count is dependent on depth, as not every well has logs that cover all additional composite confining zones up to surface; instead, most logs only have partial coverage. The number of wells with logs – and accordingly the amount of tops correlated – decreases with shallower depths of the zones of interest. For example, the deeper Miocene Composite Confining Zone 3 has a greater number of wells with log coverage and tops correlated than the shallower Miocene Composite Confining Zone 1 as shown in Figure AoR-179. This is proportional with the level of confidence in well tops over the regional extent in strike and dip direction.

This Miocene Composite Confining Zone, located above the primary Lower Miocene Confining Zone, will attenuate any vertical fluid displacement and pressure buildup outside the proposed injection zones, and is requested to be permitted as the upper-most confining system. The individual Confining Zones 1 through 3 that make up the Miocene Composite Confining Zone are most likely terrestrial paleosols, analog to the Lower Miocene Confining Zone, which was cored in the stratigraphic test well Encanto 01. Bluebonnet drilled a dedicated well Bluebonnet USDW 8 and acquired 79 ft of whole core and 29 RSWC with a targeted data acquisition in the confining shales of the Miocene Composite Confining Zone. Out of the 29 RSWC only 5 RSWC passed the laboratory inspection to continue with further analysis and most of the 79 ft of whole core are utilized in the ongoing core analysis. Bluebonnet is currently working with the laboratory performing routine and special core analyses to characterize the shallow mudrocks and their ability to trap, attenuate, or seal any escaped CO_2

Special core analyses include geomechanical measurements such as compressibility of these matrix materials in the sands and the confining shales, since those values and associated upper and lower ranges have a significant impact in the dynamic simulations. The results from these routine and special core analyses will be provided to supplement this analysis, once the laboratories complete the experiments and release the data.

The data acquisition on Bluebonnet USDW 8 also included collecting two sets of wet drill cuttings every 60 ft from surface to TD. The cuttings are crucial to inform the project about the lithology in between the cored intervals, including the shallow freshwater aquifers which are mainly unconsolidated sands containing fresh water, the confining shales in between and additional shales below the base of USDW, which make up the Miocene Composite Confining Zone.

3.8.2.5.1 Petrologic Description

This is an example of a limey mudstone/silty wackestone/argillaceous silty mudstone comprising the Miocene Composite Confining Zone. Based on XRD data, the majority of the whole rock mineralogy are clays, dominantly illite/smectite, followed by quartz, calcite, and minor K-feldspar and plagioclase. A few of the silty clasts are also pyritic (arrow).



3.8.2.5.2 MICP from Miocene Composite Confining Zone

As described under 3.8.2.5, dedicated whole core (79 ft) and RSCW (5 valid out of 29) as well as cuttings every 60 ft were acquired in this Miocene Composite Confining Zone to evaluate seal integrity and seal capacity. This data acquisition specifically targeted the confining shales of the Miocene Composite Confining Zones 1 and 2. Currently routine and special core analyses with multiple labs are underway and data delivery is expected soon.

Based on two RSWC samples situated below the Miocene Composite Confining Zone 3 and USDW, the displacement pressure criteria will need an injection height of [redacted] feet before breaking into the confining zone.

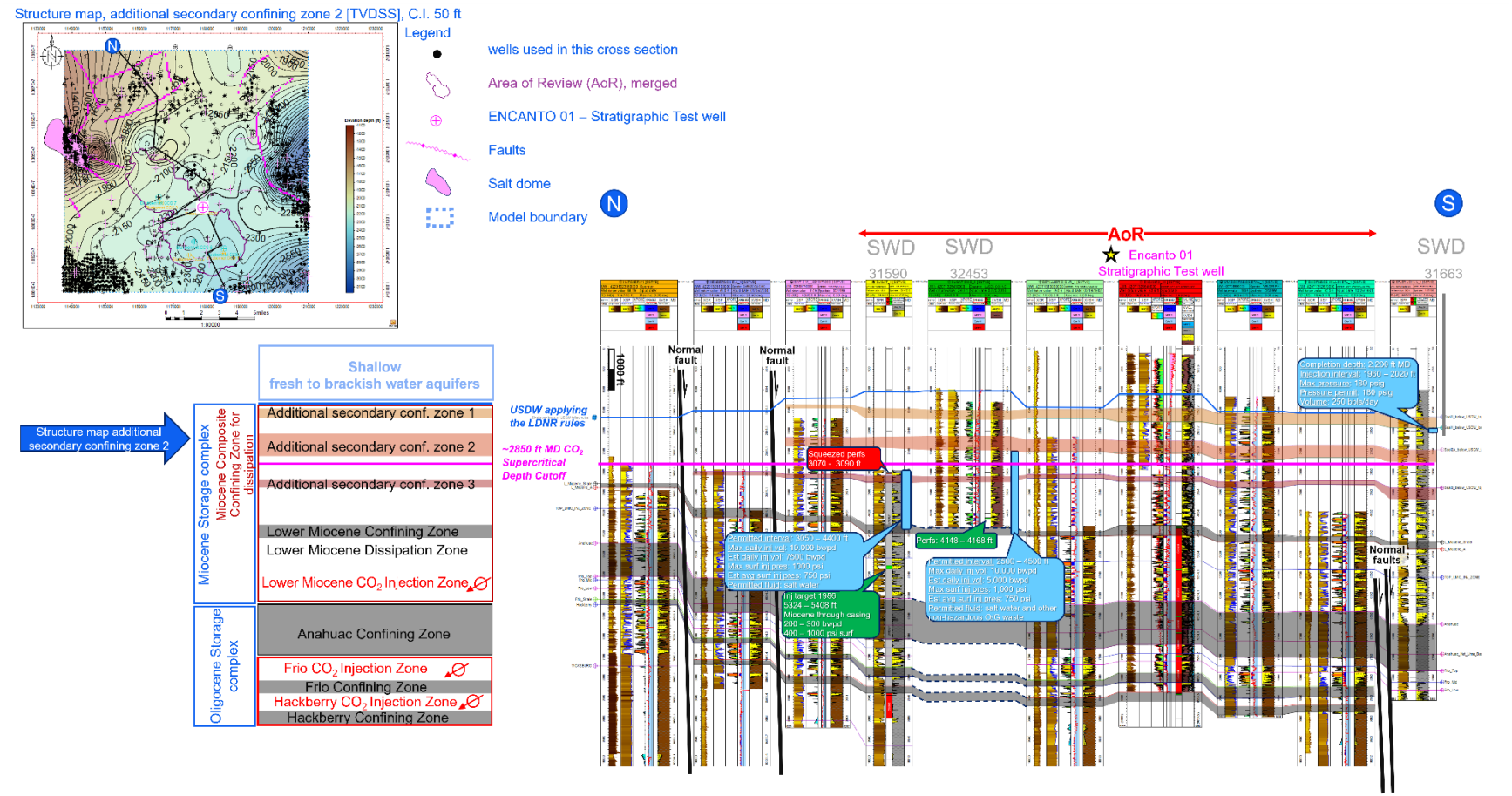


Figure AoR-179: Regional structural cross section through the Area of Interest (AOI), scale 1:8000. This cross section highlights the additional Miocene Composite Confining Zones above the Lower Miocene Confining Zone. Existing saltwater disposal wells (SWD) have been integrated to map three confining zones above the permitted SWD injection intervals; those are shown in shades of brown. They are most likely terrestrial paleosols, analog to the Lower Miocene Confining Zone, which was cored in the stratigraphic test well Encanto 01. Bluebonnet Sequestration HUB, LLC, will pursue additional core data, e.g. whole cores and rotary sidewall cores, in these Miocene Composite Confining Zone.

3.8.2.5.3 Miocene Composite Confining Zone Maps

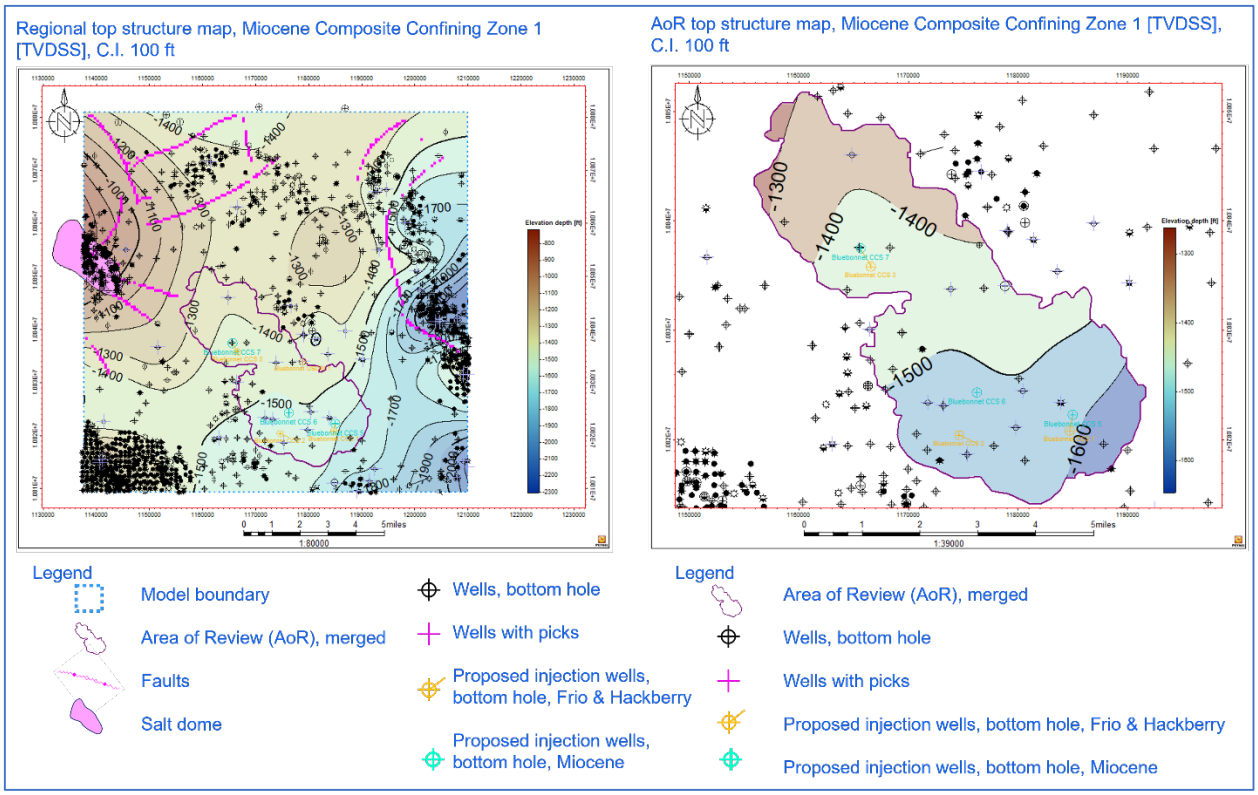


Figure AoR-180: Regional and AoR top structure map of the Miocene Composite Confining Zone 1 in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

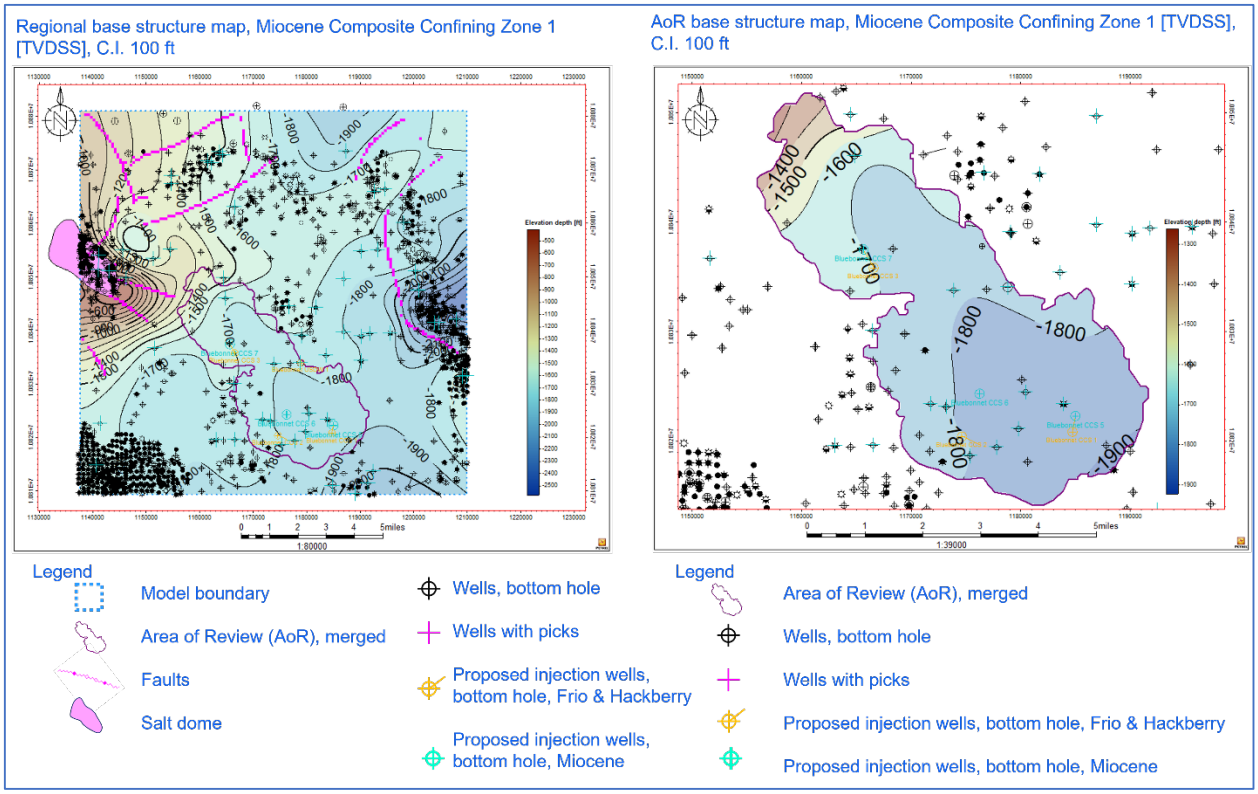


Figure AoR-181: Regional and AoR base structure map of the Miocene Composite Confining Zone 1 in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

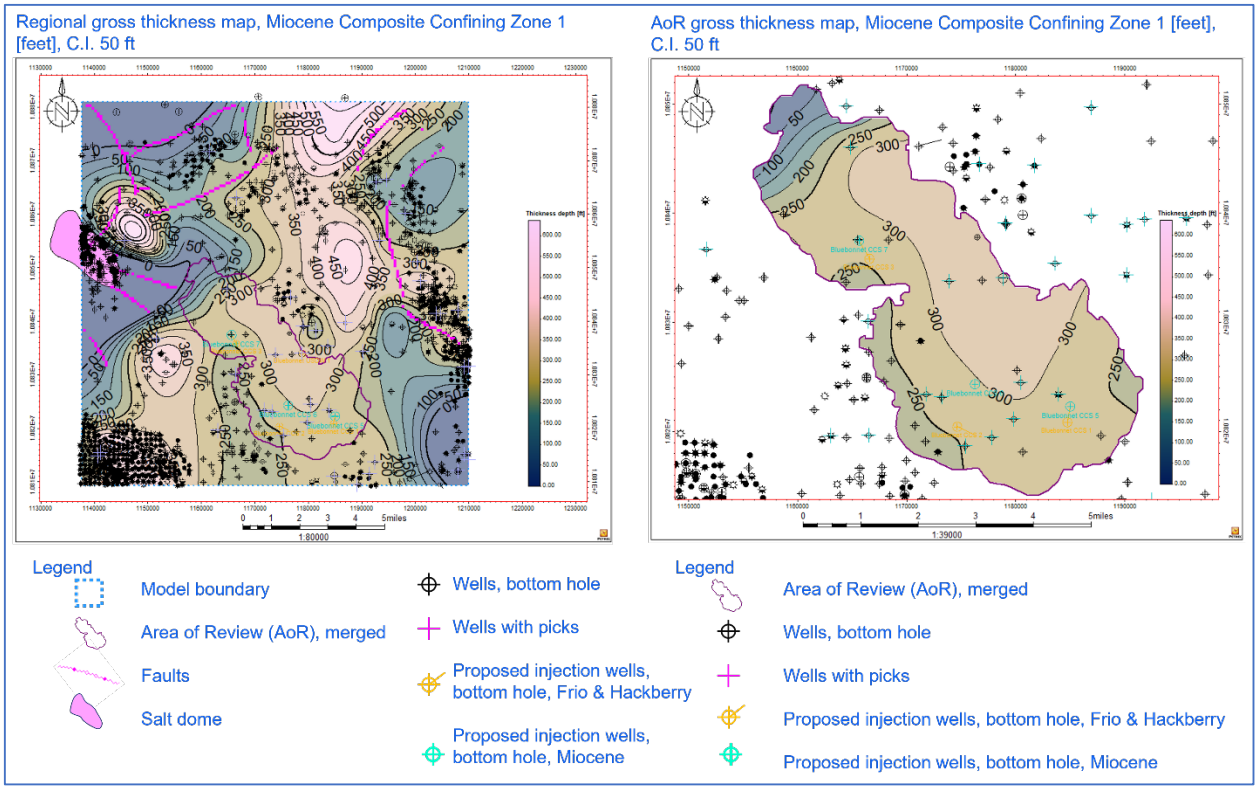


Figure AoR-182: Regional and AoR gross thickness map of the Miocene Composite Confining Zone 1 in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

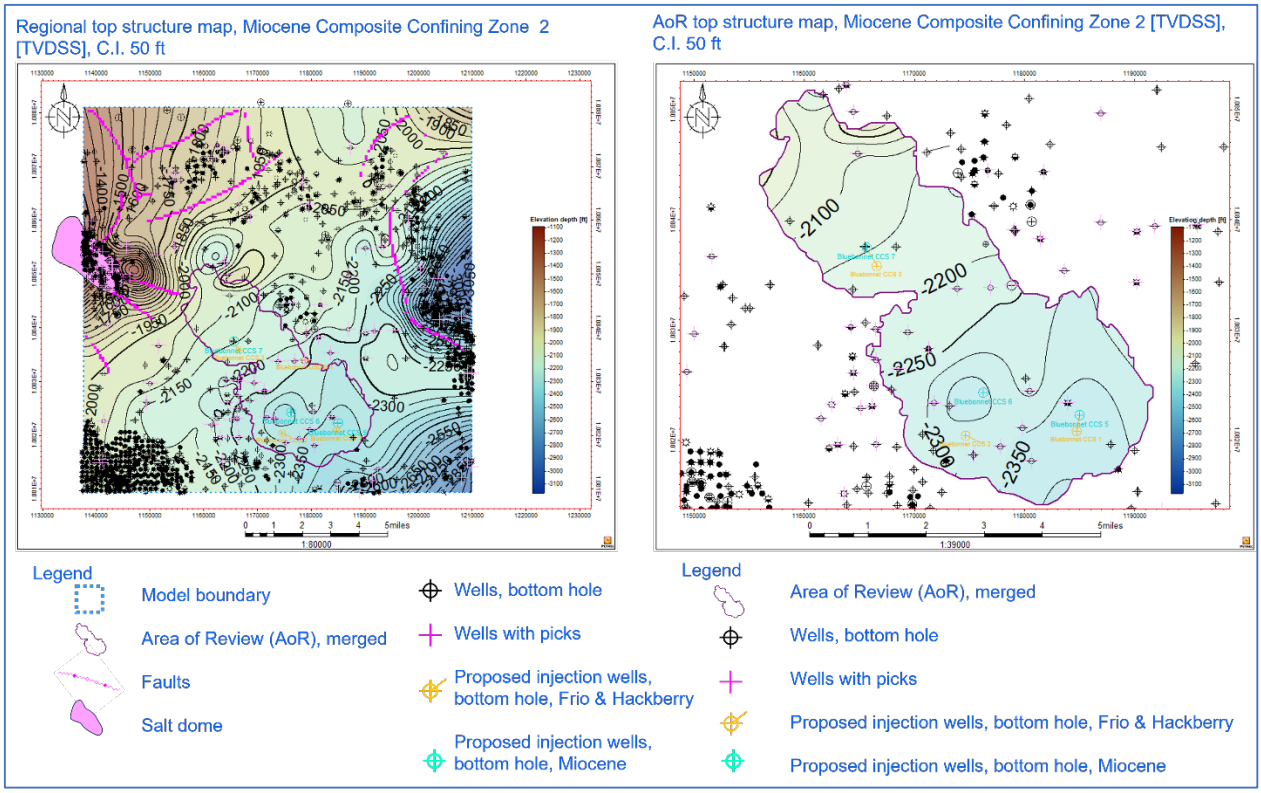


Figure AoR-183: Regional and AoR top structure map of the Miocene Composite Confining Zone 2 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

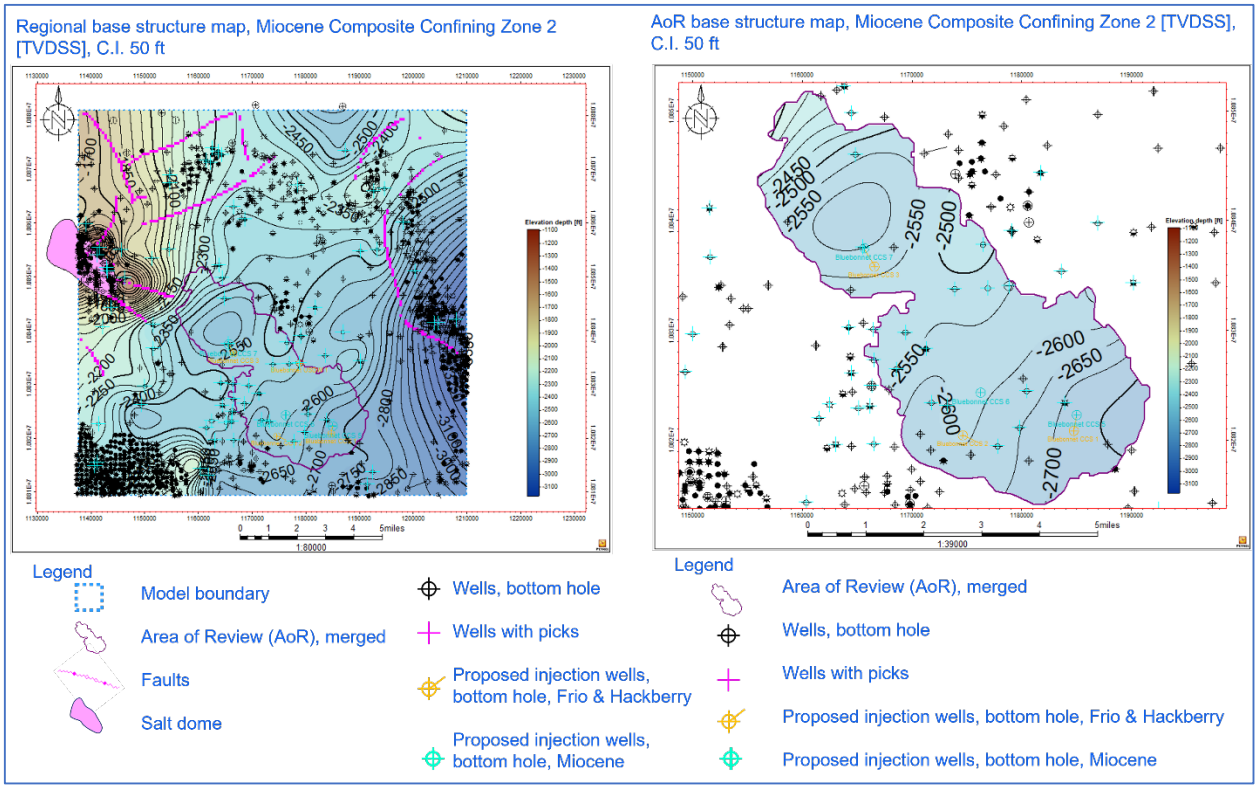


Figure AoR-184: Regional and AoR base structure map of the Miocene Composite Confining Zone 2 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

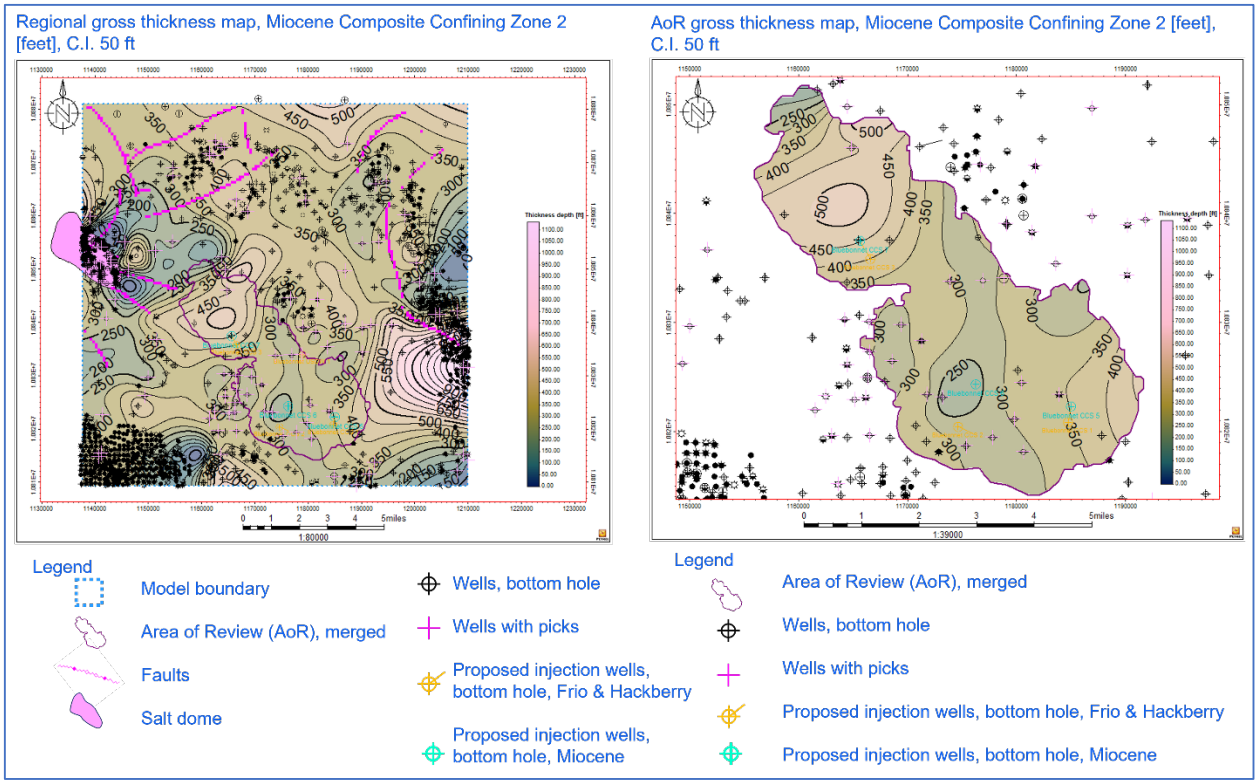


Figure AoR-185: Regional and AoR gross thickness map of the Miocene Composite Confining Zone 2 in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

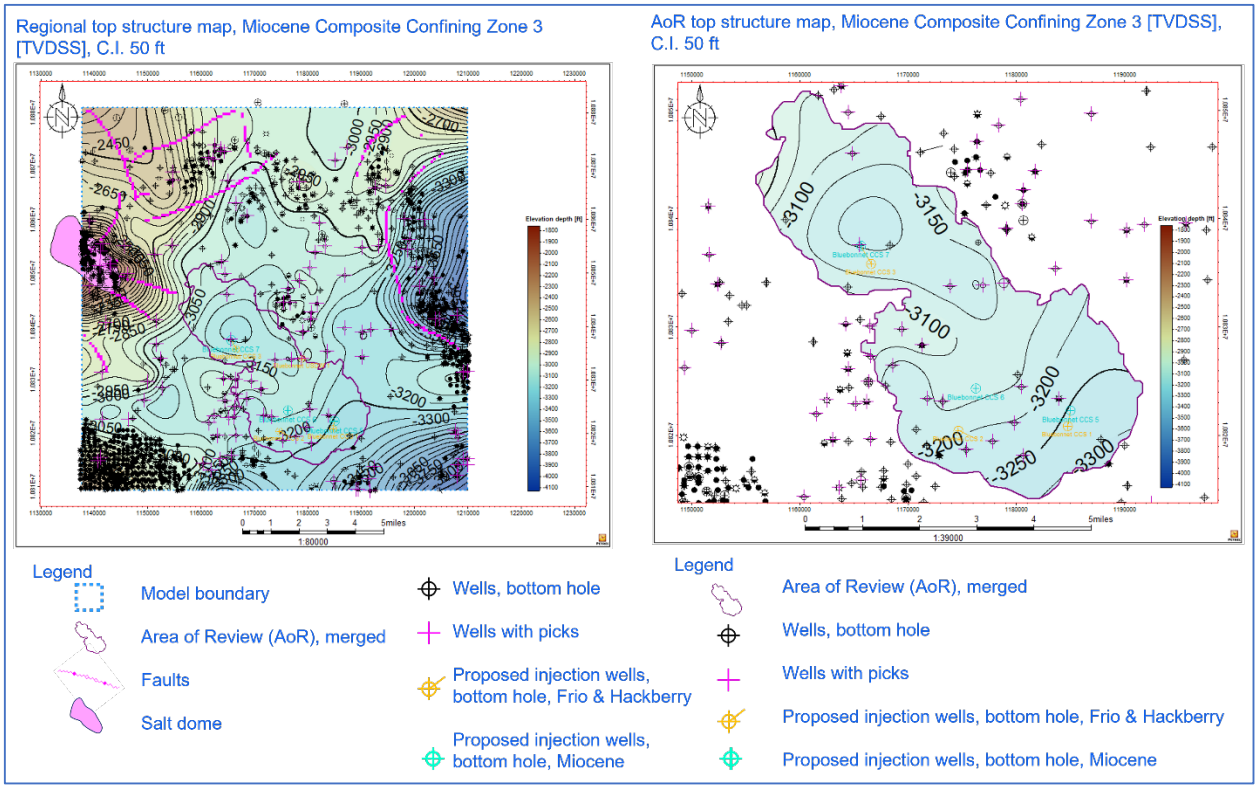


Figure AoR-186: Regional and AoR top structure map of the Miocene Composite Confining Zone 3 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

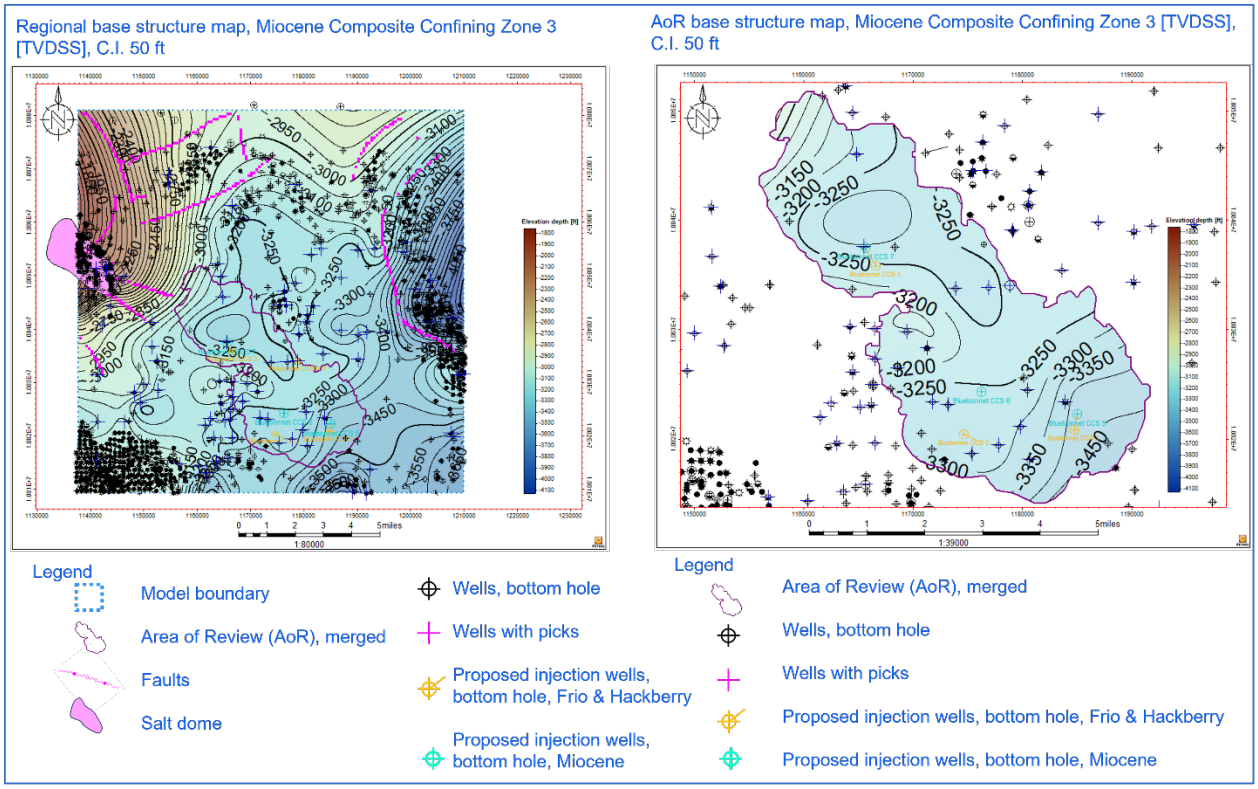


Figure AoR-187: Regional and AoR base structure map of the Miocene Composite Confining Zone 3 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

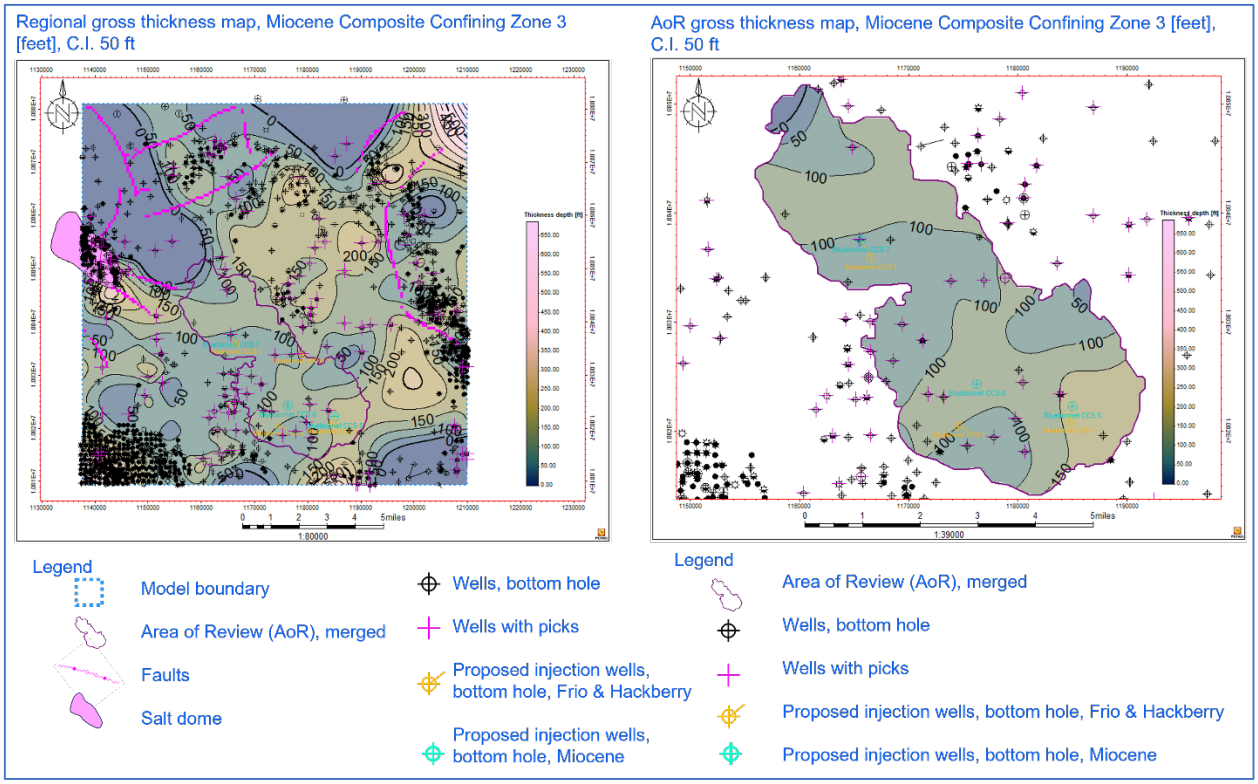


Figure AoR-188: Regional and AoR gross thickness map of the Miocene Composite Confining Zone 3 in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

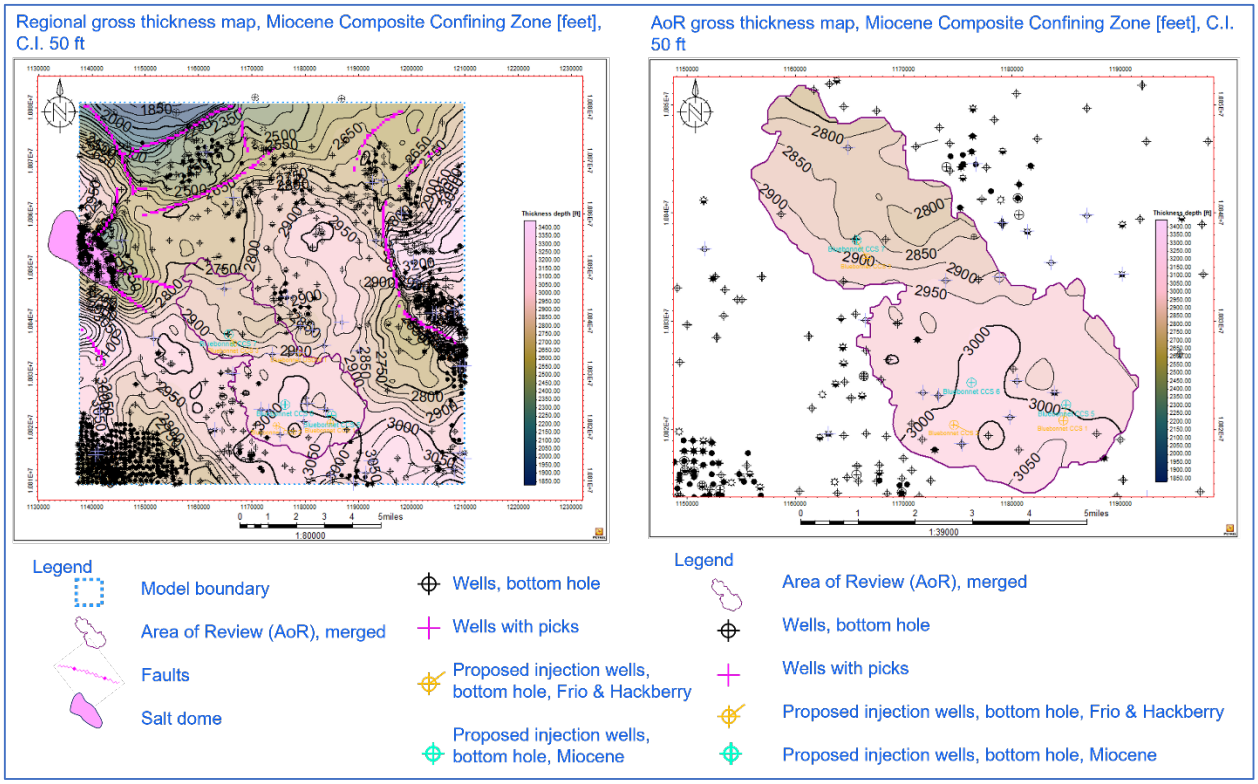


Figure AoR-189: Regional and AoR gross thickness map of the combined Miocene Composite Confining Zone in feet, contour interval 50 ft. The base of this gross thickness map is the top of the Lower Miocene Confining Zone. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-14 represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-14: Reservoir properties for the Miocene Composite Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Miocene Composite Confining Zone			
		Zone 1	Zone 2	Zone 3	Combined
Top depth [TVDSS]	Minimum	Claimed as PBI			
	Maximum				
	Average				
Base depth [TVDSS]	Minimum				
	Maximum				
	Average				
Gross Thickness [ft]	Minimum				
	Maximum				
	Average				

These three individually mapped confining zones are characterized by blocky SP log signatures that were identified above the permitted injection zones in existing saltwater disposal wells. The Miocene Composite Confining Zones 1, 2, and 3 were mappable across several miles in a north-south dip and east-west strike direction. In addition to mapping Miocene Composite Confining Zones 1, 2, and 3, the Bluebonnet Project team completed a shallow water well (Bluebonnet USDW 01) to validate the base of the USDW. Four open-hole fluid samples were acquired in Bluebonnet USDW 01 to confirm the base of the USDW. One explanation for water quality results from Bluebonnet USDW 01, used to revise the base USDW, is the presence of a low permeability shale underlying the revised base USDW, which is observed on open-hole logs in Encanto 01 and Bluebonnet USDW 01. Although this additional shale was not mapped across the AoR, yet due to sparse well log control in offset wells, it may act as an additional confining zone to protect the USDW. Further, results from Bluebonnet USDW 01, showed a strong nonlinear water quality trend with an inflection point in water quality occurring across this shale (Figure AoR-190). This boundary occurs approximately 300 ft above (i.e., 1,200 ft MD) what is currently defined as Miocene Composite Confining Zone 1.



3.8.2.5.4 Miocene Composite Confining Zone – Oil based image logs

During the characterization, the Project acquired oil-based image logs over the interval from Total Depth (TD) to the surface casing shoe. Figure AoR-191 shows the image over the interval corresponding to the Seal 3.



Zooming in to see more detail, Figure AoR-192 shows the complexity of this seal. It is laminated and it has different rock characteristics, notice how the colors change.



3.9 Freshwater Aquifers

Groundwater production for drinking and municipal use in Chambers, Liberty, and Jefferson Counties, Texas is primarily sourced from the Chicot Aquifer, the shallowest of three primary aquifers that make up the overall Gulf Coast Aquifer. The Gulf Coast Aquifer can be subdivided into major and minor flow units. The full stratigraphic column (Figure AoR-193) includes the hydrogeologic units and geologic subunits of the Gulf Coast Aquifer. The cross section (Figure AoR-200 from 3.10) illustrates the gently sloping nature, south southeast, of these units towards the Gulf of Mexico. The oldest aquifer making up the lower-most Gulf Coast aquifer is the Jasper

Aquifer, which comprises the Oakville Formation and Lower Lagarto Formation (Young 2016). The Jasper Aquifer is composed of fine to coarse sand, sandstone, and clay intervals (Shaw 2016), and ranges from approximately 900 ft to 3,100 ft thick across Chambers and Jefferson counties. The Burkeville confining unit (Middle Lagarto), sometimes referred to as the Burkeville Aquiclude, is a clay-rich formation with a low specific yield and ranges from 130 ft to 300 ft thick (Tinsley 1971). This confining unit separates the Jasper Aquifer from the Evangeline Aquifer and may act as an effective hydraulic barrier between overlying and underlying aquifer systems (Young et al. 2016). The Evangeline Aquifer, which includes the Upper Lagarto, Lower Goliad, and Upper Goliad Formations, is made up of sand and sandstone with interbedded gravel and clay (Shaw 2016) and ranges in thickness across both counties from approximately 1,250 ft to 4,900 ft (Young 2016). The youngest major flow unit is the Chicot Aquifer, made up of the Willis, Lissie, and Beaumont Formations (Osbourne 2013, Young 2016). The Chicot Aquifer is comprised of sand, gravel, sandy clay, and clay, with grain size generally increasing with depth (Shaw 2016) and ranges from approximately 900 ft to 2,500 ft thick (Young 2016) across Chambers and Jefferson counties. Here, the base of the Gulf Coast Aquifer System is defined as the base of Jasper Aquifer or the lower Oakville Formation; however, the selected base can vary study to study as well as regionally (Young 2016; Young et al. 2010, 2012). In certain areas of the aquifer, the Anahuac Shale separates the base of the Jasper from the underlying Catahoula/Frio Formation. This shale section appears to be present in both Jefferson and Chambers counties.

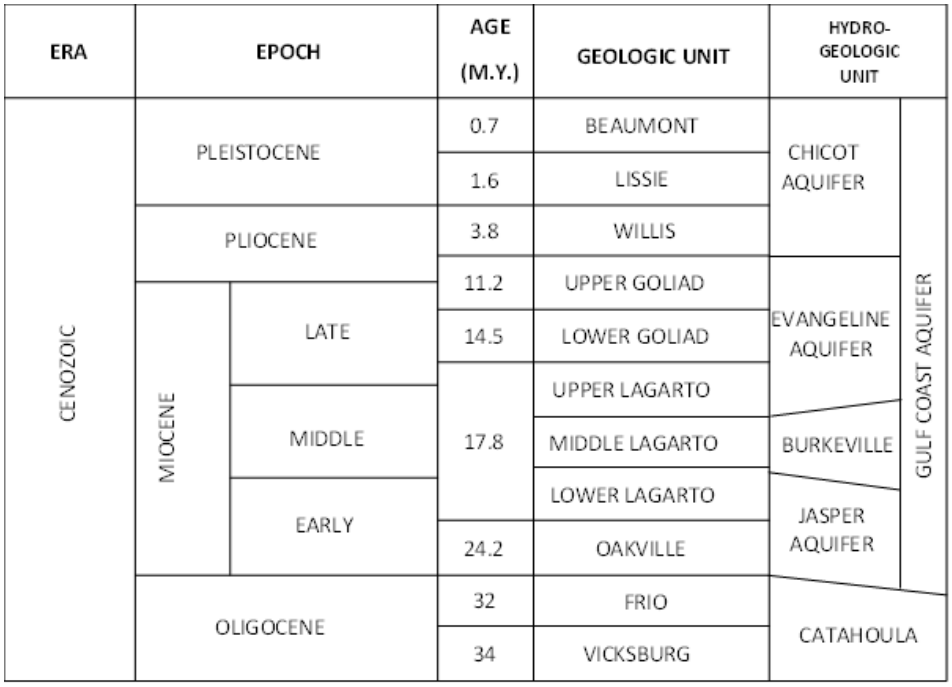


Figure AoR-193: Geologic and hydrogeologic units of the Gulf Coast Aquifer system (modified from Young et al. 2016).

Regionally, the Gulf Coast Aquifer System extends from the southern tip of Texas into western Florida with dip directions generally perpendicular to the coastline (Osbourne 2013). Aside from

the Beaumont Shale, which outcrops within both Chambers and Jefferson counties, most of the formations making up the Gulf Coast Aquifer crop out farther inland with the Jasper Aquifer cropping out up to 100 miles inland from the coast. An overpressured zone crosscuts the deepest extents of the aquifer system (Young 2016), of which the upper-most boundary can be observed at depths around 7,750 ft in Jefferson County; however, upper limits of this overpressured zone does not follow one consistent depth trend. Additionally, several fault systems running generally parallel to the coastline crosscut deeper hydrostratigraphic units, with the shallowest extents tipping out in the lower half of the Lagarto Formation (Young et al. 2016; 2012). The Frio fault zone likely extends from south to north into Chambers County and Yegua fault zone is present north of Chambers in the northwest portion of Jefferson County.

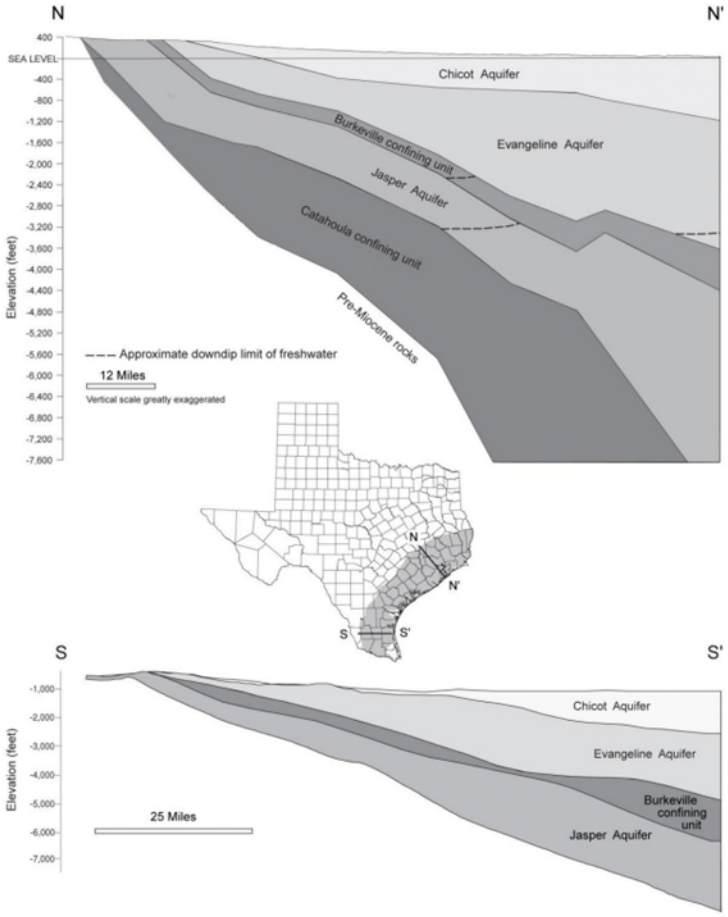


Figure AoR-194: Cross sections across the Gulf Coast Aquifer (TWDB 2016).

The Gulf Coast Aquifer System recharges mainly by precipitation on unconfined outcrop areas. Units comprising the Gulf Coast Aquifer outcrop in bands that parallel the Gulf Coast (Figure AoR-195). This is due to geologic units dipping towards the Gulf of Mexico and erosion exposing underlying layers of rock. The primary recharge mechanism of fresh groundwater is through precipitation that has not been consumed as runoff or stream flow (Tinsley 1971). Precipitation falls onto outcropped areas where a small percentage infiltrates the water table, creating recharge. In some cases, portions of water that reach saturated zones return to the surface as spring flow.

Salinity values of groundwater within the Gulf Coast Aquifer, including the Evangeline and Jasper aquifers, typically increase with depth and vary laterally.

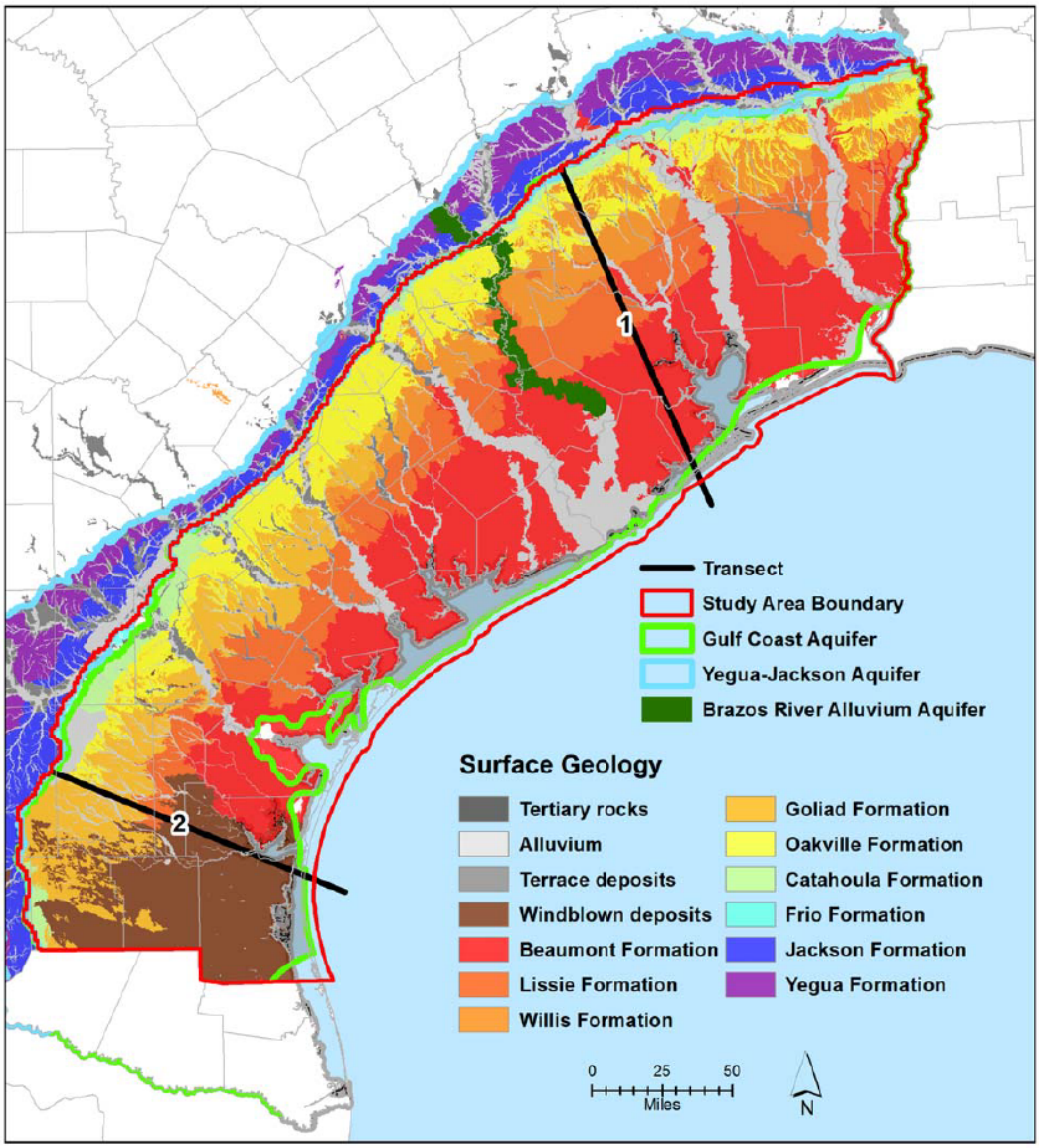


Figure AoR-195: Map of the Texas Gulf Coast showing the surface geology (outcrops) of the Gulf Coast Aquifer System (Young 2016).

The predevelopment potentiometric surface of the Chicot Aquifer flows south-southeast toward the Gulf of Mexico (Figure AoR-196). The southwardly dipping structure and northern updip limit of the Chicot Aquifer cause high head observed in the north and gradually less head moving south, resulting in the south-southeast hydraulic gradient. Groundwater development has resulted in changes to both local and regional hydraulic gradients for the Chicot Aquifer (Figure AoR-197). For example, groundwater drawdown observed in Harris County (City of Houston) has resulted in a regional pressure sink and now influences regional groundwater flow directions. Simulated

potentiometric surfaces for the Chicot Aquifer suggest current groundwater flows west-southwest (towards Harris County) in Chambers, Jefferson, and Liberty Counties (Figure AoR-197).

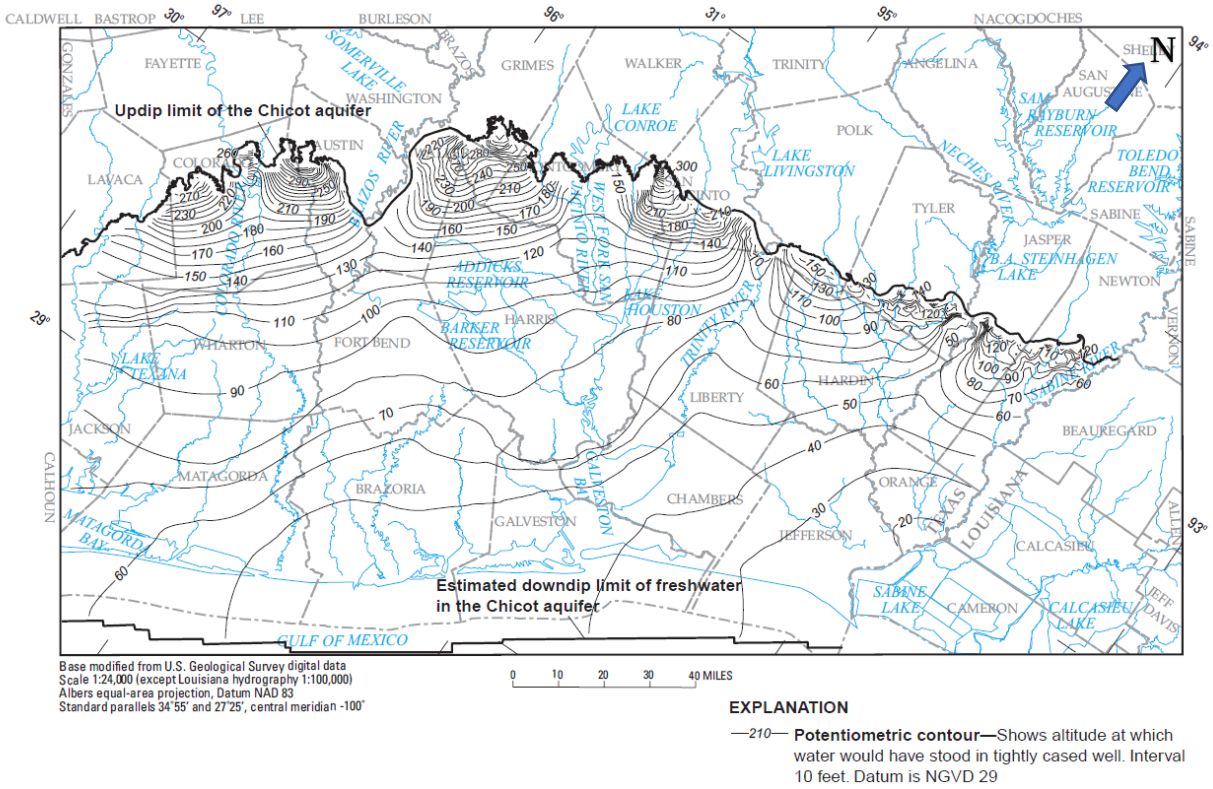


Figure AoR-196: Predevelopment potentiometric surface of the Chicot aquifer, simulated in the Groundwater Availability Model (modified from USGS).

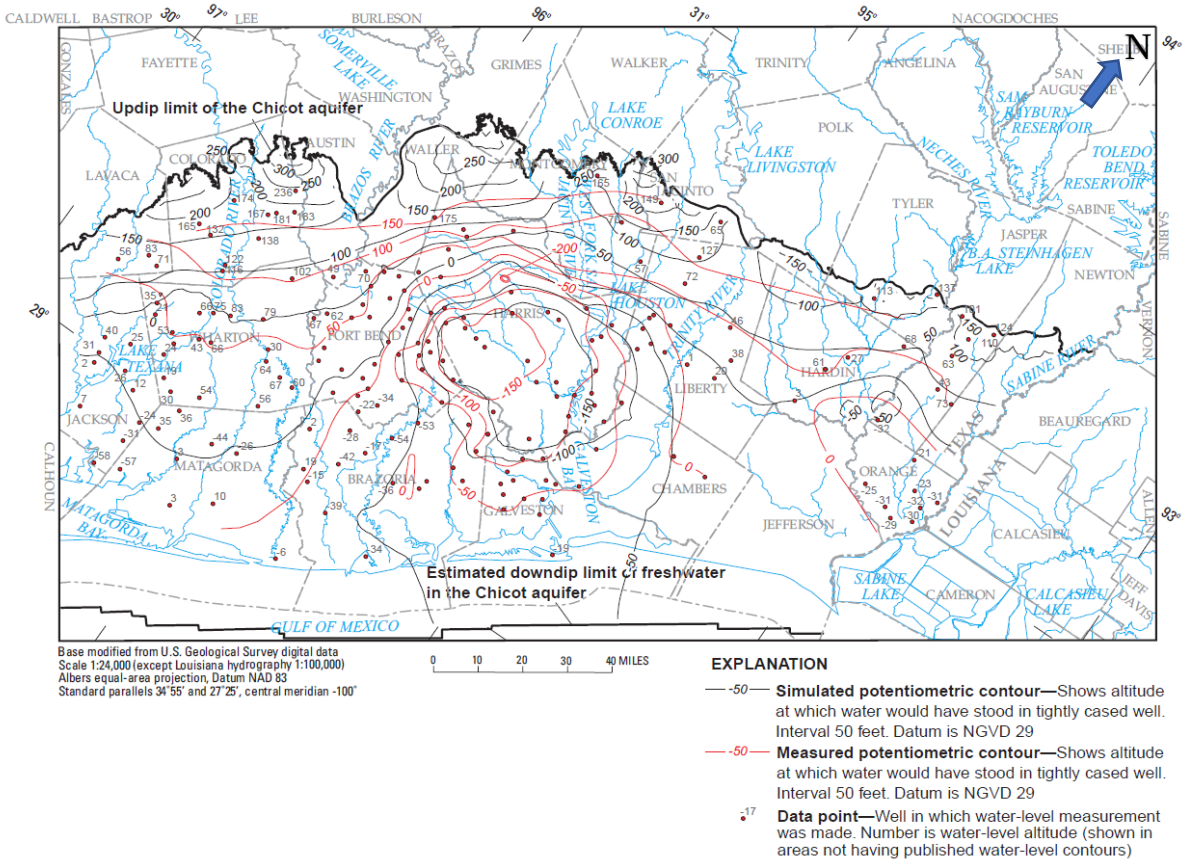


Figure AoR-197: 2000 potentiometric surface (black) and measured water levels (red) of the Chicot Aquifer, simulated in the Groundwater Availability Model (modified from Coplin and Santos 2000).

The number of water wells within the AoR is best characterized by the Texas Water Development Board (TWDB) groundwater database and Submitted Drillers Report Database (SDRDB) (Table AoR-15). Other sources of well data, although numerous, often focus on oil and gas wells. Additional research was done to located not registered legacy wells including interviews with landowners and the acquisition of a magnetic survey in 2025. The results of the magnetic survey and additional research are presented in the corrective action section. For this section, the TWDB and SDRDB data will be used. All water wells in the AoR are coded to the Chicot Aquifer. Aquifers underlying the Chicot Aquifer in the project area are generally considered too saline for drinking water and few water supply wells in the area penetrate the deeper Evangeline and Jasper Aquifers. Well use for the TWDB and SDRDB data were slightly different. TWBD well use data is broken into domestic, industrial, plugged/destroyed, stock, unused, and oil/gas (Table AoR-16). SDRDB groups wells by domestic, irrigation, rig supply, and stock (Table AoR-17). Forty water wells exist within the AoR.

Table AoR-15: The number of wells within the AoR by database. TWDB GWDB, SDRDB

Data Source	Total Wells in AoR
TWDB GWDB	14
SDRDB	25
SDRDB Plug	1

Table AoR-16: Number of wells within the AoR by use (TWDB Groundwater database).

TWDB Well Use	Number of wells
Domestic	2
Industrial	1
Plugged or Destroyed	3
Stock	1
Unused	7
Total	**14**

Table AoR-17: Number of wells within the AoR by use (SDRDB).

SDRDB Well Use	Number of wells
Domestic	19
Rig Supply	1
Stock	3
Plugged	1
Monitoring	1
Total	**25**

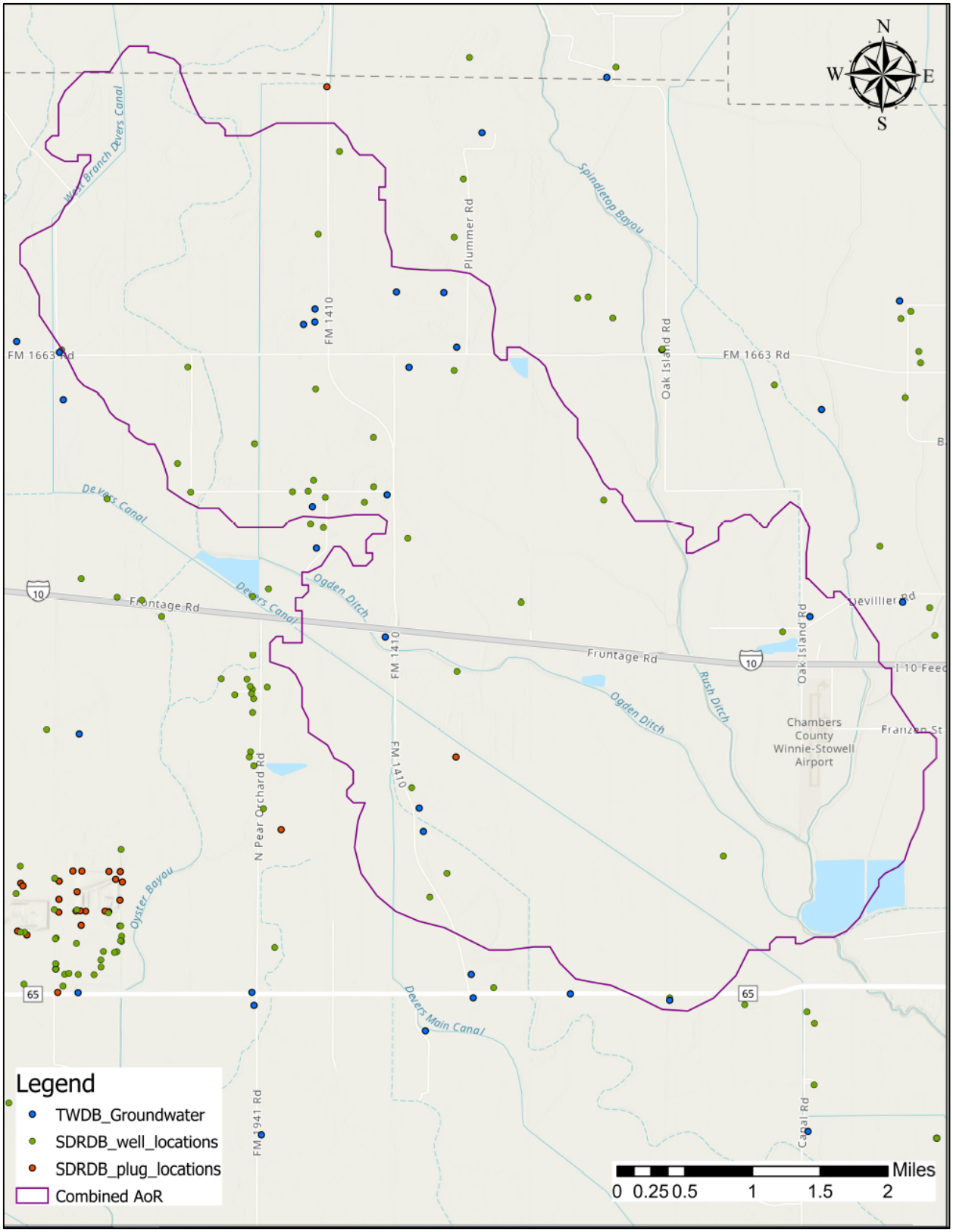


Figure AoR-198: Wells within the AoR from TWDB GWDB and SDRDB databases.

3.10 Base of the Underground Source of Drinking Water (USDW)

The Chicot Aquifer is the primary groundwater production zone for drinking and municipal use in Chambers and Jefferson Counties (Tinsley 1971). However, only small quantities of fresh groundwater (<1,000 mg/l TDS) are available in Chambers and Jefferson Counties, and these supplies are fairly well developed (Tinsley 1971). Overall, water use in Chambers and Jefferson Counties is largely sourced from surface water compared to groundwater from the Chicot Aquifer (Freese and Nichols, Inc., 2020). Historically, fresh water from neighboring Hardin and Orange Counties has been used to supplement water demand in Chambers and Jefferson Counties (Tinsley 1971).

The underground source of drinking water (USDW) is defined by USEPA as an aquifer or part of an aquifer that contains <10,000 ppm TDS. Publicly available studies suggest base USDW depth ranges from 1,000 to 2,000 ft MD (lower Chicot Aquifer) from across Chambers and Jefferson Counties (Young et al. 2016; Figure AoR-199). Within the AOI, USDW depth ranges between 1,100 ft and 1,700 ft MD (Young et al. 2016; Table AoR-18). Site-specific base USDW determinations are discussed in detail further below. Water quality in the Evangeline and Jasper Aquifers underlying the Chicot Aquifer is generally considered very saline (>10,000 mg/l) or brine (>35,000 mg/l) within the AOI, and no water supply wells within the AOI were found to penetrate these deeper aquifers. Fresh water is produced from wells in the Evangeline Aquifer towards the western extent of Chambers County (e.g., Mont Belvieu) and along the far northern and eastern extent of Jefferson County.

Table AoR-18: Base depth ranges of total dissolved solid (TDS) concentrations based on area.

Water Quality	TDS (mg/L)	Chambers Co. Base Depth (ft.)	Proposed Project Site Base Depth (ft.)
Fresh	0 - 1,000	250 - 1000	400 - 500
Slight Saline	1,000 - 3,000	300 - 1,500	500 - 750
Moderately Saline	3,000 - 10,000	800 - 3,500	1,100 - 1,700
Very Saline	10,000 - 35,000	1,600 - 5,000	2,500
Brine	>35,000	>5,000	>2,500

Groundwater classification based on the criteria established by Winslow and Kister (1956)
Base of USDW (< 10,000 mg/l TDS) depths are from TWDB Report 1600011947 (Young 2016)

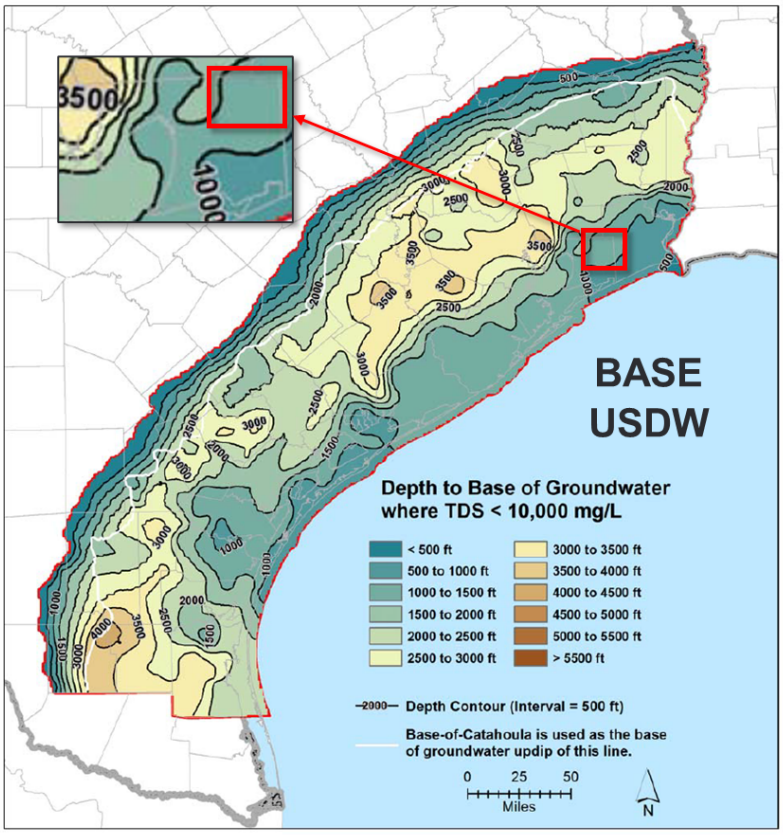


Figure AoR-199: Base of USDW (TDS < 10,000 mg/l TDS) (modified from Young et al. 2016).

Site-specific interpretation base USDW was completed using two methods: (1) deep resistivity readings from open-hole logs and (2) spontaneous potential readings from open-hole logs. Deep resistivity methodology followed the Louisiana Department of Natural Resources (LDNR) Office of Conservation, Injection, and Mining Division (IMD) guidelines. LDNR-IMD methodology was applied to wells within and outside of the AoR. Results from both methods were compared to publicly available water quality studies of the region that utilized similar methods followed by open-hole fluid samples collected *in-situ* onsite to characterize and confirm base USDW. The LDNR-IMD methodology utilizes deep resistivity readings from open-hole logs under the following guidance:

> "The IMD typically uses the deep induction curve on an e-log to define the base of the USDW. The following guidelines are used: (1) ground surface to 1,000 feet: 3 ohms or greater is considered USDW; 2) from 1,000 feet to 2,000 feet: 2 ½ ohms or greater is considered USDW; and 3) 2,000 feet and deeper: 2 ohms or greater is considered USDW. The base of the USDW is established at the base of the sand unit that contains the lowermost USDW with an isolating shale beneath it (LDNR-IMD, 2022)."

One concern with deep resistivity readings is that, in addition to resistivity responses from formation fluid salinity, resistivity responds to pore fluids such as hydrocarbons, gases, and drilling

fluids, as well as cementation effects in tight sandstones. Here, care was taken by technical staff to consistently select clean basal sandstones with high water saturations for formation water salinity estimation. Figure AoR-202 shows results of the LDNR-IMD deep resistivity method, which shows a base USDW of approximately 1,182 ft MD in Encanto 01 is reasonable. The average base of USDW using this method is -1,356 ft TVDSS within the AoR. Previous base USDW interpretations for this site did not utilize LDNR-IMD methods, but instead applied higher resistivity value cutoffs that resulted in an overly conservative interpretation of base USDW (1,845 ft MD in Encanto 01). Interpretation for revised base USDW (1,182 ft MD) using LDNR-IMD methodology is supported by water quality results from downhole fluid sampling conducted onsite in a water well drilled by Bluebonnet.

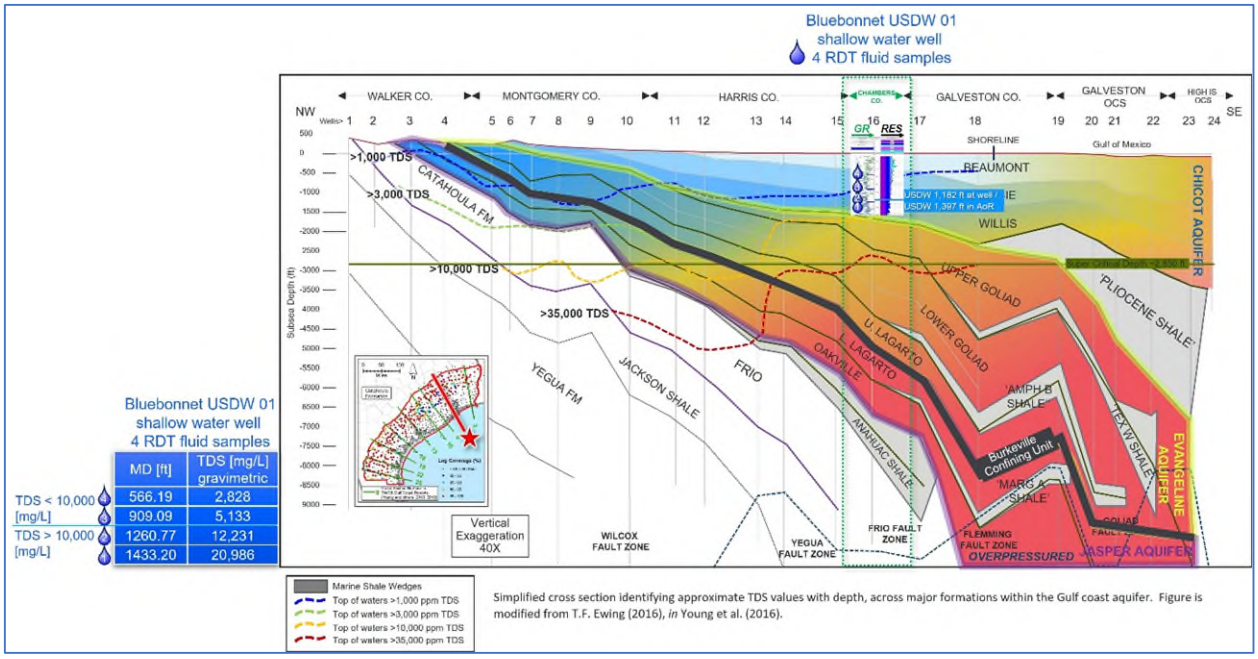


Figure AoR-200: Cross section showing TDS values with depth based on log interpretation across major formations within the Gulf Coast aquifer (modified after T. F. Ewing 2016 and Young et al. 2016). Superimposed are TDS values obtained from downhole fluid samples acquired using Halliburton's Reservoir Description Tool (RDT) in Bluebonnet USDW 01. Bluebonnet Sequestration Project site-specific fluid samples show actual base USDW is shallower than regional interpretation studies suggest.

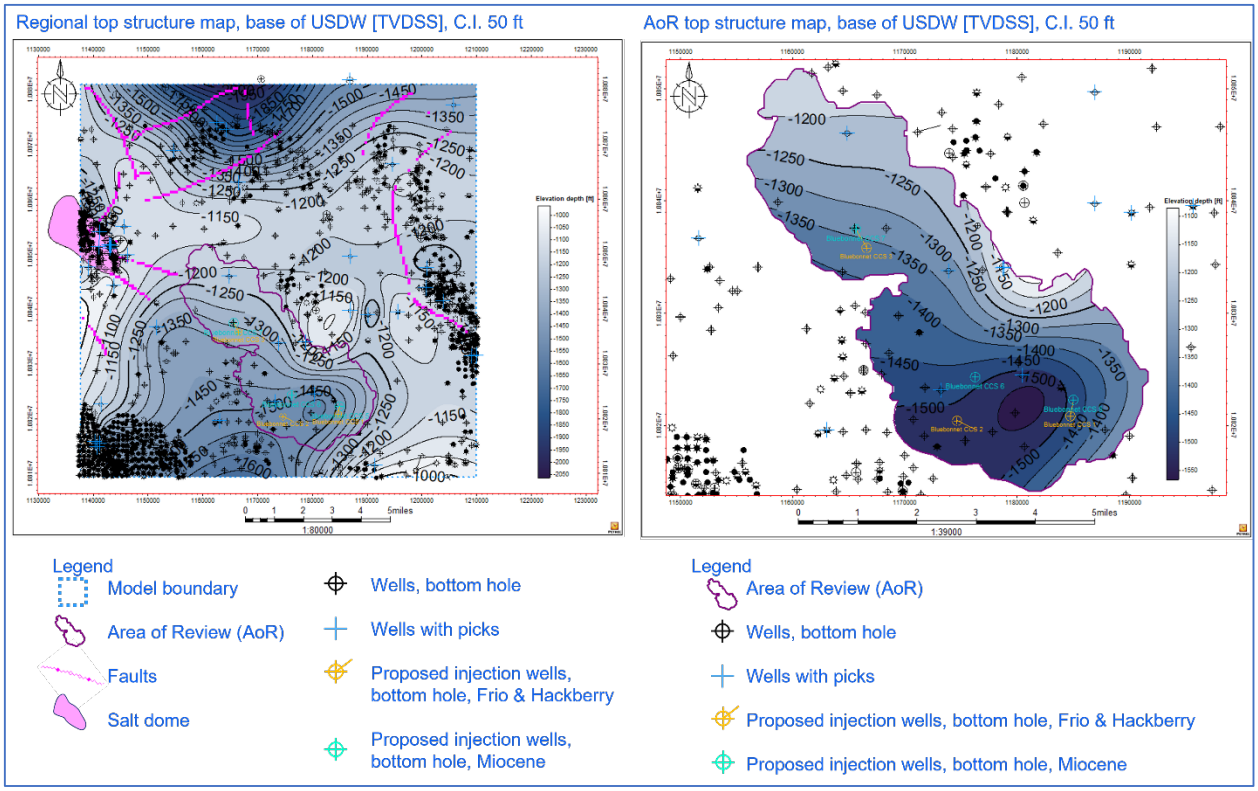


Figure AoR-201: Structure map (ft TVDSS) of the base USDW. Contour interval is 50 ft. The average base of USDW within the AoR is -1,356 ft TVDSS.

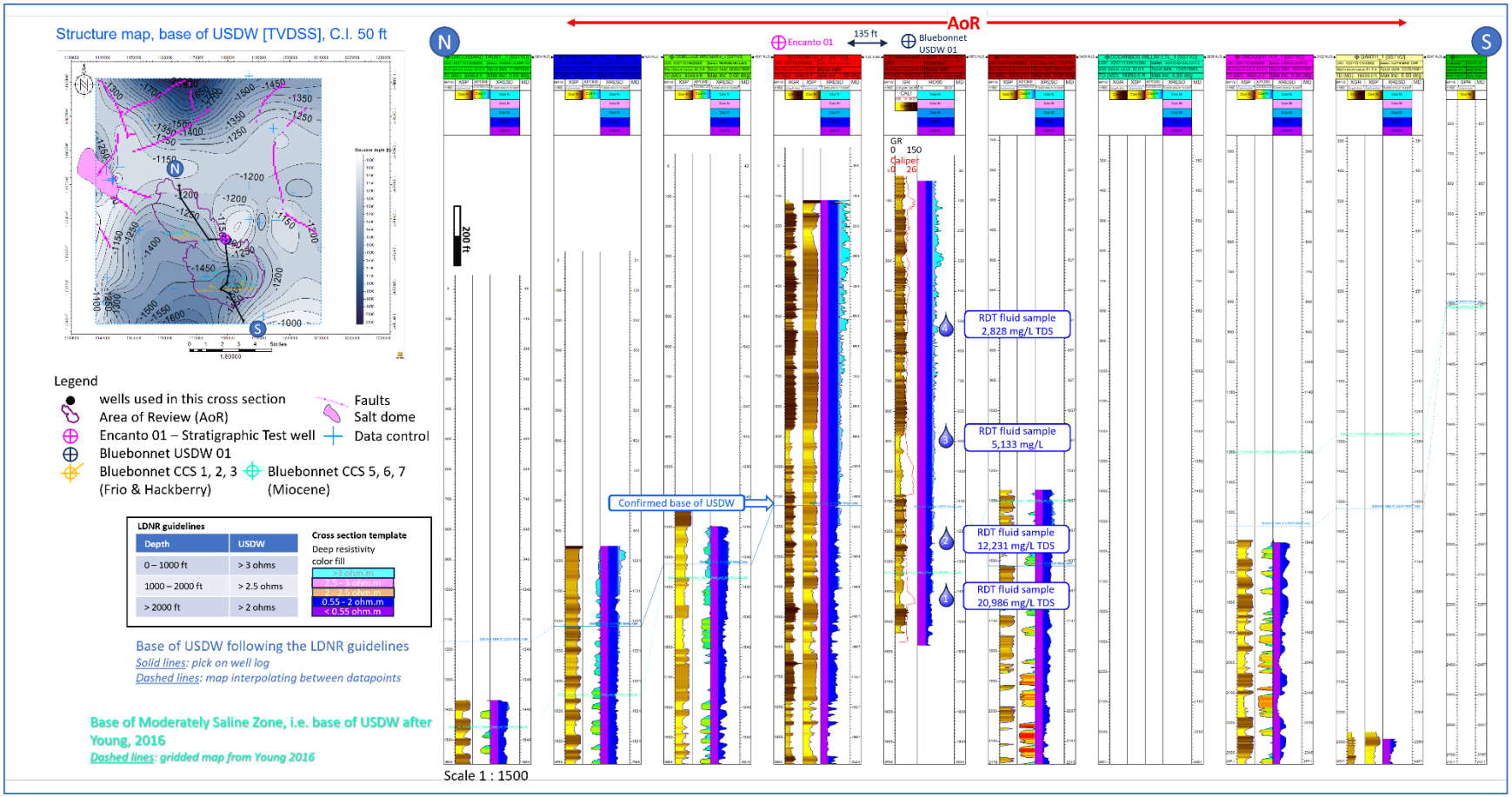


Figure AoR-202: Confirmed updated base of USDW shown in blue following the LDNR-IMD deep resistivity method. Site-specific RDT fluid samples acquired from Bluebonnet USDW 01 showed TDS values >10,000 mg/L in the sands below 1,182 ft and are compared to the interpreted base Moderately Saline Zone (10,000 mg/l TDS) after Young et al. (2016).

The second method used for base USDW was interpretation of formation water salinity using open-hole spontaneous potential (SP) logs. The SP log is a record of direct current voltage that develops naturally between a moveable electrode in the wellbore and fixed electrode at the surface (Asquith and Krygowski 2004). Electrical voltages arising from electrochemical factors (e.g., mud filtrate and formation water) within the borehole and adjacent rock create the SP log response. These electrochemical differences are used to interpret the resistivity (salinity) of formation waters in clean permeable sands. The SP method, with temperature correction, was applied to the petrophysical log obtained in the stratigraphic test well Encanto 01. Resistivity values from the SP method were compared to the LDNR-IMD deep resistivity method and indicated >10,000 mg/l TDS at 1,280 ft MD, the first clean sand below proposed base USDW at 1,182 ft MD (Figure AoR-203).

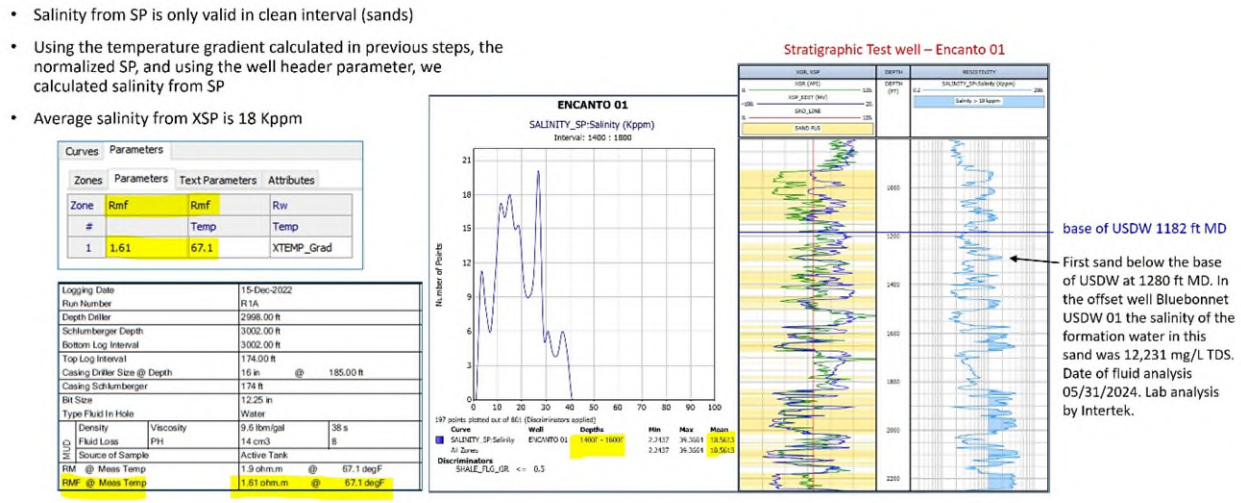


Figure AoR-203: Salinity estimation based on the Spontaneous Potential (SP) log.

LDNR-IMD and SP log-interpretation results for formation water quality were used to inform sample selection depths for open-hole fluid sampling in the Bluebonnet USDW 01 well, located 135 ft due east of the stratigraphic test well Encanto 01. Four depths were selected for open-hole fluid sampling (Table AoR-19). Open-hole fluid sampling (RDT) protocol is described further in the QASP section.

Table AoR-19: Sampling depths and lab analytical results for gravimetric TDS.

MD [ft]	Gravimetric TDS [mg/L]
566.19	2,828
909.09	5,133
1260.77	12,231
1433.20	20,986

Lab analytical results matched well with interpreted formation water salinity values. Gravimetric TDS measurements provide a high level of confidence because the actual mass of the dissolved solids is measured and compared to estimations from fluid conductivity or summation of measured dissolved constituent concentrations. Multiple fluid samples were acquired in Bluebonnet USDW 01 above and below the USDW to reduce uncertainty in salinity variations with depth and assess salinity-depth relationships. The salinity-depth relationships were found to be nonlinear and increased rapidly with depth. The fluid sample acquired from the 1,260 ft MD sand (12,231 mg/L TDS) in Bluebonnet USDW 01 correlates to the 1,280 ft sand in Encanto 01 and supports the mapped base USDW using the LDNR-IMD deep resistivity method described above.

Application of the two independent log-interpretation techniques and newly acquired field data provide support for a revised (shallower) base USDW than previously proposed in the Class VI permit application submitted to USEPA on September 28, 2023. This amendment uses the revised base USDW which ranges from 1,100 to 1,700 ft MD within the AoR.

3.11 Faults and Fractures in the Area of Review

3.11.1 Fault Analysis in the Area of Review.

The AoR was chosen due to the lack of seismic-scale faulting within the Frio, Anahuac, and Lower Miocene Confining Zones. A detailed description of the structural styles and fault interpretation are included in Section 3.5. Fault-seal analysis was performed on the faults included in the geologic model.

Shale Gouge Ratio (SGR) was evaluated as a sealing proxy to assess transmissibility of modeled faults. SGR was modeled two ways using a triangle juxtaposition plot and in a 2D sense, along each fault plane, as were other attributes, including Vshale and CO_2 column height. SGR is an attribute that is used to assess the possibility of an impermeable fault zone developing between juxtaposed reservoirs. The main assumption for SGR is that sand and shale are incorporated into the fault gouge in the same proportions (ratio) as they occur in the wall rocks of the slipped interval (Foxford et al 1998). Calculated SGR is used to model fault zone composition with a higher SGR assumed to correspond to more clay smear in the fault zone and subsequently higher capillary pressure and lower permeability. Higher SGR indicates potential for greater fault seal between juxtaposed reservoirs along the fault surface. Values of SGR <20% (<0.2 ratio) are typically associated with cataclastic fault gouge, whereas values >20% (>0.2) indicate more clay-rich or shaly gouge (Yielding et al. 1997 and Manzocchi et al. 1999). In the Bluebonnet Hub area, minimum vertical fault offset of 75 ft is required to result in SGR >0.2; this minimum is achieved in confining and injection intervals in bounding faults.

The actual VShale profile from the Vshale logs generated from petrophysical analysis are used to calculate SGR attribute values, which is defined as the net clay/shale content in the interval that has slipped past that point along the fault plane (Yielding et al., 1997). The SGR values were evaluated utilizing the 1D triangle diagram plots for various wells in the geologic model to assess the window of throw allowing for possible transmissibility. The triangle plot (Figure AoR-204) is shaded with hot colors indicating zones of greater sealing potential. Greens and bright yellows

reflect SGR values <0.2 (<20%) and indicate potential transmissible zones within juxtaposed reservoirs. SGR values were modeled in a 2D sense along the fault planes utilizing the same color scheme (see Figure AoR-205) to assess the frequency and geometry of any potentially transmissible zones through the stratigraphic intervals intersected by the fault planes.

Expected fluids within the AOI warranted the methodology of modeling CO_2 column height for comparison with the results of the SGR analysis. The Karolyte et al. (2020) equation was used to calculate CO_2 column height, which is equivalent to hydrocarbon column height modeling, but uses the CO_2 capillary pressure and substitutes expected CO_2 fluid density for hydrocarbon fluid density. CO_2 column height was also assessed utilizing both the triangle diagram juxtaposition plots, and in a 2D sense, projected along each fault plane in question. The CO_2 column height is computed at each sample node in the triangle juxtaposition plot and reflects the maximum height of the selected column that can be supported by the SGR at that point. When compared to the results of the SGR analysis, the zones of lower gamma rays indicated by the bright green and yellow colors correspond in proximity and frequency to zones of lower CO_2 column height indicated by the warmer colors on the CO_2 column height color bar. Assumptions for the CO_2 column height assessment include the same assumptions associated with the SGR analysis as well as the accuracy of the expected CO_2 fluid density in the model. For this analysis, an average of the range of expected CO_2 fluid density for the model was used.





3.11.2 Fracture Characterization Using Oil-Based Imager.

Oxy Low Carbon Ventures, LLC ran an oil-based imager log in Encanto 01 for structural information and fracture characterization, as described in section 3.8.2.5. The tool used was the Quanta Geo, a Schlumberger tool. The logging occurred on January 6 of 2023.

Overall, the quality of SLB's Quanta Geo was medium to poor. Interestingly, the calipers were engaged nicely for most of the well, minus a few sections in the Lower Miocene Injection Zone. Typically, image log data quality is worse in sections of wellbore rugosity. This Quanta Geo seemed to suffer quality issues from other influences.

Schlumberger's "Bed Boundary" dip-type was used for interval bedding orientations, as it discriminated between actual bed boundaries and stratigraphy nuanced from deformed bedding. This gave a more representative estimation of the background true dip of the intervals and eliminated using data from crossbedding, debris flows, slumps, etc. The true dip values ranged between 5° - 7°, with dip azimuths ranging between 135° - 190° (SE-S), consistent with Gulf Coast trends (see Table AoR-20, below).

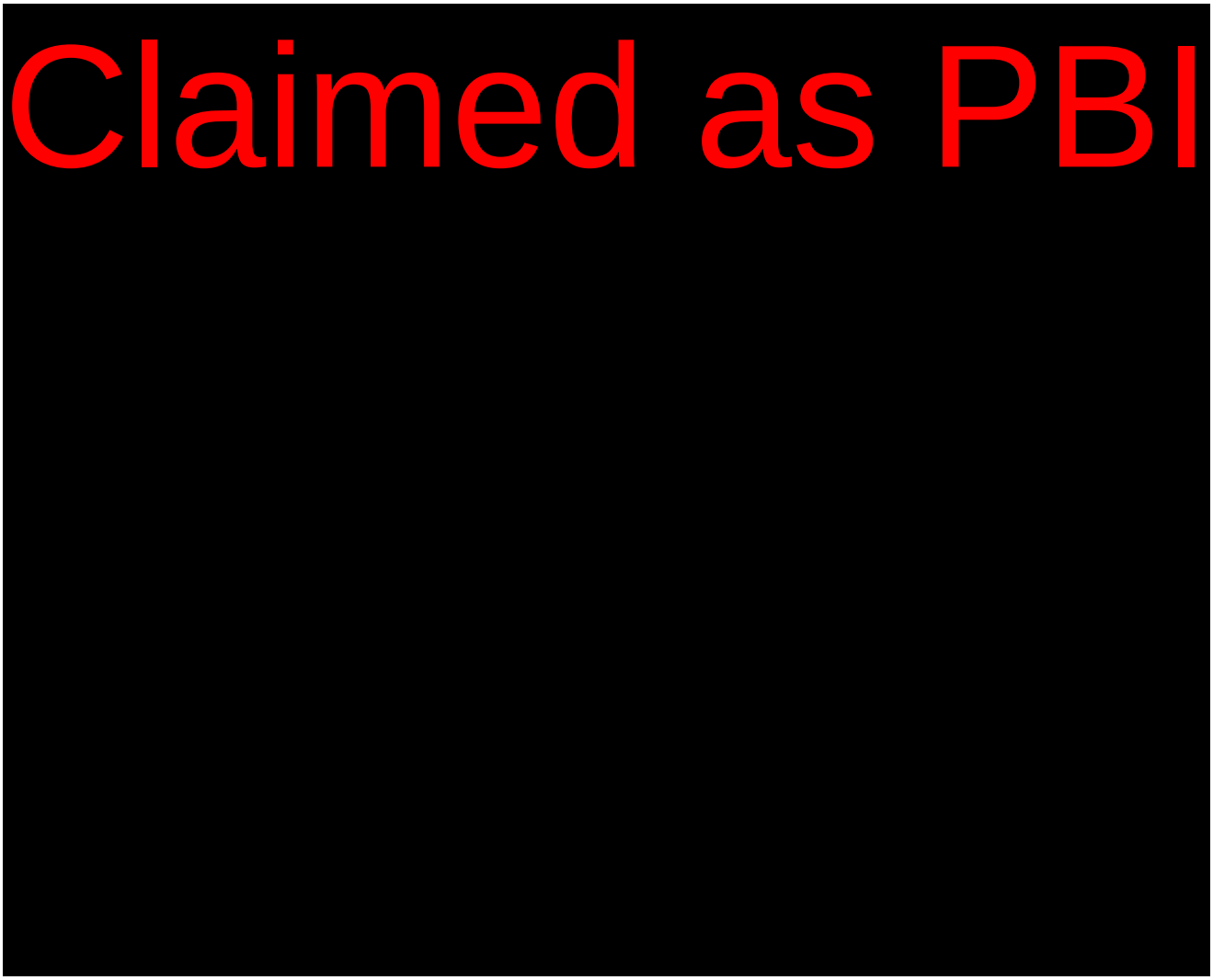
Table AoR-20: Average dip and azimuth by formation.

Formation name	Avg. Dip	Avg. azimuth
Miocene Lower Confining Zone	Claimed as PBI	
Miocene Lower Injection Zone		
Anahuac Conf. Zone		
Frio Injection Zone		
Frio Confining Zone		
Hackberry Injection Zone		
Hackberry Confining Zone		

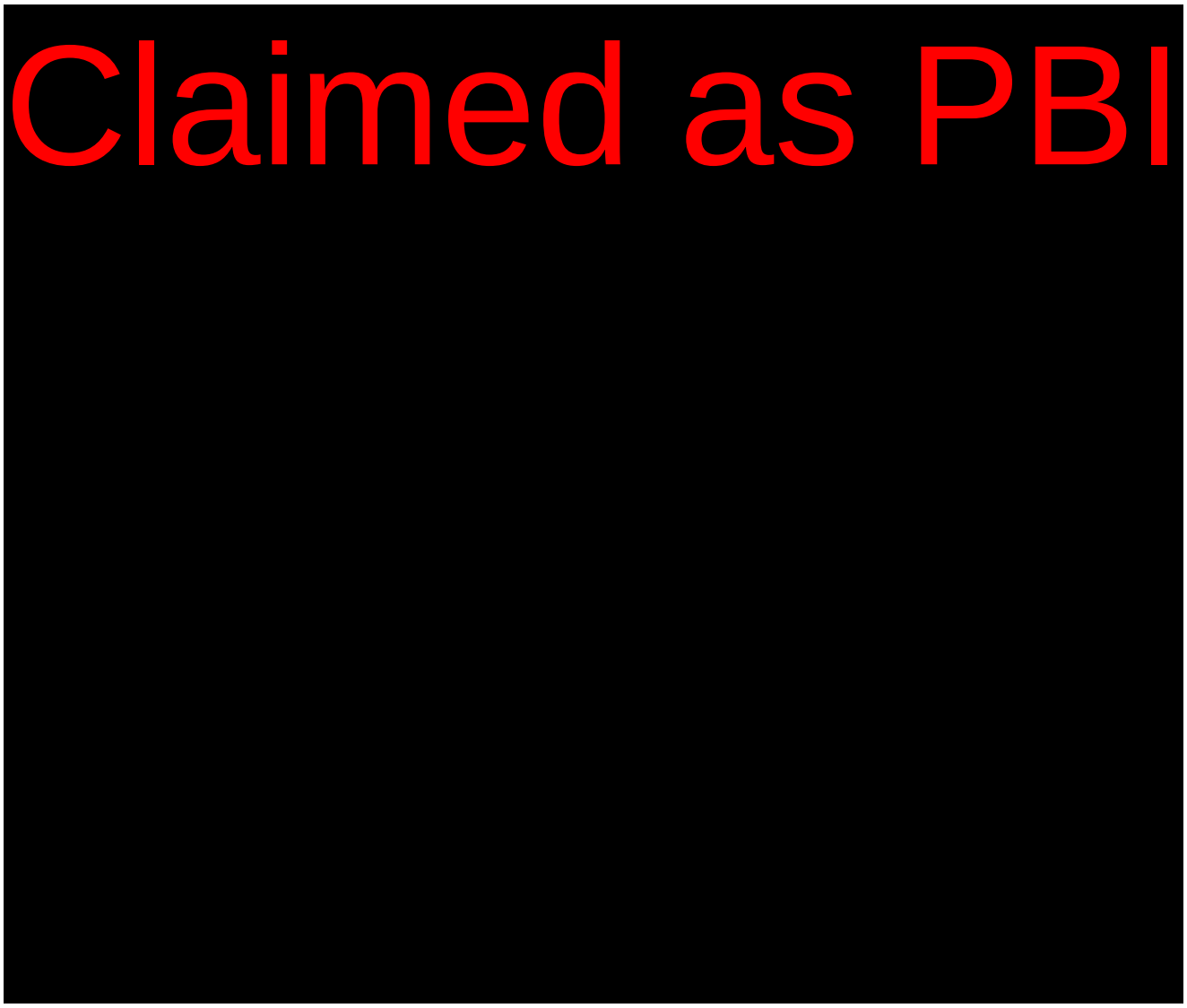
Most of the in-house interpretation was focused on structural characterization and fracture analysis, which, in the end, was a minor part of the results. Only one minor fault was observed in the Frio Injection Zone. This one minor fault (dip: 42°, dip azimuth: 142°) had no associated fractures, suggesting it was not part of a significant fault zone (see Figure AoR-209). This strike ° is consistent with Gulf Coast trends. Image logs often provide insightful data on SHMax (Maximum Horizontal Stress Direction) orientation, if borehole breakout or induced tensile fractures are observed. None were seen in this image. This fault is under the seismic resolution; therefore, it cannot be identified in seismic.

The analysis of the Quanta Geo log in the confining zones, Lower Miocene, Anahuac, and Hackberry Confining Zones, shows no fractures or faults as observed in Figure AoR-206, Figure AoR-207, Figure AoR-208, and Figure AoR-210.




Claimed as PBI


Claimed as PBI


Claimed as PBI



3.12 Geomechanics Analysis

The risk associated with formation breakdown and fracture generation during or after CO_2 injection is understood in the context of long-term pressure changes in the subsurface and potential to induce fractures in the formation. The resolved normal and shear stresses acting on an existing fault surface are calculated, and then, the Mohr-Coulomb analysis uses those stresses to estimate the risk of failure during CO_2 injection. Uncertainties of inputs to the in-situ stress model increase the risk due to the decreased accuracy and precision of stress magnitudes and injection pressures required to induce tensile or shear failure, collectively described as failure tendency. The increase in fluid pressure from CO_2 injection has the potential to cause failure from the generation of fractures in the matrix of the formation, dilation or shear slip along pre-existing faults, and/or reactivation of the basement fault systems, producing induced seismicity. This analysis only includes the risk of failure initiation of the matrix.

Mohr-Coulomb analysis considers the ratio of shear stress (τ) and effective normal stress (σ'_n) acting on a plane in a given orientation compared with the amount of friction of that plane. The plane can be an existing fault surface or a potential failure plane in the matrix of the subsurface. The coefficient of friction (μ) is defined as the ratio of shear stress to effective normal stress:

Figure AoR-210: Hackberry Injection Zone, no visible fractures.

$$\mu = \frac{\tau}{\sigma n}$$ ..... (Equation 3)

Failure using the Mohr-Coulomb failure criterion is defined as conditions where the ratio of shear stress to effective normal stress acts on an optimally orientated plane and exceeds the failure limit defined by the relationship:

$$\tau = \mu\sigma + So$$ ..... (Equation 4)

where So is cohesion and is a function of friction and unconfined compressive strength (UCS):

$$UCS = 2So(\sqrt{\mu^2 + 1} + \mu)$$ ..... (Equation 5)

Figure AoR-211 shows the graphical representation of the linear Mohr-Coulomb failure criterion. The state of stress is represented by the Mohr circle defined by the maximum (σ'_1) and minimum (σ'_3) effective principal stresses. Any plane orientation is defined along the boundary of the circle by an angle of 2β from σ_1 to σ_3, where β is the angle between the σ_1 and normal plane. In Figure AoR-211, the red circle represents the original state of effective stress. In the case of CO_2 injection into the reservoir, pore pressure is estimated to increase while decreasing the magnitude of the effective principal stresses and moving the circle to the left on the x-axis. The failure limit shown is the sloped solid black line defined by Equation 6. The dashed line would represent the failure limit of a preexisting fault with comparatively little friction. While the friction of faults is not zero, it is small compared to the friction required to initiate a fracture in the matrix.

As pore pressure increases during injection, the Mohr circle moves to the left along the x-axis and the circle boundary eventually intersects the failure envelope. Under those conditions, any plane oriented along the Mohr circle that crosses or intersects the failure envelope will be subject to failure risk. The linear model presented below represents a simplified version of the Mohr-Coulomb failure criterion, as the failure envelope is not often linear and as pore pressure increases, the effective stress decreases but the horizontal principal stress magnitude increases, making the circle smaller. The result of the linear model is a conservative interpretation, which is appropriate in a scenario where large uncertainties exist in the stress model.

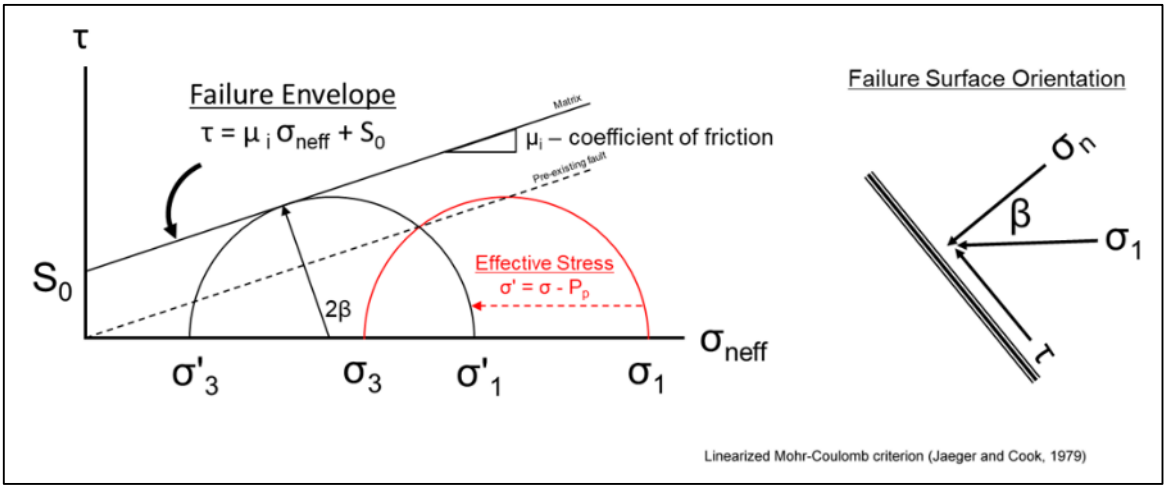


Figure AoR-211: Mohr-Coulomb Failure Criterion.

The Oxy Best Practices workflow for calculating pore pressure and the three principal stresses was implemented. Pore pressure was modeled using the effective stress, normal compaction trend Eaton method, using compressional velocity well data. The method utilized the Terzaghi effective stress principle to estimate pore pressure from the calculation of overburden and estimate of effective stress such that:

$$Pp = TVDft*0.465\ psi/ft \quad \text{..... (Equation 6)}$$

The state of stress was modeled using the isotropic poroelastic uniaxial strain model shown in Equation 6.

$$\sigma 3 = \frac{\nu}{1-\nu}(\sigma v - \alpha Pp) + \frac{\varepsilon hE}{1-\nu^2} + \frac{\varepsilon H\nu E}{1-\nu^2} + \alpha Pp \quad \text{..... (Equation 7)}$$

$$\sigma 3 = \frac{\nu}{1-\nu}(\sigma v - \alpha Pp) + \alpha Pp \quad \text{..... (Equation 8)}$$

where:

σ_3 = least horizontal principal stress
ν = Poisson's ratio
σ_v = maximum principal stress
α = Biot's coefficient
Pp = pore pressure
ε_h = minimum tectonic strain
ε_H = maximum tectonic strain
E = Young's modulus

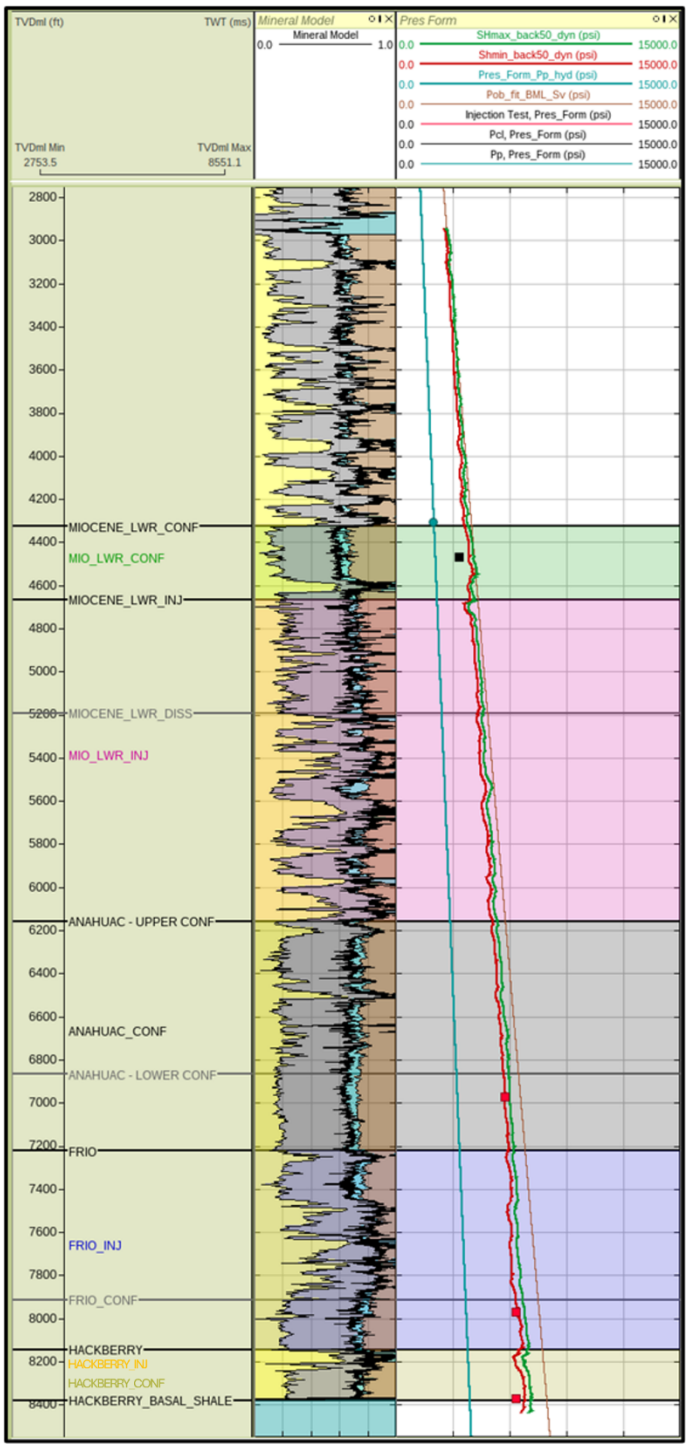


Figure AoR-212: Stress model for Encanto 01 well. Lower Miocene Confining Zone (Green), Lower Miocene Injection Zone (pink), Anahuac Confining Zone (gray), Frio Injection Zone (Blue), and Hackberry Injection Zone (Yellow) highlighted.

Results

The stress model was constrained by core measurements and calibrated to pressures and interpretations of minimal principal horizontal stress from wellbore pressure tests. The elastic properties of core from geomechanical core tests are summarized in Table AoR-21. The stresses used to calibrate the stress model are summarized in Table AoR-22.

Table AoR-21: Summary of elastic properties interpreted from geomechanical core tests results for Anahuac Confining Zone and Hackberry Confining Zone. Lower Miocene Confining Zone core sample testing is in progress at the time of publication.

Formation	Sample No.	Depth	Young's Modulus (GPa)	Poisson's Ratio (unitless)
Lower Miocene Confining Zone	ENC-RM4	Claimed as PBI		
	ENC-RM4B			
	ENC-RM5			
Anahuac Confining Zone	ENC-RM12			
	ENC-RM13			
Hackberry Confining Zone	ENC-RM17			
	ENC-RM18			
	ENC-RM19			

Table AoR-22: Summary of pore pressure increase (psi) required to cause failure in a hypothetical, optimally oriented fault and matrix in formations identified as confining and injection zones.

Formation	Depth (ft TVD)	Pore Pressure (psi)	Pp Gradient (psi/ft)	Overburden Stress (psi)	Overburden Gradient (psi/ft)	Sh_{max} (psi)	Sh_{max} Gradient (psi/ft)	Sh_{min} (psi)	Sh_{min} Gradient (psi/ft)
Lower Miocene Confining Zone	4,450								
Lower Miocene Injection Zone	5,350								
Anahuac Confining Zone	6,800								
Frio Injection Zone	7,800								
Hackberry Confining Zone	8,260								

Claimed as PBI

The stress model was plotted in Mohr circle space to assess the required increase in pore pressure required to initiate shear and /or tensile failure on the optimally oriented faults and rock matrix for the Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac Confining Zone, Frio Injection Zone, and Hackberry Confining Zone. Mohr Coulomb failure analysis is conducted at a particular depth as shown in Figure AoR-213 to Figure AoR-217 but are representative of the entire formations.

Figure AoR-213 shows the state of stress in the Mohr circle space for the Lower Miocene Confining Zone at around 4,460 ft TVD in the Encanto 01 well. The failure envelope defines the failure threshold for faults. A matrix failure envelope (not shown) would be at the same slope but have a larger y-axis intercept as a function of cohesion (rock strength). Even a small amount of cohesion would likely result in tensile effective minimum stress causing initial failure, so that threshold (zero effective normal stress) is used as the failure limit here. It is a conservative estimate as a function of cohesion and tensile strength, both of which are poorly constrained. Pore pressure increases required to cause failure on a hypothetical, optimally oriented fault and matrix are summarized in Table AoR-23.

The results of failure analysis in the Lower Miocene Confining Zone indic[Claimed as PBI] psi increase in pore pressure would be required to reactivate a hypothetical fault optimally oriented to be the most susceptible fault in the area as the highest risk and most conservative estimate. The black arrow in Figure AoR-213 intersects the Mohr circle at the location of the most susceptible orientation of any fault. The risk of matrix failure is [Claimed as PBI] psi and is interpreted here when effective minimum horizontal stress reaches the origin of the plot and changes from compressive to tensile. That interpretation is likely conservative as it does not consider rock matrix cohesion or tensile strength.

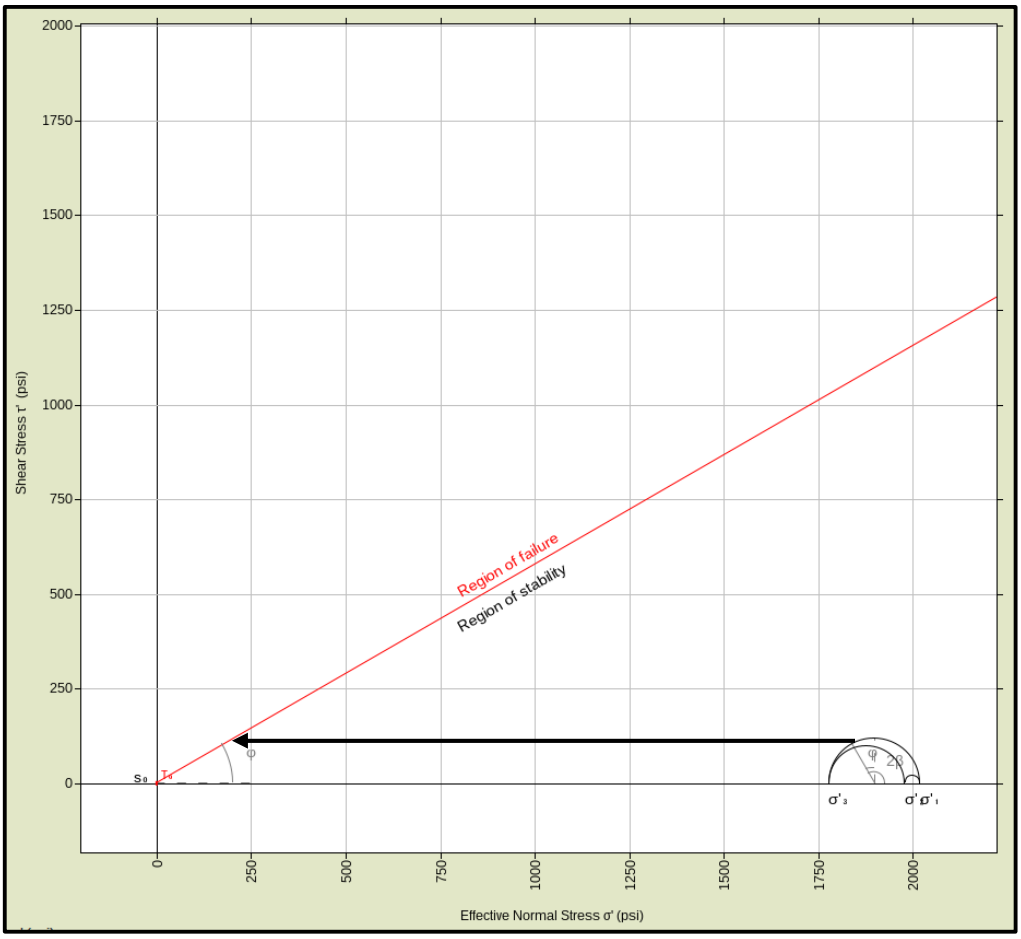


Figure AoR-213: Mohr Coulomb plot showing the state of stress in the middle of the Lower Miocene Confining Zone requires Claimed as PBI pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Lower Miocene Confining Zone would require Claimed as PBI.

The results of failure analysis in the Lower Miocene Injection Zone indicate Claimed as PBI increase in pore pressure (black arrow in Figure AoR-214) and risk of matrix failure is Claimed as PBI.

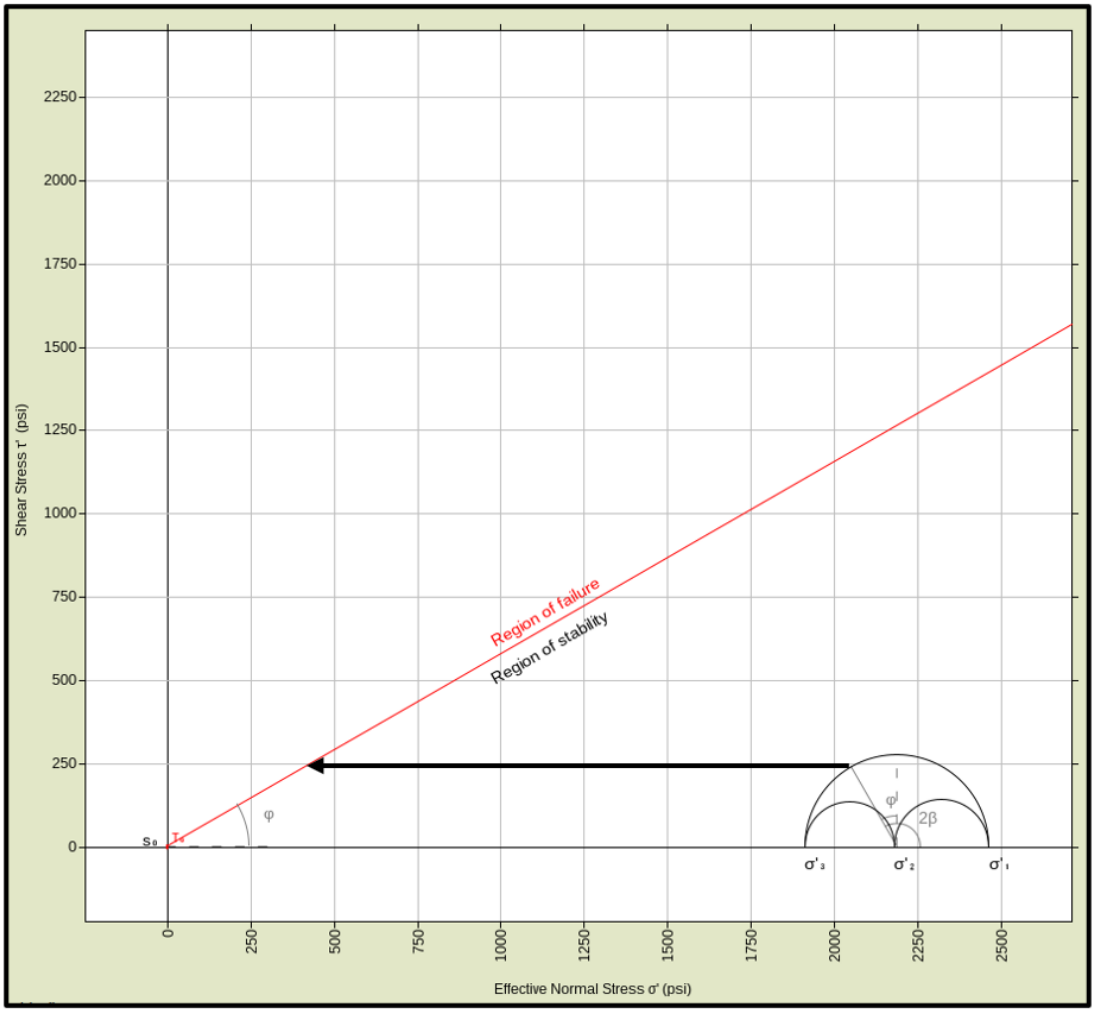


Figure AoR-214: Mohr Coulomb plot showing the state of stress in the middle of the Lower Miocene Injection Zone requires Claimed as PBI si of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Lower Miocene Injection Zone would require Claimed as PBI

The results of failure analysis in the Anahuac Confining Zone indicate Claimed as PBI i increase in pore pressure (black arrow in Figure AoR-215) and risk of matrix failure is Claimed as PBI

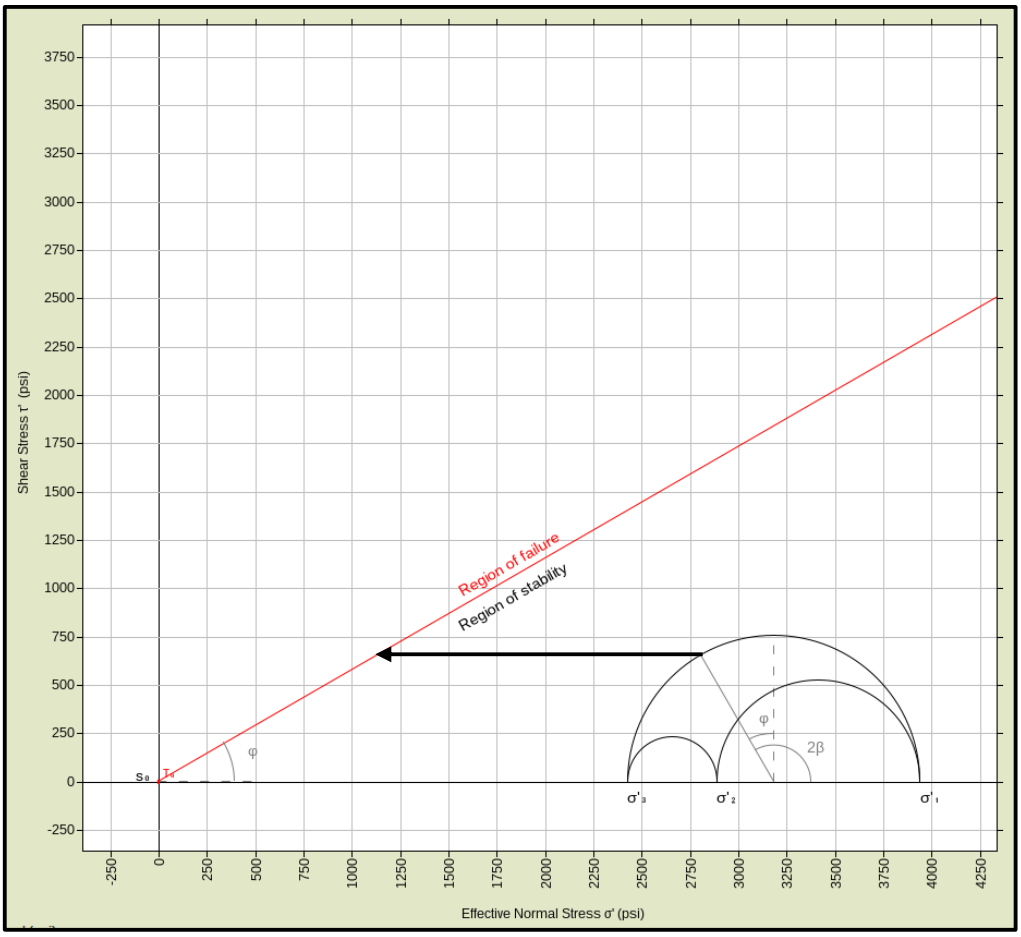


Figure AoR-215: Mohr Coulomb plot showing the state of stress in the middle of the Anahuac Confining Zone requires Claimed as PBI **psi of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Anahuac Confining Zone would require** Claimed as PBI

The results of failure analysis in the Frio Injection Zone indicate Claimed as PBI psi increase in pore pressure (black arrow in Figure AoR-216) and risk of matrix failure is Claimed as PBI

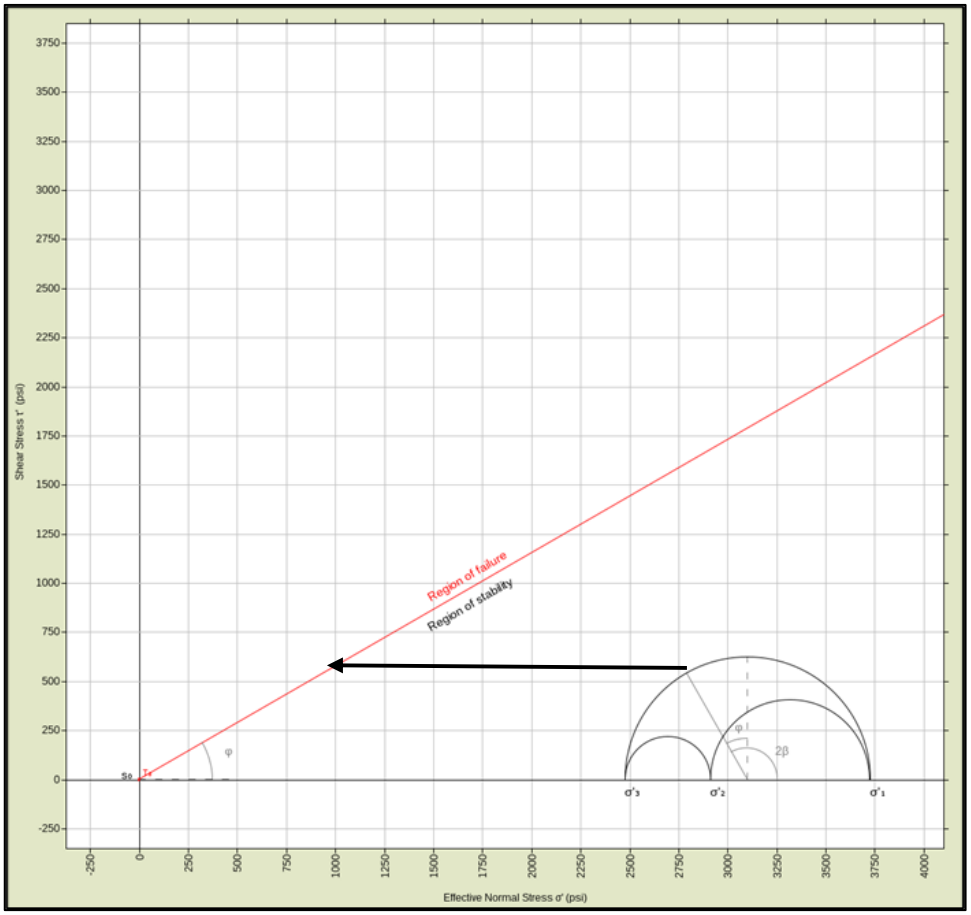


Figure AoR-216: Mohr Coulomb plot showing the state of stress in the middle of the Frio Injection Zone requires Claimed as PBI of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Frio Injection Zone would require Claimed as PBI

The results of failure analysis in the Hackberry Confining Zone indicate Claimed as PBI si increase in pore pressure (black arrow in Figure AoR-217) and risk of matrix failure is Claimed as PBI i.

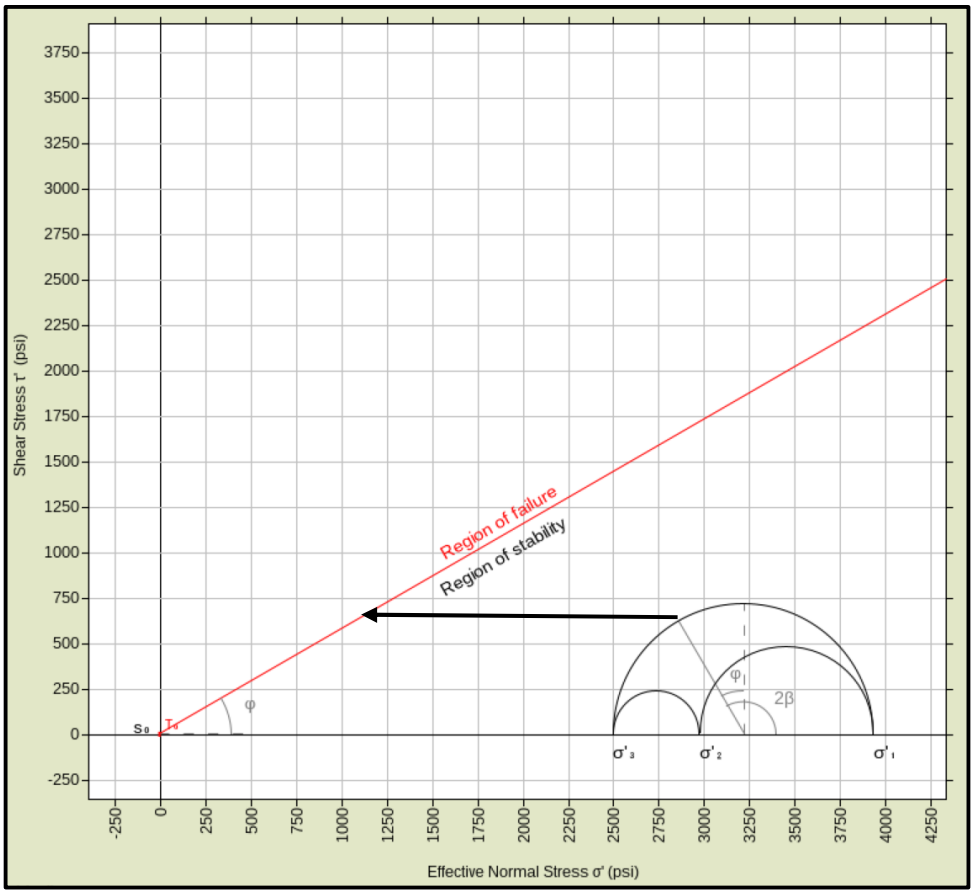


Figure AoR-217: Mohr Coulomb plot showing the state of stress in the middle of the Hackberry Confining Zone requires [redacted] psi of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Hackberry Confining Zone.

Table AoR-23: Summary of pore pressure increase (psi) required to cause failure in a hypothetical, optimally oriented fault and matrix in formations identified as confining and injection zones.

Formation	Depth (ft TVD)	Hypothetical Fault	Matrix
Lower Miocene Confining Zone	Claimed as PBI		
Lower Miocene Injection Zone			
Anahuac Confining Zone			
Frio Injection Zone			
Hackberry Confining Zone			

Summary

Preliminary critical stress analysis indicates that the risk of tensile or shear failure is similar in both all the confining and target injection zones. Using a hypothetical, optimally oriented fault for the purpose of analysis, it can be demonstrated that around Claimed as PBI of pore pressure increase would be required to reactivate that fault in shear failure. Assuming a minimal amount of cohesion and tensile strength would indicate that initiation of matrix failure would occur in tension at about Claimed as PBIsi pore pressure increase. The stress model is well calibrated and constrained, while the critical strength and frictional properties are constrained through interpretation. Reasonable estimates indicate that the rock properties are less a control on the failure analysis than are the stress magnitudes at the Encanto 01 well.

Table AoR-24: Fracture and injection pressure details.

Injection Pressure Details	CCS 1	CCS 2	CCS 3	CCS 5	CCS 6	CCS 7
Fracture gradient (psi/ft)	Claimed as PBI					
Maximum injection pressure (90% of the isotropic fracture pressure) (psia)						
Depth corresponding to maximum injection pressure (ft TVD)						

Table AoR-25 summarizes the key results gathered from the step-rate-tests (SRT) and leak-off tests (LOT) on the Encanto 01 stratigraphic well. In this project, the simulation model used the transmissibility, fracture gradient, and injectivity test results at the Frio formation. For all practical purposes, the use of Claimed as PBI as fracture gradient was reasonable.

Table AoR-25: Key results of step-rate and leak-off tests on Encanto 01 well.

Formation	Test	FBP (psia)	FPP (psia)	LOP (psia)	Frac Gradient (psi/ft)	Transmissibility mD*ft
Hackberry Confining Zone	Claimed as PBI					
Hackberry Injection Zone						
Frio Confining Zone						
Frio Injection Zone						
Anahuac Confining Zone						
Lower Miocene Injection Zone						

Notes:

- LOT: Leakoff Test
- SRT: Step Rate Test
- FBP: Fracture Breakdown Pressure
- LOP: Leakoff Point
- FPP: Fracture Propagation Pressure

3.13 Geopressure Analysis

Identification of overpressured and underpressured regions is a critical parameter for assessing the viability of geological sequestration and long-term containment of supercritical fluids (GCAGS Journal, v. 1, 2012), such as CO_2.

Within the Houston Delta, sediments were transported to the coastal margin by rivers, and subsequently deposited in deltas or reworked by marine processes into strandplains and barrier bars (BEG Dodge and Posey, 1981). Contemporaneous growth faults developed parallel to the shelf margin and syndepositional movement resulted in sediment thickening on the downthrown

side of the faults. Due to the throw offsetting these sediments, they became isolated from sediments on the upthrown side of the fault. In some of these isolated sediments, abnormally high pressure and temperature gradients developed as a result of fluid entrapment (BEG Dodge and Posey, 1981) because high sedimentation rates, i.e., rapid burial, fed by large river systems in these deltaic deposits prevented the escape of pore water trapped in the shales, and thus, built-up fluid pressures and under compacted sediments. Under overpressure conditions, the shale layers can act as detachment planes for faults and can accumulate significant hydrocarbon accumulations (Texas Water Development Board Report 365, 2006).

The U.S. Geological Survey created a comprehensive geopressured-gradient model of the regional pressure system spanning the onshore and offshore portions of the U.S. Gulf of Mexico basin (GCAGS Journal, v. 1, 2012). From that model, several regional subsurface geopressured-gradient maps are available, based on mud weight data obtained from vertical wells, which are plotted on regional cross sections and well logs. These contour maps characterize surfaces of equal pressure, also called isopressure-gradient maps.

They characterize the depth and distribution of isopressure-gradient surfaces from 0.60 psi/ft to 1.00 psi/ft, in 0.10 psi/ft intervals. The depth at which the 0.70 psi/ft pressure gradient occurs is critical as it represents the “top of overpressure” or the “top of the overpressure transition zone” (Figure AoR-218).

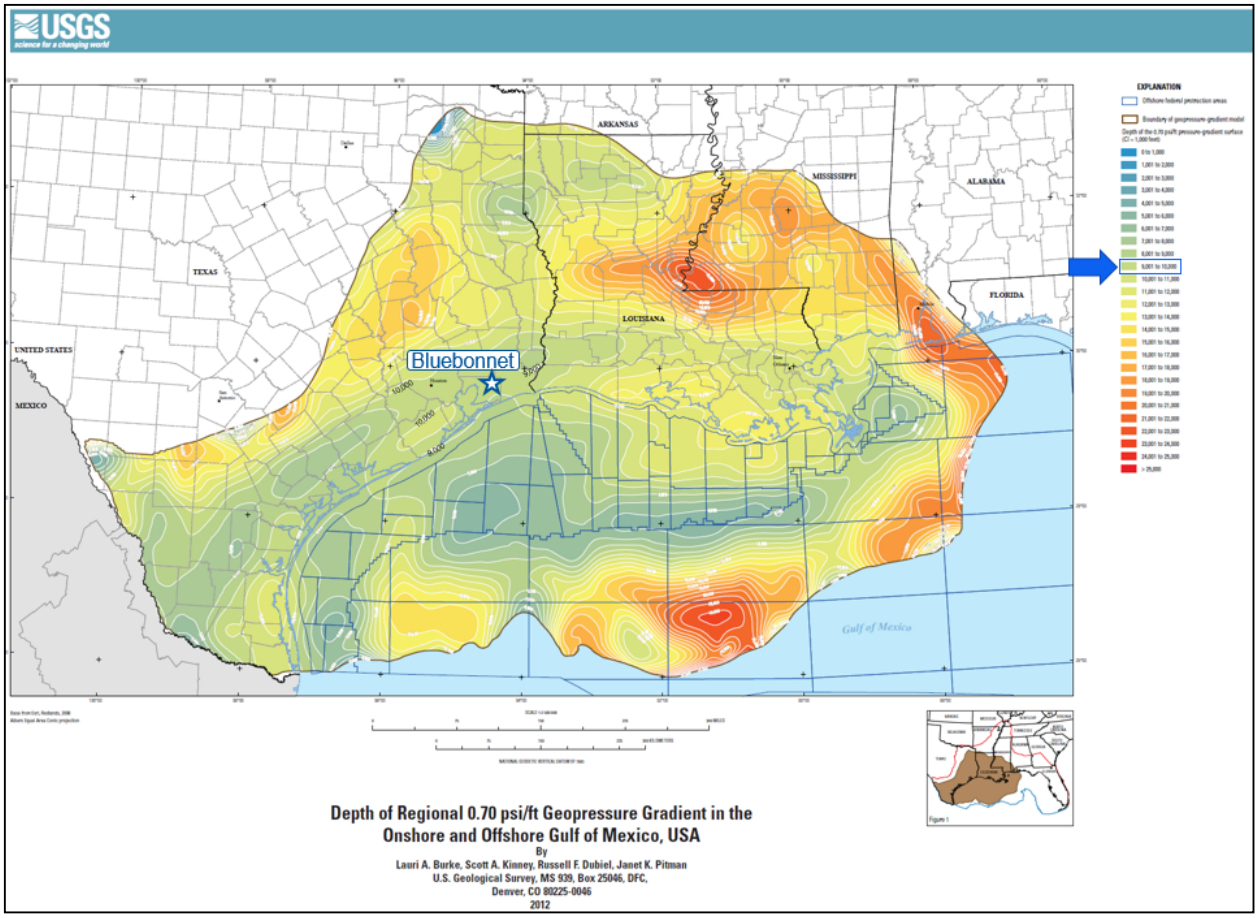


Figure AoR-218: Regional 0.7 psi/ft Geopressure Gradient map by Burke et al., U.S. Geological Survey, 2012. The depth at which the 0.7 psi/ft gradient occurs is interpreted as the onset of overpressure. Based on this regional map, the overpressure at the Bluebonnet Sequestration site is expected to occur between 9,000 ft and 10,000 ft measured depth.

In the shallow subsurface of the Gulf Coast, pressure gradients generally follow a hydrostatic pressure-gradient trend, which represents the theoretical pressure gradient exerted by a column of fresh water. In the Gulf of Mexico Basin, using an average formation water salinity of 100,000 ppm TDS, yields a hydrostatic pressure-gradient of 0.465 psi/ft (GCAGS Journal, v. 1, 2012). The pressure gradient deviates from the hydrostatic gradient line with increasing depth. Pressure gradients in the region below the hydrostatic gradient represent underpressured regimes; whereas, overpressured regimes refer to regions with pressure gradients above the hydrostatic gradient.

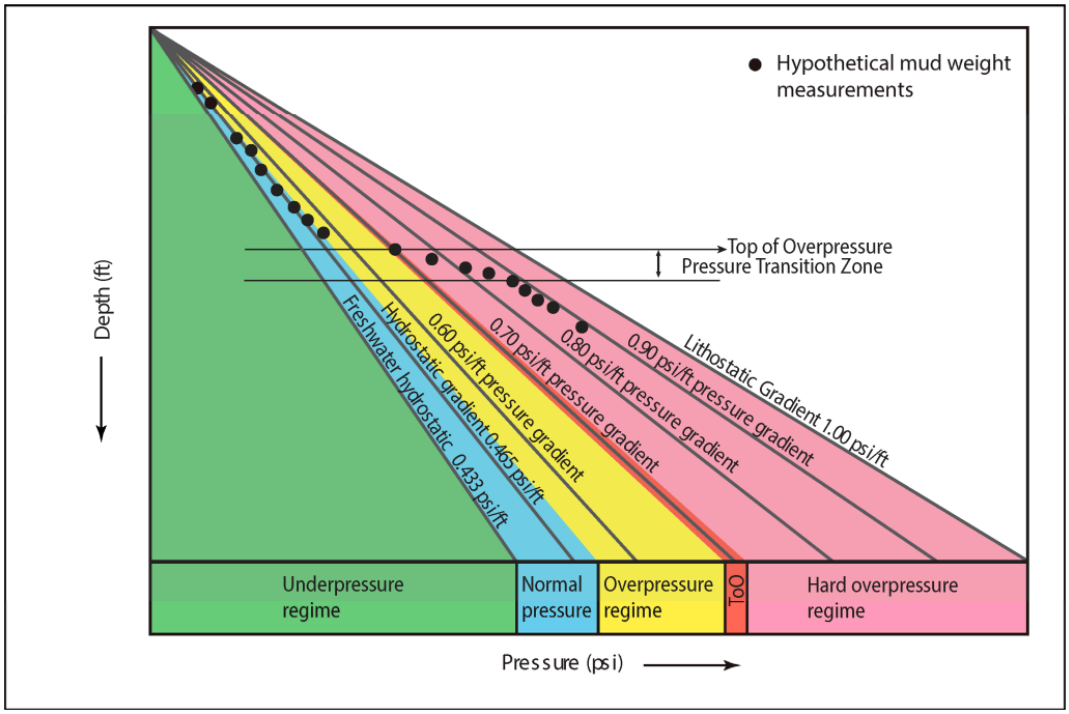


Figure AoR-219: Schematic diagram of generalized pressure gradients and associated pressure regimes. The top of overpressure is denoted by ToO; by Burke et al., U.S. Geological Survey, 2012.

Because this regional geopressure-gradient model characterizes subsurface isopressure gradients spanning the entire Gulf of Mexico basin, the results from this regional investigation are not applicable for small-scale, detailed pressure examinations of specific locations. Therefore, this regional map was supplemented at the local Bluebonnet Hub site scale by analyzing sonic logs and mud weights by depth.

Within the proposed Bluebonnet Hub, sonic logs were used to determine the onset of overpressure at the transition to slow velocities at depth, in addition to the expected values from the regional map (Figure AoR-218). The top of overpressure based on sonic logs occurs between 8470 ft, two miles north of the AoR (shallowest), and 10,365 ft, three and three-quarters miles south southeast of the AoR (deepest). The onset of overpressure is located 229 – 1040 ft below the targeted Frio and Hackberry injection zones (Figures AoR-220 and AoR-221) within the proposed AoR.

These estimated depths based on increasing sonic velocities are in agreement with the actual measured mud weights from wells drilled within and nearby the AoR (Figure AoR-222).

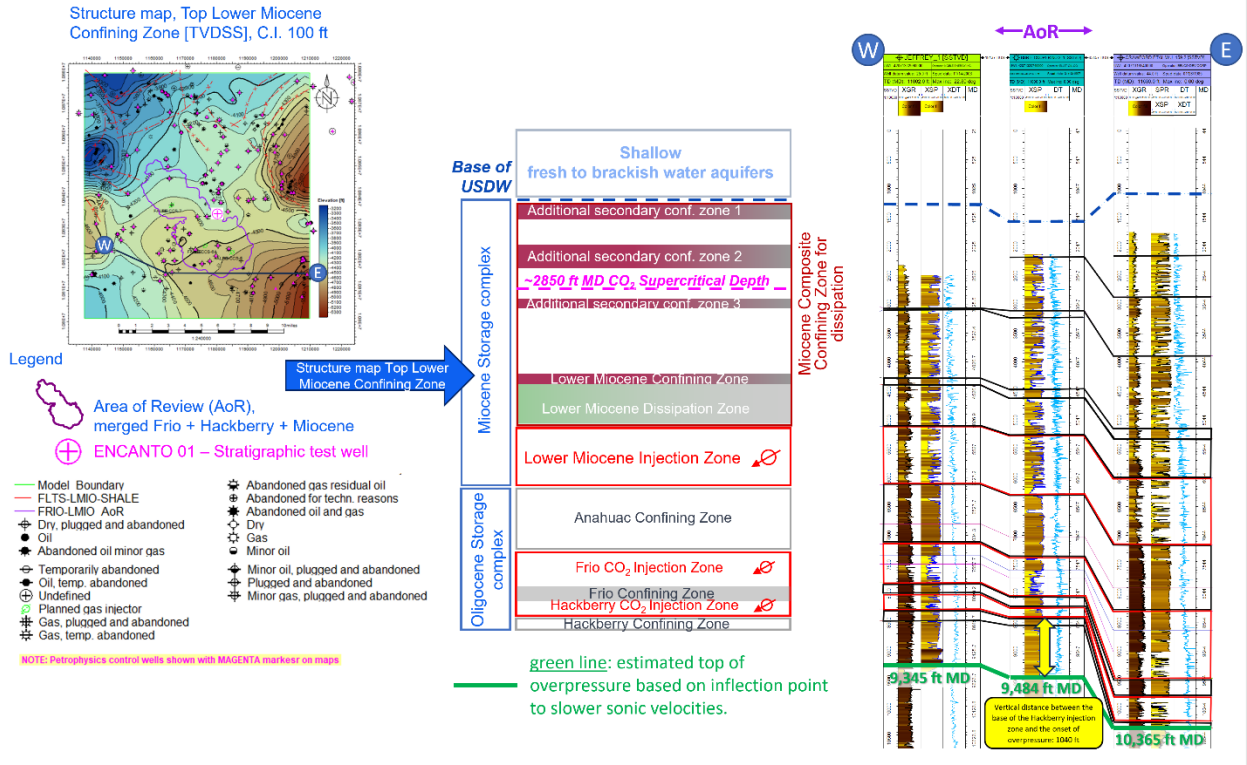


Figure AoR-220: West-east strike cross section through the proposed Bluebonnet Sequestration Hub site. The top of overpressure is shown by the green line and estimated based on the inflection to slower velocities on the sonic log shown in blue. The onset of overpressure in this strike cross section occurs approximately 1,040 ft below the base of the injection zone.

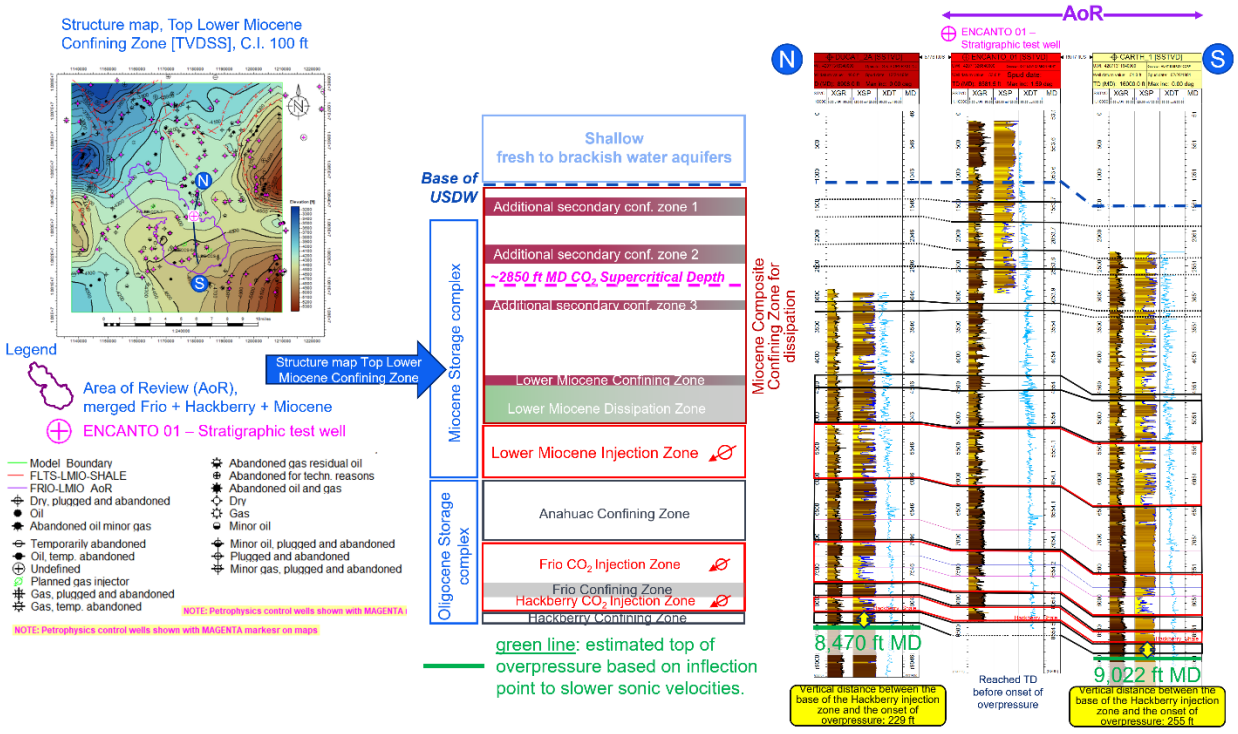


Figure AoR-221: North-south dip cross section through the proposed Bluebonnet Sequestration hub site. The top of overpressure is shown by the green line and is estimated based on the inflection to slower velocities on the sonic log shown in blue. The onset of overpressure in this dip cross section occurs approximately 229 to 255 ft below the base of the injection zone.



Figure AoR-222: Mud weights over depth from wells drilled within and nearby the proposed Bluebonnet Sequestration Hub. The Top of Overpressure is shown by the increase in mud weight.

3.14 Existing hydrocarbon fields

In the Tertiary section of the Upper Texas Gulf Coast, the majority of known fields produce from structural traps: salt domes (Spindletop Field); faulted anticlines (Anahuac Field); elongated anticlines located downthrown to the growth faults; and smaller fields produce from subtle stratigraphic traps (Devillier Field) (Gordon, 1982). The accumulation of the Walla-Boyt Field was likely controlled by the contemporaneous effects of deltaic sedimentation and of growth-fault tectonics. The Walla-Boyt and Spindletop Bayou Fields are oil and gas fields producing from sands below the proposed storage complex. In the Texas Railroad Commission well files, those sands are called Frio Basal, Struma 1st Sand, and Texas Mississippian Sand, and they occur stratigraphically below the lowest proposed Hackberry Injection Zone. These two fields are located on the downthrown side of Vicksburg aged faults and they are localized structures outside the proposed AoR.

The Bluebonnet Project team performed a detailed analysis of the isotube mud gases and samples collected in the stratigraphic well Encanto 01. The encountered methane gas in the Hackberry formation is likely not thermogenic. Synthetic oil-based mud was used to drill Encanto 01. The drilling fluid was also analyzed and solvent extracted. The purpose of this was to obtain the fingerprint of the added synthetic oil so that if oil was noted in rock samples, a differentiation could be made of any possible thermogenic natural crude oil from the drilling mud additive. However, no naturally derived crude oil was found in any of the rock samples analyzed in Encanto 01 via rock pyrolysis and gas chromatography (see Appendix D).



and gas fields. The logs shown are Gamma Ray (GR) and Spontaneous Potential (SP) logs; perforations are shown in red. Walla-Boyt and Spindletop Bayou Fields are localized structures on the downthrown side of Vicksburg aged faults (not shown here) below the proposed storage complex. These producing fields and salt water disposal operations are located outside of the proposed AoR (purple polygons in inset map).

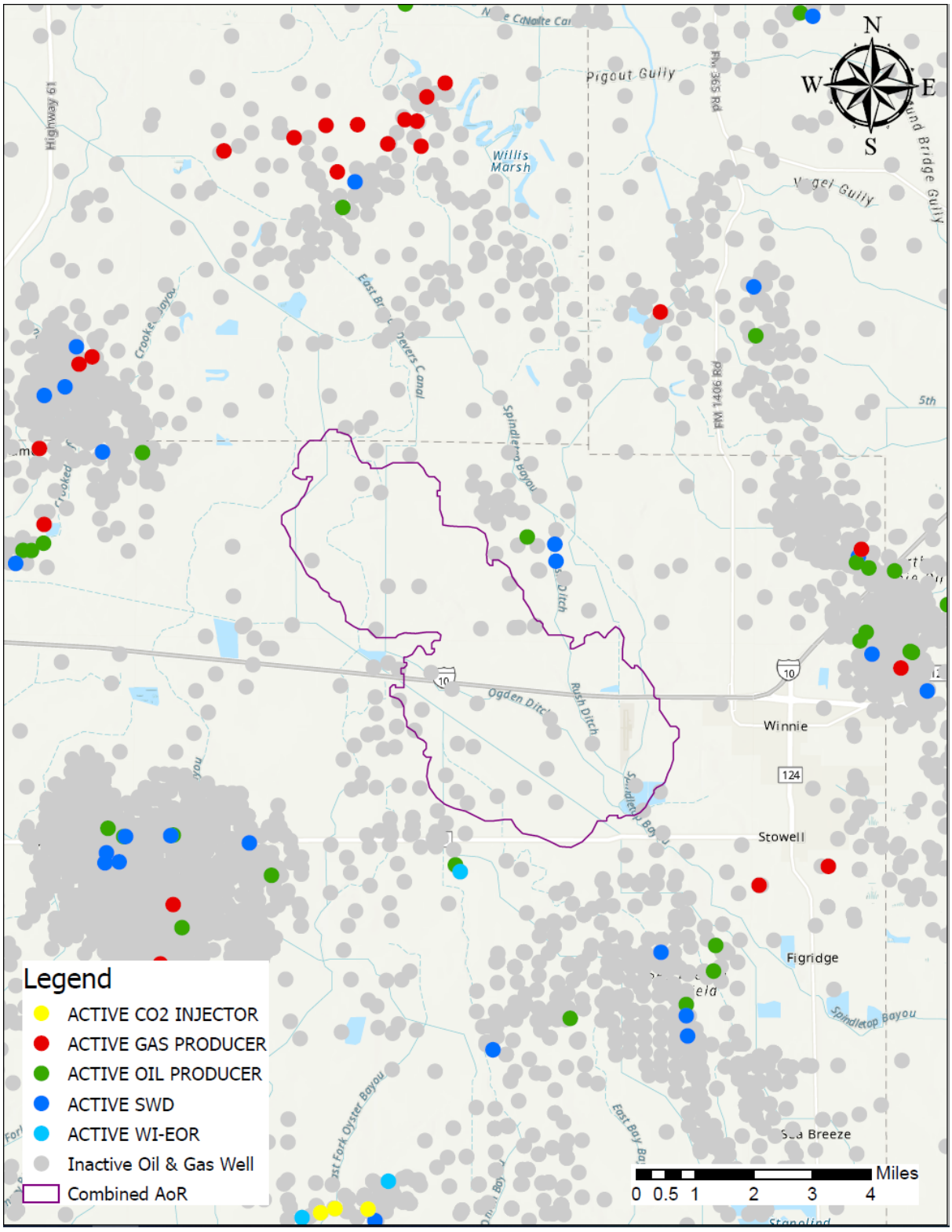


Figure AoR-224: Active oil and gas wells near the CCS project area from the IHS Database.

3.15 Seismic History

Regional earthquakes were identified using the USGS online database cross checked against the Bureau of Economic Geology's TEXNET database to determine the location of events (Figure AoR-225). No recorded events of any magnitude from 1900 to present were identified within 50 miles of the Bluebonnet site. A single earthquake was identified within a 75-mile radius of the Bluebonnet project: this magnitude 3.8 event occurred in 1983, 1 km WNW of Sulphur Louisiana at a depth of 5.9 km. The USGS Long-Term Seismic Hazard Map (Figure AoR-227) indicates that this area is at relatively low risk for natural earthquake activity.

Seismometer stations were identified via the Incorporated Research Institute for Seismology's database (Figure AoR-225 and Table AoR-26). There are three stations identified within a 50-mile radius of the Bluebonnet project, none of which are active today. A total of 68 stations are identified within a 75-mile radius of the Bluebonnet project, seven of which are currently recording. A local seismometer array consisting of 14 sensors was installed for the Bluebonnet project area with a designed Magnitude of Completeness of <0.0 on the Richter scale. The array is designed to provide reliable seismic coverage of the AoR and surrounding project area, focusing on monitoring around the planned injection well(s) and local faults. The installed seismometer locations in relation to injection well(s) and faults are seen in Figure AoR-226 .

A risk assessment of induced seismicity due to injection activities is presented in Figures AoR-228, AoR-229, and AoR-230.

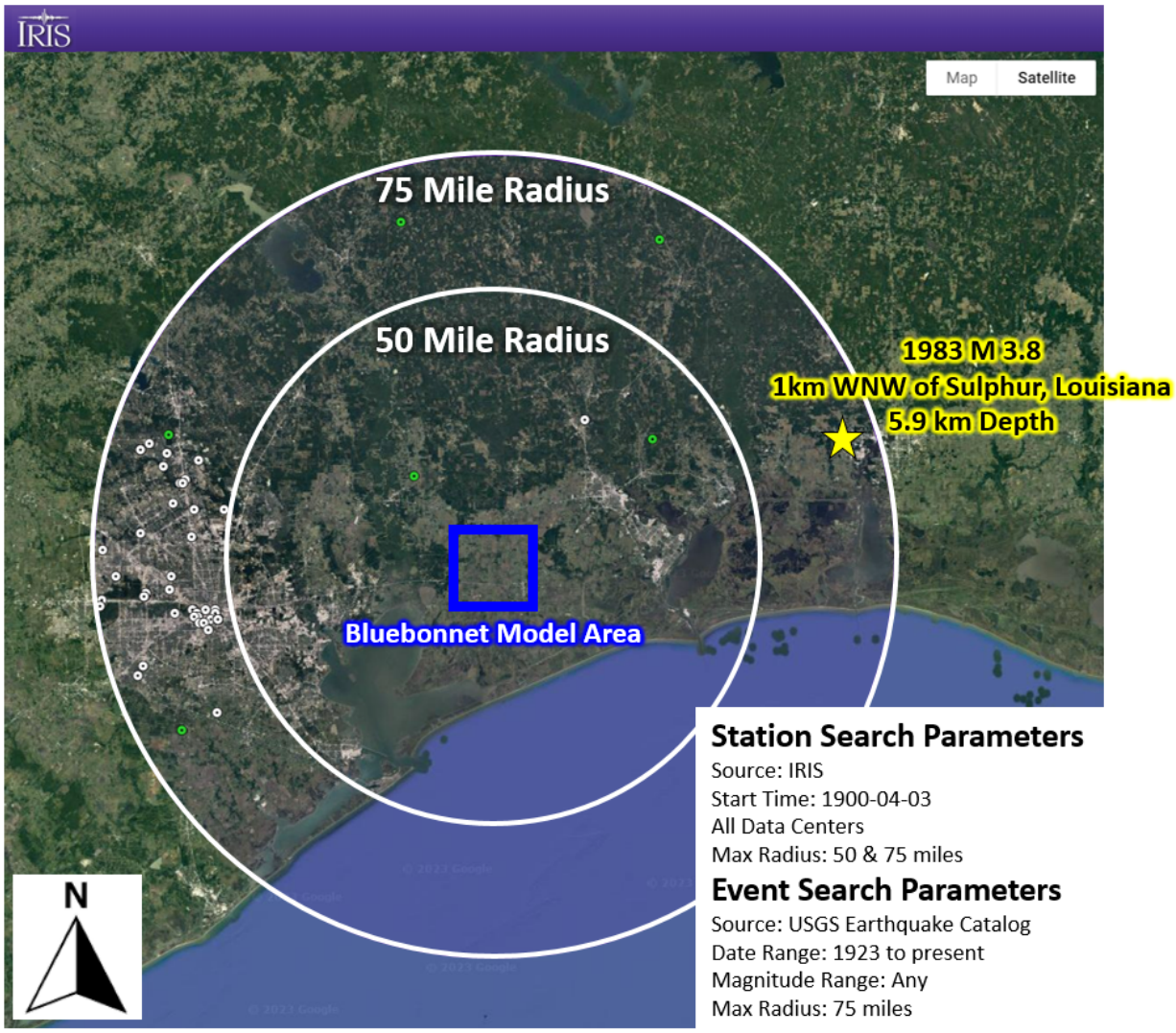


Figure AoR-225: Seismometer stations (green and white circles) and historic seismic activity (yellow star).

Table AoR-26: Seismometer stations within a 50- and 75-mile search parameter of Bluebonnet.

Network	Station	Latitude	Longitude	Start Date	End Date
Stations within 50 Mile Radius of Bluebonnet					
AM	RFDFC	30.26126126	-94.19050493	7/22/2020	8/9/2020
TA	539A	30.1084	-94.723602	4/13/2010	11/10/2011
TA	540A	30.209299	-93.979599	5/23/2010	12/7/2011
Stations within 75 Miles Radius of Bluebonnet					
AM	R0172	30.18018018	-95.57948534	3/18/2017	4/22/2019
AM	R0F1A	29.59459459	-95.56960457	12/2/2016	1/16/2023
AM	R0F1A	29.59459459	-95.56941507	1/16/2023	12/31/2599
AM	R1294	29.74774775	-95.41182473	7/2/2020	10/15/2020
AM	R151C	30.01801802	-95.41090816	7/22/2020	8/8/2020
AM	R151C	29.72072072	-95.33627264	5/16/2021	6/12/2021
AM	R1E10	29.72972973	-95.40954644	1/2/2020	2/17/2020
AM	R21BC	29.74774775	-95.41334752	6/29/2021	8/4/2021
AM	R22C0	29.72072072	-95.35825576	12/6/2016	4/22/2019
AM	R347E	29.75675676	-95.70602629	7/28/2018	12/31/2599
AM	R3C08	29.79279279	-95.56185406	5/18/2021	6/8/2021
AM	R4457	29.72072072	-95.33589264	6/3/2020	5/16/2021
AM	R4457	29.72072072	-95.33627264	5/16/2021	11/25/2021
AM	R475C	30.17117117	-95.49596743	6/1/2020	5/4/2021
AM	R475C	29.72072072	-95.33627264	5/4/2021	12/31/2599
AM	R475C	29.73873874	-95.40316622	5/5/2021	5/15/2021
AM	R5378	29.83783784	-95.65642907	7/21/2020	7/21/2020
AM	R5378	29.83783784	-95.65623752	7/21/2020	8/7/2020
AM	R5378	29.69369369	-95.36695782	8/7/2020	5/16/2021
AM	R5378	29.72072072	-95.33627264	5/16/2021	6/9/2021
AM	R5771	29.72072072	-95.33627264	5/16/2021	6/18/2021
AM	R5DDF	30.09009009	-95.445128	12/4/2019	12/31/2599
AM	R5E2B	30.0990991	-95.43712881	12/31/2020	12/31/2599
AM	R60B9	29.71171171	-95.39442894	7/21/2021	12/31/2599
AM	R7489	30.18018018	-95.57948534	11/11/2017	4/22/2019
AM	R7A14	29.79279279	-95.56185406	5/18/2021	6/8/2021
AM	R7AF6	30.03603604	-95.47670271	10/8/2019	10/11/2019
AM	R87F8	30.18018018	-95.57948534	2/11/2019	4/25/2021
AM	R89CA	29.8018018	-95.4886332	6/29/2021	12/6/2021
AM	R8A94	29.75675676	-95.70593077	2/17/2018	4/22/2019
AM	R9393	29.72972973	-95.40021753	12/31/2019	1/13/2020
AM	R9393	29.72972973	-95.4000273	2/5/2020	6/11/2021
AM	R95FA	29.95495495	-95.57962713	7/18/2020	5/16/2021
AM	R95FA	29.72072072	-95.33627264	5/16/2021	7/1/2021
AM	R98DD	29.75675676	-95.70593077	1/22/2019	12/31/2599
AM	R98E5	29.72972973	-95.41182938	7/22/2020	5/16/2021
AM	R98E5	29.72072072	-95.33627264	5/16/2021	6/7/2021
AM	R98E5	30.01801802	-95.31851566	5/28/2021	6/7/2021
AM	R9B84	29.90990991	-95.69529211	4/4/2018	2/13/2021
AM	RA140	30.1981982	-95.55056527	2/23/2023	12/31/2599
AM	RA302	29.75675676	-95.70583525	3/11/2018	4/22/2019
AM	RAD87	30.09009009	-95.45380285	1/14/2018	10/18/2019
AM	RAD87	30.09009009	-95.445128	10/18/2019	12/6/2019
AM	RC1A6	29.71171171	-95.38063469	5/30/2020	6/12/2020
AM	RC1A6	29.71171171	-95.38053968	6/12/2020	8/28/2020
AM	RC9DD	29.78378378	-95.56679185	3/4/2021	5/19/2021
AM	RC9DD	29.78378378	-95.56707832	5/20/2021	6/19/2021
AM	RC9DD	29.46846847	-95.33968893	5/28/2021	6/3/2021
AM	RC9DD	29.78378378	-95.56688734	9/3/2021	1/6/2022
AM	RCD56	29.72072072	-95.33627264	5/5/2021	6/9/2021
AM	RE0EF	29.83783784	-95.48091615	7/16/2020	7/16/2020
AM	RE0EF	29.83783784	-95.48082055	7/16/2020	1/20/2023
AM	RE117	29.73873874	-95.47246479	1/17/2018	4/22/2019
AM	RE998	30.18018018	-95.57938832	2/11/2019	5/26/2021
AM	REA98	29.56756757	-95.58660898	1/1/2017	8/15/2019
AM	REC5C	29.77477477	-95.70007855	3/2/2021	8/16/2022
AM	REF4D	30.13513514	-95.50665562	5/8/2017	5/9/2021
AM	RF3D8	30.15315315	-95.39586037	8/28/2021	6/6/2022
AM	RFF98	29.72072072	-95.33627264	5/17/2021	8/26/2021
AM	RFF98	29.74774775	-95.34413504	6/1/2021	6/1/2021
AM	RFF98	29.73873874	-95.34557167	6/1/2021	6/1/2021
AM	RFF98	29.74774775	-95.41572712	6/1/2021	6/1/2021
AM	RFF98	29.74774775	-95.37393402	6/1/2021	6/1/2021
AM	RFF98	29.94594595	-95.41914435	6/1/2021	6/10/2021
TA	439A	30.793699	-94.765999	4/12/2010	12/13/2011
TA	440A	30.7456	-93.958702	5/22/2010	12/7/2011
TA	538A	30.221901	-95.489998	1/28/2010	11/10/2011
TA	638A	29.4193	-95.448097	2/17/2011	11/6/2011

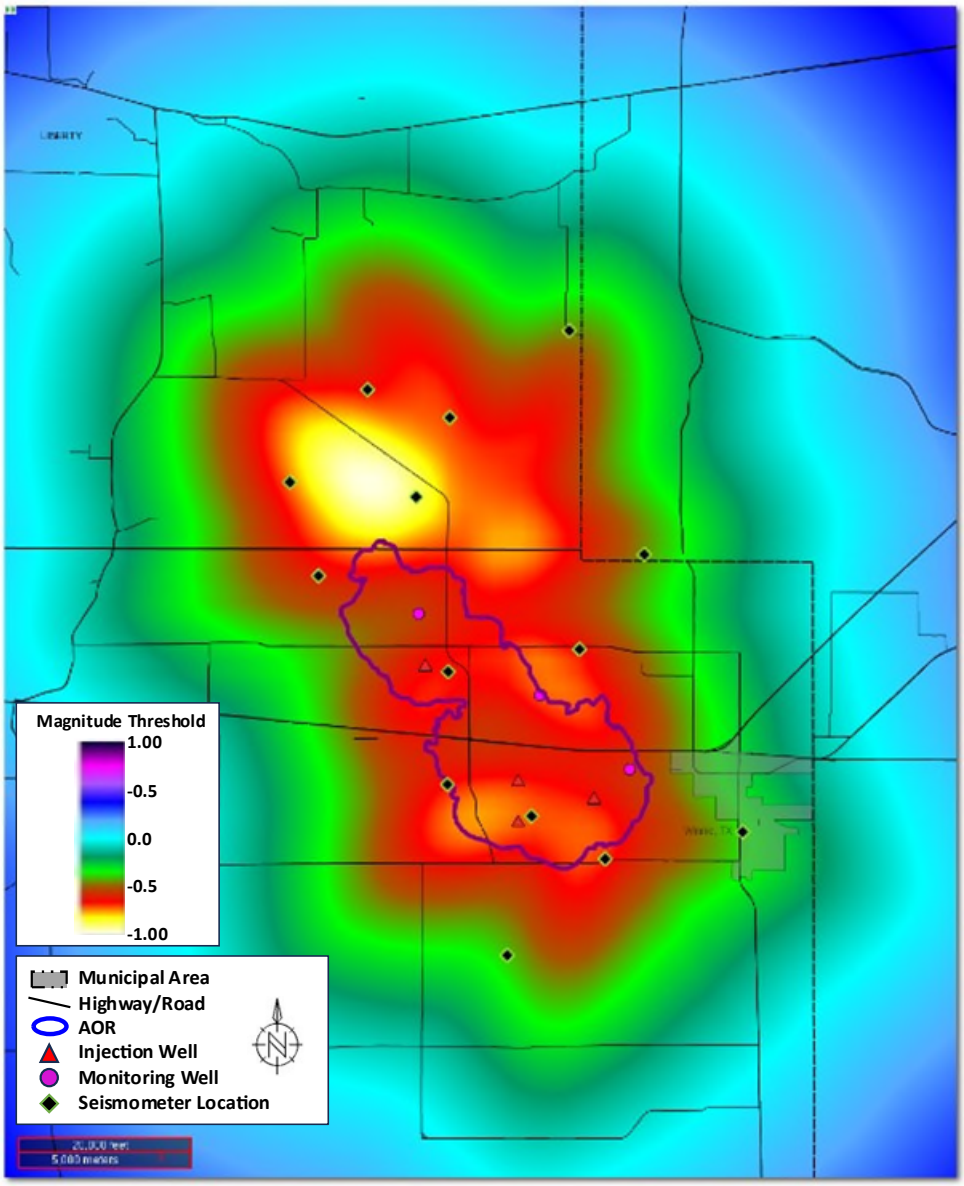


Figure AoR-226: Proposed seismometer array to monitor for induced seismicity at or related to injection wells and regional faults. Faults are colored according to relative hazard, determined by comparing the strike of the fault to principle horizontal stress direction.

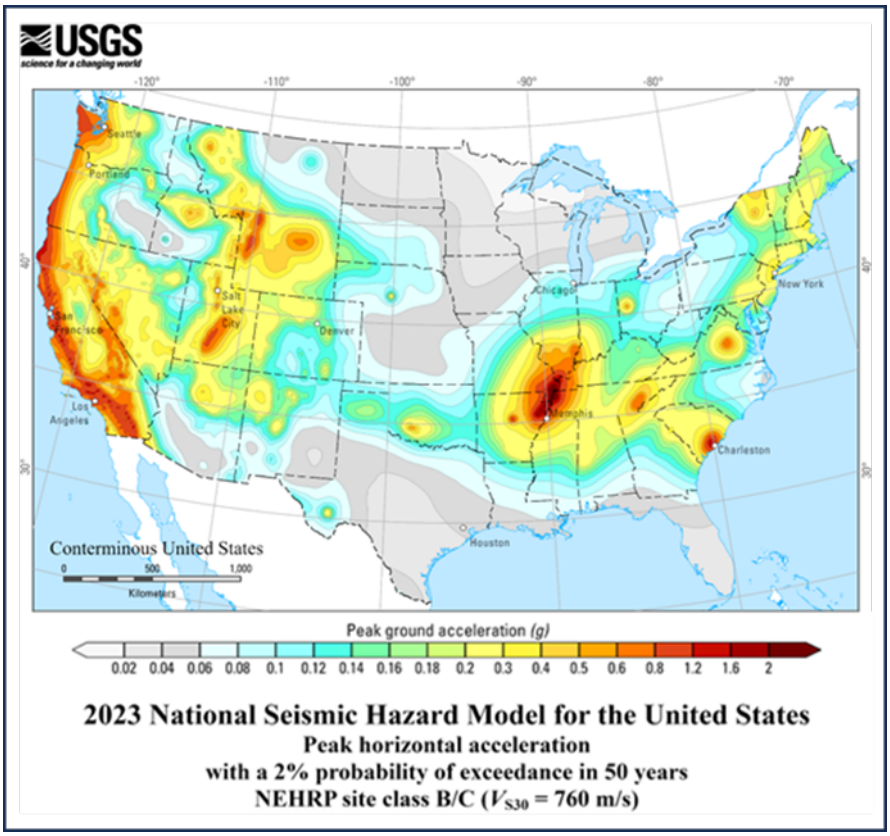


Figure AoR-227: Seismic hazard map showing that peak ground accelerations have a 2% probability of being exceeded in 50 years from USGS 2018 Long-Term National Seismic Hazard Map (USGS, 2018). Seismic hazard potential in the study area is one of the lowest in the U.S.

Claimed as PBI

Details on the basis for the probability presented in Figure AoR-172 are given below.

- **Seismometer Coverage**: 14 new seismometers were installed within the project area, providing reliable detection of seismic events measuring 0.0 on the Richter scale in the AoR and along mapped faults.

- **Seismic Coverage**: High quality 3D seismic is available over the project area.
- **Basement Faulting**: All faults proximal to the Bluebonnet Hub are observed to detach within the Wilcox (more than 10,000 ft above the estimated basement depth).
- **Basement Proximity**: The proposed injection zone is more than 20,000 ft above the estimated basement depth.
- **Injection Rate**: Fault reactivation pressures were modeled for the greater Bluebonnet Hub area and all faults required a delta-P of >1000 PSI to reactivate. Modeled injection pressures for the Bluebonnet Hub do not exceed 232 psi in the Frio and 541 psi in the Hackberry.



Details on the basis for the probability presented in Figure AoR-173 are given below.

- **Public Impact/Tolerance:** Public tolerance for induced seismicity is fragile in Texas and media exposure of induced seismic events related to CCS activity is predicted to be high.
- **Proximity to Critical Infrastructure:** The Bluebonnet Hub is not proximal to critical infrastructure.
- **Seismic Regulatory Regime:** Local seismicity monitoring is recommended for CCS operations.
- **Impact on Development:** Significant seismic events have the potential to stop project advancement.



Figure AoR-230: Assessed risk matrix for induced seismicity at the Bluebonnet site. The probability of induced seismicity related to injection activity is low, while the assessed consequence of an event is classified as high.

4.0 Oligocene Storage Complex Model

4.1 Simulation Model Background – Oligocene Storage Complex

4.1.1 Geocellular Model Introduction

The static geocellular model was constructed using Schlumberger's Petrel (v2021) 3D geostatistical modeling software, which is a comprehensive, integrated subsurface platform containing data interpretation tools for well correlation, mapping, and structural and property modeling. Application of this software has been demonstrated in reliable subsurface models containing faults, horizons, and properties, which are then used to estimate volumetrics and are further passed on to dynamic reservoir simulation.

4.1.2 Dynamic Simulation Model Introduction

The dynamic simulation models were created using the GEM (v2023.3YES0) reservoir simulator with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd. (CMG). GEM is a commercially available, compositional, and finite-difference simulator that is commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. GEM has also been used to model several carbon capture and storage projects. The Greenhouse Gas (GHG) module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (liquid), CO_2-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, and enthalpy) of the H_2O and CO_2 phases and CO_2 solubility in H_2O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions, including temperature ranges between 53.6°F (12°C) and 302°F (150°C) and pressures up to 16,000 psi (110 MPa). Details of this method can be found in Collins et al. (1992, CMG GEM Manual), Thomas and Thurnau (1983, CMG GEM Manual), and Nghiem and Li (1989, CMG GEM Manual).

Additional assumptions governing the phase interactions throughout the simulations are as follows:

- CO_2-rich phase (gas) density is obtained by using the Peng-Robinson equation of state. The model was accurately tuned and modified as described below (Peng and Robinson, 1976, CMG GEM Manual).
- CO_2 dissolution in brine is calculated from Henry's Law Constant Correlation using Harvey's method (Harvey, 1996, CMG GEM Manual).
- Brine density is specified at a reference pressure of 1,952 psi and corrected for local pressure variations using a specified water compressibility. Brine density is then corrected for the dissolved CO_2 and ionic components using their partial molar volumes. Brine viscosity is calculated using the Kestin (1981) correlation.
- Chemical equilibria among H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2, H_4SiO_4, HCO^-, OH^-, CO_3^{2-}, $CaOH^+$, $MgHCO_3^+$, and $AlOH^{+2}$ ions in the aqueous phase are modeled with 13 equilibrium constants. Aqueous complexes were selected based on simulation results from geochemical equilibrium runs (Geochemist's Workbench) with minerals and CO_2. Solid phases included calcite, kaolinite, anorthite, dolomite, illite, K-feldspar, and quartz

minerals. Reactions among these minerals and ions are modeled with chemical reactions and reaction coefficients from the Lawrence Livermore National Laboratory database (Thibeau, 2007) which were also used in a simulation study by Nghiem et al. (2004).

- The CO_2 gas viscosity is calculated per the methods described by Pedersen et al. (1984).
- The gas density is obtained by using a cubic equation of state developed by Peng and Robinson (1976) described by Equation 1:

$$P = \frac{RT}{(v - b_{mix})} - \frac{a_{mix}}{(v^2 + 2vb_{mix} - b_{mix}^2)} \quad \text{..... (Equation 1)}$$

Where:
v is the molar volume;
P is the pressure;
T is the temperature in Kelvin;
R is the universal gas constant;
a_{mix} and b_{mix} are mixture-specific functions of temperature and composition, calculated from the critical properties and acentric factors of the components.

The CMG WinProp software has a built-in library for the properties CO_2 and CH_4 based on Reid et al. (1977). No changes were made to the library components.

The transition between liquid and gaseous CO_2 can lead to rapid density changes in the gas phase. The simulator uses a narrow transition interval between the liquid and gaseous density to represent the two-phase CO_2 region.

Because the compression/pumping facility controls the CO_2 delivery temperature to the injection well to keep it between 60°F and 120°F, the temperature of the injectant will be comparable to the reservoir formation temperature at the injection interval. Therefore, the simulations were based on isothermal operating conditions with a linear initial reservoir temperature gradient of 0.01757°F/ft.

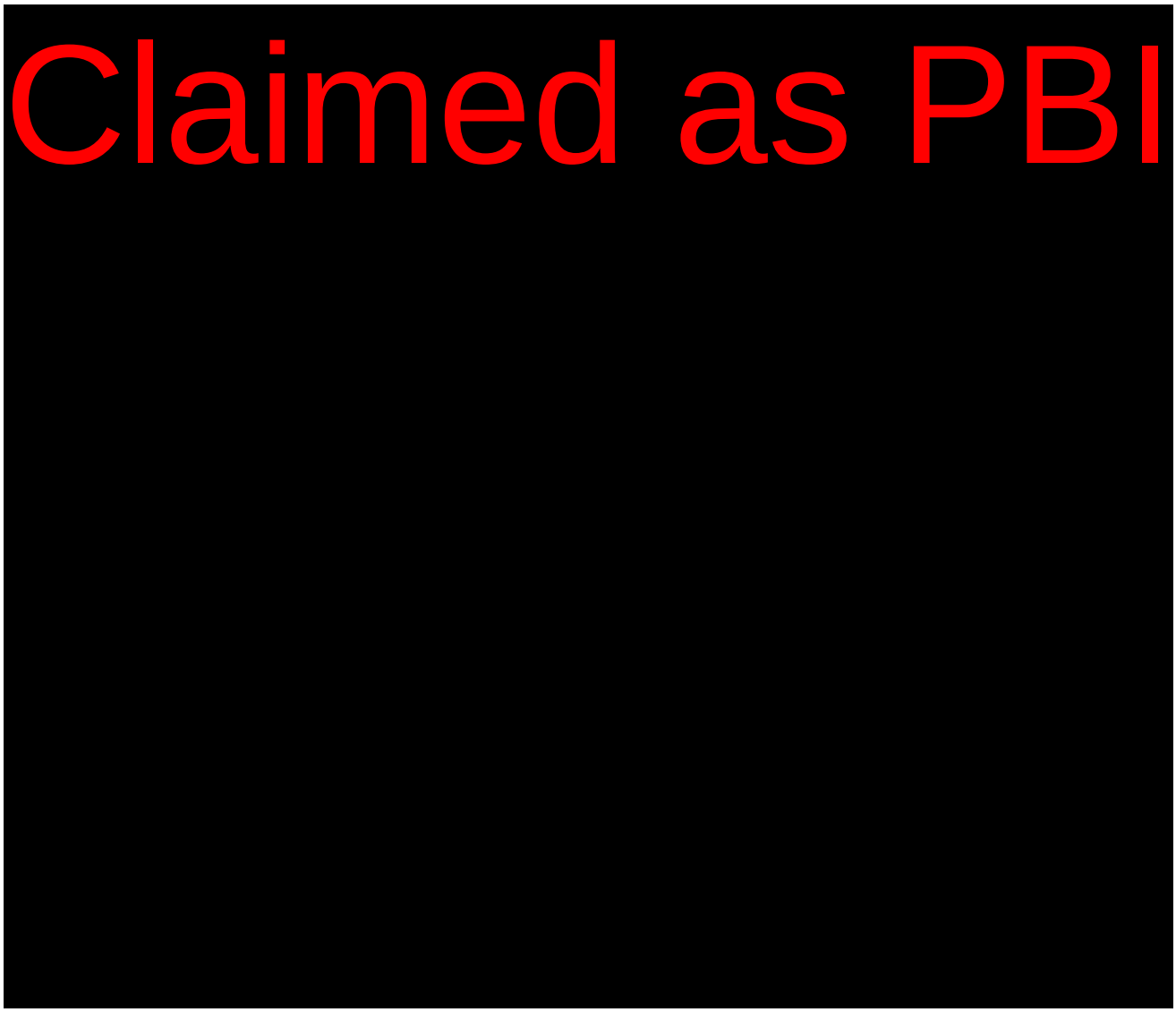
With respect to the timestep selection, the software algorithm optimizes the timestep duration based on the specific convergence criteria designed to minimize numerical artifacts. For these simulations, the timestep size ranged from 0.001 to 10 days. In all cases, the maximum solution change over a timestep was monitored and compared with the specified target. Convergence was achieved once the model reaches the maximum tolerance where small changes of the temperature and pressure calculation results occur on successive iterations. New timesteps were chosen so that the predicted solution change is less than a specified target.

Chemical equilibria of ionic species in brine and reactions of minerals with ions were simulated in only limited cases due to their long computing times. The results suggested negligible net carbon capture by minerals during the CO_2 injection period. After CO_2 injection has ceased, however, continued precipitation of calcite, dolomite, and other minerals over an extended period (100+ years) may indeed play a key role in retaining a large fraction of carbon atoms permanently in the reservoir.

4.2 Model Domain - Oligocene Storage Complex

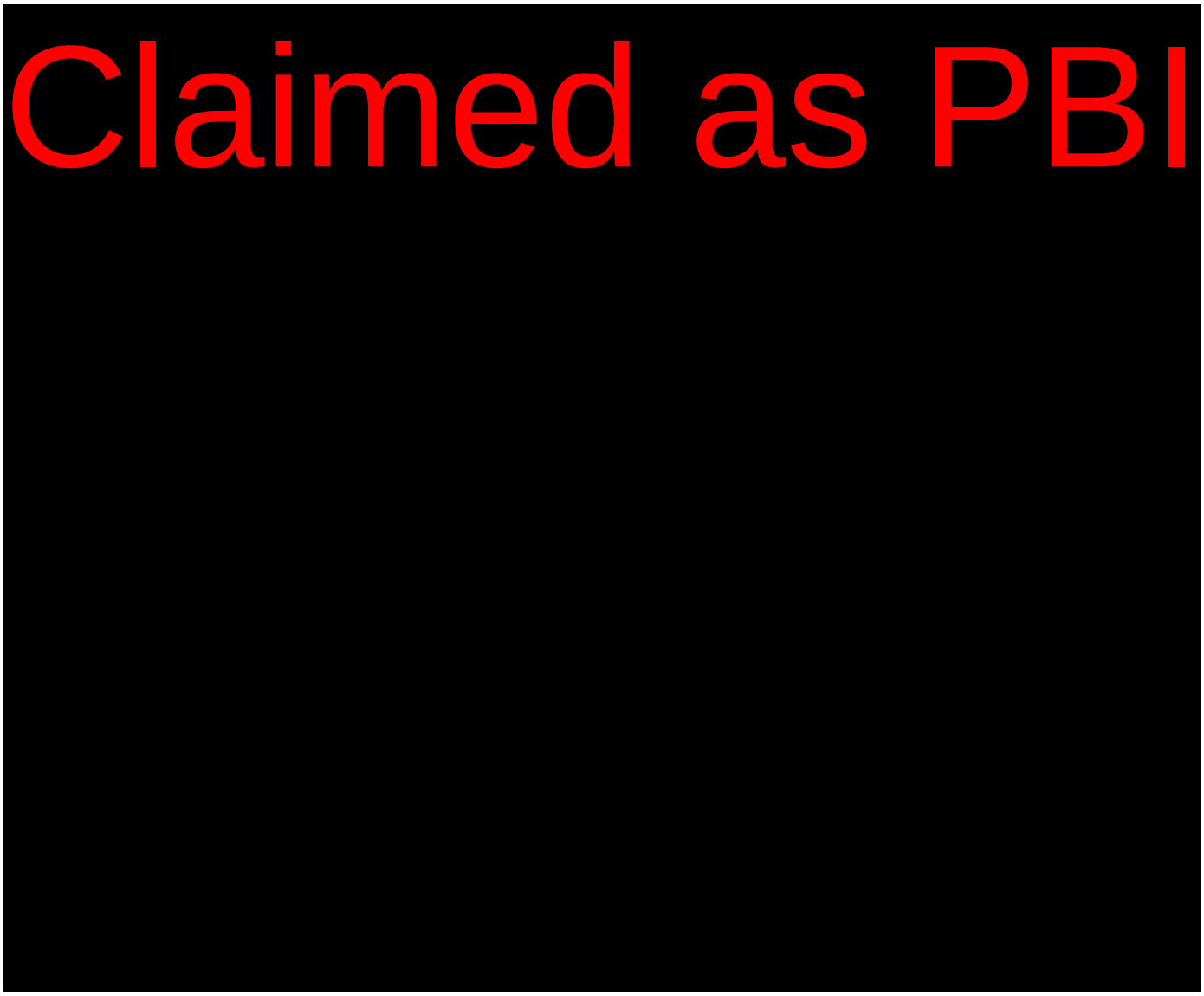
This Class VI permit contains information about both stacked Oligocene and Miocene storage complexes which collectively comprise the Bluebonnet Sequestration Project. Site-specific subsurface characterization does not suggest vertical fluid communication between each storage complex; therefore, each storage complex is described and modeled independently. Examples of subsurface characterization supporting separate storage complexes include differences in local geology, depositional environment, seismic amplitudes, fairway mapping, sand distribution, facies, formation fluids, and well tests. The first model described under 4.0 is the original Frio model submitted in the July 2024 Class VI permit, which was calibrated to well logs and adjusted to well test data. The second model described under 5.0 is the latest Miocene model, which is calibrated to the core data and adjusted to well test data, and includes two additional faults in the south, with which the existing Class VI permit is now updated, merged, and completed. The Bluebonnet Sequestration HUB LLC is seeking approval for CO_2 storage in both storage complexes as a whole unit.

Figure AoR-231 displays the Bluebonnet Hub location in Chambers, Jefferson, and Liberty Counties with 3D seismic coverage and legacy wells in the area where the Bluebonnet geomodel has been built to quantify CCS potential and plan for its development.



The static geological model was created using Schlumberger Petrel (v2021) and is based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout public data, literature, and in-house 3D seismic data.

Figure AoR-232 displays 152 wells with quality logs and reservoir top data that were used, in conjunction with 3D seismic data, to construct reservoir top surfaces. Eighty-nine of these wells also had the appropriate digital logs to be petrophysically analyzed and used in the building of the petrophysical property models. Sixty-three of these wells have basic logs and have been used to pick the formation tops. Detailed information of these wells is tabulated in Appendix D.



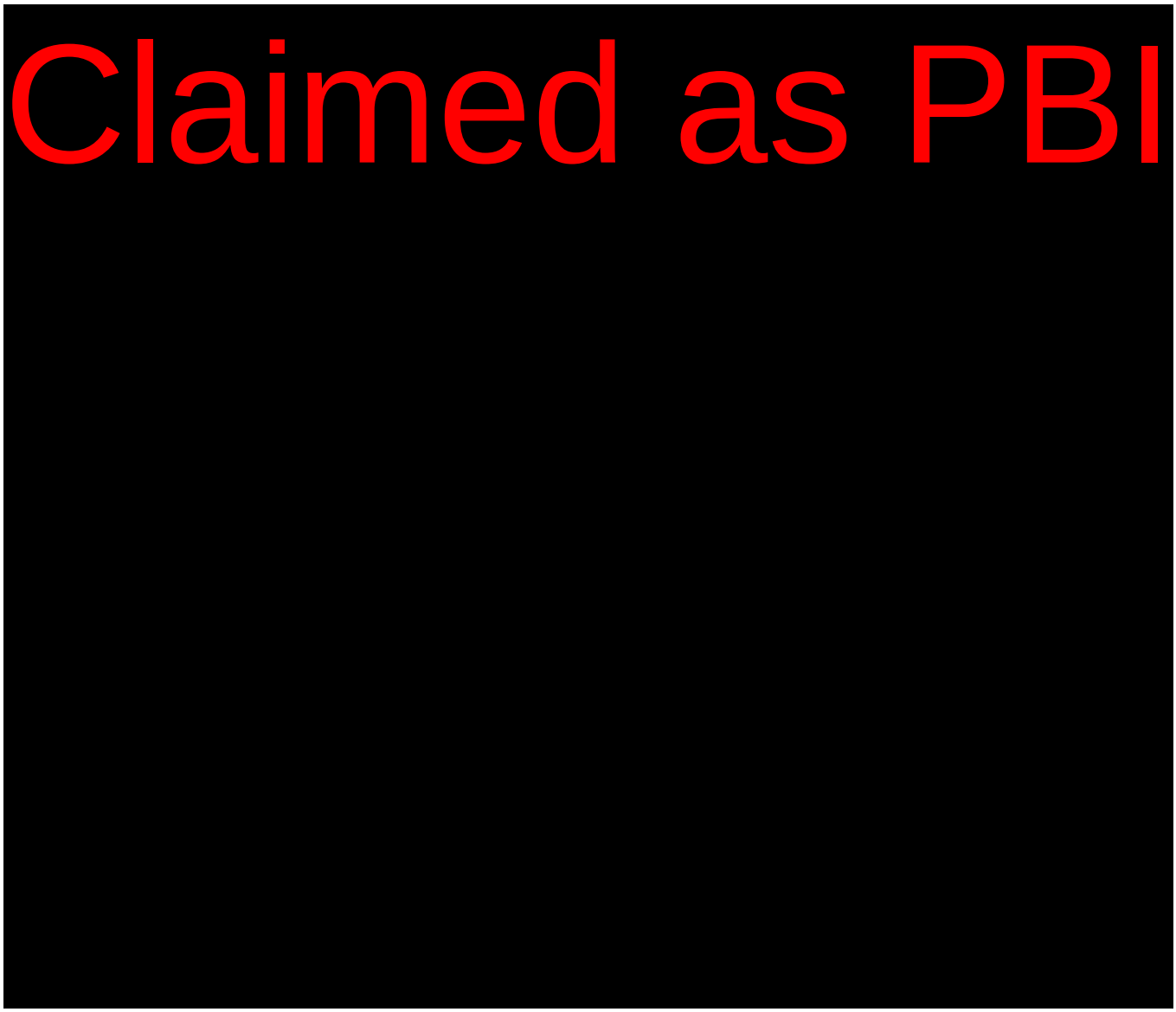
The model includes several major geological zones from top to bottom: the Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac Confining Zone, Frio Injection Zone, Frio Confining Zone, Hackberry Injection Zone, and Hackberry Confining Zone. The model covers an area of about 13.58 miles by 13.69 miles. The bottom confining zone is the Hackberry Confining Zone. Grid cell area is consistent throughout the geomodel area at 500 ft x 500 ft. The grid thickness varies somewhat but averages at about 10 ft. The final geologic model is represented by a 143 × 142 × 310 grid in a Cartesian system for a total of 6+ million active grid cells.

Horizons were first interpreted from multitude of well log data sets including both depth registered image logs and digital log data on 152 wells shown in Figure AoR-232. Those horizons were then combined with 3D seismic data to give a more accurate view of the horizons where log data may have been scarce.

The methodology applied to the static geomodel was to model the large-scale features, followed by modeling progressively smaller and more uncertain features. The first step applied to the Bluebonnet geomodel was to establish a conceptual structural and depositional model as well as

its characteristic stratigraphic layering. The structural and stratigraphic architecture provided a first-order constraint on the spatial continuity, porosity, permeability, net sand, and other attributes within each layer. Next, petrophysical values were distributed for each zone using a cell-based methodology.

Figure AoR-233 displays locations of Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 wells. Also, shown is the location of the stratigraphic well Encanto 01, which was drilled to gather key reservoir/performance data in support for this supplication.



The model domain coordinate reference system is summarized in Table AoR-27.

Table AoR-27: Geologic model domain information.

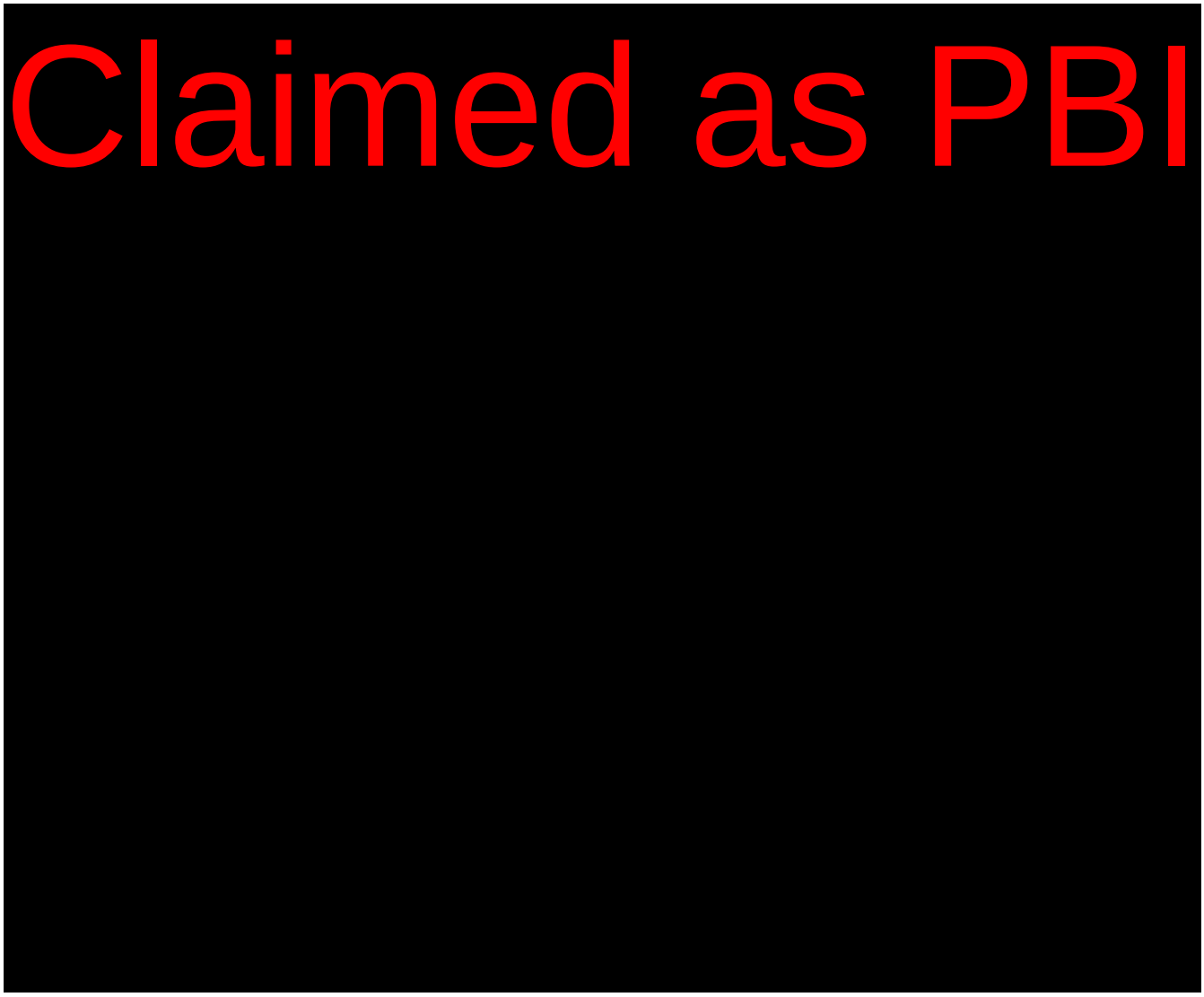
Coordinate System	NAD 27/BLM zone 15 N (ftUS)		
Horizontal Datum	NAD1927		
Coordinate System Units	Ft US		
Zone	BLM 15 N		
FIPSZONE	N/A	**ADSZONE**	N/A
Coordinate of X min	1138000	**Coordinate of X max**	1209500
Coordinate of Y min	10809500	**Coordinate of Y max**	10880500
Elevation of top of domain	-3,144	**Elevation of bottom of domain**	-10,879

4.3 3D Seismic Input to Model Geologic Structure – Oligocene Storage Complex

4.3.1 3D Seismic Data

Approximately 193 square miles of Seitel Inc's Hankamer Merge survey was licensed by Oxy Inc. covering the 78% of the Bluebonnet Model Area (Figure AoR-234). The Hankamer Merge 3D Survey is a pre-stack merge processed by Matrix Geophysical in 2008. The two source surveys that cover the Bluebonnet model area are the Raywood South (acquired 2001) and Hankamer (acquired 2007) 3D surveys. Both surveys were acquired by Quantum Geophysical for Seitel, Inc. using dynamite with 220' source spacing and a 220' line interval. Volumes licensed from Seitel, Inc. are shown in Table AoR-28 below. Table AoR-29 lists the acquisition parameters for the constituent volumes and Figure AoR-235 presents the processing flow.

Additional 3D seismic licensed by Oxy Inc. from SEI Seismic Exchange is currently under evaluation. The SEI survey overlaps the Hankamer Merge survey and provides full coverage over the southern portion of the AoR that is not covered by the Hankamer Merge. Preliminary results from the SEI survey interpretation support the conclusion that the AoR is absent of any transmissive or transecting faults impacting the storage complex, but a comprehensive interpretation will be integrated into the existing geo model in conjunction with pre-operational testing.


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4.3.2 Interpretation Workflow

The 3D seismic interpretation workflow is summarized in Figure AoR-236. Synthetic well ties were initially generated for five wells in the 3D area including the stratigraphic test well Encanto 01 (see Figure AoR-237, Figure AoR-238, and Figure AoR-239). Relevant horizons were identified from well surface picks and mapped across the survey.

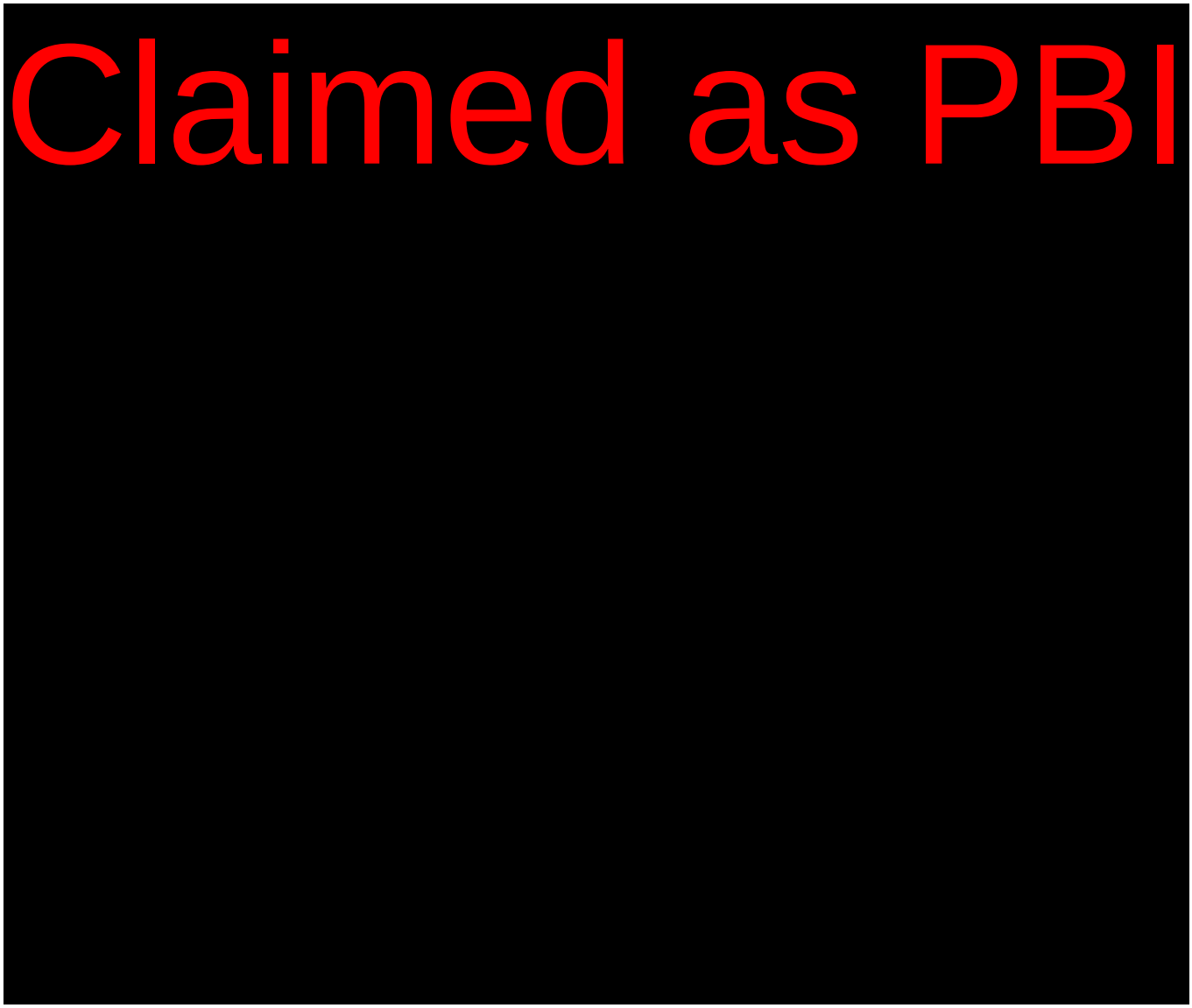
The 3D structure framework was smoothed to generate a structure model used to guide the 3D velocity model in conjunction with time depth curves from synthetic well ties and well surface picks tied to horizons in all available wells (Figure AoR-240). The resulting 3D velocity model was used to convert all interpretations and seismic volumes to depth.

The depth converted structure grid was then quality-controlled against the depth converted seismic volumes and refined slightly where needed. The final depth structure model contained eight surfaces ranging in depth from the Top Vicksburg to the Top of Lower Miocene Confining Zone along with roughly 60 individual fault planes.


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Faulting within the 3D survey was interpreted manually with the assistance of various fault enhancement attributes including Lankmark's Structure Oriented Filter and Fault Likelihood attributes. All faults were interpreted using fault plane mapping techniques to assure reasonable and proper fault geometries. All interpreted faults were incorporated into the Geomodel. There is no evidence from the 3D seismic data interpretation for faults that transect the storage unit within the AoR.

The unconsolidated amalgamated sands in the Frio formation do not generate seismic signal conducive to attribute analysis needed to provide stratigraphic constraints on the model. Additional seismic interpretation methods such as spectral decomposition similarly did not result in any usable output.



4.4 Geologic Model Zones and Layering

The geological model has four major zones: the Lower Miocene, Anahuac, Frio, and Hackberry. These major zones were further subdivided to contrast lithology variations and were subsequently modeled separately.

1. The Lower Miocene was further subdivided into the following: Lower Miocene Confining Zone, Lower Miocene Dissipation Zone, and Lower Miocene Injection Zone

2. The Anahuac has four subzones to isolate a thin sand and the Het lime within the Upper Anahuac Confining Zones and below that the Lower Anahuac Confining Zone

3. The Frio was further divided into the three distinct Top, Mid, and Low Frio Injection Zones, and the underlying Frio Confining Zone

4. The Hackberry was split into two separate zones, namely the Hackberry Injection Zone and underlying Hackberry Confining Zone.

Out of the three Frio Injection Zones, the Mid Frio and Low Frio are the main CO_2 storage reservoirs within the proposed AoR. They are composed of unconsolidated sandstones and interbedded clay layers, which were deposited in a fluvial-deltaic environment. The Mid and Low Frio Injection Zones yield excellent storage quality. Figure AoR-241 depicts the NW-SE cross section of these geological subzones.

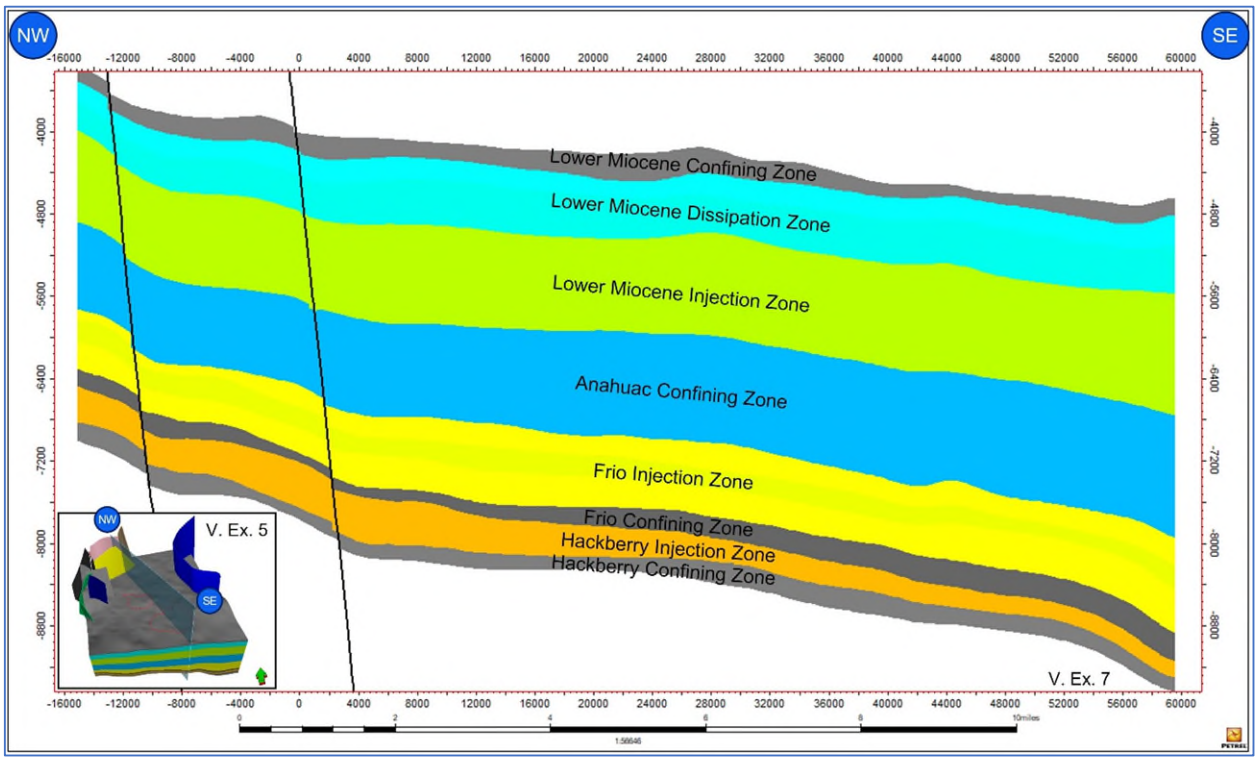


Figure AoR-241: Northwest-southeast cross section of the main geological zones, Lower Miocene, Anahuac, and Frio, and Hackberry subzones in the Petrel geological model. Note that Lower Miocene Confining Zone and Anahuac Confining Zone represent a competent confining system above the Frio and Hackberry Injection Zones. V. Ex. = Vertical exaggeration.

The geologic subzones were created from horizons based on well log correlations with 3D seismic data. In addition, for the internal characterization of the stacked injection and confining zones, 152 digital logs were interpreted to create the horizons that were used to interpret thicknesses, which determined each subzone. Proportional layering was applied to each subzone and the number of layers within each zone division was based on the upscaled thickness of each interpreted zone, targeting ~10 ft for each grid layer as a guideline, with the actual average incremental cell thickness being 13.5 ft. A 3D index view of the eleven subzones is shown in Figure AoR-242.

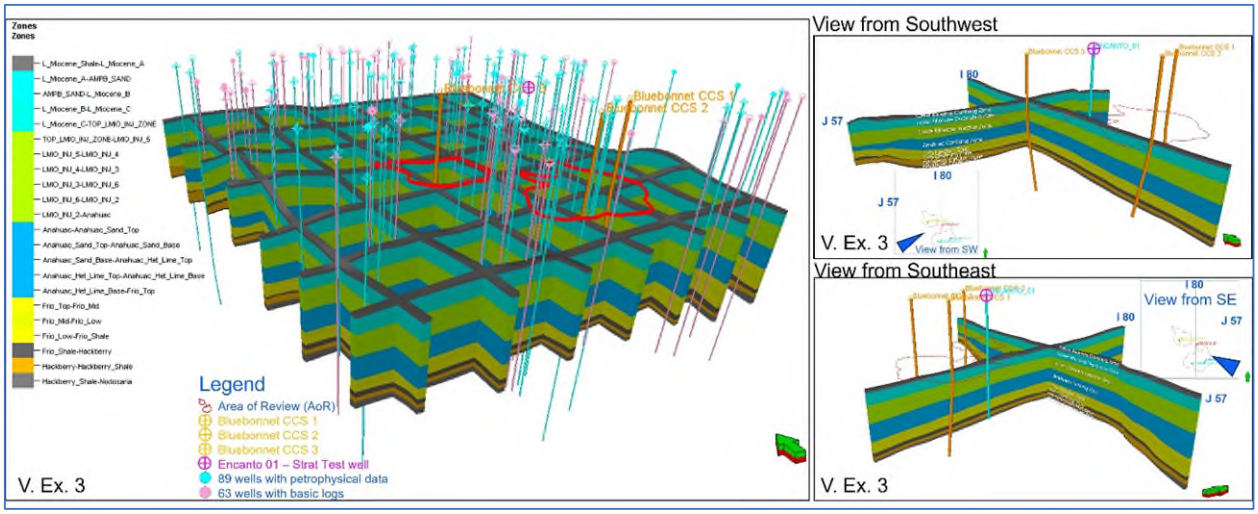
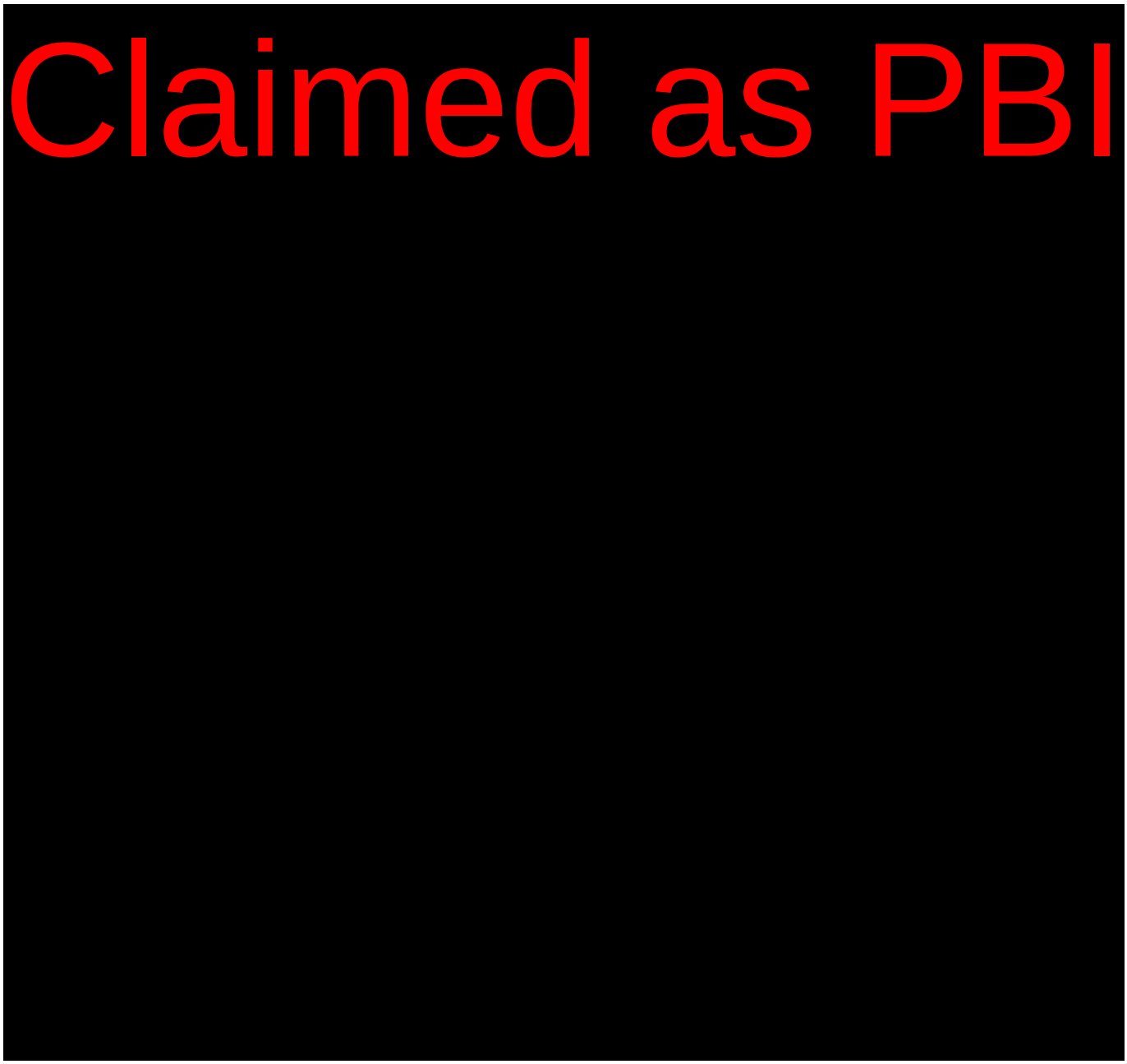


Figure AoR-242: A fence diagram displaying the 3D index view of the geologic model subzones from the Lower Miocene Confining Zone to the basal Hackberry Confining Zone.

The 21 individual zones within the geological model include the strata from the base of the Hackberry Confining Zone as the lowermost confining zone to the top of the Lower Miocene Confining Zone as the uppermost confining zone.

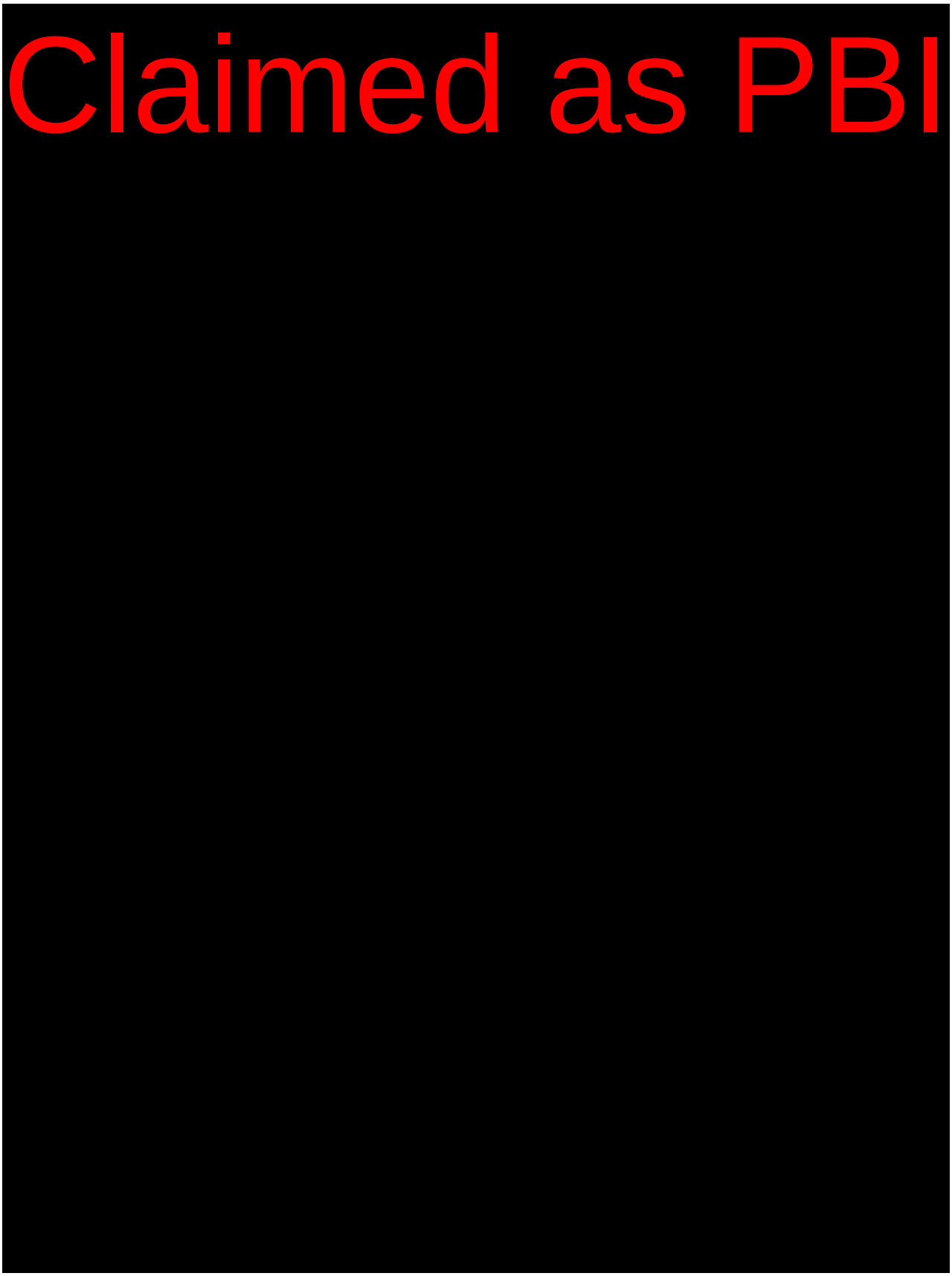
A total of 89 wells were selected for petrophysical calculation of porosity, permeability, and net reservoir thickness that provided the best data quality and coverage. Within the geomodel, 89 petrophysically analyzed wells were selected for 3D distribution of petrophysical properties as shown in Figure AoR-244 and listed in Table AoR-30. A summary of the average properties by zone is shown in Figure AoR-245.


Claimed as PBI

A composite type well log from Encanto 01 is shown in Figure AoR-243. The Gamma ray track contains the total and uranium free GR and the difference is shaded in yellow. The Depth track is showing in purple the cored intervals. The formation picks track has labeled the different confining and injections zones. The E. Porosity (Effective porosity) Color coded by NCS (net confining stress): Blue points have a NCS of 1800 psi and represent the Lower Miocene Confining Zone, red points have a NCS of 2300 psi and represent the Lower Miocene Injection Zone, orange points have a NCS of 2800 psi and represent the Anahuac Confining Zone, and green points have a NCS of 3000 psi and represent the Frio Injection Zone. This is followed by the mud log lithology track, the interpreted lithology, and finally the permeability track with our calculated permeability and core data in red points and the green triangles is the data from MICP.



Figure AoR-244: Map representing 156 control wells within and surrounding the Bluebonnet Focus Area (dotted line) used for petrophysical interpretation of porosity, permeability, and net reservoir thickness of the Primary Storage Unit (FRIO), and Confining Zones. Pie charts outlined in blue represent 33 wells with Neutron and Density well-logs. The stratigraphic well, Encanto 01 is identified with a black star. Detailed information of these wells is summarized in Appendix D.


Claimed as PBI

Net reservoir thickness was calculated using a petrophysical cutoff of [redacted] volume of shale and was used to create a net-to-gross (NTG) sand distribution per zone. Porosity was then modeled for each zone separately based on data analysis and a collocated, co-kriging method for net to gross distribution. Permeability was calculated using the porosity model.

The porosity and NTG logs were sampled into the geomodel's 3D grid for each zone and used to determine the lateral ranges in the long and short axes and vertical direction. Furthermore, a trend map of the net to gross distribution within the geomodel area was constructed based on petrophysically analyzed well log data for each subzone, and this 2D trend map was used as soft information to guide the net to gross distribution in between data points. The net porosity log was generated using the NTG logs to only populate net porosity in the net sand. The Petrel grid was populated using the following procedure:

1. Net porosity and NTG curves were upscaled into the geomodel grid at the well locations.

2. NTG in the geomodel grid was populated using Sequence Gaussian Simulation (SGS) honoring the values at well locations, ranges in long/short axes and vertical direction, and guided by the 2D trend map of the net to gross sand distribution.

3. Porosity in the geomodel grid was populated using SGS honoring values at the well location, ranges in long/short axes and vertical direction, and co-kriged with the NTG property.

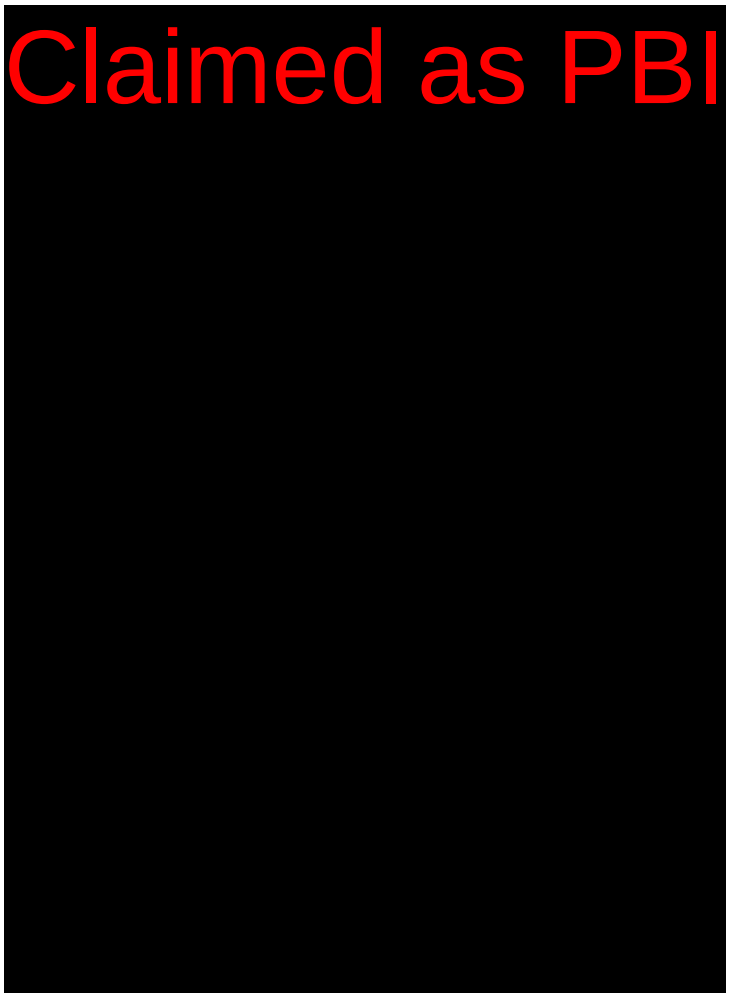
4. Permeability was calculated using the porosity – permeability regression developed by the GCCC (Frio Pilot in CO_2 Sequestration in Brine – Bearing Sandstones, Hovorka et al. 2003)

5. Steps 2 through 4 were done on a zone-by-zone basis.

4.4.1 Porosity

The total porosity of the injection zone is based on Neutron and Density porosity logs from 33 wells within and around the Geologic Model Domain (Figure AoR-244 and listed in Table AoR-30). An interconnected (effective) porosity for wells with porosity logs was calculated from total porosity corrected for the shale volume. The remaining wells did not have neutron and/or density porosity logs but were required for porosity calculation in the petrophysical interpretation. A linear correlation between volume of shale and effective porosity from wells with porosity logs developed by the GCCC (Frio Pilot in CO_2 Sequestration in Brine – Bearing Sandstones, Hovorka et al. 2003) was used and corroborated with local data. The results of this method compared largely with the 33 well subset, so the linear correlation was applied to the remaining wells.

Table AoR-30: The 33 wells in the petrophysical interpretation used to calculate total porosity from neutron and density porosity logs.



Based on the properties in the geomodel, the Frio injection zones start from a Claimed as PBI The average net effective porosity for the Low Frio is Claimed as P with an average net reservoir thickness of Claimed as PBI (Figure AoR-245). The average net effective porosity for the Mid Frio is Claimed as P with an average net reservoir thickness of Claimed as P. The average net effective porosity for the Top Frio is Claimed a with an average net reservoir thickness of Claimed as PBI The net effective porosity of the Anahuac Confining Zone, Frio Confining Zone, and Hackberry Confining Zone is also based on Neutron and Density porosity logs from 33 wells within the geomodel domain. An interconnected (effective) porosity for those wells was calculated from total porosity corrected for shale volume. The average net effective porosity of the Anahuac Confining Zone is Claimed as the average net effective porosity of the Frio Confining Zone is Claimed as and the average effective porosity of the Hackberry Confining Zone is Claimed a based on the above-mentioned methodology.

Before distributing net-sand porosity into the geological model, the net-to-gross volume was developed first. To guide the Sequential Gaussian Simulation process, 2D net-to-gross trend maps were developed by a geological subject matter expert, guided by well control and likely sand distributions in the perceived depositional environment. These 2D maps were then used as soft

trends to guide the subsequent Sequential Gaussian Simulations, which honored the actual well controls, to generate the net-to-gross volumes for all subzones. An outcome of the simulation process is the 3D net-to-gross distribution as shown in Figure AoR-246.

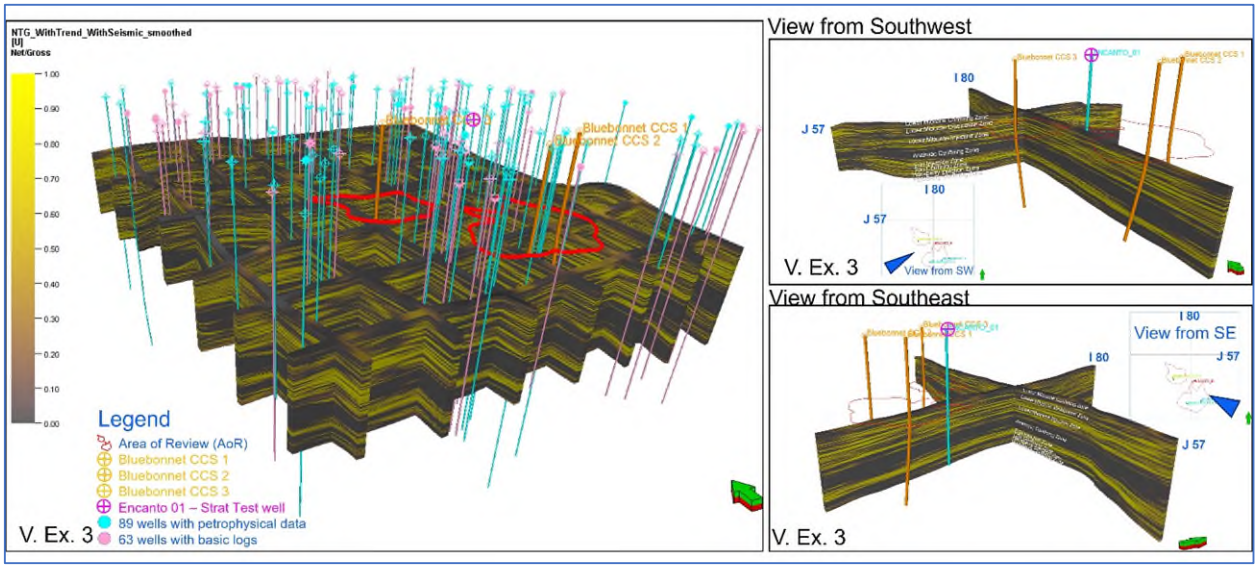


Figure AoR-246: The Net-to-Gross distribution generated from subzone 2-D trend maps and hard data at the wells. Yellow regions represent sands whilst dark gray regions are shales.

The porosity model was constructed using Sequential Gaussian Simulation (SGS) Local Varying Mean (LVM) with Net-to-Gross (NTG) model with varying coefficients applied. The porosity logs were upscaled using arithmetic averaging. The raw upscaled porosity histogram was used during SGS and final porosity model was then smoothed. The following parameters were used as inputs:

I. Variogram
    a. Type: Spherical
    b. Nugget: 0.0001
    c. Anisotropy range and orientation:
        i. Lateral range: 8000 x 5000 in the base case
        ii. Vertical range: 20-50

II. Distribution
    a. Actual histogram range (0.0–0.40) from upscaled logs
    b. Distribution method: General

III. Co-kriging for the three cases built from the static porosity model
    a. Secondary variable volume: NTG[U]
    b. Method: Collocated co-kriging
        i. LVM (no co-kriging coefficient applied)
        ii. Coef. Constant: 0.75
        iii. Coef. Constant: 0.5
        iv. Untrended (NTG secondary variable was not applied)

This methodology resulted in three porosity cases based on the value of the co-kriging coefficient with NTG. The base-case porosity model distribution uses the co-kriging coefficient of 0.5. High

and low cases of porosity distribution were chosen as the co-kriging coefficient of 0.75 and the untrended case, respectively. Figure AoR-247 depicts distributions of equivalent porosity (net-porosity * net-to-gross) at various net-to-gross values in the entire geological model. Figure AoR-248 shows the base-case porosity distribution in the Petrel geological model.

Claimed as PBI

Figure AoR-247: Equivalent Porosity relationship to Net-to-Gross ratio (NTG) for the base case (Phi_Eq_50_vs_NTG) porosity distribution used in the reservoir simulation.

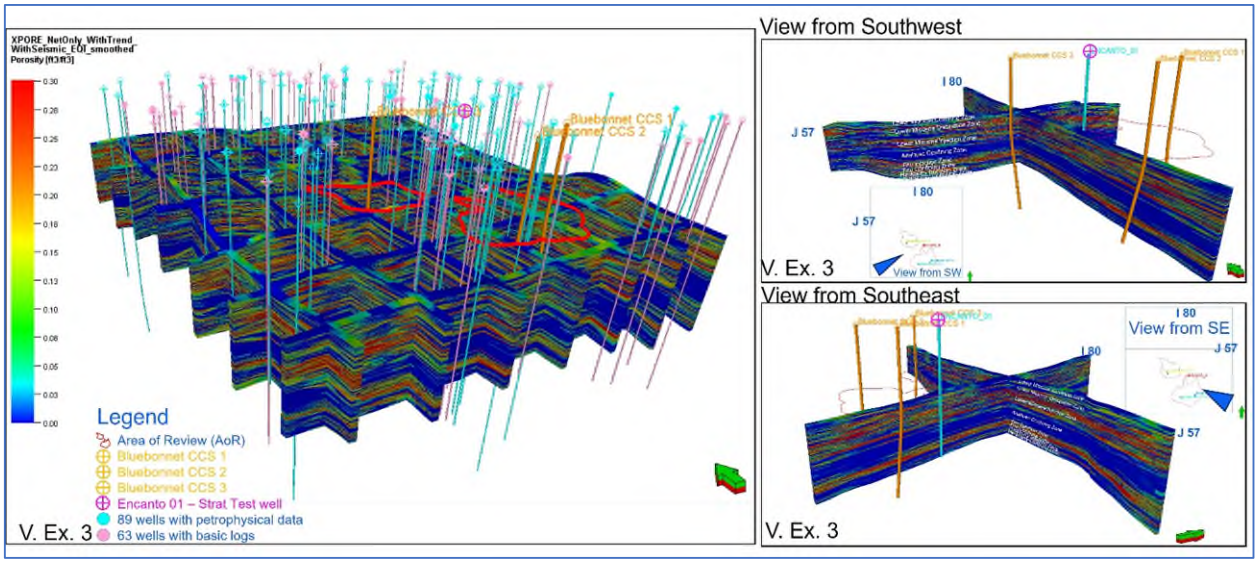


Figure AoR-248: The 3D net equivalent porosity index view from the Lower Miocene Confining Zone to the Hackberry Confining Zone.

4.4.2 Permeability

For the pre-construction static modeling effort, the horizontal permeability for the injection zones is based on a porosity permeability relationship established by the GCCC in the 'Frio Pilot CO_2 Sequestration in Brine – Bearing Sandstones' by Susan Hovorka and others 2003. Using this relationship, an average horizontal permeability of [redacted] is calculated for the Frio Injection Zone within the geomodel using the modeled net effective porosity. This average is composed of 49 md in the Top Frio and higher average permeabilities of [redacted] in the Mid Frio and [redacted] in the Low Frio. Please note that these are average numbers, and the minimum and maximum ranges are wider. These permeabilities are based on well logs only and that method is described below. The static geomodel does not include a calibration to permeabilities derived from well test data; the dynamic simulation model, however, does.

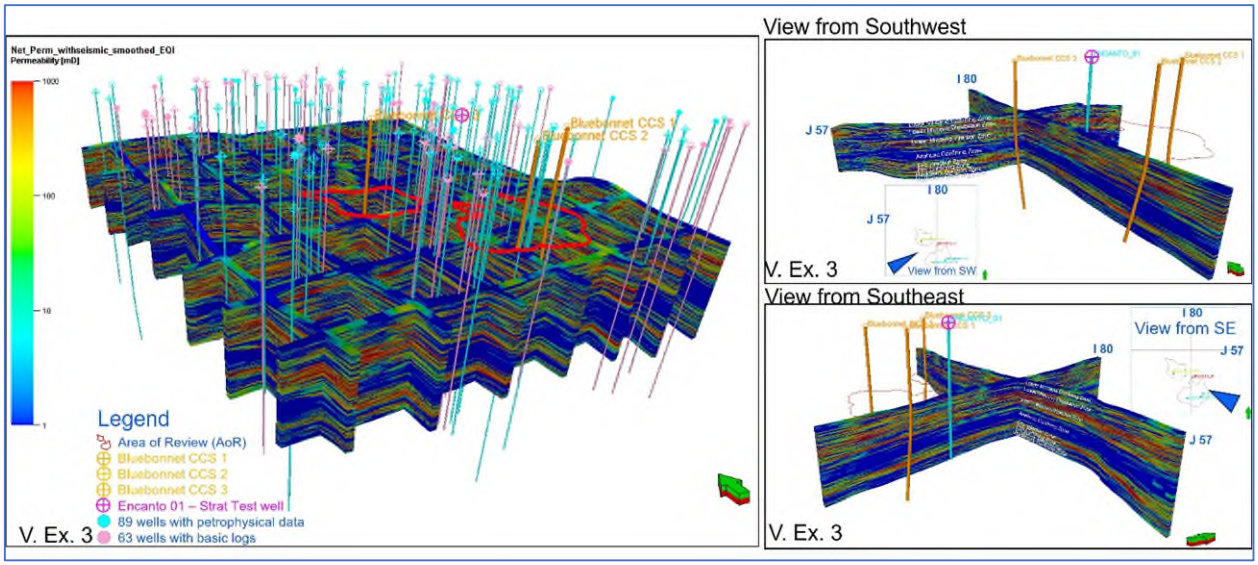


Figure AoR-249: Reservoir permeability distribution in the base-case simulation model. Blue represents lower permeability and red represents the highest permeability within the model.

The porosity and permeability relationships used were extracted from 'Frio Pilot CO2 Sequestration in Brine-Bearing Sandstones', GCCC digital publication series #03-04 by Susan D. Hovorka and others, 2003. The area of this pilot study is 27 miles to the northwest of Encanto 01.

Calculated volume of shale is based on a normalized SP (spontaneous potential) log and GR (Gamma Ray) log when available and used the correlation presented in Figure V-27 in the cited paper to calculate porosity from volume of shale. To calculate permeability, the barrier values (empty diamonds in Figure AoR) were used from routine core analysis in the Frio formation from the Felix Jackson No.1 well in Chambers County (Hovorka and others, 2003).

In Encanto 01, a full core was collected in the Lower Miocene Confining Zone, Lower Miocene Injection zone, Anahuac Confining Zone, Frio Injection Zone, and Hackberry Confining Zone. Plugs were extracted from the core, and Routine Core Analysis (RCA) was performed to extract porosity and permeability (P&P) in the plugs. The P&P cross-plots are presented in the Figure

AoR-250. P&P vary per zone, with the highest P&P values in the Lower Miocene Injection Zone and lowest values in the Hackberry Confining Zone.



4.5 Constitutive Relationships and Other Rock Properties

The Bluebonnet Sequestration Hub dynamic reservoir simulation followed a method developed by Ghomian et al. (2008), who had successfully matched the results of a 2004 Frio pilot injection test, described in detail by Sakurai et al. (2004). The project team adopted these established processes in petrophysical evaluation, geological model construction, Equation-of-State (EOS) modeling for CO_2 properties and solubility, and the gas-water relative permeability model with higher trapped gas saturations during the imbibition process.

Further, all simulations runs were executed using the GEM simulator, as used by Ghomian et al. (2008). The grid properties of porosity, horizontal net sand permeability (k_{sand}), and Net-to-Gross ratio (NTG) were directly imported from the static geomodel. The base vertical permeability (k_v) for each grid cell was calculated using a geometric average of sand and shale permeability based on the NTG, as shown in Equation 2.

$$kv = [(A * k_{sand})^{(NTG)}] * [(k_{shale})^{(1 - NTG)}] \quad \text{..... (Equation 2)}$$

Where:

kv is the base vertical permeability;
A is a multiplier for sand permeability;
k_{sand} is the horizontal net sand permeability;
NTG is the net-to-gross ratio;
k_{shale} is the horizontal shale permeability;

The base case used a value of [redacted] and [redacted]

The water-gas relative permeability curves were constructed using a Corey model with exponents previously reported by Ghomian (2008). These curves were also used in the simulation of the Frio CO_2 Pilot test. The following endpoint values and Corey exponents were used:

[redacted]

During the imbibition cycle (water displacing gas), the gas is trapped at S_{gt} or trapped gas saturation. S_{gt} values depend on the maximum gas saturation, S_{gh}, that a grid block has experienced. The base case maximum trapped gas saturation is specified as [redacted] All dynamic simulation runs include relative permeability hysteresis.

To calculate the capillary pressure, the maximum capillary pressure during drainage is estimated as [redacted] and the threshold capillary entry pressure as [redacted]

4.6 Boundary Conditions

Pore volume multipliers of [redacted] to [redacted] were applied to the outermost ring of the cells adjacent to the horizontal boundaries of the GEM model to simulate an extensive reservoir. The horizontal boundaries were initialized as hydrostatic conditions, and no changes were made to the boundary conditions following pre-operational testing. One of the faults, B06, is identified as sealing fault based on the Fault Analysis described in Section 3.11 and its transmissibility is set as zero in the model.

Figure AoR-251 shows a high probability of thick Frio sands over the entire Gulf Coast region, though there is some uncertainty about good hydraulic connectivity over such a large distance. To quantify its impact on AoR predictions, the horizontal boundary conditions were included as a sensitivity parameter. In Figure AoR-251, the red dash line rectangle represents the low case boundary, red solid rectangle represents the mid (base) case boundary, and blue rectangle represents the high case boundary, within which reservoir pore volumes were included to predict the pore pressure increases from CO_2 injection.



4.7 Initial Conditions

Initial conditions for the model are given in Table AoR-31.

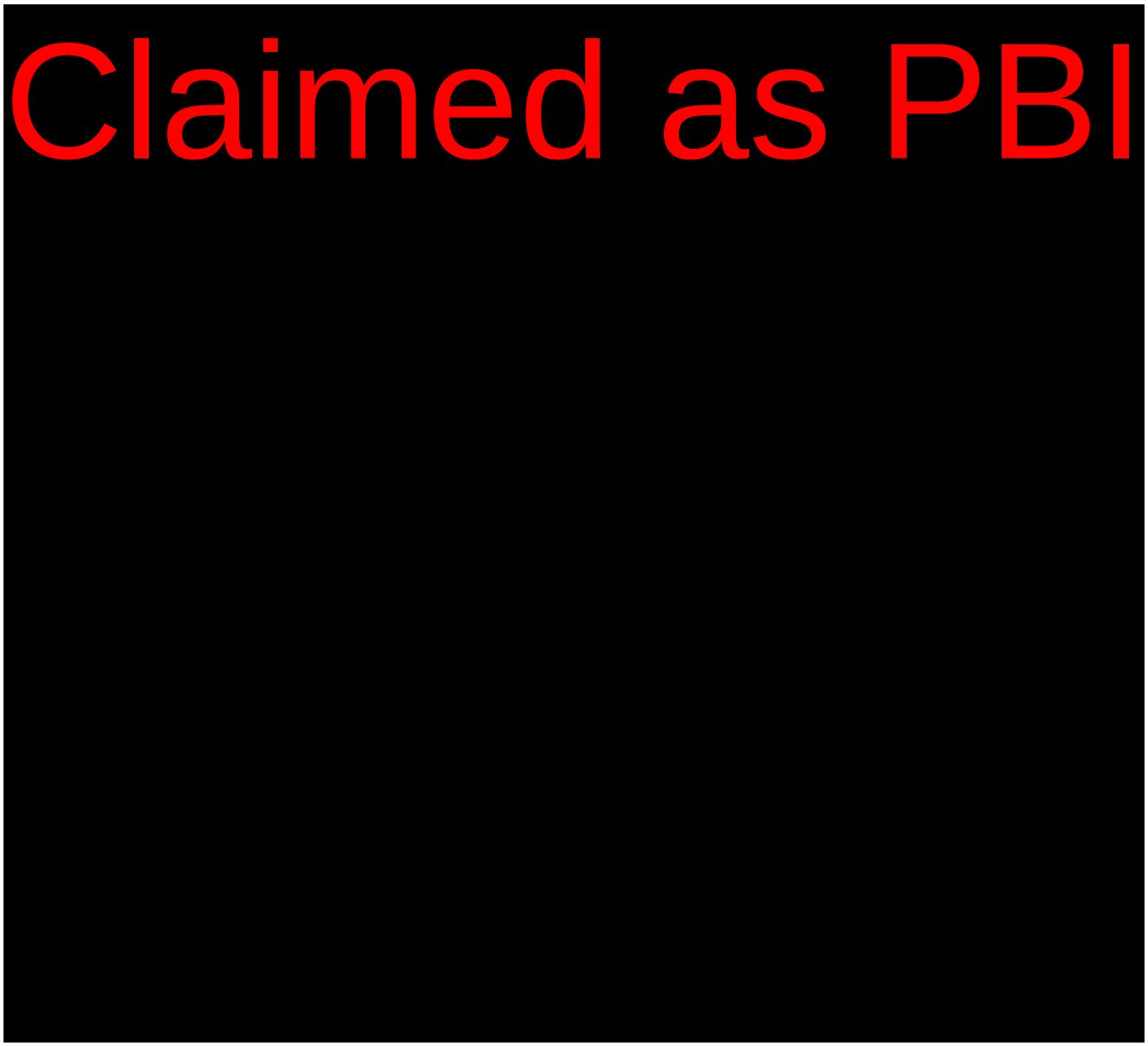
Table AoR-31: Initial Condition.

Parameter	Value or Range	Units	Corresponding Elevation (ft, MD)	Data Source
Temperature	Claimed as PBI			
Formation pressure				
Formation water density				
Formation water salinity				
Rock compressibility				

In this study, a pressure gradient based on Claimed as PBI was adopted in the model. For the modeled pressure gradient within the injection zone, a water density of Claimed as PBI was specified. This formation salinity of Claimed as PBI was determined from the water analysis report in the Encanto 01 well Miocene formation since there was not any Frio salinity data available at that time. The actual Frio salinity received in May 2024 is Claimed as PBI, which will not bring any noticeable difference in our predicted AoR. The reservoir temperature was initialized using a linear temperature gradient representative of with reference temperatures of Claimed as PBI at Claimed as PBI from the actual temperature measurement in Encanto 01 well. Brine viscosity is calculated using Kestin, Khalifa, and Correia correlation in CMG. There is no measured rock compressibility. It is assumed as 1e-05 1/psi based on Newman (1973).

In all the simulations, a maximum BHP was assigned based on a very conservative Claimed as PBI fracture gradient Claimed as PBI, but even under this BHP constraint, the model had no problems in taking in the desired CO_2 rate for all three injectors.

The geomodel permeability was adjusted based on the GCCC correlation, transmissibility, and injectivity test results from Encanto 01 stratigraphic well. The estimated transmissibility from the Frio sand test is Claimed as PBI. A comparison of the transmissibility values for the same intervals from the Encanto 01 well log was made, which is used in the geologic model. The results show that, on the average, the transmissibility is about Claimed as PBI that from the Encanto 01 well log. Consequently, a regional multiplier Claimed as PBI was applied in the Frio and Hackberry injection zones.



4.8 Operational Information

The model was initialized with hydrostatic conditions and run without any active wells for four years to ensure equilibrium and no fluid movement. In the fifth year, the Bluebonnet CCS 1, CCS 2, and CCS 3 wells begin injecting with a primary rate constraint of 105 MMscfd (2.0 million metric ton (MMTA)), 89.25 MMscfd (1.7 MMTA), and 73.5 MMscfd (1.4 MMTA), respectively. A secondary bottomhole pressure (BHP) constraint (Claimed as PBI of the minimum estimated fracture gradient of Claimed as PBI) is set at the well reference depth. The frac gradient, Claimed as PBI has been established by step-rate and leak-off tests on the Encanto 01 stratigraphic well. The injection stream composition is assumed as 100% CO_2. CCS 1 and CCS 3 continue injection until the end

of Year 20, but CCS 2 only injects for 15 years. The base-case run continued for 100 years post-injection to simulate CO_2 migration after post-injection site closure.

Two water withdrawal wells, Bluebonnet PRDW F1 and Bluebonnet PRDW F2, are proposed to help relieve the pressure increase from CO_2 injection. Both wells are completed in the Frio only and produce for the first 15-years of injection. Produced water from the water withdrawal wells is reinjected to Upper Miocene formation that includes the sands between the Lower Miocene Confining Zone and base of the USDW.

Table AoR-32 shows the completion design for all three injectors. During the first 8 years of injection, Bluebonnet CCS 1 is completed at Frio Low only (Layer 231 - Layer 262). Starting from Year 9, this well is recompleted in Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230). Meanwhile, the Frio Low intervals are opened for the first 9-year injection period and are left open. Starting from Year 16, this well is recompleted into the Hackberry (Layer 271 – Layer 304) and all the Frio completions will be plugged. Bluebonnet CCS2 is only completed in the Frio formation. This well first completes in Frio Low (Layer 231 - Layer 262), and then, recompletes in Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230) at Year 9, while leaving the Frio Low open. CCS 3 completes in the Hackberry (Layer 271 – Layer 304) for the first eight years and all perforations in the Hackberry are plugged at the end of Year 8. At year 9, this well is recompleted into the Frio Low (Layer 231 - Layer 262), and then in Year 16, is recompleted into the Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230).

The recompletion design provides higher CO_2 storage capacity by filling each zone of the reservoir separately. The CO_2 plume areal extent is also reduced by injecting to the high permeable zone for shorter time. Both Bluebonnet PRDW F1 and Bluebonnet PRDW F2 are completed at Frio Low only (Layer 231 – Layer 262) during the first eight years of injection and are recompleted in Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230) from Year 9 to Year 15. Bluebonnet PRDW F1 and Bluebonnet PRDW F2 are shut in permanently after Year 15.

Details on the injection operation are presented in Table AoR-32 and Table AoR-33.

Table AoR-32: Operating details of Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3.

Operating Information	Bluebonnet CCS 1	Bluebonnet CCS 2	Bluebonnet CCS 3
Bottomhole Location (NAD27) Latitude Longitude	 29.80813285 -94.43723568	 29.80664177 -94.46905961	 29.84865529 -94.49510821
Model coordinates (ft) X Y	 1184728.1 10820884.0	 1174630.0 10820469.2	 1166568.3 10835850.8
No. of perforated intervals	3	2	3
Perforated interval (ft TVDSS) Z top Z bottom	 7982.66 8257.46	 7922.72 8178.12	 8079.94 8400.57
Recompletion interval (ft TVDSS) Z top Z bottom	 7779.96 8257.46	 7714.06 8178.12	 7638.44 7898.79
Recompletion interval (ft TVDSS) Z top Z bottom	 8542.85 8719.46	 n/a	 7374.83 7898.79
Wellbore diameter (in.)*	6.0	6.0	6.0
Planned injection period Start End	 time = 0 time = 20	 time = 0 time = 15	 time = 0 time = 20
Injection duration (years)	20	15	20
Average Injection rate (t/day)	5,479 (1^{ST} and 2^{nd} completion) 1370 (3^{rd} completion)	4,658 (1^{ST} and 2^{nd} completion)	3,836 (1^{ST} and 2^{nd} completion) 2,740 (3^{rd} completion)

TVDSS: True Vertical Depth Sub Sea

Table AoR-33: Operating details for water withdrawal wells.

Operating Information	Bluebonnet PRDW F1	Bluebonnet PRDW F2
Bottomhole Location (NAD27) Latitude Longitude	 29.852257630 -94.51667365	 29.810133590 -94.49717700
Model coordinates (ft) X Y	 1,159,749.99 10,837,250.00	 1,165,730.49 10,821,853.47
No. of perforated intervals	2	2
Perforated interval (ft MSL)* Z top Z bottom	 7627.63 7885.58	 7864.68 8105.80
Recompletion interval (ft MSL) Z top Z bottom	 7344.93 7885.58	 7624.00 8105.80
Wellbore diameter (in.)*	6.0	6.0
Planned injection period Start End	 time = 0 time = 15	 time = 0 time = 15
Injection duration (years)	15	15
Injection rate (bbl/day)	8500 (1^{ST} and 2^{nd} completion)	8500 (1^{ST} and 2^{nd} completion)

4.9 Computational Modeling Results

The dynamic simulations were carried out in 3D using full physics, an Equation of State for fluid PVT, and on the full geologic model encompassing a 13.58 × 13.69 square mile area. The dynamic reservoir simulation was performed with the same 500 ft × 500 ft × ~13.5 ft grid cells as those in the geologic model. The areal extent of the simulation model is shown in Figure AoR-71.

Twenty-two zones were imported into CMG BUILDER (Table AoR-34).

Table AoR-34: Zones imported into CMG Builder.

Zone	Layers
L_Miocene_SH	1-4
L_Miocene_A	5-14
AMPB_SAND	15-22
L_Miocene_B	23-42
L_Miocene_C	43-54
LMIO_INJ	55-64
LMIO_INJ_5	65-72
LMIO_INJ_4	73-80
LMIO_INJ_3	81-98
LMIO_INJ_6	99-124
LMIO_INJ_2	125-142
Anahuac	143-148
Anahuac_Sand_Top	149-152
Anahuac_Base	153-158
Anahuac_Het_Lime_Top	159-168
Anahuac_Het_Lime_Base	169-172
Frio_Top	173-192
Frio Mid	193-222
Frio Low	223-262
Frio_Shale	263-270
Hackberry	271-304
Hackberry_Shale	305-310

The dynamic model contains 143 × 142 × 310 cartesian grids and more than 6.2 million active cells.

4.9.1 Predictions of System Behavior

The simulated well rates and pressures are shown in Figures AoR-253, AoR-254, and AoR-255. Wellhead pressures were calculated using a PROSPER-generated tubing table with 5.5-inch tubing. Table AoR-35 shows the maximum bottomhole and well head pressure for each stage at operative conditions.

Table AoR-35: Well Bottomhole pressure and wellhead pressure for each stage at proposed average rates.

Injector	Completion	Reference Depth, TVDSS, ft	Maximum Well Bottom-hole pressure, psi	Maximum Well Head Pressure, psi	Average Well Bottom-hole Pressure, psi	Average Well Head Pressure, psi
Bluebonnet CCS 1	Claimed as PBI					
Bluebonnet CCS 2						
Bluebonnet CCS 3						

Simulation results supported bottom-up, staged completions as an attractive completion strategy (Table AoR-36). The proposed completion design for each well is based on the overall forecasted sequestration volume, injectivity of each well, and availability of the pore space. At the beginning of injection, Bluebonnet CCS 1 is completed in the Frio Low subzones only. After injecting CO_2 for more than eight years in the Frio Low, the Frio Mid subzones are added to the injection interval in Year 9 and Hackberry is added in Year 16.

Bluebonnet CCS 2 only injects in the Frio formation. Similar to CCS1, it injects in the Frio Low for the first eight years, then recompletes Frio Mid in Year 9.

CCS 3 starts injecting in Hackberry first, then moving up to the Frio Low and Frio Mid. Simulation results suggested that there is not much difference in pressure increase and plume size between plugging back or leaving the Frio Low open after adding Frio Mid.

Different from Bluebonnet CCS3, Bluebonnet CCS1 recompletes into the Hackberry after Frio development because of the overall volume balance needs and pressure front extent at that time.

Table AoR-36: Stage injection, injection, and production rate for all the wells.

Injection Years	CCS 1 Completion	CCS 1 injection rate , MMTA	CCS 2 Completion	CCS 2 injection rate , MMTA	CCS 3 Completion	CCS 3 injection rate , MMTA	PRDW F1, bwpd	PRDW F2, bwpd	DSW M2, bwpd
1	Claimed as PBI								
2									
3									
4									
5									
6									
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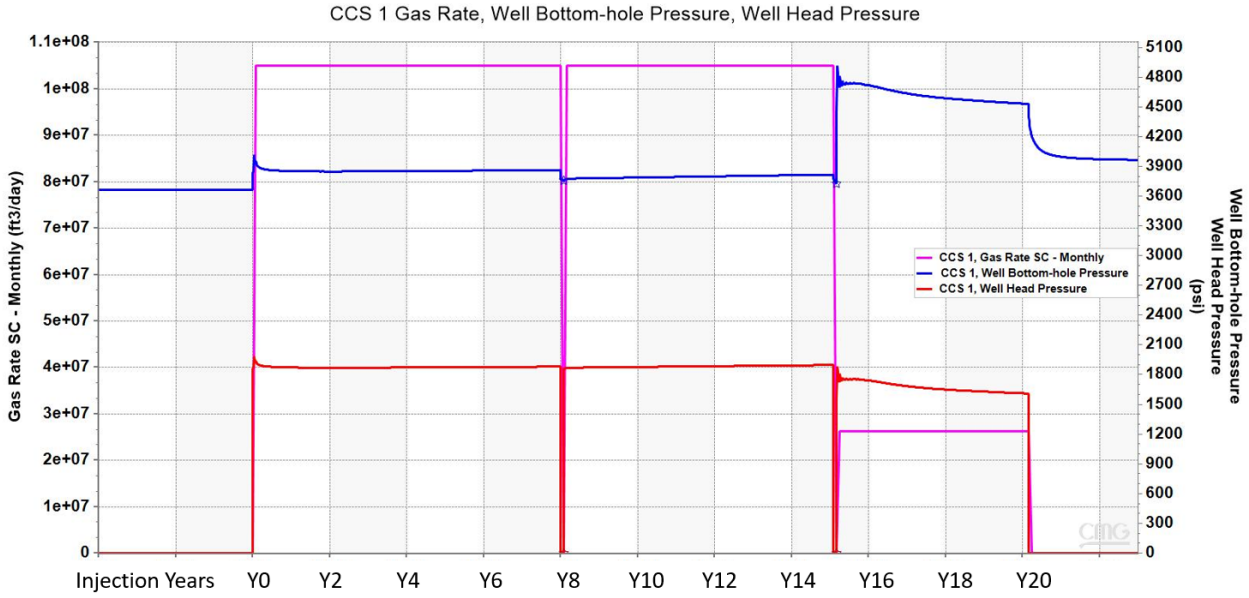


Figure AoR-253: Simulated well Bluebonnet CCS 1 gas injection rates and corresponding wellhead and bottomhole pressures.

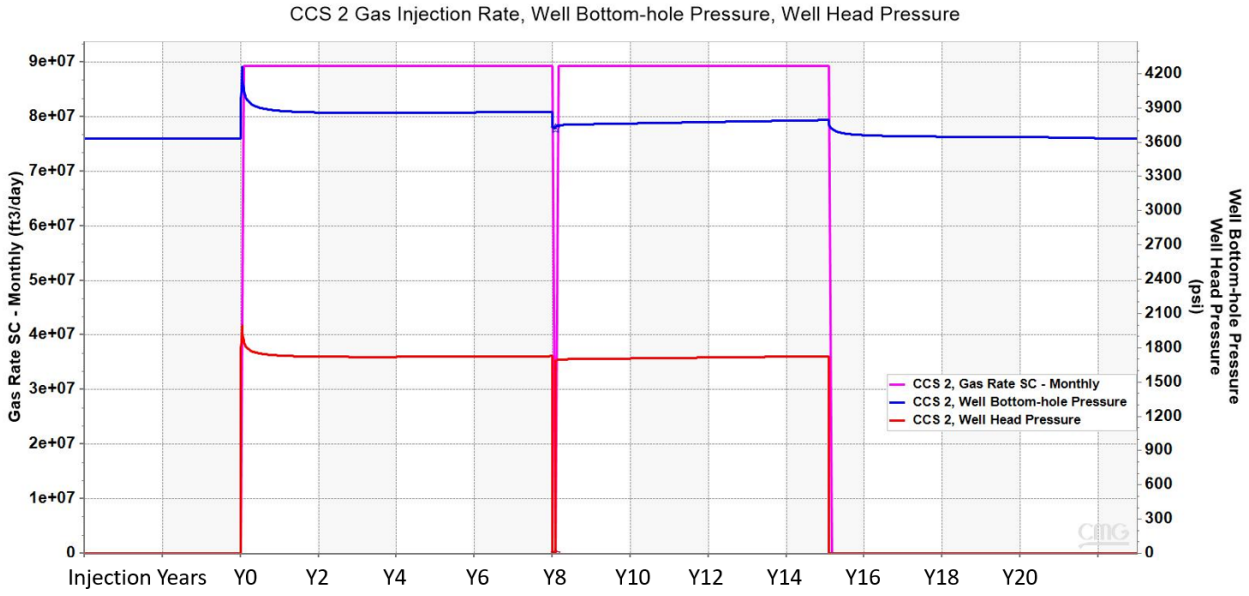


Figure AoR-254: Simulated well Bluebonnet CCS 2 gas injection rates and corresponding wellhead and bottomhole pressures.

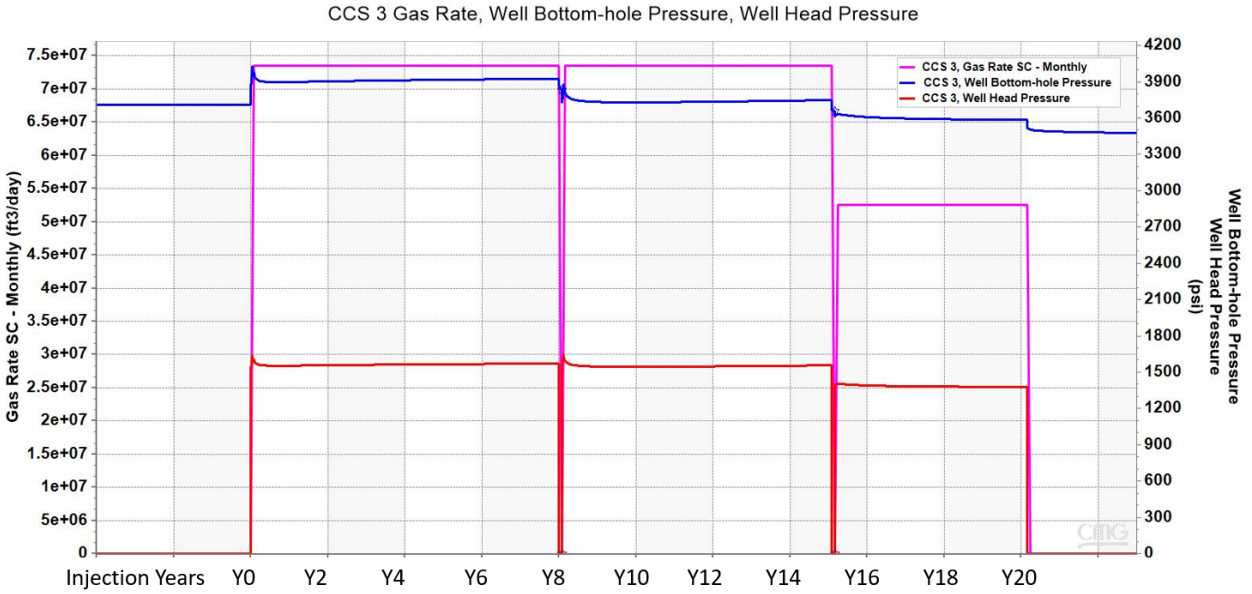


Figure AoR-255: Simulated well Bluebonnet CCS 3 gas injection rates and corresponding wellhead and bottomhole pressures.

4.9.2 Model Calibration and Validation

4.9.3 Sensitivity to Input Parameters

Due to the uncertainties in some of site-specific pilot data used to calibrate the dynamic model, sensitivity of the results to subsurface input was explored. These subsurface uncertainties include vertical-to-horizontal permeability ratio (K_v/K_h), trapped gas saturations (S_{gt}), faults transmissibility, rock compressibility, plugging back the first stage during completion of the second stage, and size of the boundary aquifers.

Table AoR-37 summarizes the possible ranges of these subsurface inputs. The base case inputs are indicated in the left column. Many simulation runs were made by varying these parameters one at a time and plotting the results to see their impacts. The parameters used to compare the different sensitivity cases are reservoir pressure increase and CO_2 retention.

Table AoR-37: Simulation sensitivity cases.

Parameter	Best Value	Sensitivity Values
Kv/Kh	Claimed as PBI	
Sgt (fraction)		
Edge Volume Enhancement		
Faults Transmissibility Multiplier		
Stage 2 Completion		
Rock Compressibility, 1/psi		

Figure AoR-256 shows the sensitivity of forecasted reservoir pressure to various reservoir parameters. The highest change in the reservoir pressure occurs in the low rock compressibility or low edge pore volume cases. This change is at the local level near the injection wellbores with the highest increase less than Claimed as PBI. Figure AoR-256 also shows the reservoir pressure is most sensitive to the size of the boundary aquifer. The pressure increase is moderately sensitive to K_v/K_h and faults transmissibility multiplier. The pressure increase is not sensitive to the trapped gas saturation, S_{gt}, and plugging back or leaving the first stage open. Figure AoR-257 shows the CO_2 100-year post injection plume in the Frio and Hackberry formations, respectively, for two most sensitive cases (High edge volume and high Kv/Kh case) to CO_2 migration. They are almost identical to the base case.

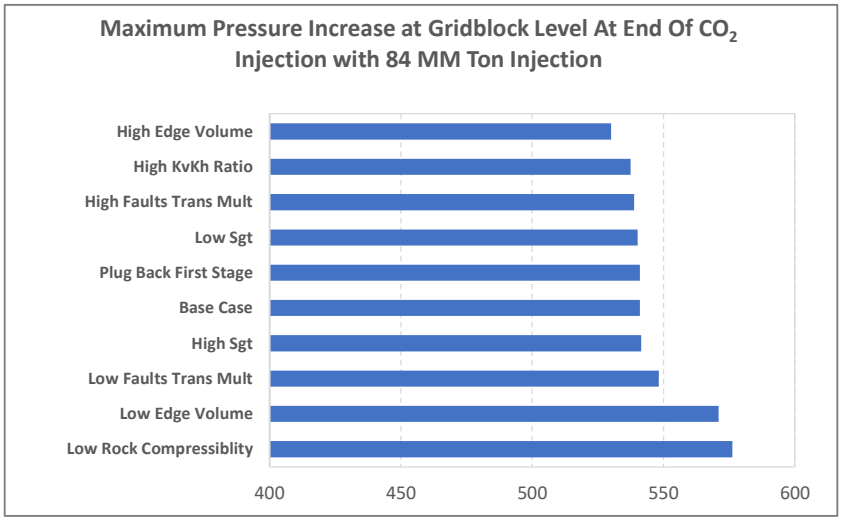


Figure AoR-256: Maximum pressure increase at gridblock level at end of CO_2 injection with 84 MM Ton injection.

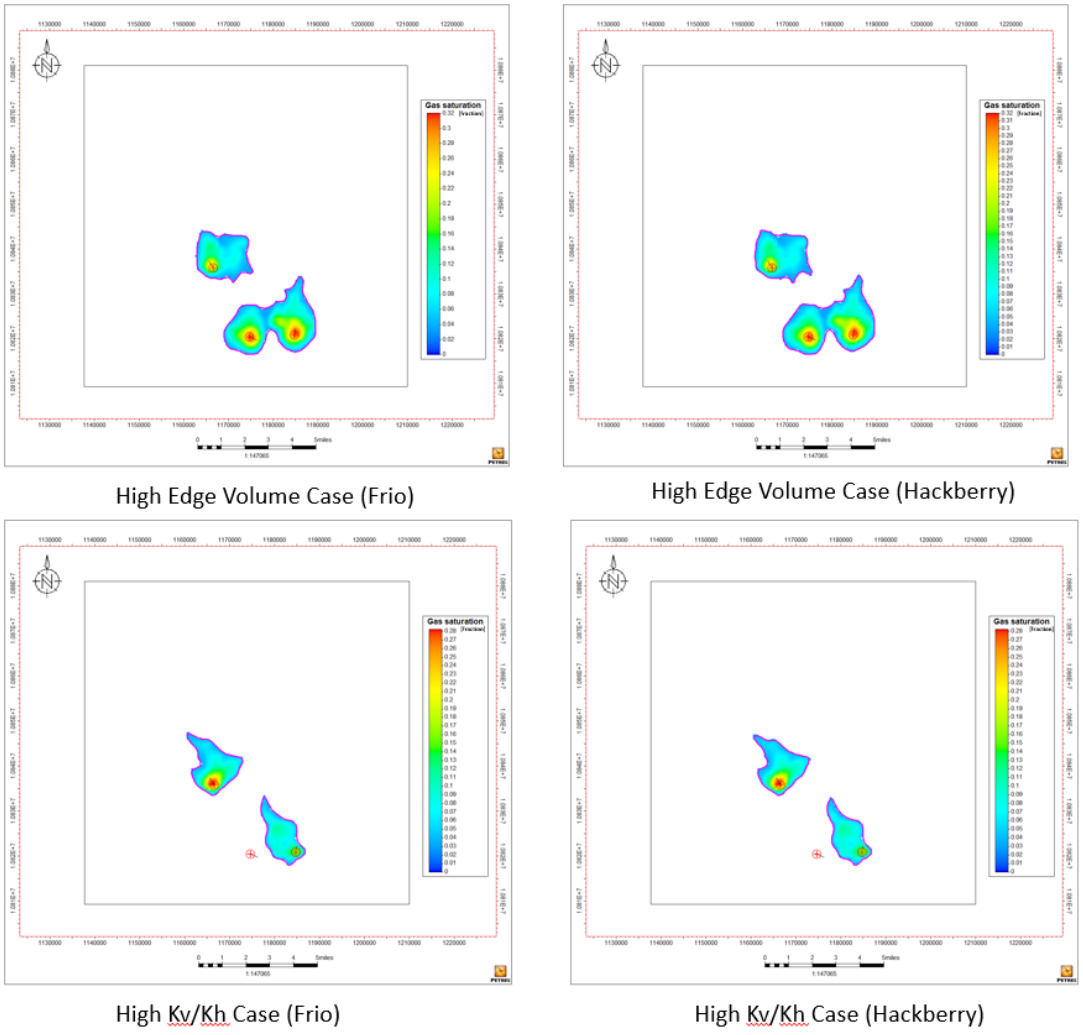


Figure AoR-257: Forecasted CO_2 saturation for high edge volume case and high Kv/Kh case.

4.10 Area of Review (AoR)

4.10.1 Critical pressure calculations

To delineate the critical pressure front, it is necessary to calculate the minimum pressure differential that can reverse flow direction between the lowermost USDW and injection zone, thereby, causing fluid flow from the injection zone into the USDW formation matrix. In other words, the pore pressure increase is high enough to overcome the hydraulic head of the fluid in a hypothetical wellbore and enter the USDW.

In the previous application, the Project team calculated the critical pressure threshold, ΔP_c, using Method 2 provided in the EPA May 2013 Program Class VI Well Area of Review and Corrective Action Evaluation Guidance (EPA, 2013). Method 2 was developed and published by Nicot et al. (2008), that assumes the critical pressure threshold (ΔPc) in the injection zone is given by Equation 8:

$$\Delta P_c = ½ * g * \xi * (z_u - z_i)^2 \quad \text{..... (Equation 8)}$$

where:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \quad \text{..... (Equation 9)}$$

This method, also called uniform density approach, estimates a pressure differential that would displace fluid initially present in a hypothetical borehole into the lowermost USDW and is based on the following assumptions: (1) hydrostatic conditions; (2) initially linearly varying densities in the borehole and constant density once the injection zone fluid is lifted to the top of the borehole; (3) brine from the injection formation will not equilibrate with the borehole surroundings; and (4) a constant density of the brine in the injection formation. In Nicot's paper, another approach is introduced assuming that fluid can reach thermal equilibrium with the surrounding rock (Equation 10). Whether using uniform density approach or the equilibrium approach, it is assumed that the wellbore is open and filled with brine.

$$\frac{\Delta P}{g} = (z_v - z_I)\left(\frac{\lambda - \xi}{2}(z_v - z_I) + \rho_{I,\lambda} - \rho_I\right) \quad \text{..... (Equation 10)}$$

However, after collecting and reviewing the site base data, in reality, the assumptions made in developing the uniform density approach are not valid for this site, rendering the derived formulas unacceptable. The existing formation fluids do not have a lineal behavior with depth, having considerable variation of salinity with depth as demonstrated during the water sampling in Encanto 01 stratigraphic well (see AoR and Corrective Action Attachment). The existing formations have hydrostatic pressure gradients slightly more than 0.433 psi/ft and the bottom sections of the injection targets are close to the transition zone for the overpressure section, as described in the AoR and Corrective Action Attachment. Lastly, the assumption that the wells are filled just with formation brine is not realistic since, at the very minimum, the wells are filled with native drilling mud.

As an alternative, the project evaluated different approaches used in permitting Class I wells and studies done by subject matter experts in hazardous and nonhazardous waste disposal, plugging

and abandonment of wells, and drilling fluid properties, amongst others. Studies such as Bump (2023), Johnston and Knape (1986), J.E Clark (2005), and others support the following methodology.

Claimed as PBI



The calculated critical pressure is defined as the pressure due to the mud column inside the wellbore and pressure needed to overcome the gel strength, subtracting the initial reservoir pressure (pre-injection). The project also added a 50 ft falloff of the mud level inside the wellbore as additional safety factor.

Claimed as PBI



$$\text{Critical Pressure} = MW \times 0.052 \times (TD_{perf} - 50) + GS - \nabla P_{Reservoir} \times TD_{perf} \quad \text{(Equation 11)}$$

$$\text{Gel Strength Pressure (GS)} = A \times \text{Gel Strength} \times L_{Hole} / D_{Hole} \quad \text{(Equation 12)}$$

MW: Mud weight (ppg)
TD_{perf}: Top of perforation depth (ft)
GS: Gel Strength Pressure (psi)
$\nabla P_{Reservoir}$: Reservoir Pressure Gradient (psi/ft)
A: Conversion factor (1/300)
Gel Strength (lbs/ft^2)
L_{Hole}: Length of the wellbore (ft)
D_{hole}: Diameter of the wellbore (inch)

Additional details and justification for the critical pressure calculation methodology are included in Appendix F of this application.

4.10.2 AoR delineation

4.10.2.1 Critical pressure front

The maximum differential pressure occurs at the maximum cumulative volume of CO_2 injection since the wells are operating at a constant injection rate. In the model, this occurs 15 years after injection commences for the Frio formation and 20 years after injection commences for the Hackberry formation. The movement of the pressure front was evaluated at 5, 10, 15, and 20 years after injection starts to find optimal locations for the in-zone monitoring wells. The forecasted

pressure increases in year 15 (Frio) and 20 (Hackberry) after injection are shown in Figures AoR-258 and AoR-259, respectively. A critical pressure front of 172.3 psi for the Frio and 157.9 psi for the Hackberry is projected onto the 2D areal map.

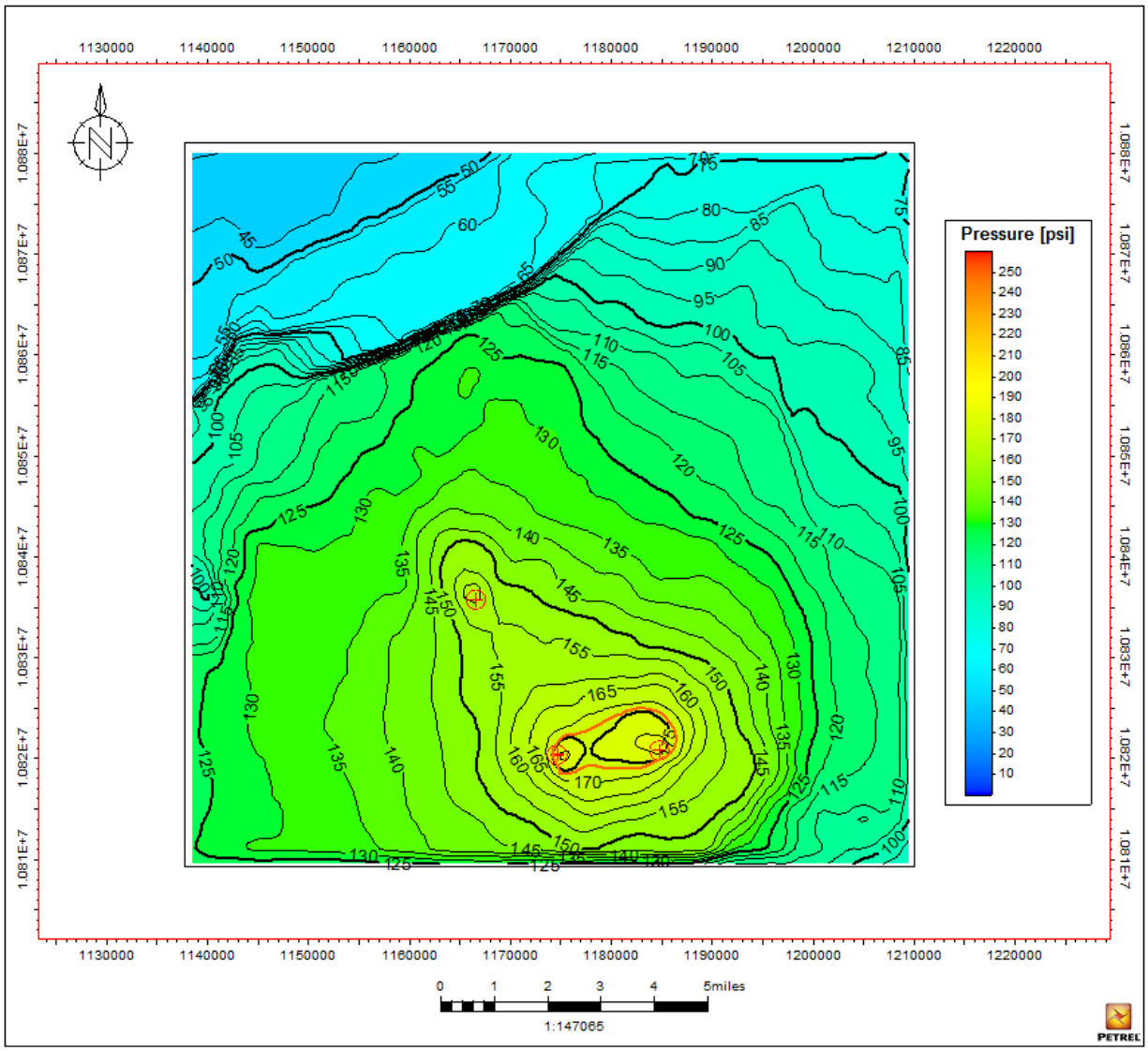


Figure AoR-258: View of highest pore-pressure increases after 65.3 million MT of total CO_2 injection in Frio for 15 years. Values displayed are pore-volume-weighted averages across the injection interval. The orange polygon is the pressure front for Frio Formation.

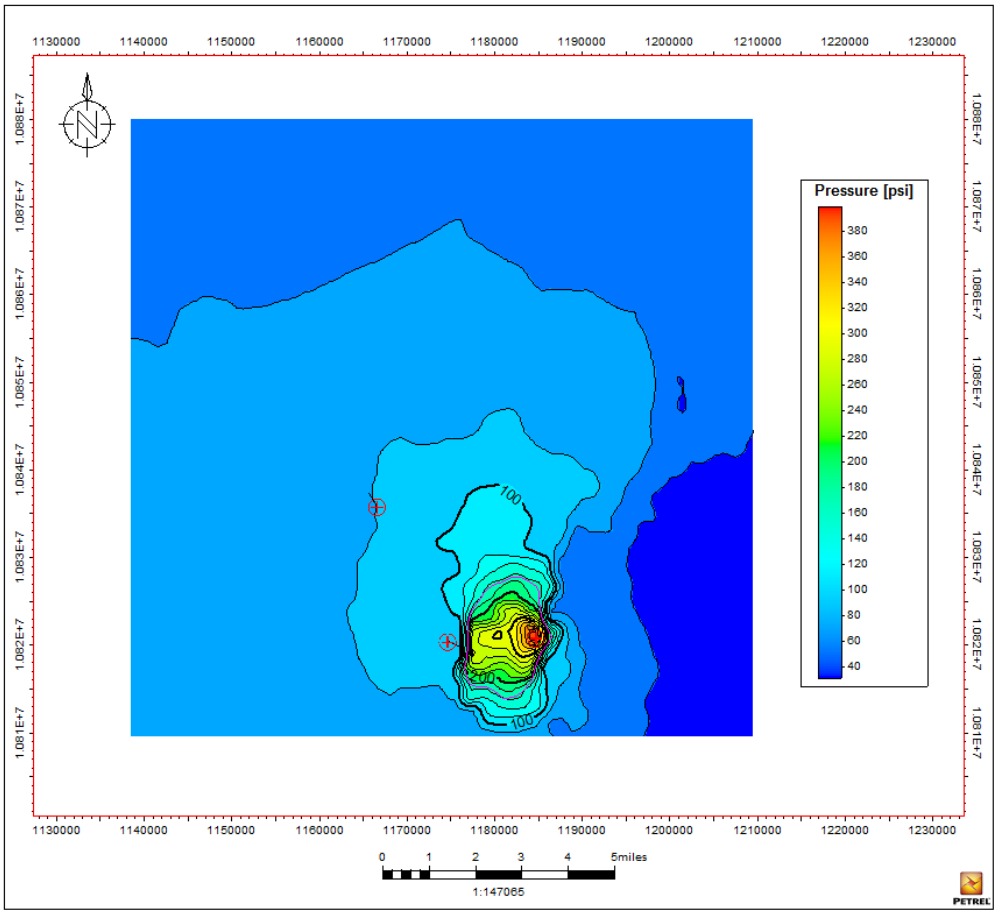


Figure AoR-259: View of highest pore-pressure increases after 13.7 million MT of total CO_2 injection in Hackberry for 20 years. Values displayed are pore-volume-weighted averages across the injection interval. The purple polygon is the pressure front for Hackberry Formation.

4.10.2.2 CO_2 plume extent

The CO_2 plume extend was simulated assuming 20 years of injection as described in the previous section. The Project simulated 50 years post-injection as well as 100 years post-injection. Plume tends to stabilize before the 50 years of post-injection period; however, the Project defined the 100-year plume outline to delineate the maximum extend of the CO_2 plume in the AoR as a conservative approach. The Project used a cut off of [redacted] saturation as supported by the fluid substitution analysis provided in Section 7.

Figures AoR-260 and AoR-261 show CO_2 distribution at 100 years after injector shut-in in Frio and Hackberry, respectively. The highest CO_2 saturation is around the wellbore and has moved up dip with time. Figures AoR-262 and AoR-263 display the top view of CO_2 plume extents at 5, 10, 15, and 20 years (during injection) and 50 and 100 years after injection is shut-in. Results suggested that CO_2 plume extents can be retained within the AoR and migration of CO_2 plume from 50 to 100 years is predicted to be minimal.

Figure AoR-264, Figure AoR-265, and Figure AoR-266 show the simulated CO_2 saturations along a north-south cross section through Bluebonnet CCS 1, CCS 2, and CCS 3 wells in year 20 after injection. The figure displays a desirable uniform CO_2 profile within the injection zone, effectively utilizing all intervals in the project's pore spaces. In the modeling exercises, such a profile has been achieved by employing the staged completions bottom up.

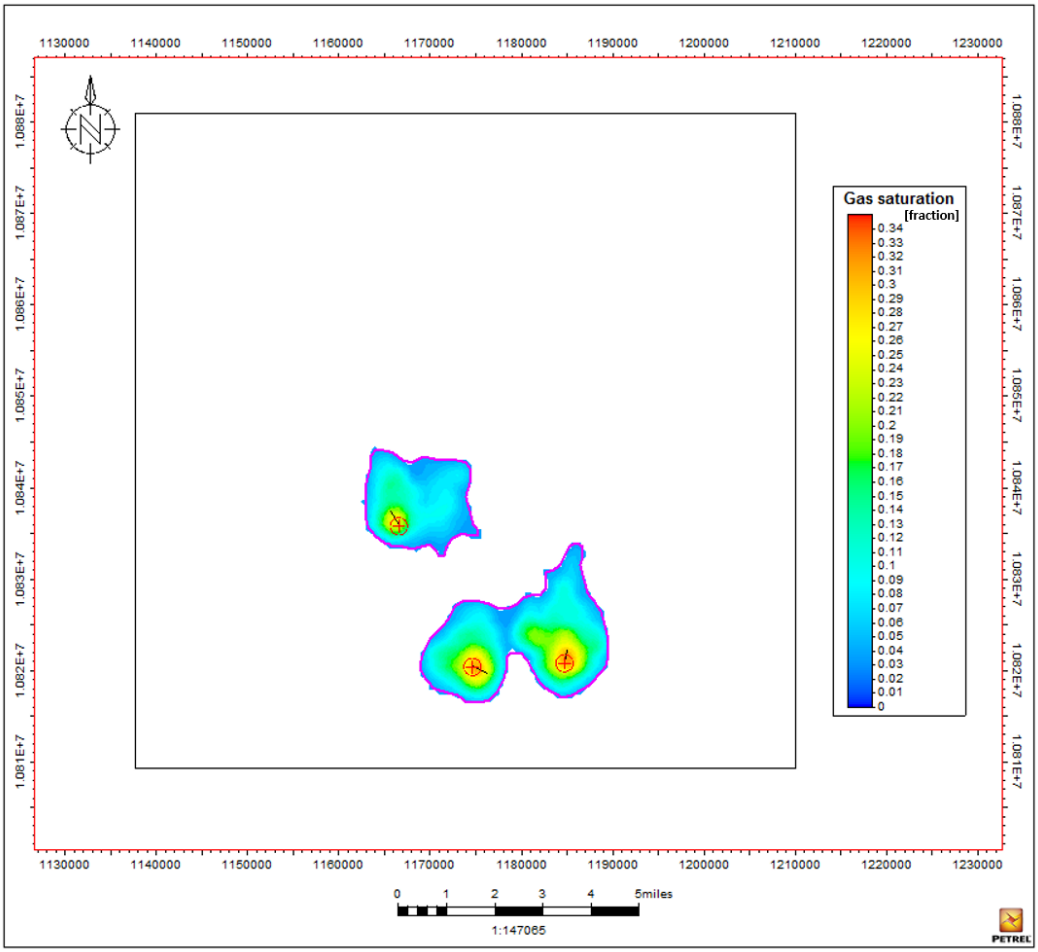


Figure AoR-260: Pore volume weighted CO_2 saturation map distribution after 70.3 million MT CO_2 injection in Frio.

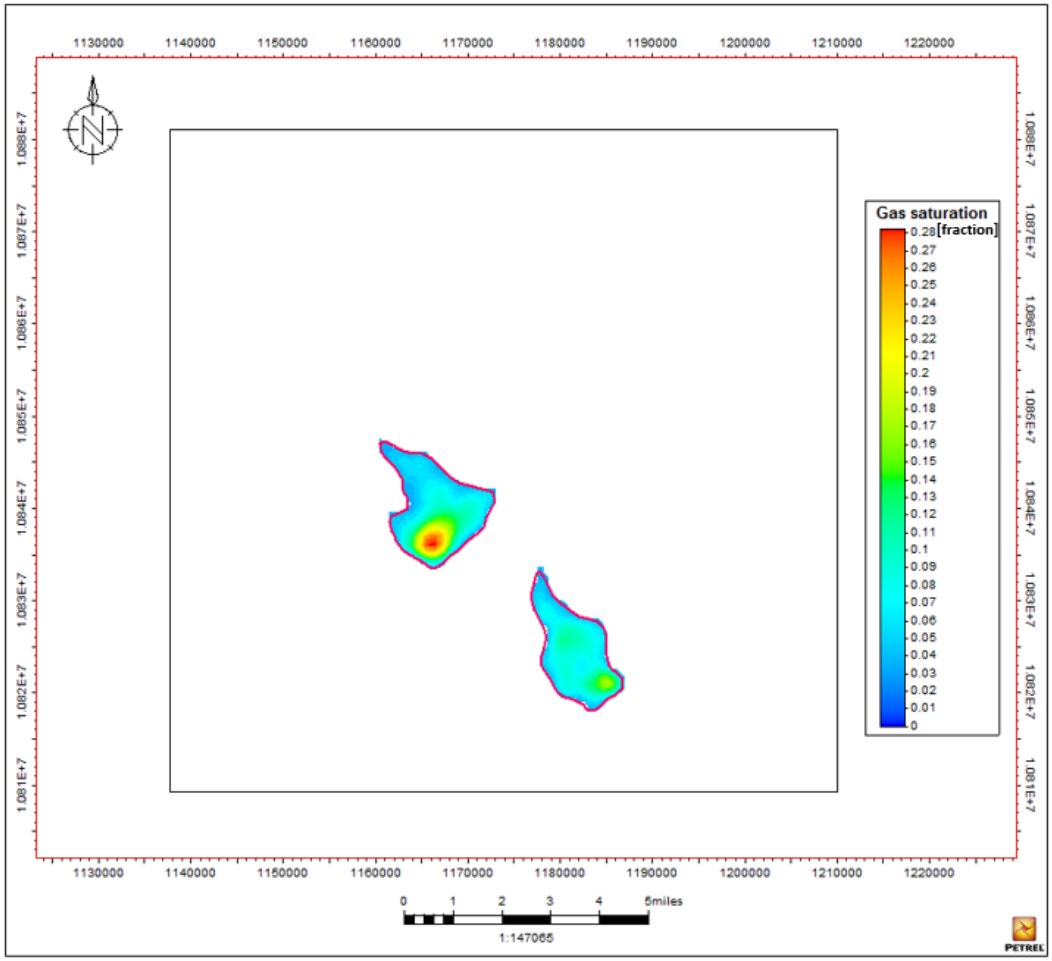


Figure AoR-261: Pore volume weighted CO_2 saturation map distribution after 13.7 million MT CO_2 injection in Hackberry.



Figure
(oran

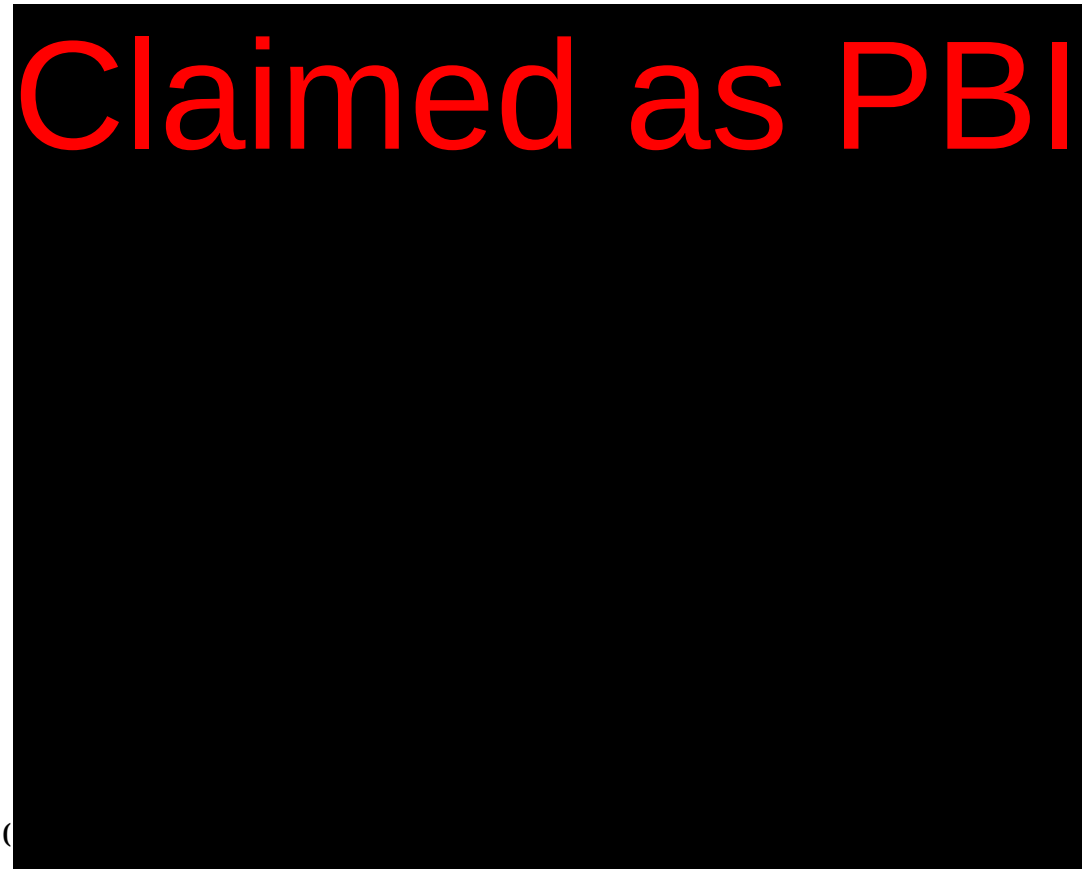


**Figure AoR-263:
(orange), 15 year (**

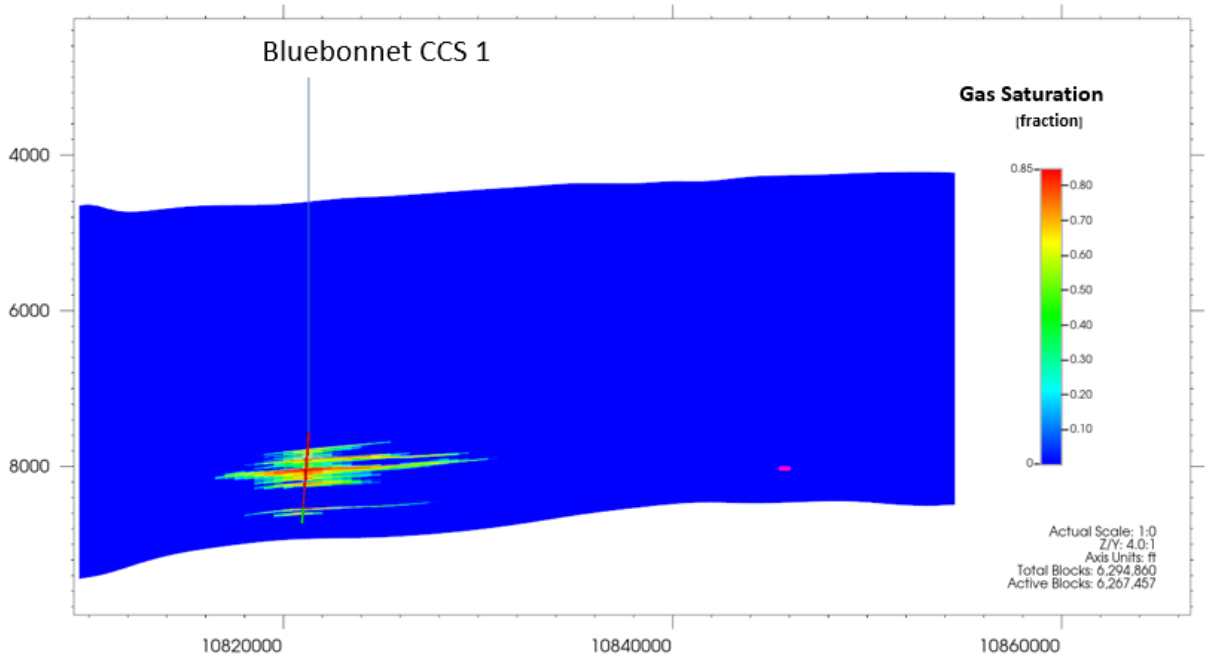


Figure AoR-264: North-south cross section through well CCS 1 showing simulated CO_2 saturation at year 20 after injection starts.

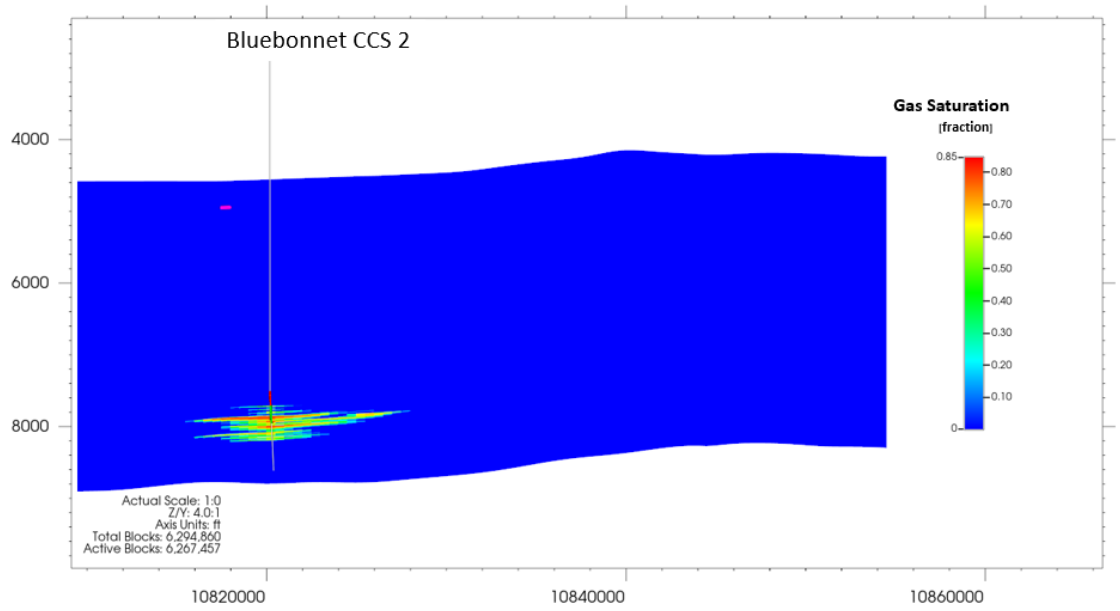


Figure AoR-265: North-south cross section through well CCS 2 showing simulated CO_2 saturation at year 20 after injection starts.

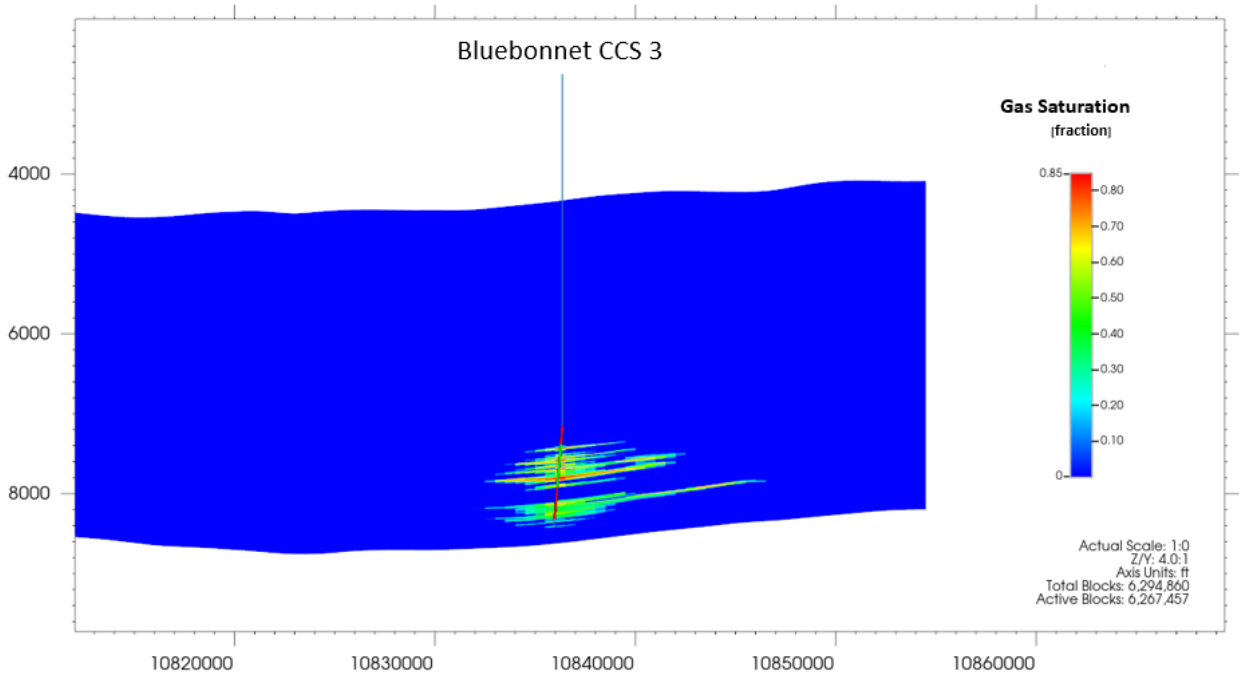


Figure AoR-266: North-south cross section through well CCS 3 showing simulated CO_2 saturation at year 20 after injection starts.

4.11 Geochemical Modeling

4.11.1 Background and Literature Review

The main reactive-transport pathways in clastic reservoirs for CCS projects are (1) carbonic gas dissolution in in-situ brine, (2) carbonic acid increase, (3) mineral dissolution and precipitation that could result, and (4) overall net CO_2 mineralization for long-term storage. The dissolution or precipitation of the mineral can alter the porosity and permeability of the reservoir rock, affecting sequestration storage capacity, well injectivity, and integrity of confining zones. For the Bluebonnet Sequestration Project, quartz is the dominant mineral in the Frio and Hackberry Injection Zones and a mixture of quartz and clays are the dominate minerals in the Anahuac Confining Zone. Oxy's operational experience in CO_2 injection in subsurface reservoirs has shown that the effect of reactive transport on reservoir performance is usually insignificant. However, a geochemical and reactive-transport literature review was performed to evaluate the lessons learned from previous projects and current on-site available data.

In October 2004, a CO_2 pilot was conducted by GCCC in the Frio sand formation, same as one of the target injection zones for this project. This pilot was later named Frio-I. A small quantity was injected, about 1,600 tons of CO_2, for about 10 days. Various post-injection measurements were acquired to evaluate the short-term geochemical impact such as injection and monitoring wells for fluid sampling, saturation logs, and pressure data collection. Publications showed attempts to interpret the observed results in relation to reactive-transport modeling and the main findings are described in the following paragraphs.

Hovorka et al. (2006) provided a comprehensive overview of the Frio-I pilot program executed with details on the experimental design, reservoir characterization, well construction, injection and hydrogeological testing, seismic profiling, well logging, tracer tests, fluid sampling, modeling, and monitoring. Regarding geochemical analysis, fluid sampling, modeling, and monitoring are the most important. With fluid sampling, the authors reported issues in degassing effect and temperature changes that might have affected the data significantly. In-situ brine showed high TDS content, close to 93,000 mg/L, and low CO_2 concentration. After a few hours of injection, the collected fluid samples from monitoring showed a sharp drop in pH, from about 6.7 to 5.8, and a large increase in CO_2, bicarbonate, iron, calcium, and magnesium concentrations. After the injection period, the pH showed a tendency to increase steadily. Modeling showed acceptable agreement between observed data and simulations.

Kharaka et al. (2006) corroborated with the findings provided by Hovorka et al. (2006), showing the same results for the fluid sampling and monitoring in Frio-I. However, the authors provided a more detailed interpretation of the results. The publication showed that pH is the most sensitive parameter to track CO_2 content in the subsurface. In addition, the authors mentioned that the pH modeled previously to the injection was about 3.0, much lower than observed. This larger pH was

attributed to the presence of carbonate minerals that would result in a buffer effect as expected from the CO_2-carbonate system equilibria, already pointed out by Hovorka et al. (2003) in a preliminary study.

Hovorka et al. (2009) reported the results of continued monitoring of the Frio-I pilot conducted in in 2004, and a second injection test, called Frio-II, conducted in 2006. The later test had the same experimental design as the Frio-I trial conducted in 2004. Similar geochemical results were obtained with the Frio-II pilot showing a sharp pH drop at CO_2 breakthrough and increase in alkalinity, iron, calcium, and magnesium. The authors discuss the limitations of modeling the increase on iron content since it was not predicted initially. It was attributed to three different causes: (1) combinations of various reactions, (2) dissolution of Fe-oxyhydroxides, and (3) corrosion of the tubing in contact with acidic environment. Kharaka et al. (2009) developed a more detailed chemical modeling on the possible dissolution of iron-bearing minerals using complex redox reactions. The authors concluded that no leakage was observed from the Frio sand to the Anahuac shale formation. Both publications could not determine the origin of increased iron content at that time, keeping the corrosion from pipes a reasonable possibility.

Xu et al. (2010) conducted a reactive-transport modeling study of the Frio-I pilot. The authors included detailed information on the kinetic parameters used such as reaction rates, reactive surface area, and activation energy for each selected reaction. The authors discussed the importance initial assessment with batch equilibrium reactions and combination of multiphase flow with geochemical reactions for improved results accuracy. Besides primary minerals that were present initially in the formation (e.g., quartz, kaolinite, calcite, illite, and oligoclase), the authors modeled secondary minerals that could precipitate from complex chemical reactions, such as magnesite, dolomite, smectite, and others. The publication had a special focus on modeling the unusual iron concentration increase in the monitoring wells, assuming that pipe corrosion is not a determinant factor. The long-term simulation results indicate rapid carbonate mineral dissolution followed by its reprecipitation, including kaolinite and illite precipitation. Other secondary minerals were considered stable.

The data results and interpretations provided by the authors in the previous publications is not meant to be an exact behavior expected for the current project, but a reference on which type of chemical reactions could occur when CO_2 contacts the Frio formation. It is important to highlight that the brine and mineral composition provided in the publications differ from the ones collected at the Encanto 01 stratigraphic well for this project. One of the most probable reasons is that the pilot tests were conducted closer to a salt dome, while the current study is performed for a different region and depth of the reservoir. In addition to literature and Oxy's experience in CO_2 injection at various formations, the Bluebonnet technical team conducted geochemical equilibrium and reactive-transport simulation modeling to evaluate site specific data acquired from the Encanto 01 stratigraphic well. The study is separated in two steps: first batch reactions with detailed

geochemical equilibrium simulations performed followed by reactive-transport, and the multiphase flow simulations are then conducted using the full-field model.

4.11.2 Geochemical Equilibrium Simulations

Geochemical equilibrium modeling was conducted using PHREEQC Simulator Version 3 (Parkhurst and Appelo, 2013), a program developed by the USGS, that includes a robust thermodynamic database for aqueous, mineral, and gaseous interactions (Krupka et al. 2010). PHREEQC includes the Peng-Robinson equation of state to improve the solubility calculation of gas at high pressures, which is important to consider when studying CO_2 sequestration in saline aquifers.

The objective of this work is to identify primary chemical reactions (solid and aqueous phase) to be included into the reactive-transport simulations and provide initial assessment of the CO_2 compatibility with rocks and fluids in the Frio and Hackberry Injection Zones and Anahuac Confining Zone. The modeling includes brines speciation, geochemical baseline prior injection, and CO_2 interaction with reservoir brine and minerals.

Table AoR-38 shows the brine composition used in geochemical simulations (See Appendix A: Stratigraphic Well Summary for full geochemical results). At the time of geochemical and reactive-transport modeling, the Miocene formation brine was used as reference because the Frio Injection Zone water analysis was only available closer to the application submission date. A comparison between each water composition is performed at the end of the Geochemical Modeling section. Other ions were not considered in modeling because their concentration is negligible or below detection limits. Trace metals (i.e., arsenic, mercury, and lead) have insignificant concentration values and were not tracked during modeling.

Table AoR-39 summarizes the rock mineralogy used during geochemical equilibrium runs for the Frio Injection Zone, Hackberry Injection Zone, and Anahuac Confining Zone. The normalized values were obtained from the average of the five closest depth samples reported in the XRD data (See Appendix A: Stratigraphic Well Summary for XRD results).

Table AoR-38: Water composition and brine properties for geochemical and reactive-transport simulations.

Ion (mg/L)		Brine sample
Calcium	Ca^{2+}	Claimed as PBI
Magnesium	Mg^{2+}	
Potassium	K^{+}	
Sodium	Na^{+}	
Barium	Ba^{2+}	
Iron	Fe^{2+}	
Silicon	Si^{4+}	

Ion (mg/L)		Brine sample
Strontium	Sr^{2+}	Claimed as PBI
Bicarbonate (alkalinity)	HCO_3^-	
Chloride	Cl^-	
Sulfate	SO_4^{2-}	
Borate	$B(OH)_4^-$	
Bromide	Br^-	
pH (lab)		
Total dissolved solids		

Table AoR-39: Rock mineralogy retrieved from average XRD data for the five closest core samples.

Mineral (mol %)	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
Quartz	Claimed as PBI		
K-Feldspar			
Plagioclase			
Anatase			
Calcite			
Siderite			
Pyrite			
Smectite			
Illite			
Kaolinite			
Chlorite			

Although some chemical reactions are known to be time-dependent, the equilibrium assumption was selected at this stage because it is the most conservative approach. In this method, minerals can dissolve or precipitate instantaneously and achieve the final stage of interaction with other solid phase and aqueous species. Thus, this process can simulate the long-term exposure and mimic permanent CO_2 storage. For reactive-transport simulations, kinetics approach is assumed and further details are presented in Section 12.3.

Geochemical simulations were performed to equilibrate each sample with its respective reservoir mineralogy and in-situ CO_2 concentration to simulate conditions prior to the injection period and establish the baseline condition. Table AoR-40 shows the results for the Hackberry Injection Zone, Frio Injection Zone, and Anahuac Confining Zone, respectively. For equilibrium simulations, a rock with porosity equal to 10% is assumed. The initial CO_2 concentration in the reservoir was

retrieved using flashed gas composition and fugacity was calculated using PHREEQC based on Peng-Robinson model at reservoir pressure and temperature. The fugacity calculated is -0.07 atm.

The PHREEQC database file was selected as the thermodynamic data and activity coefficient model for equilibrium and reactive-transport simulations. Although Pitzer virial model is known to be more suitable for brines with high ionic strength (above 1.0 M) at certain conditions, the extended Debye-Hückel equation is determined to be suitable for the brines analyzed for this site. Besides the ion-size parameters, the extended terms based on ionic strength have been fit for the main ions in chloride-dominated waters such as calcium, magnesium, sulfate, potassium, and carbonate species (Truesdell and Jones 1974). In addition, the Pitzer approach has limited parametrization for iron and aluminum species as pointed out by Krupka et al. (2010). These aqueous components are very important for brines in equilibrium with clay-type minerals because they modify the ions' activity, having a critical impact on mineral solubility product (Appelo and Postma 2005).

Secondary mineral phases were included in the simulation even though they are not present in measured XRD data (i.e., dolomite, hematite, goethite, anhydrite, gypsum, k-mica, barite, strontianite, celestite, and magnesite) to evaluate their precipitation tendency. In addition, plagioclase is assumed to be anorthite phase. Since the reservoir is assumed to be initially in equilibrium, saturation indexes were slightly adjusted (from database equilibrium constant value, Ksp) to avoid large mineral dissolution or precipitation and honor measured brine composition and XRD data. Positive and negative saturation index numbers (ΔSI) indicate changes to more supersaturated or undersaturated conditions in relation to a mineral, respectively.

Table AoR-40: Adjusted saturation indexes and pH for the Hackberry and Frio Injection Zones and the Anahuac Confining Zones prior to CO_2 injection (baseline reservoir condition).

Mineral ΔSI (adjusted)	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
Quartz	Claimed as PBI		
K-Feldspar			
Plagioclase			
Anatase			
Calcite			
Siderite			
Pyrite			
Smectite			
Illite			
Kaolinite			
Chlorite			
pH			

Quartz, siderite, smectite, dolomite, hematite, goethite, anhydrite, gypsum, k-mica, barite, strontianite, celestite, and magnesite were considered stable phases without precipitation tendencies. As expected, all brine samples are in close equilibrium conditions with their respective minerals and initial CO_2 in the reservoir. Kaolinite is the phase that requires the largest changes in saturation index caused by negligible concentrations of aluminum in the formation brine. Quartz and smectite are the most stable phases initially present in the reservoir.

The calculated pH from simulations is noticeable smaller in comparison to the laboratory-measured values, due to the degassing effect from depressurization when the samples are open to atmospheric conditions for analysis. Even with the quickest analysis in the laboratory after the chamber has been open, CO_2 is quickly released to atmosphere, decreasing its amount dissolved in water and shifting the equilibria to more a basic condition (Appelo and Postma, 2005, page 14). In addition, the calculated pH has similar values as reported by other publications (Kharaka et al. 2009 and Xu et al. 2010)

The same shift in saturation index found in previous simulations was used to equilibrate the brines and minerals with fully saturated CO_2 gas to represent the injection period. CO_2 fugacity was assumed to be 1.78 for 100% CO_2 gas at reservoir temperature and pressure. Table AoR-41 shows the mineral stability tendency after equilibration for each sample in the Hackberry Injection Zone, Frio Injection Zone, and Anahuac Confining Zone. Delta minerals (Δ Mineral) represent the qualitative analysis of the solid to dissolve, precipitate, or be stable based on the mineral mass reduction, increase, or maintenance after equilibration with CO_2, respectively.

Precipitation or dissolution was negligible or not observed for quartz, siderite, smectite, hematite, goethite, dolomite, anhydrite, gypsum, k-mica, barite, strontianite, celestite, and magnesite. Quartz and smectite are the most stable phases initially present in the reservoir. For the Hackberry and Frio Injection Zones, simulation results show plagioclase (anorthite) dissolution as larger amounts of CO_2 dissolved in water shifts the equilibria to a more acidic environment. In addition, a substitution process occurs by precipitation of calcite and kaolinite. However, the dynamics in the reservoir during injection are more complicated as reactions are time-dependent and calcite might dissolve first at a lower pH, then reprecipitate at later times (equilibrium conditions). The Anahuac Confining Zone shows smaller reactivity as clay content increases.

The Anahuac Confining Zone shows lowest reactivity in comparison to the other formations, corroborating the assumption that CO_2 will not affect the Anahuac Confining Zone integrity as pointed out by Kharaka et al. (2009). It is important to highlight that further precipitation might provide a healing effect to microfracture that might have been formed due pressure increase (i.e., mechanical deformation), as proposed by Hangx et al. (2009), improving the Anahuac Confining Zone long-term integrity.

Table AoR-41: Mineral stability tendency, pH, and overall molar change for Hackberry and Frio Injection and Anahuac Confining Zones in equilibrium with fully saturated CO_2.

Δ Mineral	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
K-Feldspar	Claimed as PBI		
Plagioclase			
Calcite			
Illite			
Kaolinite			
pH			
Overall change (mol)			

Thus, the most important mineral reactions with CO_2 identified for the injection are the solubility equilibria for calcite, plagioclase, and kaolinite. Minor changes are observed for quartz, k-feldspar, and illite, and are included in the reactive-transport simulations since previous publications pointed out their possible reactivity when using the kinetics approach.

4.11.3 Reactive-Transport Simulations

The reactive-transport simulations were conducted using CMG-GEM. The objective of this section is to evaluate geochemical impact on reservoir storage capacity, possible injectivity modification, and long-term trapping mechanisms. The same activity model is used (extended Debye-Hückel equation) to be consistent with geochemical equilibrium simulations. Quartz, calcite, plagioclase (anorthite), kaolinite, k-feldspar, and illite are the minerals considered during the dynamic simulations. The minerals present in the XRD results as nonreactive are not included in the simulations (e.g. anatase, pyrite, and chlorite) and are lumped with the quartz phase. Figure AoR-267 illustrates a vertical cross section for different mineralogy regions based on each formation depth. Table AoR-42 shows the mineral volume fraction based on the normalized average XRD data for each region.

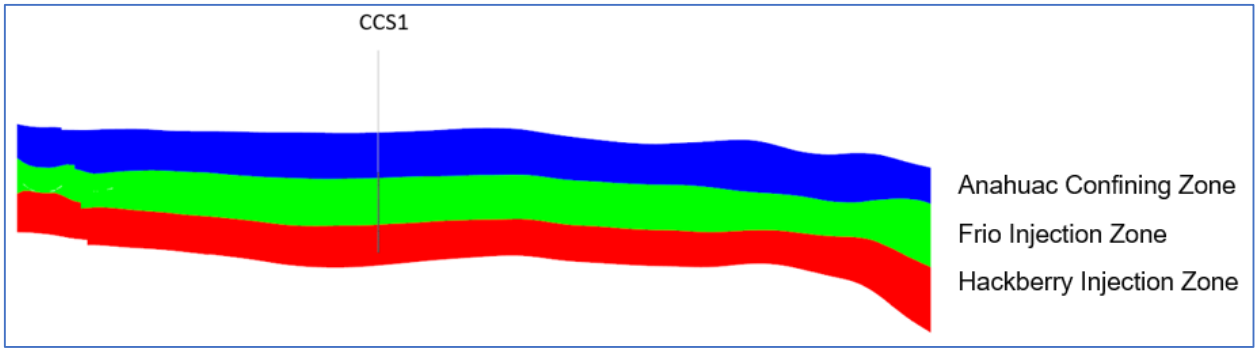


Figure AoR-267: Cross section schematic of the simulation model showing the different lithology zones based on lithology logs.

Table AoR-42: Mineral volume fraction used to initialize the reactive-transport simulation model per lithology region.

Mineral (volume %)	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
Quartz	Claimed as PBI		
Calcite			
Kaolinite			
Plagioclase			
K-feldspar			
Illite			

Quartz, calcite, kaolinite, plagioclase, and illite mineral solubility reactions were simulated using the kinetics approach based on the transition state theory (TST). K-feldspar solubility reaction is simulated using the equilibrium approach because its reaction is assumed to be much faster than the fluid residence time in the reservoir compared to other minerals (Appelo and Postma, 2005, page 119). Activation energies, TST reaction rate constants, and equilibrium constants are retrieved from the literature (Palandri and Kharaka, 2004, Krupka et al. 2010, Jia et al. 2021, and Zhang et al. 2019). The mineral reactive surface area is considered one of the largest uncertainties for modeling kinetic reactions. Actual reactivity area values are assumed to be significantly lower in comparison to the conventional methods of surface area measurements (e.g., BET adsorption method) because certain pores are not expected to contact the injected fluid due to preferential flow paths in the porous media. For the current simulations, reactive surface area values were retrieved from Jia et al. (2021) and Zhang et al. (2019) and were multiplied by 0.01 as recommended by Xu et al. (2010). For practical purposes, the final state of mineral stability is insensitive to the reactive surface area (hundreds of years after injection). However, as reactive surface area value increases, the simulation will reach equilibrium faster. Thus, it allows the interpretation of how long-term CO_2 storage affects reservoir properties within a reasonable computational time.

The effect of mineral dissolution and precipitation on porosity is also included to evaluate its impact on reservoir storage capacity. The model is a direct correlation of the amount of mineral change (dissolution or precipitation) with the solid volume using its respective mineral mass, molar weight, and density to calculate the new void volume (porosity) over time. The effect of porosity changes in rock permeability is included to evaluate the effect of possible modification in well injectivity. Simulations use the modified Kozeny-Carman model (Equation 7), where the porosity exponent r is assumed to be equal to 3.0 and where k, Ø, and r represent permeability, porosity, and porosity exponent, respectively.

$$\frac{k_n}{k_k} = \left(\frac{\text{Ø}_\text{n}}{\text{Ø}_\text{k}}\right)^r \left(\frac{1-\text{Ø}_\text{k}}{1-\text{Ø}_\text{n}}\right)^2 \qquad \text{Equation 7}$$

The subscripts n and k represent the properties changes in previous and current timesteps, respectively.

The reservoir is initialized with the brine composition as shown in Table AoR-38. In total, 12 aqueous species were initialized in reservoir connate water and allowed to flow with aqueous phase in the reactive-transport simulations. The aqueous species modeled are $H_4SiO_4^0$, H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2^0, HCO_3^-, OH^-, CO_3^{2-}, and $CaOH^+$. The selection of the aqueous complexes was based on the simulation results from geochemical equilibrium runs (PHREEQC) with minerals and CO_2. Aqueous species that were not originally in the complete water analysis were assumed to have trace concentrations. The reservoir is allowed to equilibrate prior to the simulation start.

Figures AoR-268 and AoR-269 illustrate the aggregate of all layers in a top map view of the maximum pH and HCO_3- concentration values at end of the injection period (Year 20). Note that the pH values (initially equal to 7.5 and at saturated CO_2 equal to 5.8) are in similar ranges with the values simulated using PHREEQC (Tables 13 and 14). Bicarbonate concentration increases significantly, almost 21 times more than initial conditions, which aligns with results reported in previous publications and simulations using PHREEQC.

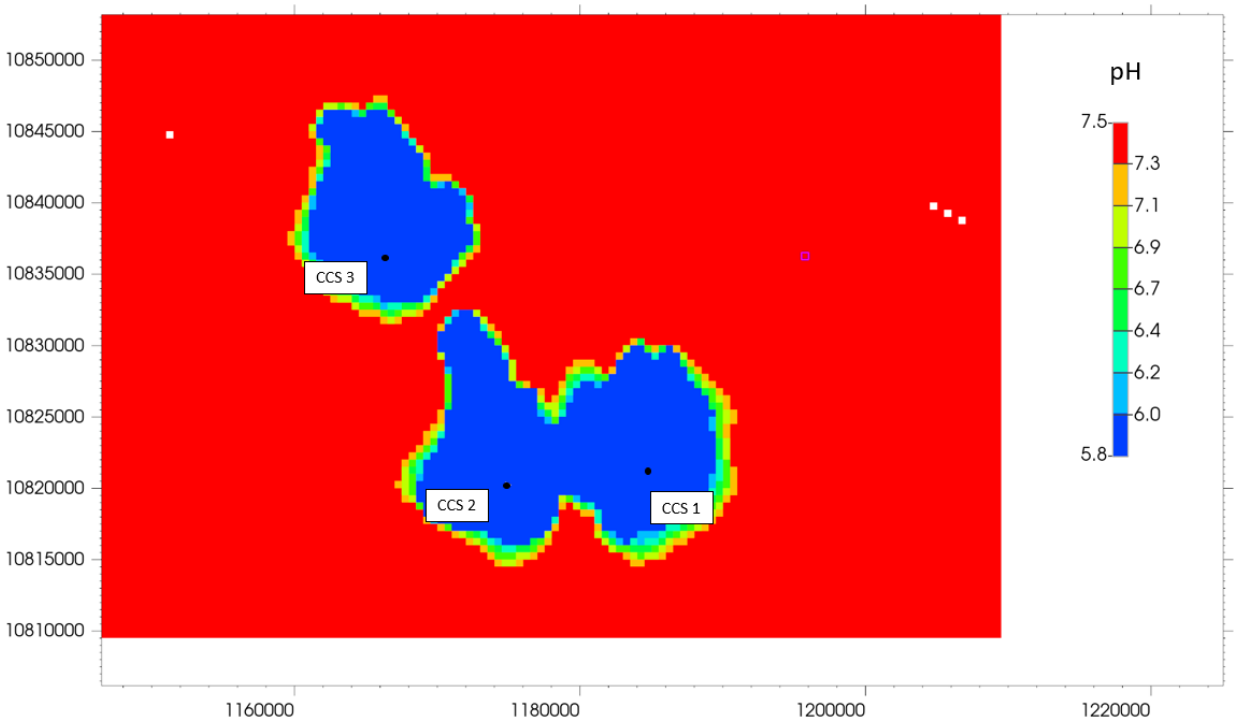


Figure AoR-268: pH map view of the layer with the largest CO_2 extension at the end of injection period (20 years).

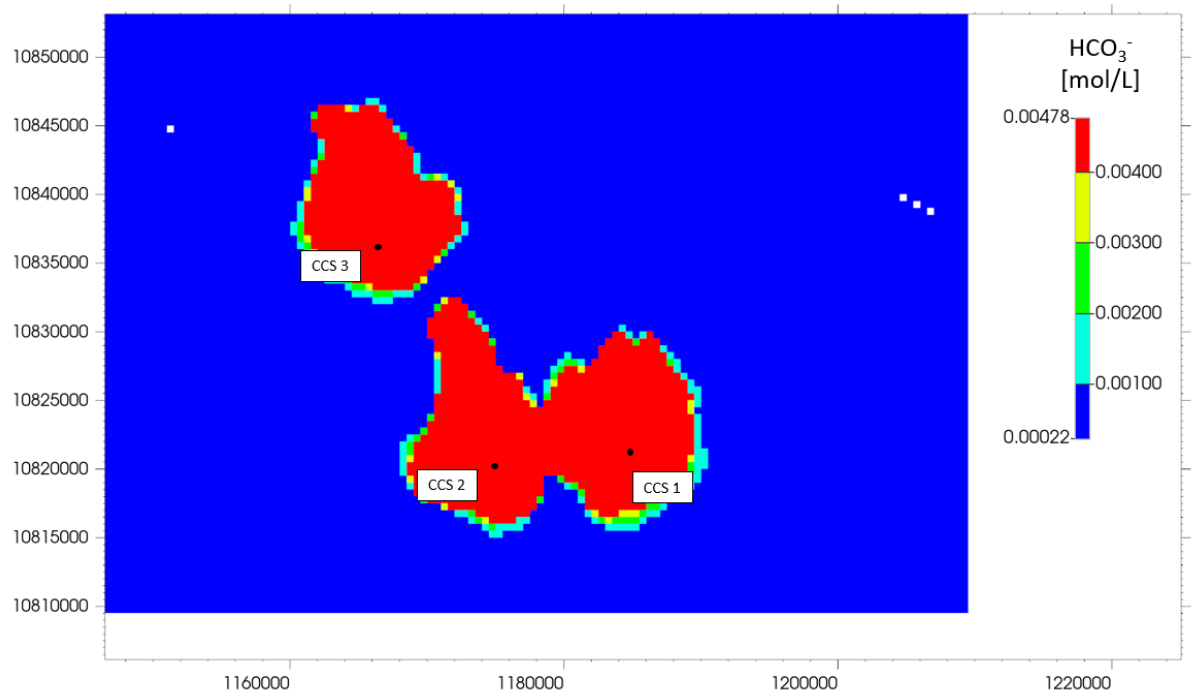


Figure AoR-269: HCO_3^- concentration (mol/L) map view of the layer with the largest CO_2 extension at the end of injection period (20 years).

Figures AoR-270 and AoR-271 show the reservoir mineral volume change for calcite, anorthite, kaolinite, illite, k-feldspar, and quartz at 100 and 1,000 years after injection time finished, respectively. For the injection period, a quick dissolution of calcite and anorthite with precipitation of kaolinite is observed. The initial dissolution of calcite is expected and has been reported in several previous publications (Xu et al. 2010, Hovorka et al. 2009). For longer periods of time, anorthite continues to dissolve while calcite starts to reprecipitate. Most of the total decrease in mineral volume is due to a solid change that occurs after the injection period. Kaolinite precipitates due to the release of aluminum from the anorthite mineral. Calcite starts to precipitate due to excess of calcium and bicarbonate as a result from the CO_2 injection (mineralization). Figure AoR-214 shows the increase of bicarbonate ion in relation to their initial value.

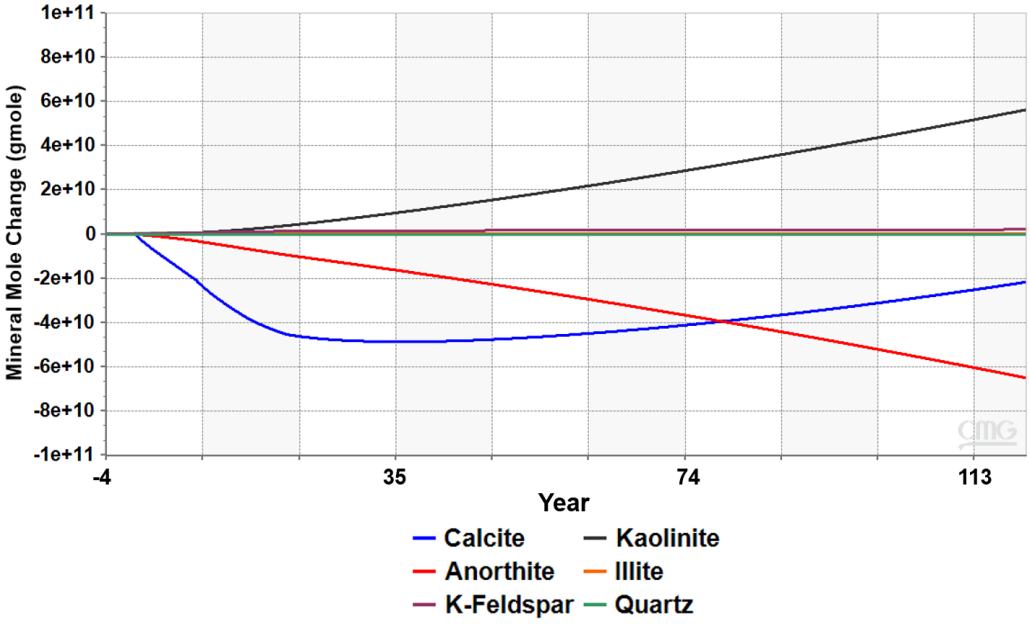


Figure AoR-270: Molar change over time in the reservoir for calcite, kaolinite, anorthite, illite, k-feldspar, and quartz for 100 years after the injection period.

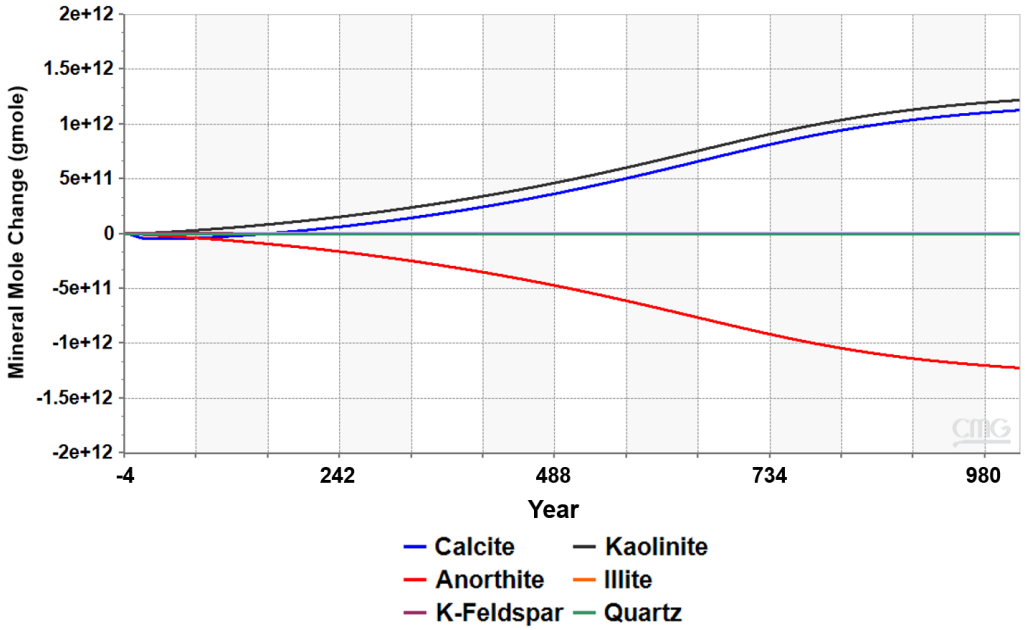


Figure AoR-271: Molar change over time in the reservoir for calcite, kaolinite, anorthite, illite, k-feldspar, and quartz up to 1,000 years after end of injection period.

Figures AoR-272, AoR-273, and AoR-274 show the aggregate of all layers in a top map view of the maximum porosity change due to dissolution/precipitation at end of the injection period as well as 100 and 1,000 years after the end of the injection period. Figures AoR-275, AoR-276, and AoR-277 show the north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation at end of the injection period as well as 100 and 1,000 years after the end of the injection period. Negative and positive values represent the amount of increase and decrease from the initial porosity, respectively. Porosity slightly increased with a maximum of 0.5% for the Frio and Hackberry Injection Zones from the start of injection up to about 100 years after injection. Porosity remained unchanged for the Anahuac Confining Zone. Since the Anahuac Confining Zone has a very low permeability and small fluid mobility, no significant changes are observed in the current model, confirming its integrity. The long-term decrease in porosity is due to calcite and kaolinite precipitation. A maximum decrease in porosity was about 3.5% in the region where the CO_2 plume contacted the reservoir. This represents less than 1% change in pore volume within the simulation domain.

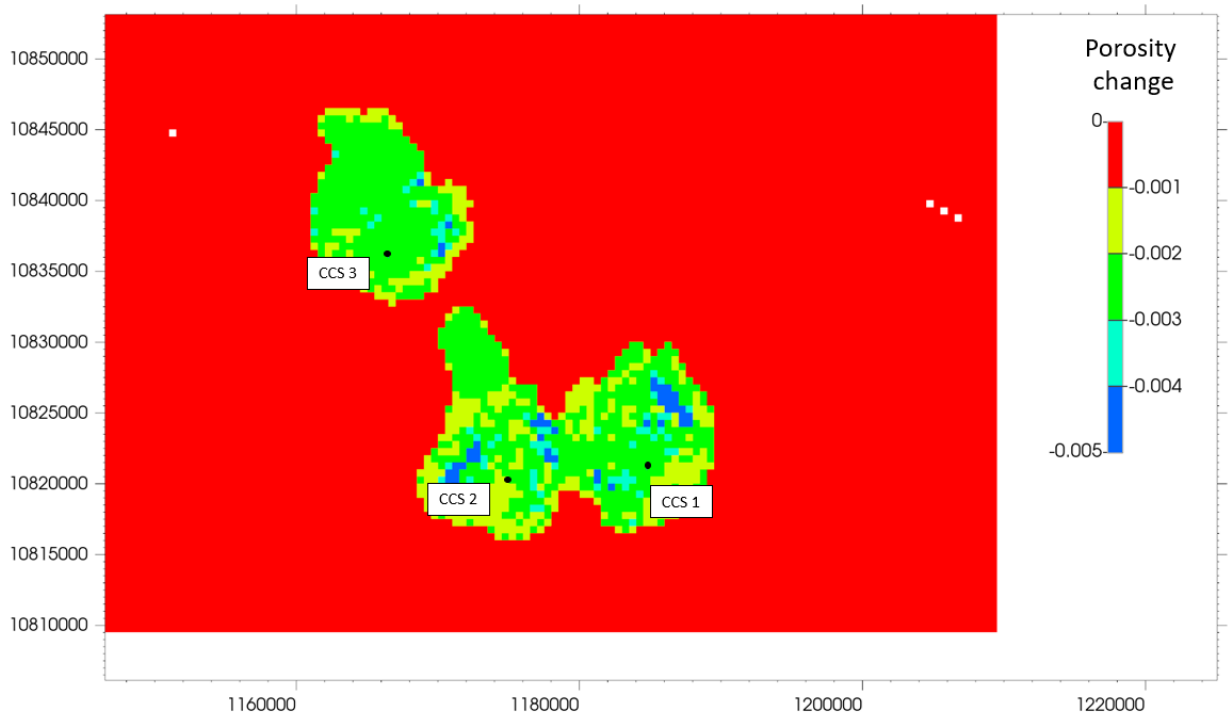


Figure AoR-272: Porosity change aggregate of all layers in a top map view at the end of injection period (20 years).

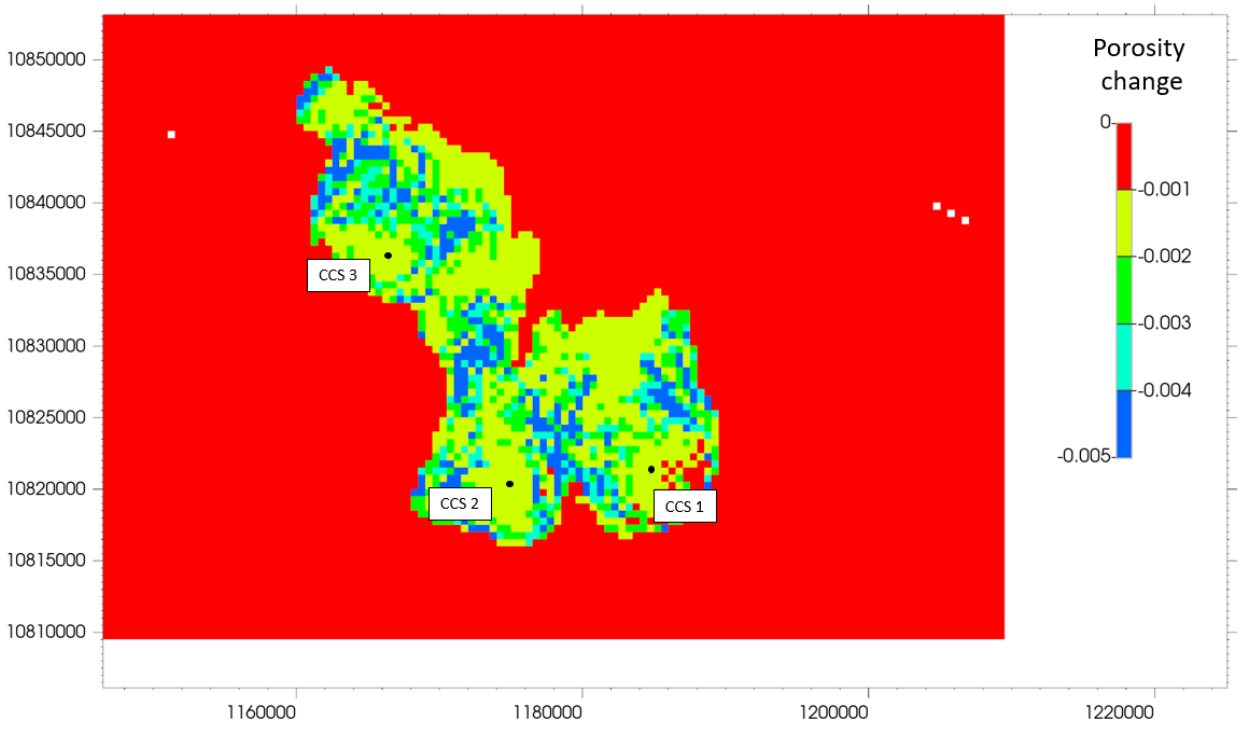


Figure AoR-273: Porosity change aggregate of all layers in a top map view after 100 years post injection.

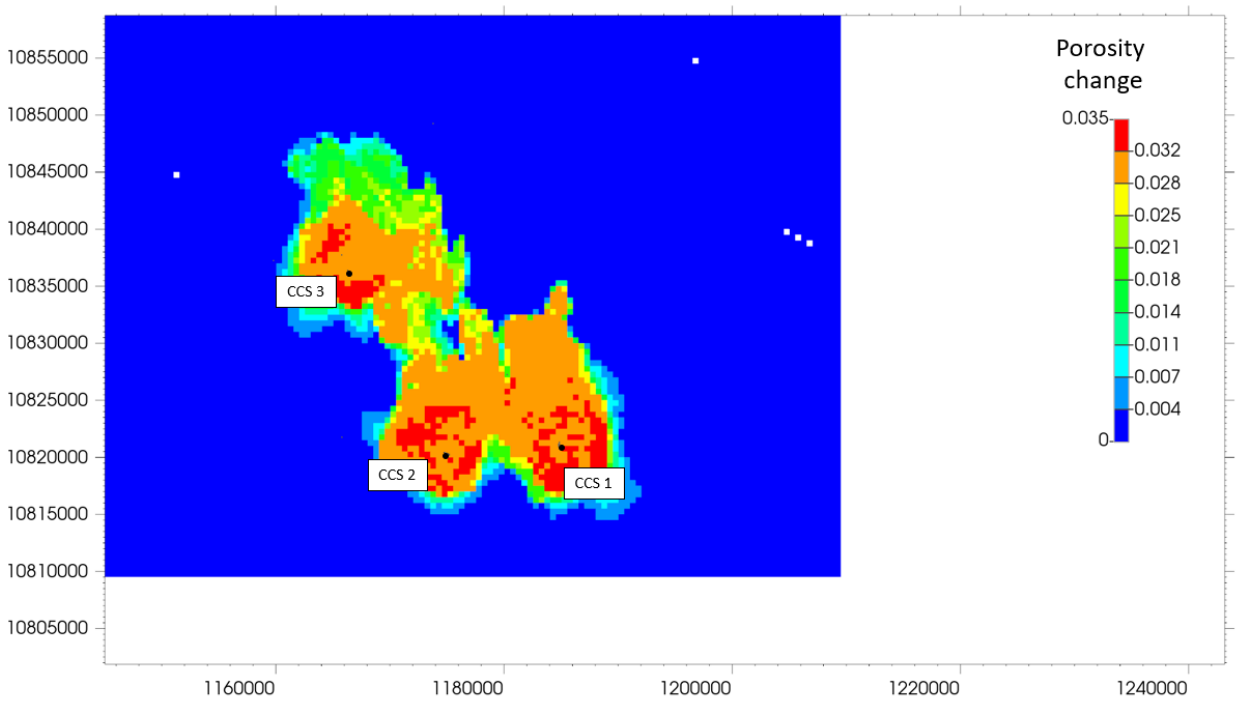


Figure AoR-274: Porosity change aggregate of all layers in a top map view after 1000 years post injection.

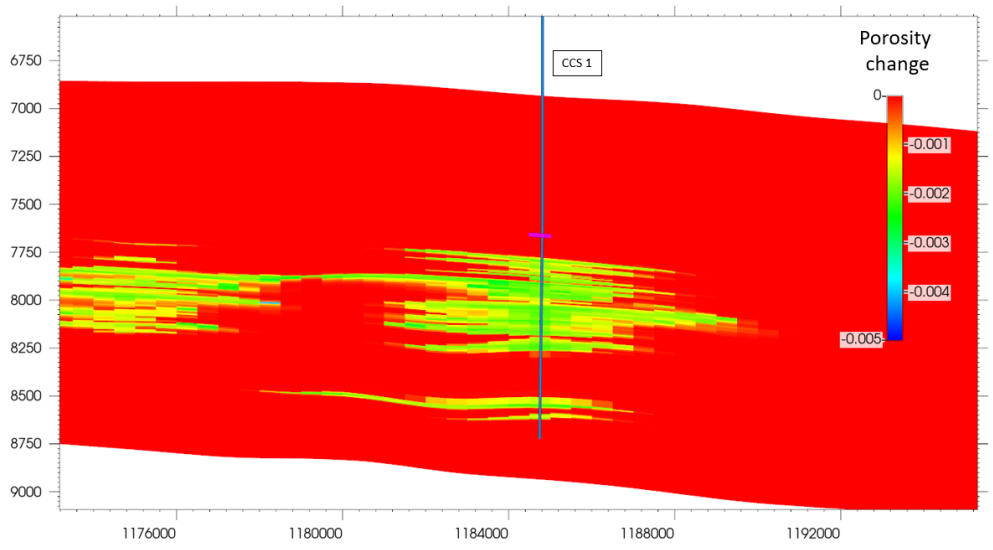


Figure AoR-275: The north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation at the end of the injection period (20 years). The highlighted grid block in pink the interface between the Frio Injection Zone and the Anahuac Confining Zone.

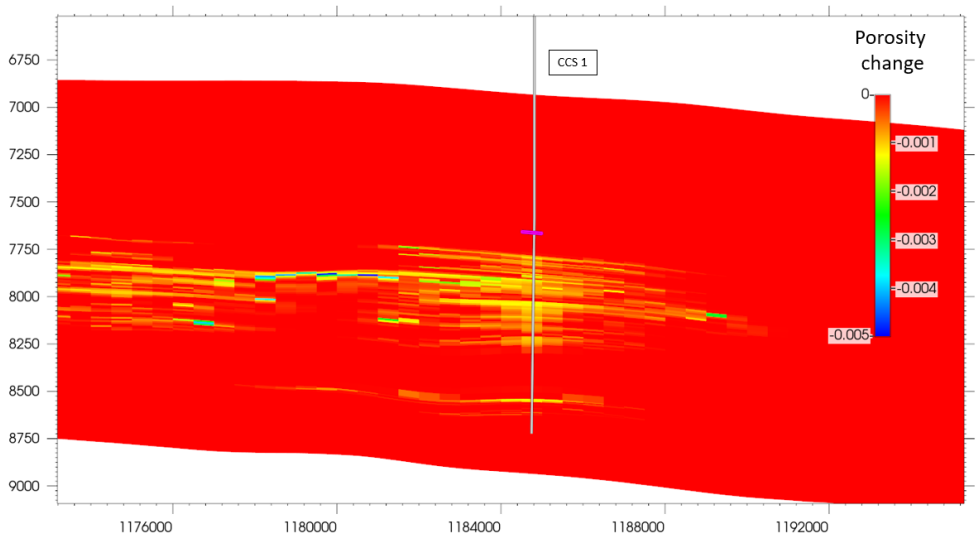


Figure AoR-276: The north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation after 100 years post injection. The highlighted grid block in pink shows the interface between the Frio Injection Zone and the Anahuac Confining Zone.

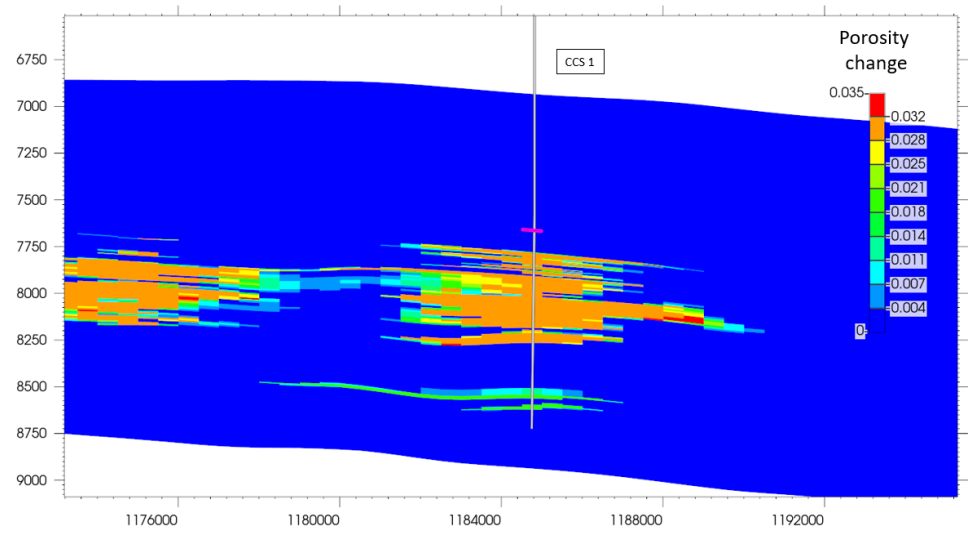


Figure AoR-277: The north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation after 1000 years post injection. The highlighted grid block in pink shows the interface between the Frio Injection Zone and the Anahuac Confining Zone.

Figures AoR-278 and AoR-279 show the aggregate of all layers in a top map view of the maximum CO_2 saturation to compare compositional simulation (without geochemistry) and reactive-transport simulation (with geochemistry) at the end of the injection period and 100 years after the injection period. The compositional simulation shows a larger plume in relation to the reactive-

transport runs. The reason the reactive-transport simulations have smaller CO_2 plumes, even with smaller pore volume, is due to part of the CO_2 being transferred from the super-critical state to two additional conditions that are not modeled using conventional runs: conversion in aqueous ions (e.g., HCO_3^-) and precipitation as solid phase (e.g., kaolinite, calcite). Thus, the compositional simulations (without geochemistry) provide the most conservative approach to estimate the CO_2 plume (largest extent).

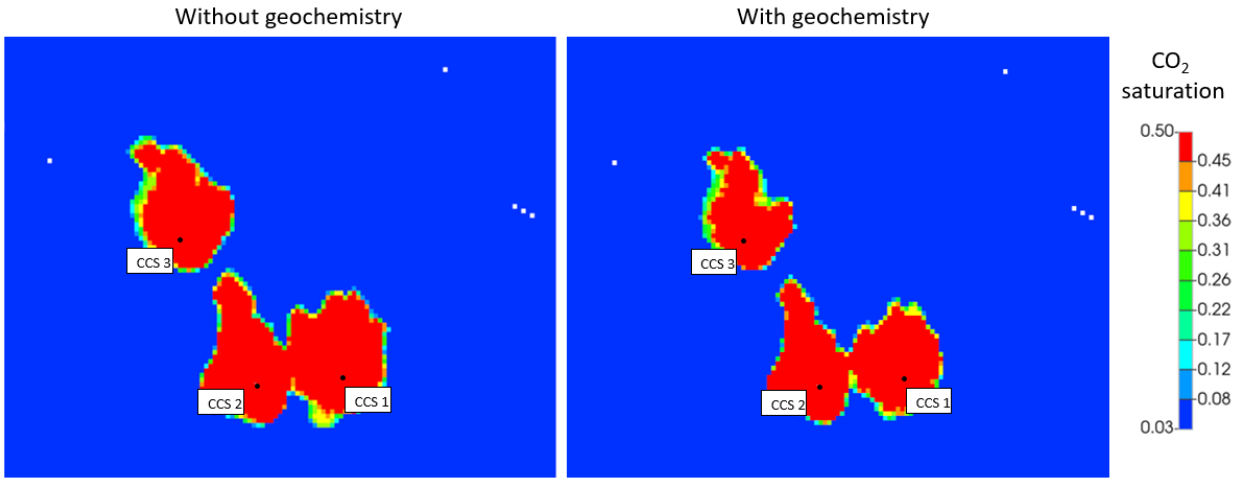


Figure AoR-278: The aggregate of all layers in a top map view of the maximum CO_2 saturation to compare simulations without and with geochemistry capability turned on at the end of injection period (20 years).

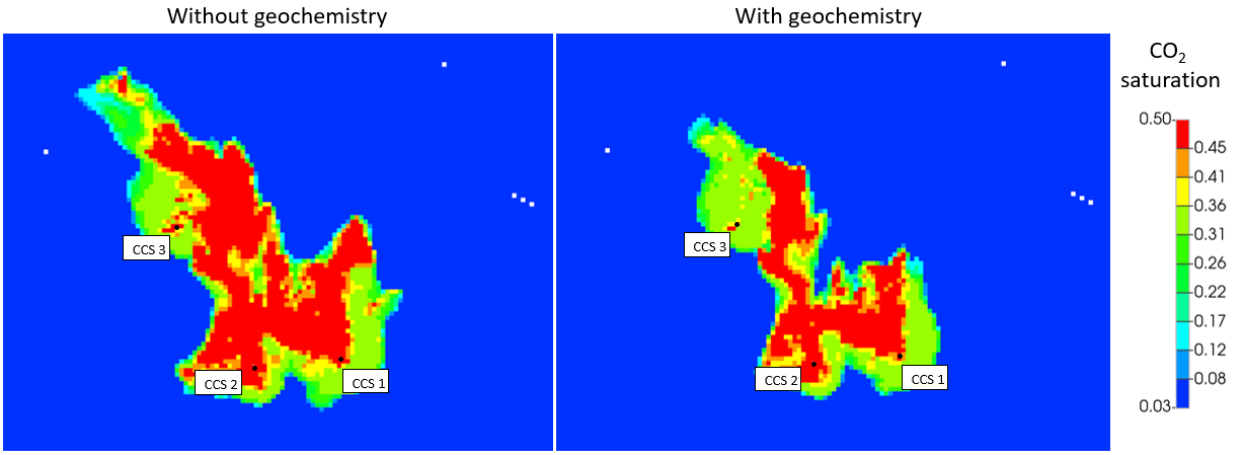


Figure AoR-279: The aggregate of all layers in a top map view of the maximum CO_2 saturation to compare simulations without and with geochemistry capability turned on at 100 years after the end of injection period (2147).

Figures AoR-280 and AoR-281 show the injection comparison for the simulations with and without geochemistry capability turned on, including the gas injection rate and injectivity index

over time. The injectivity index is calculated by the gas injection rate divided by the difference between the bottomhole pressure and reservoir pressure (Inj. Index = $q_{gas}/\Delta P$). The differences in injection rate and injectivity index are negligible as both curves collapse in top of each other. Thus, the increase in porosity has insignificant impact on wells injectivity.

An additional risk to the injectivity is the possible halite ($NaCl_{(s)}$) precipitation because of high-saline water vaporization formed by continuous dry CO_2 injection that could induce pore blockage. Muller et al. (2008) conducted laboratory experiments and simulation modeling to quantity halite precipitation in 22 wt.% reservoir brine in similar reservoir conditions of this project. The authors showed that in just a few hours, freshwater pre-flush would be sufficient to mitigate the salt precipitation. Since the Injection Zone contains brine that is identified to have high TDS of about 110,000 ppm, a pre-flush of fresh water for a brief period will be performed to avoid this potential risk.

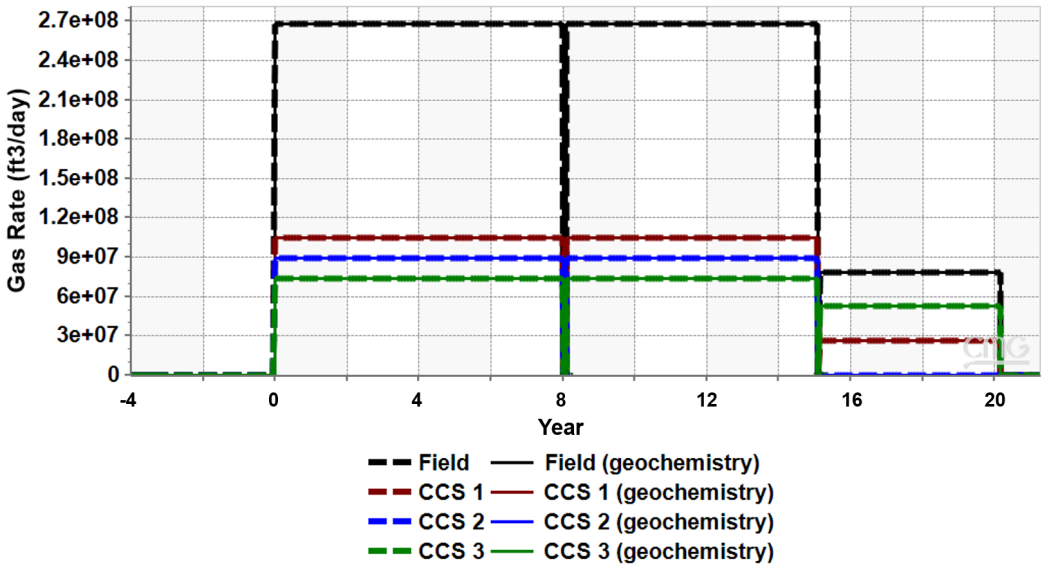


Figure AoR-280: Injection gas rate over time comparison for the simulations with and without geochemistry capability turned on, including total field rate (black line), Bluebonnet CCS1 (red line), Bluebonnet CCS 2 (blue line) and Bluebonnet CCS 3 (green line).

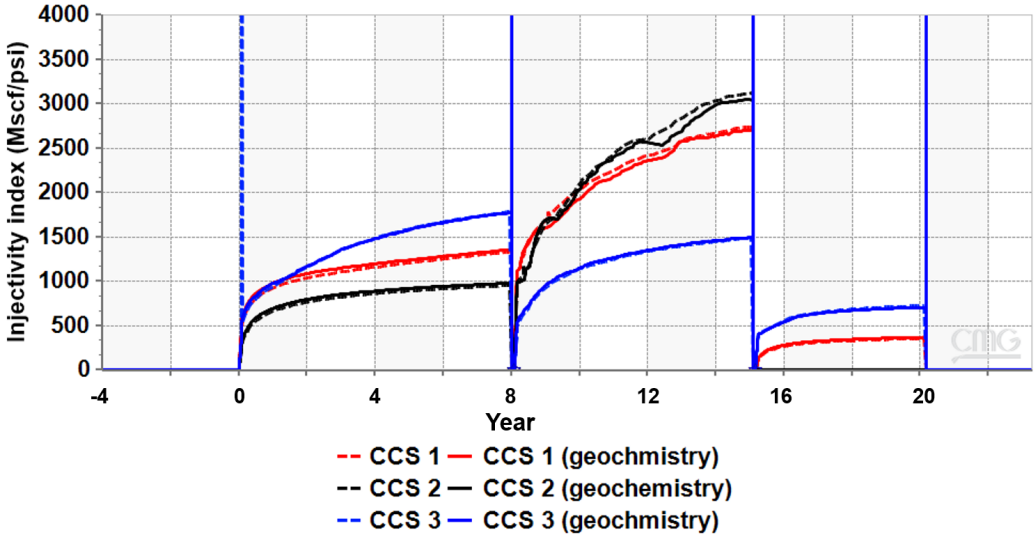


Figure AoR-281: Injectivity index over time comparison for the simulations with and without geochemistry capability turned on, including Bluebonnet CCS1 (red line), Bluebonnet CCS 2 (black line) and Bluebonnet CCS 3 (blue line).

Figures AoR-282 and AoR-283 show the CO_2 trapping mechanisms (total stored, aqueous ions, dissolved in water, mineralization, super-critical, and trapped in residual phase) comparison with geochemistry capability turned on up to 100 and 1,000 years after the injection period. Results indicate that the main trapping mechanisms during the injection period are the super-critical phase as mobile and trapped CO_2. Note that the mineral CO_2 storage is negative during initial period due to calcite dissolution and release of HCO_3^-. Then, CO_2 is mainly trapped in residual phase up to about 600 years after injection, when the mineralization starts to be the main storage mechanism due to carbonate precipitation. Super-critical mobile CO_2 show a steady decrease over time, reaching close to zero at longer periods.

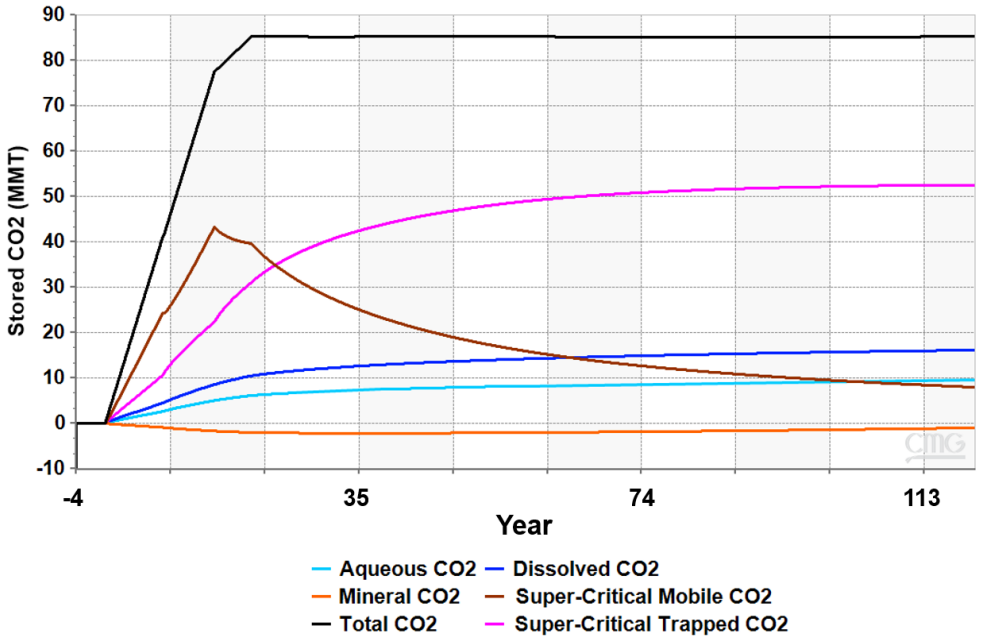


Figure AoR-282: Total, aqueous ions, dissolved, mineral, super-critical and trapped stored CO_2 for simulations with geochemistry turned on up to 100 years after injection period.

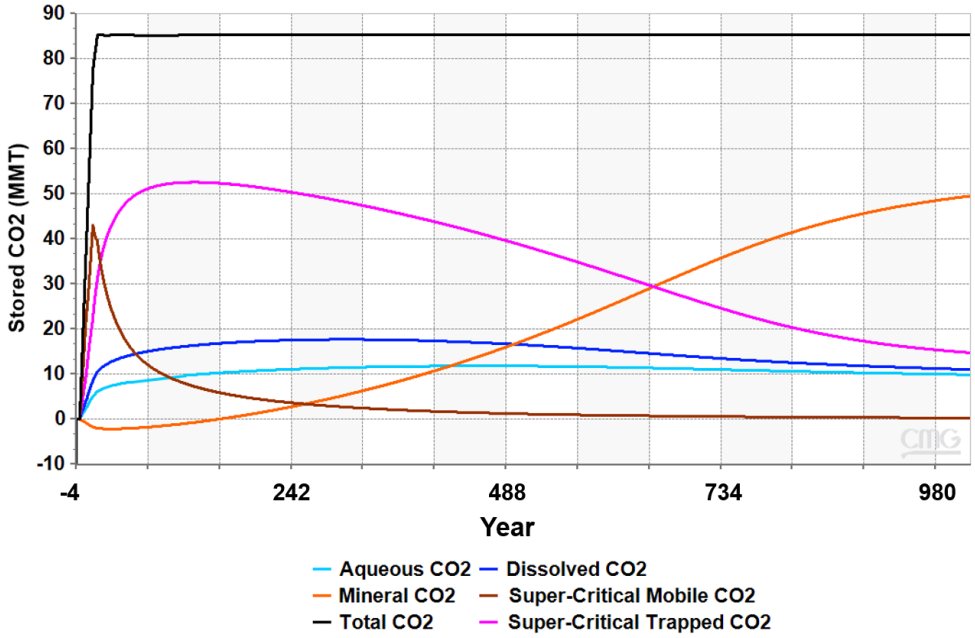


Figure AoR-283: Total, aqueous ions, dissolved, mineral, super-critical and trapped stored CO_2 for simulations with geochemistry turned on up to 1,000 years after injection period.

4.11.4 Miocene and Frio formation water composition comparison

As mentioned previously, the Miocene formation brine was used as reference because the Frio Injection Zone water analysis was available only closer to the application submission date. The brine composition comparison is shown in Table AoR-43. In general, the concentration values have similar proportion for both brines since the Miocene and Frio formations have analogous mineral composition (as shown in XRD data). Since the baseline brines are equilibrated for long periods of time with its respective reservoir rock, it is reasonable that both brines have similar composition. The salinity values (TDS) are within the same range corroborated by the large values for Na^+ and Cl^- ions. The largest difference observed is for Mg^{2+} and Ca^{2+} ion concentrations within the Frio Injection Zone brine being much lower values than the Miocene formation. However, the Mg^{2+}/Ca^{2+} ratios are similar (approximately 0.3 and 0.2 for each formation, respectively). This means that the expected precipitation of calcite mineral, as shown in the modeling as the main long-term trapping mechanism, is still expected to occur in the Frio Injection Zone since the solubility product for magnesium-type mineral is proportionally lower than calcium-type mineral. In addition, calcium concentration is still at least one order of magnitude larger than the other cations.

Table AoR-43: Water composition and brine properties for geochemical and reactive-transport simulations.

Ion (mg/L)	Miocene formation brine sample	Frio Injection Zone brine sample
Calcium	Claimed as PBI	
Magnesium		

Ion (mg/L)	Miocene formation brine sample	Frio Injection Zone brine sample
Potassium	Claimed as PBI	
Sodium		
Barium		
Iron		
Silicon		
Strontium		
Bicarbonate (alkalinity)		
Chloride		
Sulfate		
Borate		
Bromide		
pH (lab)		
Total dissolved solids		

5.0 Miocene Storage Complex Model

5.1 Simulation Model Background – Miocene Storage Complex

5.1.1 Geocellular Model Introduction

The static geocellular model was constructed using Schlumberger's Petrel (v.2023.7.0) 3D geostatistical modeling software, which is a comprehensive, integrated subsurface platform containing data interpretation tools for well correlation, mapping, and structural and property modeling. Application of this software has been demonstrated in reliable subsurface models containing faults, horizons, and properties, which are then used to estimate volumetrics and are further passed on to dynamic reservoir simulation.

5.1.2 Model Grid Creation and Revisions

Figure AoR-284 summarizes various grids involved in static to dynamic model. The original Frio model under Oligocene storage complex section 4 encompasses the Lower Miocene section with a grid of 500 × 500 × 14 ft; however, a more refined grid was adopted for the detailed modeling of the Miocene storage complex using a grid size of 250 × 250 × 14 ft to capture lateral complexities of fluvial facies in the Miocene section. All static model properties were populated into this refined stair-step Miocene Static model grid.

Some artifacts were observed in cells near faults when static stair-step grid was exported from Petrel to CMG. To eliminate those grid anomalies in the Petrel stair-step grid, a new un-faulted "Simple" Petrel grid was built in order to transfer to the Dynamic model. All static properties were upscaled from the static stair-step grid into it. This new un-faulted grid does not attain the exact same I, J, K index as the static stair-step grid used in the property modeling.

Furthermore, to optimize the computational time for the dynamic model in CMG software, zones below Anahuac_CZ were excluded along with cropping northern boundary area cells of Miocene static stair-step grid. Later, faults were added as "Petrel simulation faults" into the dynamic grid to simplify fault handling in the CMG model.

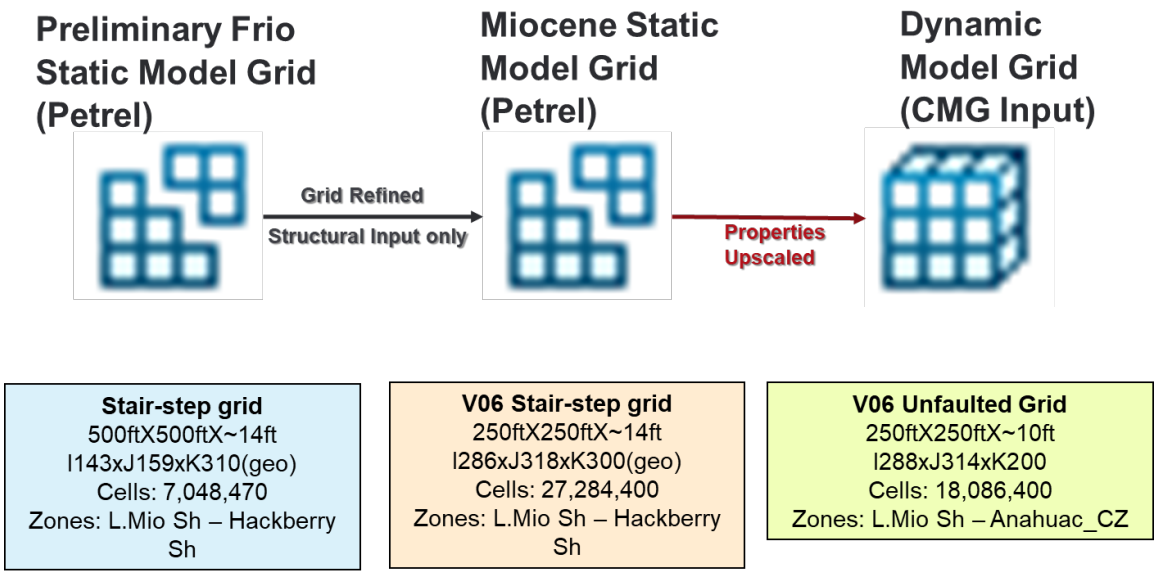


Figure AoR-284: Static and Dynamic Model Grids.

5.1.3 Dynamic Simulation Model Introduction

The dynamic simulation models were created using the GEM (2024.10) reservoir simulator with the Greenhouse Gas (GHG) module from Computer Modeling Group Ltd. (CMG). GEM is a commercially available, compositional, and finite-difference simulator that is commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. GEM has also been used to model several carbon capture and storage projects. The Greenhouse Gas (GHG) module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (liquid), CO_2-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, and enthalpy) of the H_2O and CO_2 phases and CO_2 solubility in H_2O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions, including temperature ranges between 53.6°F (12°C) and 302°F (150°C) and pressures up to 16,000 psi (110 MPa). Details of this method can be found in Collins et al. (1992, CMG GEM Manual), Thomas and Thurnau (1983, CMG GEM Manual), and Nghiem and Li (1989, CMG GEM Manual).

Additional assumptions governing the phase interactions throughout the simulations are as follows:

- CO_2-rich phase (gas) density is obtained by using the Peng-Robinson equation of state. The model was accurately tuned and modified as described below (Peng and Robinson, 1976, CMG GEM Manual).
- CO_2 dissolution in brine is calculated from Henry's Law Constant Correlation using Harvey's method (Harvey, 1996, CMG GEM Manual). Here, CO_2 dissolution in brine was only modeled in reactive-transport simulations.

- Brine density is specified at a reference pressure of 14.7psi. Brine viscosity is calculated using the Kestin (1981) correlation.
- Chemical equilibria among H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2, H_4SiO_4, HCO^-, OH^-, CO_3^{2-}, $CaOH^+$, $MgHCO_3^+$, and $AlOH^{+2}$ ions in the aqueous phase are modeled with 13 equilibrium constants. Aqueous complexes were selected based on simulation results from geochemical equilibrium runs (Geochemist's Workbench) with minerals and CO_2. Solid phases included calcite, kaolinite, anorthite, dolomite, illite, K-feldspar, and quartz minerals. Reactions among these minerals and ions are modeled with chemical reactions and reaction coefficients from the Lawrence Livermore National Laboratory database (Thibeau, 2007), which were also used in a simulation study by Nghiem et al. (2004).
- The CO_2 gas viscosity is calculated per the methods described by Pedersen et al. (1984).
- The gas density is obtained by using a cubic equation of state developed by Peng and Robinson (1976) described by Equation 1:

$$P = \frac{RT}{(v - b_{mix})} - \frac{a_{mix}}{(v^2 + 2vb_{mix} - b_{mix}^2)} \quad \text{..... (Equation 1)}$$

Where:
v is the molar volume;
P is the pressure;
T is the temperature in Kelvin;
R is the universal gas constant;
a_{mix} and b_{mix} are mixture-specific functions of temperature and composition, calculated from the critical properties and acentric factors of the components.

The CMG WinProp software has a built-in library for the properties CO_2 and CH_4 based on Reid et al. (1977, CMG GEM Manual). No changes were made to the library components.

The transition between liquid and gaseous CO_2 can lead to rapid density changes in the gas phase. The simulator uses a narrow transition interval between the liquid and gaseous density to represent the two-phase CO_2 region.

Because the compression/pumping facility controls the CO_2 delivery temperature to the injection well to keep it between 60°F and 120°F, the temperature of the injectant will be comparable to the reservoir formation temperature at the injection interval. Therefore, the simulations were based on isothermal reservoir conditions at 127.4°F.

With respect to the timestep selection, the software algorithm optimizes the timestep duration based on the specific convergence criteria designed to minimize numerical artifacts. For these simulations, the timestep size ranged from 0.001 to 30 days. In all cases, the maximum solution change over a timestep was monitored and compared with the specified target. Convergence was achieved once the model reaches the maximum tolerance where small changes of the temperature and pressure calculation results occur on successive iterations. New timesteps were chosen so that the predicted solution change is less than a specified target.

Considerations for computational efficiency of numerical simulations of geochemical reactive transport models resulted in modeling only aqueous constituents and minerals that are highly reactive or comprise significant proportions of their respective liquid- and solid-phases. Model

results suggested negligible mineralization (sequestering) of injected CO_2 during injection periods. However, upon cessation of CO_2 injection, mineral precipitation (e.g., calcite) occurs over long timescales (100s of years). Preliminary model results suggest geochemical reactions play a key role in permanent (mineralized) sequestration of injected CO_2 as well as reduction in potential stray CO_2 migration due to porosity loss from mineralization in the reservoir.

5.2 Model Domain Miocene Storage Complex

The Lower Miocene static geological model was created using Schlumberger Petrel (v.2023.7.0, Build Date: April 2, 2024, Build Number I11012) and is based on the collaborative interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired from public databases, published literature, in-house studies, and in-house 3D seismic data.

Figure AoR-285 displays 166 wells total used for the construction of the stratigraphic framework. The geological subzones were created from horizons based on a combination of well log correlations in combination with the 3D seismic horizon interpretation. The internal layer subdivisions of the zones were based on the interpretation of 153 digital well logs, which were used to determine the thickness of each subzone. Detailed information for the wells used in model construction as well as the wells used in the petrophysical analysis is tabulated in Appendix A.

The static geological model includes several major geological zones from top to bottom: Lower Miocene Confining Zone, Lower Miocene Dissipation Zone, Lower Miocene Injection Zone, and Anahuac Confining Zone. The model extent covers approximately 14 miles by 15 miles. The top and bottom confining zones are the Lower Miocene Shale (LMIO_Shale_CZ) and Anahuac Shale (Anahuac_CZ), respectively.

The 3D geomodel was constructed with an orthogonal, north-south oriented grid, with grid cell dimensions of 250 ft. x 250 ft. Vertical grid layer thickness varies slightly by zone, but the average layer thickness is 10 ft. The final 3D geological model is represented by a 288 x 314 x 200 grid in a Cartesian system for a total of 18.1 million cells (includes from LMIO_Shale_CZ to Anahuac_CZ).

Model horizons were first interpreted from available well log datasets, including depth-registered image logs and digital log data on 153 wells shown on Figure AoR-285. These horizons were then combined with interpreted 3D seismic data to provide more accurate control of horizon construction where log data may be sparse.

The methodology applied to the static geomodel was to model the large-scale features, followed by modeling progressively smaller and more uncertain features. The first step applied to the Bluebonnet geomodel was to establish a conceptual structural and depositional model as well as its characteristic stratigraphic layering. The structural and stratigraphic architecture provided a first-order constraint on the spatial continuity, porosity, permeability, net sand, and other attributes within each layer. Next, petrophysical values were distributed for each zone using a cell-based methodology. Detailed discussion of model property development is presented below.

Figure AoR-285 displays locations of the proposed Bluebonnet injection wells, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, targeting the Lower Miocene Injection Zone. Also, shown is the location of the stratigraphic test well Encanto 01, which was drilled to gather key reservoir and performance data in support for this application.



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The geomodel domain coordinate reference system is summarized in Table AoR-44.

Table AoR-44: Summary of geomodel domain coordinate system

Coordinate System	NAD 27/BLM zone 15 N (ftUS)		
Horizontal Datum	NAD1927		
Coordinate System Units	ftUS		
Zone	BLM 15 N		
FIPSZONE	N/A	**ADSZONE**	N/A
Coordinate of X min	1,137,700	**Coordinate of X max**	1,209,700
Coordinate of Y min	10,801,000	**Coordinate of Y max**	10,879,500
Elevation of top of domain	-3,100	**Elevation of bottom of domain**	-7,800

5.2.1 Well Data Description

A total of 158 wells with digital curves and petrophysical analysis were used for Facies interpretation (for more detail on facies interpretation see Appendix A). Several of these wells were outside the geomodel AOI, thick blue squared in Figure AoR-286. Fourteen wells with PEF were the base wells for facies analysis and were used to distribute the facies to the rest 144 wells. From the 158 wells with porosity, permeability, and facies, 102 were used in the geo-model, these wells fall inside the AOI.

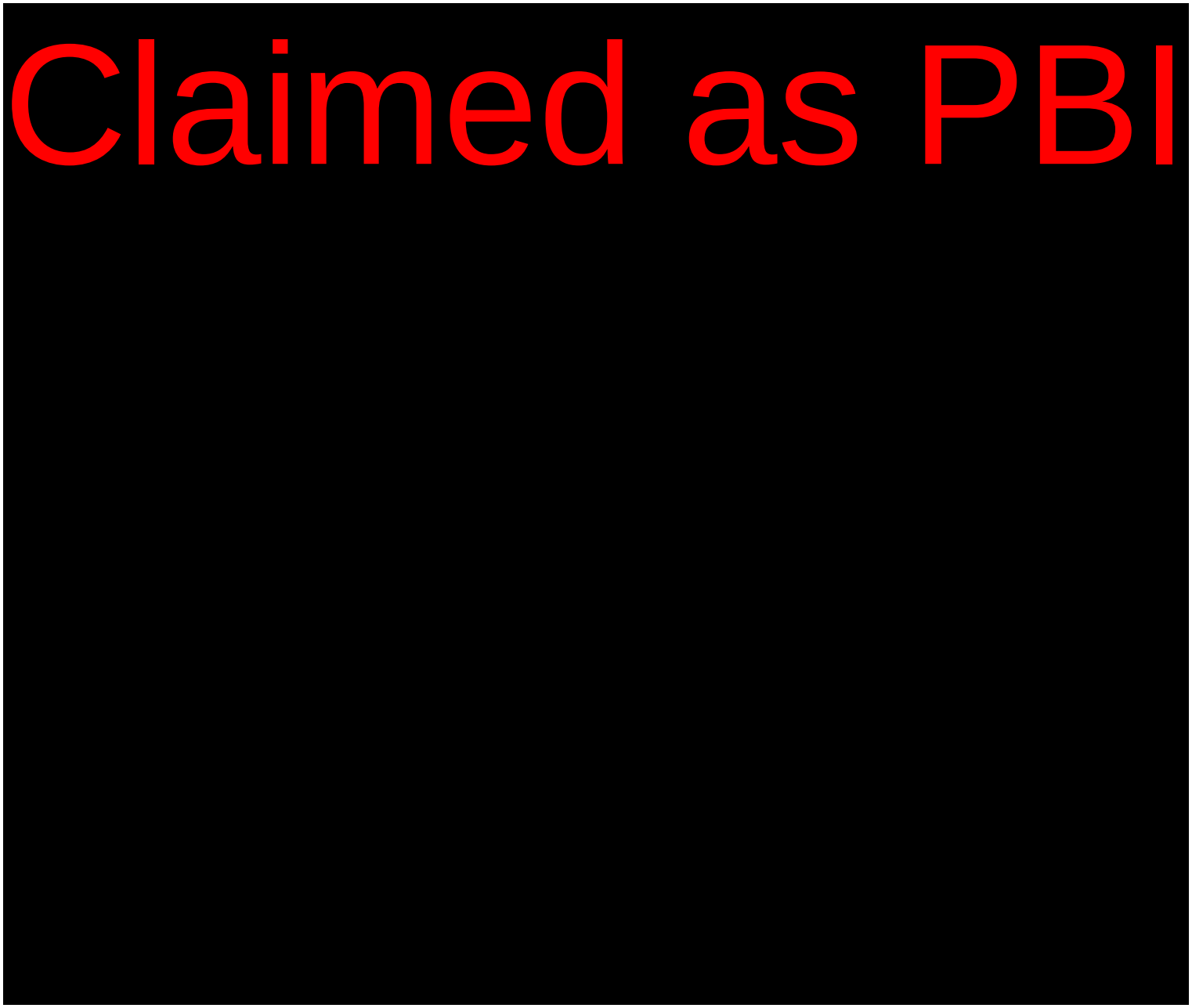


Table AoR-45 provides a summary of the computed log data inside AoI used for the static model properties.

Table AoR-45: Computed log data for static model inside the AOI.

Log Data Set	Inside Model AOI
Phi and K logs	Claimed as PBI
GR Facies	
Additional SP Facies (no GR Facies)	
GR + SP Facies Logs (used in Facies Model)	

5.2.2 Log-Derived Lithofacies Data

The facies definitions were adjusted using the Encanto 01 core data for calibration. In addition to the core calibration, refinement of the facies categories was expanded to include the following log-based lithotypes (with the legend key and color code show to the right):

A complete description of this methodology is included in Appendix A. The log-based lithofacies data were imported as discrete lithology logs based on the SP and GR curves, designated with the FACIES_CORE_ prefix in the global curve name. Also, the normalized SP and RESD curves were added as well as the Vshale from GR calculated curve:

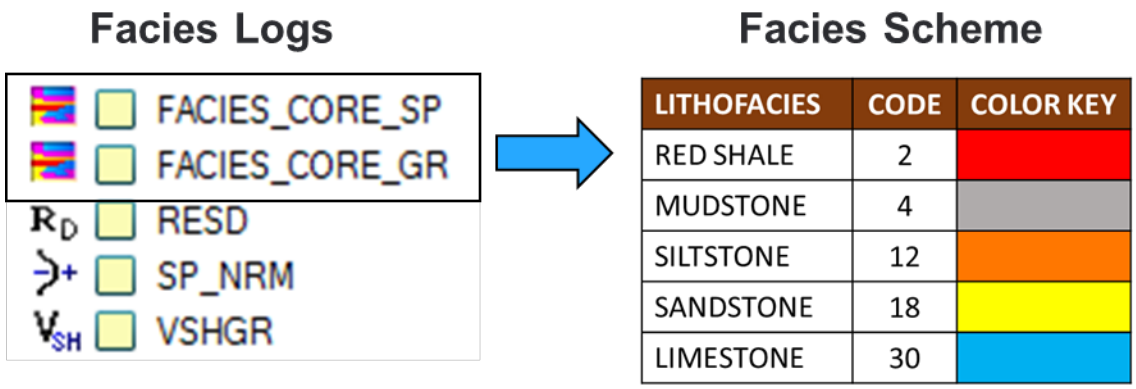


Figure AoR-287: Lithofacies Scheme and Facies Curves.

Because the GR-derived lithofacies data are considered more reliable than the SP-based interpretation, the FACIES_CORE_SP logs were upscaled into the 3D grid using a “most of” upscaling algorithm, and then, replaced by (or added to) with the FACIES_CORE_GR logs into the same model property (FACIES_CORE) for a combined 106 upscaled lithology curves inside the static model boundary used in Facies modeling process.

5.3 3D Seismic Input to Model Geologic Structure – Miocene Storage Complex

The incorporation of the seismic data was described in section 4.3 including the Miocene Storage complex. Seismic interpretation provides top and base horizons for the Miocene Storage Complex. Between the confining Miocene horizons, seismic attribute extractions informed facies distributions within the Miocene geologic model. Similar attribute extractions were performed on the Frio Storage Complex, but they did not produce any geologically reasonable output and were not utilized in the geological model for the Frio.

5.4 Geologic Model Zones and Layering –Miocene Storage Complex Model

The geological model was constructed from a volume-based framework (VBF) model derived from 3D seismic interpretation. There are a total of 12 major zones in the model: Lower Miocene Shale Confining Zone, Lower Miocene Dissipation Zones (4), Lower Miocene Injection Zones (6) and Anahuac Shale Confining Zone. These major zones were further subdivided by layering and modeled separately to better characterize the depositional trends and reservoir parameters for each zone in more detail.

The Lower Miocene Dissipation Zone was subdivided into the Lower Miocene A, AMPB Sand, Lower Miocene B, and Lower Miocene C. Together these zones represent the expected Lower Miocene dissipation zone.

The Anahuac Confinement Zone was not subdivided into additional zones as was done for the Frio, but only the upper Anahuac was included in the geomodel, with appropriate vertical layering created to facilitate the distribution of reservoir properties and better characterize the vertical heterogeneity of this zone.

The remainder of the Lower Miocene was subdivided into injection disposal zones as follows: LMIO_INJ_1, LMIO_INJ_5, LMIO_INJ_4, LMIO_INJ_3, LMIO_INJ_6, and LMIO_INJ_2. Each of these zones was in turn subdivided into additional vertical layers to facilitate distribution of reservoir properties to capture the vertical heterogeneity of the target injection reservoirs.

The Lower Miocene Injection Zones are the main CO_2 storage reservoirs proposed for the Miocene Storage Complex within the proposed AoR. These reservoirs are characterized by relatively unconsolidated sandstones with high porosity and permeability, with interbedded siltstones, minor mudstones and shales, and some calcareous layers. These units were deposited in a dominantly fluvial to fluvio-deltaic environment.

The geological subzones were created from horizons based on a combination of well log correlations in combination with the 3D seismic horizon interpretation. The internal layer subdivisions of the zones were based on the interpretation of 153 digital well logs, which were used to determine the thickness of each subzone. Proportional layering was applied to each subzone, with the number of layers in a zone determined from the subzone thickness targeting a layer thickness of approximately 10 ft. for each layer. The average incremental vertical cell thickness for the total model is 14 ft. and approximately 10 ft. in the injection zones.

The 12 individual zones within the geological model include the stratigraphic units from the base of the Anahuac Confining Zone as the lowermost confining zone to the top of the Lower Miocene Shale Confining Zone as the uppermost confining zone.

Table AoR-46: Summary of key statistics for the Lower Miocene Confinement, Dissipation, and Injection zones.

ZONE TYPE	Model Zone Name	TVDss (ft.)	PORe (frac.)	PERM (md)	Gross TVT (ft.)
TOP CONFINING ZONE	LMIO Shale CZ	Claimed as PBI			
LOWER MIOCENE DISSIPATION ZONES	LMIO A				
	AMPB Sand				
	LMIO B				
	LMIO C				
LOWER MIOCENE INJECTION ZONES	LMIO_INJ_1				
	LMIO_INJ_5				
	LMIO_INJ_4				
	LMIO_INJ_3				
	LMIO_INJ_6				
	LMIO_INJ_2				
BASE CONFINING ZONE	Anahuac Shale				

An oblique 3D index view of the 12 subzones of the Lower Miocene section is shown below in Figure AoR-288.

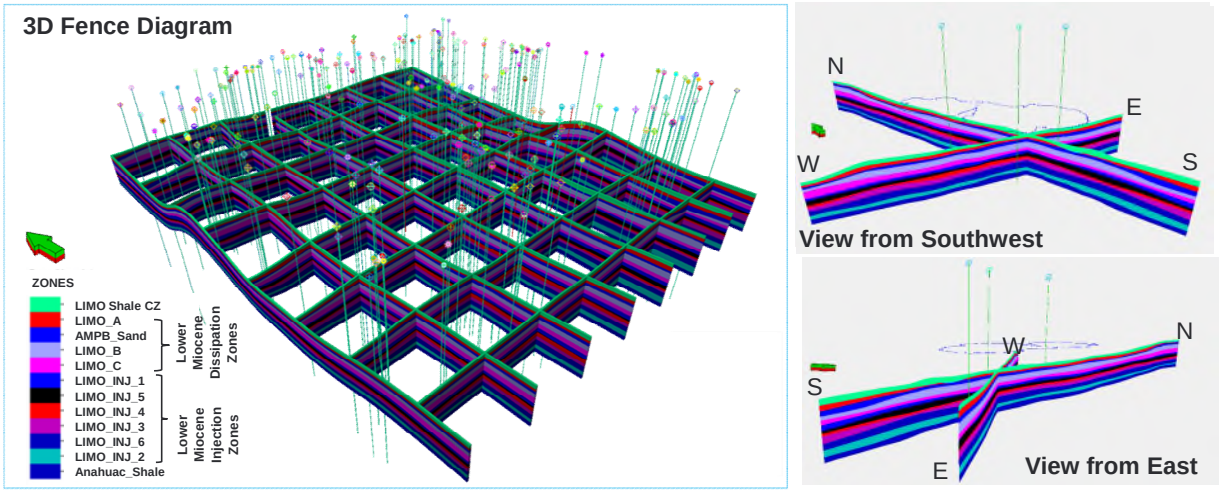


Figure AoR-288: 3D Fence diagram, NS section and EW section showing the geologic model subzones from the Lower Miocene Confinement, Dissipation, and Injection zones to the basal Anahuac Confining Zone.

A total of 158 wells were selected that provided the best data quality and coverage, and used to make petrophysical calculations of porosity, permeability, and net reservoir thickness. Within the geomodel, 153 petrophysically analyzed wells were available for use in 3D distribution of petrophysical properties, as shown in Figure AoR-289. A summary of average petrophysical properties is shown in Table AoR-47.

5.5 Property Modeling Workflows and Procedures

Property modeling for the Bluebonnet Lower Miocene static geomodel followed standard procedures in most cases. Generally, the well log data were upscaled into the model, data analyses were performed, and log data was checked for accuracy and consistency. In some cases, extreme outlier data points were filtered from the data analyses (generally petrophysical properties with spurious or incorrect data). For example, out-of-range porosity and permeability values <0.00 were considered analytical artifacts and were set to “Undefined” in the data analysis distributions.

Basic geometric properties (Layers, Zones, and Regions) were created for use in checking grid consistencies and for input to other intermediate property calculations.

5.5.1 Well Log Upscaling

Upscaling of the fundamental petrophysical logs (porosity, permeability, and shale volume) used the computed X-Curves: XPORE, XPORT, XK, and XVsh created for the original project dataset. The logs were upscaled using a Mid-Point Pick (MPP) algorithm rather than the traditional and standard Arithmetic, Harmonic, or Geometric algorithms. Although these methods were tested, the use of the MPP algorithm is much better at characterizing vertically heterogeneous reservoirs.

Lithofacies data (Appendix A) were upscaled into the model using a standard “most of” upscaling algorithm, the preferred methodology for discrete properties. As noted above, the SP-based lithofacies data were upscaled first, then GR-based lithofacies logs (52 wells) were re-upscaled

while keeping SP-based lithofacies where there is no GR-base lithofacies exists (54 wells). This provided a total of 106 wells with facies control points inside the model boundary.

5.5.2 Data Analysis

All continuous petrophysical properties were evaluated using the Petrel Data Analysis tools. A vertical proportion curve and probability curve was created for each facies by zone. For continuous properties, data transform distributions were created by facies in each zone. The example below shows the data distribution curve definitions for the LMIO_INJ_3 zone. While there is limited overlap between the sand and siltstone facies, there is more overlap between siltstone and shale/mudstone facies, indicating that the shale/mudstone facies are gradational in nature.



During the data analysis work, it became apparent that the mean permeability values for shale/mudstone facies appeared to be higher than expected. A comparison to limited core plug permeability data from the Encanto 01 well through a shale interval suggested that the log-based permeability calculation for shales was almost an order of magnitude higher than the corresponding plug permeability, which averaged about Claimed as PBI

Table AoR-47: Example Average petrophysical values for the LMIO_INJ_3 zone.



To compensate for this difference, the grid property values for shale/mudstone facies (only) was reduced by a factor of 10 to bring the overall values into closer alignment with the core analysis data.

5.5.3 Lithofacies Modeling

The new, core-calibrated lithofacies were upscaled into the grid using the methodology described above. The upscaled cells were distributed into the 3D space using sequential indicator simulation (SIS), with conditioning to geometric trends that are intended to act as proxies for depositional trends indicated by seismic data (as described in previous documents). Although a regional NS

variogram trend was used for most lithologies, an isotropic variogram with a wider range was used to condition the non-reservoir lithofacies (red shale and mudstone).

Upscaled lithofacies logs (Appendix A) were distributed into the 3D grid using a Sequential Indicator Simulation (SIS) algorithm, with the distribution conditioned with a probability trend map generated from depositional trend lines interpreted from the above workflow. The trend line polygons and derived probability maps used as horizontal trend surfaces were generated for each zone in the Lower Miocene section as geometric distance-to-object properties.

5.5.4 Model Property Distribution Workflow

Lithofacies were distributed in the geomodel using methodology described in Appendix A. The basic workflow, however, incorporates a combination of interpreted environments of deposition from well log cross-sections, amplitude extractions from 3D seismic, and interpretations of sand distribution and geometries. Initial stratigraphic correlations were developed in a network of well log cross sections, primarily intended to help visualize the distribution of depofacies in the AOI.



Figure AoR-291 shows SW-NE stratigraphic cross-section where Encanto 01 is highlighted in red dashed box. Seven (7) distinct depofacies have been interpreted for the Lower Miocene section between the Lower Miocene Shale and Anahuac Shale.

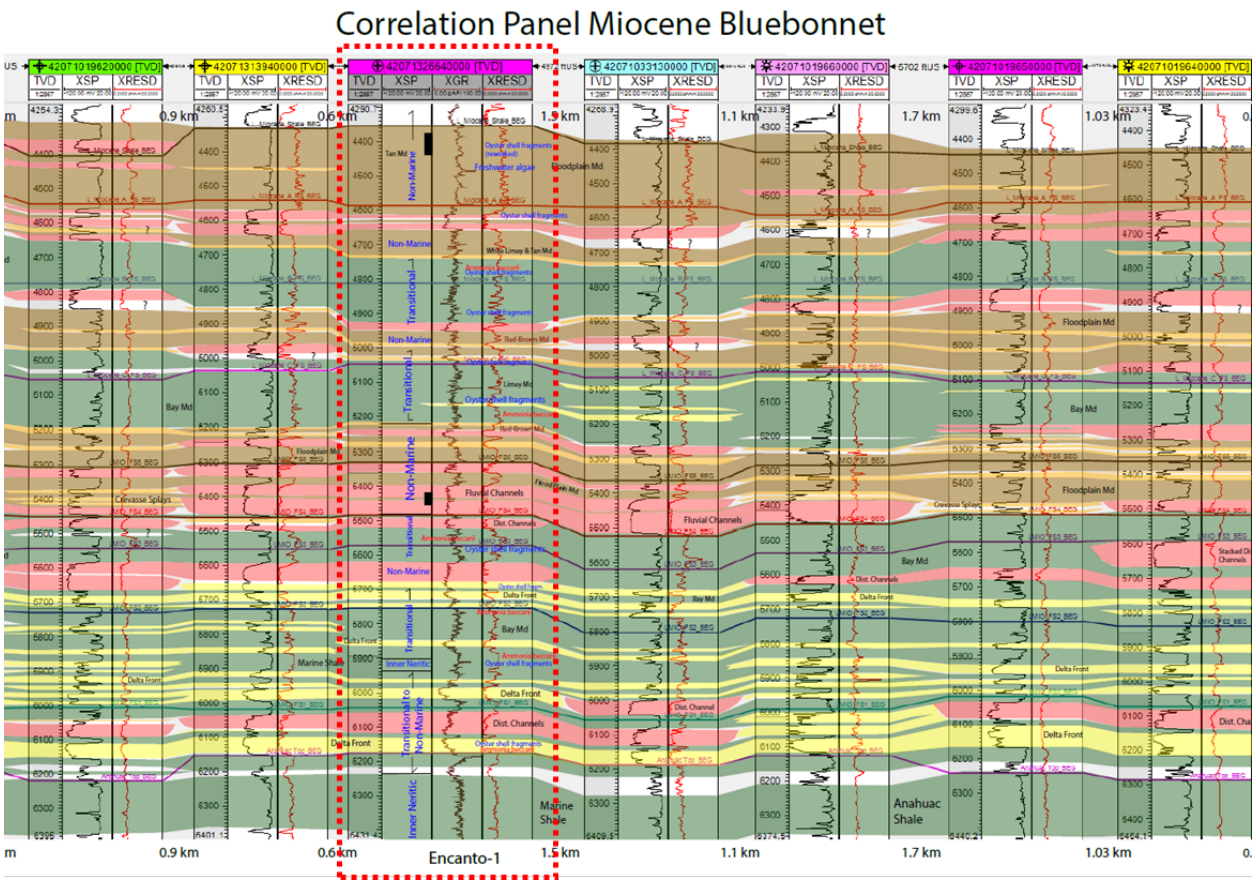


Figure AoR-291: SW-NE Stratigraphic cross-section showing depofacies in the Lower Miocene section.

Note that while the detailed correlations of depofacies interpreted from log signature is somewhat difficult to relate to the log-derived lithofacies. Specifically, the interpreted depofacies (on the left) often contain various percentages of the lithofacies (on the right), Figure AoR-292.

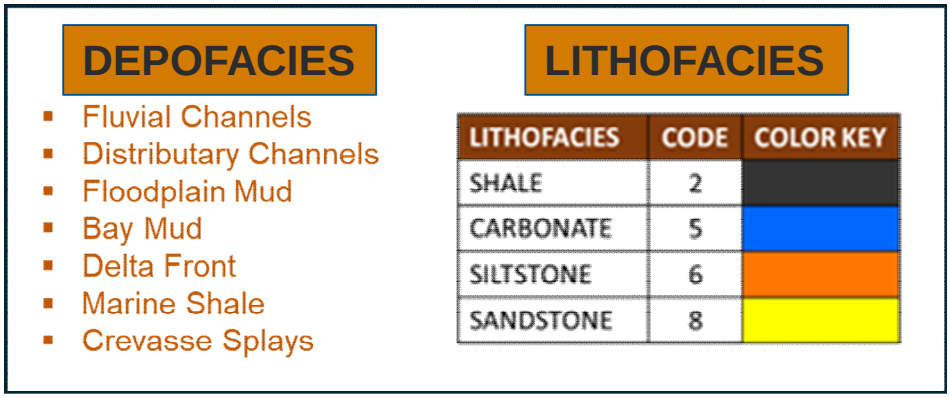


Figure AoR-292: Comparison of depofacies interpreted from log signature and seismic attribute data (left) with the log-derived lithofacies codes.

The general steps in the property modeling workflow incorporated the interpretation of depofacies distribution in combination with RMS amplitude extractions at specific 3D seismic levels. As shown in Figure AoR-293 below, data trends in the RMS amplitude extraction are highlighted (far left view, in yellow) and combined with the depofacies at that level interpreted from well log cross-sections (left center view). These trends are then used to condition the distribution of model properties and compared with the original depofacies distributions (right center and far right views):



Figure AoR-293: General geomodeling workflow to incorporate depofacies trends interpreted from 3D seismic and well log cross-sections into model property distributions.

The key steps in the Petrel property modeling workflow are shown below on Figure AoR-294. The first step is to distribute the log-derived lithofacies using a general N-S variogram with a 2:1 major to minor axis ratio as a preliminary estimate to distribute the lithofacies properties with a Sequential Gaussian Simulation (SIS) algorithm. Next, the interpreted environment of deposition (EOD) trends were digitized as polylines and a distance-to-object (DTO) property was created in the 3D grid. The DTO property was then inverted and normalized to create a sand deposition probability property (*Ps*) in the grid, which represents the likelihood of sand deposition (*Ps* = 1.0) or non-sand (*Ps* = 0.0). This property (*Ps*) was then used to condition the property distribution and compared with the original EOD trends as shown on the far right:



Figure AoR-294: Property modeling workflow steps to condition property distribution to the depositional trends interpreted from seismic and EOD interpretation.

Using the workflows for interpretation of EOD and depositional trends from seismic and well log interpretation and incorporation of these trends into the property modeling process in Petrel, the distribution of the key model properties (lithofacies, porosity, and permeability uses the following general steps:

- Distribute the lithofacies in the 3D grid using a Sequential Indicator Simulation (SIS) with a general N-S variogram with a 2:1 major:minor axis ratio, with conditioning to the depositional probability (*Ps*). To compare the lithofacies distribution for the 3D property on a zone-by-zone basis, net sand maps (for the zone) were generated and compared with the digitized depositional trends.

- Using the Petrel Data Analysis tools, normal-score distributions for each lithofacies were generated for each of the model zones.

- Porosity modeling was done with a Sequential Gaussian Simulation (SGS) algorithm by conditioning the well data to each facies using the normal-score distributions created in the data analysis process. After conditioning to lithofacies, an isotropic variogram was combined with the facies-specific data distributions, with co-kriging to the horizontal depositional probability trend (*Ps*) with collocated co-kriging using a coefficient from the upscaled data.

- Permeability modeling was also done with an SGS algorithm conditioned by facies using the data distribution curves from the data analysis process. After the facies conditioning, the property was distributed using an isotropic variogram and co-kriging with the porosity property as a secondary variable volume. Again, collocated co-kriging was applied with the coefficient from the upscaled data.

These workflow steps are shown below on Figure AoR-295 showing an example of each of the products of the modeling process:



Figure AoR-295: Property modeling workflow incorporating seismic and depofacies trends, data analysis, and petrophysical modeling to create the key petrophysical properties for the 3D grid.

A comparison of the results of the overall modeling workflow is best visualized by comparing the net sand maps for each of the twelve major zones in the 3D model (Figure AoR-296). In these maps, the warmer color represents higher sand percentages, while cooler colors represent non-sand intervals (i.e. mostly fine-grained siltstones and mudstone). The displays compare the upper confinement zone (LMIO_Shale) on the upper left, the dissipation zones (LMIO_A, AMPB, LMIO_B, and LMIO_C), the injection zones (LMIO_INJ_1, LMIO_INJ_5, LMIO_INJ_4, LMIO_INJ_3, LMIO_INJ_6, and LMIO_INJ_2), and finally the lower confinement zone (Anahuac Shale) on the lower right.

Claimed as PBI

5.5.5 Porosity

The XPORE (Effective Porosity) log defines 3D porosity property for the static and dynamic model, although both XPORE and XPORT (Total Porosity) properties were populated as part of the overall Frio–Lower Miocene study. The log curves were upscaled in the fine grid and distributed using a Sequential Gaussian Simulation (SGS) algorithm, with the porosity property conditioned both by depositional trends as described in previous section sand by lithofacies.

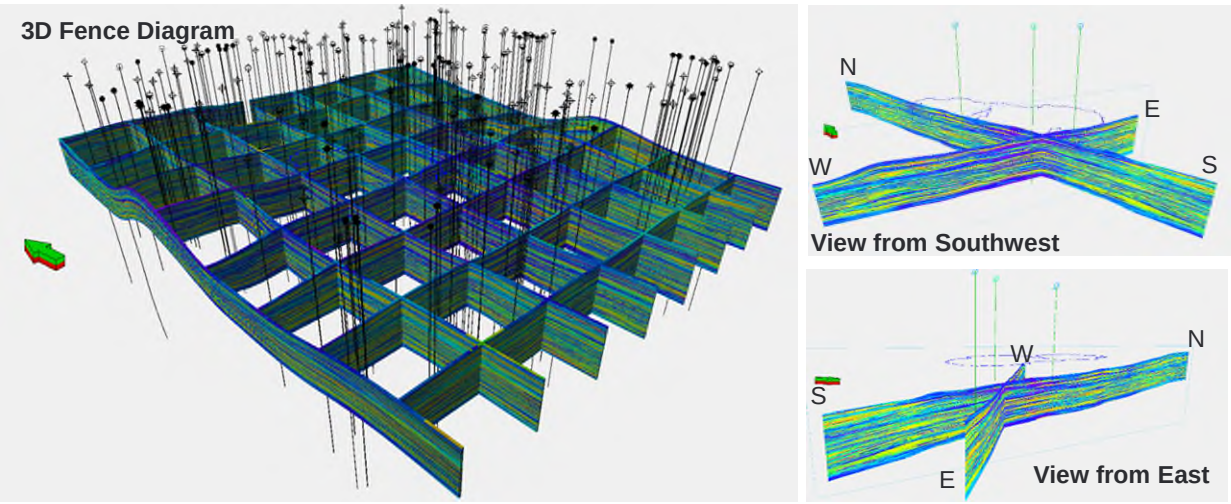


Figure AoR-297: 3D Fence diagram, NS Section and EW Section showing effective porosity property from the Lower Miocene Confinement, Dissipation, and Injection zones to the basal Anahuac Confining Zone.

5.5.6 Permeability

The XK curve was upscaled into the fine grid and distributed in the model using a SGS algorithm, with conditioning to lithofacies and collocated co-kriging to XPORE as a secondary variable. Although a porosity-permeability transform was used for the Frio section, the availability of a calculated XK curve permitted the generation of a facies-conditioned horizontal permeability directly from log data.

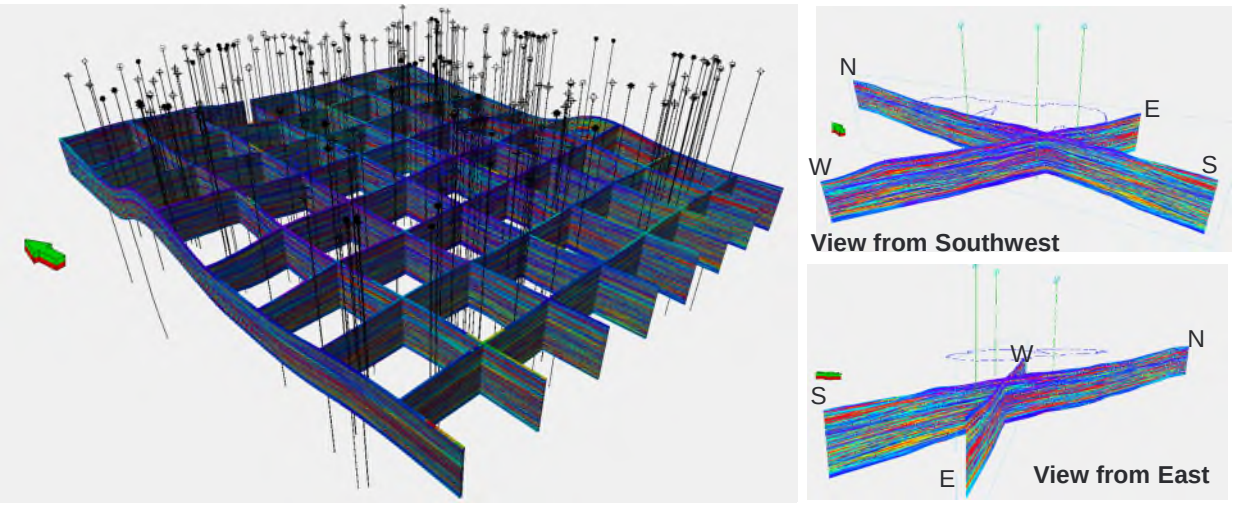


Figure AoR-298: 3D Fence diagram, NS and EW Sections showing the permeability property from the Lower Miocene Confinement, Dissipation, and Injection zones to the basal Anahuac Confining Zone.

A key observation in the core data from the Encanto 01 well suggests that the XK curve data may be overestimating the permeability in the "true" shale intervals by almost an order of magnitude. To allow for testing of this possibility, a pseudo permeability property was created that reduces the XK value (XK/10) in the cells containing the fine-grained facies (red shale and relative mudstone).

During the data analysis work, the XK property distribution did not provide a good match between log, upscaled cells, and total property in 3D. Truncating the XK curve to Claimed as PBI (from the log data maximum of Claimed as PBI provided a much better match. Further investigation of the XK data range might be done or a core-derived porosity-permeability transform should be created by facies to derive a more accurate model permeability.

5.6 Constitutive Relationships and Other Rock Properties – Miocene Model

All simulations runs were executed using the GEM simulator. The grid properties of porosity and horizontal permeability (k_h) were directly imported from the static geomodel. Horizontal permeability for each grid cell was considered isotropic ($k_x = k_y$). Vertical permeability for each grid cell was considered anisotropic and calculated using Claimed as PBI.

The water-gas relative permeability curves were constructed using a Corey model with exponents previously reported by Ghomian (2008). These curves were also used in the simulation of the Frio CO_2 Pilot test. Three set of curves were generated and assigned to each of the facies included in the dynamic simulation. For the injection zone (coarse sand facies) the curves were calibrated using the core lab data obtained from the plugs collected in Lower Miocene Sand in the Encanto 01 well. Refer to Appendix A for more details.

During the imbibition cycle (water displacing gas), the gas is trapped at S_{gt} or trapped gas saturation. S_{gt} values depend on the maximum gas saturation, S_{gh}, that a grid block has experienced. The base case maximum trapped gas saturation is specified as [redacted] All dynamic simulation runs include relative permeability hysteresis.

5.7 Boundary Conditions

Pore volume multipliers were used to represent additional reservoir volume beyond the model domain and transmissibility multipliers were specified along each respective model boundary to properly account for additional pore volume. Pore volume multipliers of [redacted] along north and south boundaries and [redacted] along east and west boundaries were applied. The numerical model was initialized assuming hydrostatic conditions. Fault B06 was identified as sealing fault based on the fault analysis described in Section 3.11 and transmissibility multiplier for Fault B06 was specified as 0.00001 in the model. The additional faults in the model were set at 0.1 transmissibility multiplier.

Figure AoR-299 shows continuous Jasper net sands in an East-West strike direction parallel to the Gulf Coast. The Jasper flow direction map shows variability across multiple counties; however, the Bluebonnet site seems to be located within one larger flow compartment that may be linked to the Lower Miocene depositional environment map. To quantify its impact on AoR predictions, the horizontal boundary conditions were included as a sensitivity parameter. In Figure AoR-299, the red solid rectangle represents the low value boundary and blue solid rectangle represents the mid value boundary that was used in the base case, within which reservoir pore volumes were included to predict the pore pressure increases from CO_2 injection.


Claimed as PBI

5.8 Initial Conditions

Initial conditions for the model are given in Table AoR-48.

Table AoR-48: Initial Condition.

Parameter	Value or Range	Units	Corresponding Elevation (ft, MD)	Data Source
Temperature	Claimed as PBI			
Formation pressure				
Brine viscosity				
Fluid density				
Rock compressibility				

In this study, a pressure gradient based on 2Claimed as PBI was adopted in the model. For the modeled pressure gradient within the injection zone, a water density of Claimed as PBI3 was specified. The reservoir temperature was initialized using a constant temperature of Claimed as PBI. Brine viscosity is calculated using Kestin correlation in CMG. Site-specific values for rock compressibility were not determined and a value of Claimed as PBI was specified based on values reported in the literature (Hall, 1953; Newman, 1973).

The estimated transmissibility from the Lower Miocene reservoir is Claimed as PBI based on the data acquired during the step rate test performed in Encanto 01 stratigraphic well. The static model is predicting higher permeabilities in the sands up to Claimed as PBI due to the XK curves being adjusted with the core analysis results for the Lower Miocene plugs. In order to calibrate the permeability predicted by the model with the field data acquired during the step rate test, a permeability multiplier of Claimed was applied to the Lower Miocene Injection Zone.

5.9 Operational Information

Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells all begin injection with primary rate constraints of 97.6 MMscfd (1.86 million metric ton (MMTA)), 85.4 MMscfd (1.63 MMTA), and 73.2 MMscfd (1.39 MMTA), respectively. Secondary constraints using maximum bottomhole pressure (BHP) were set at 3,300 psi (Claimed as PBI of the minimum estimated fracture gradient of ClaimClaimed as PBI) for all injectors. Frac gradient was established from step-rate and leak-off tests on the Encanto 01 stratigraphic well. The injection stream composition is assumed to be 100% CO_2. Recompletion of injector wells were simulated with addition of successively shallower perforations using the completion schedule proposed in Section 5.11. Proposed injection period for each injector wells is 15 years with 50 years of post-injection, and base-case simulation times were allowed to run for 100 years post-injection to simulate an extra buffer for CO_2 migration after post-injection site closure.

Table AoR-49 shows the completion design for all three injectors. The recompletion design provides higher CO_2 storage capacity by filling each zone of the reservoir separately.

Table AoR-49: Completion design for Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7

Injection Years	CCS 5 Completion Formation	CCS 5 Layer No	CCS 6 Completion Formation	CCS 6 Layer No	CCS 7 Completion Formation	CCS 7 Layer No
1	LMIO_IN_2	172-185	LMIO_IN_2	173-189	LMIO_IN_2	174-184
2						
3						
4						
5	LMIO_IN_6 LMIO_IN_2	172-185 152-160			LMIO_IN_3 LMIO_IN_2	174-184 136-144
6						
7						
8	LMIO_IN_3 LMIO_IN_6 LMIO_IN_2	172-185 152-160 133-145	LMIO_IN_3 LMIO_IN_2	173-189 131-144		
9					LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_2	174-184 136-144 115-119 91-97
10						
11						
12	LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_6 LMIO_IN_2	172-185 152-160 133-145 102-111				
13					LMIO_INJ LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_2	174-184 136-144 115-119 91-97 75-85
14	LMIO_INJ LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_6 LMIO_IN_2	172-185 152-160 133-145 102-111 72-81				
15			LMIO_IN_5 LMIO_IN_3 LMIO_IN_2	173-189 131-144 92-106		
Shut-In						

Details on the injection operation are presented in Table AoR-50.

Table AoR-50: Operating details Bluebonnet CCS 5, Bluebonnet CCS 6, Bluebonnet CCS 7.

Operating Information	Bluebonnet CCS 5	Bluebonnet CCS 6	Bluebonnet CCS 7
Bottomhole Location (NAD27) Latitude Longitude	 29.812133 -94.436456	 29.817417 -94.464104	 29.853222 -94.498078
Model coordinates (ft) X Y	 1,184,993.56 10,822,335.15	 1,176,251.281 10,824,366.75	 1,165,648.56 10,837,523.25
No. of perforated intervals	5	3	4
Perforated interval (ft TVDSS) Z top Z bottom	 6,281 6,415	 6,166 6,295	 5,971 6,065
Recompletion interval (ft TVDSS) Z top Z bottom	 6,004 6,132	 5,708 5,817	 5,534 5,630
Recompletion interval (ft TVDSS) Z top Z bottom	 5,771 5,926	 5,470 5,532	 5,243 5,413
Recompletion interval (ft TVDSS) Z top Z bottom	 5,597 5,685	 n/a	 5,127 5,207
Recompletion interval (ft TVDSS) Z top Z bottom	 5,432 5,453	 n/a	 n/a
Wellbore diameter (in.) *	6.0	6.0	6.0
Planned injection period Start End	 time = 0 time = 15	 time = 0 time = 15	 time = 0 time = 15
Injection duration (years)	15	15	15
Average Injection rate (t/day)	5,095	4,465	3,808

TVDSS: True Vertical Depth Sub Sea

5.10 Computational Modeling Results

Dynamic simulations were carried out in 3D using full physics, an Equation of State for fluid PVT. The dynamic reservoir simulation was performed with the same 250 × 250 × ~10 ft grid cells as those in the geologic model.

Twelve zones were imported from Petrel into CMG BUILDER (Table AoR-51).

Table AoR-51: Zones imported into CMG Builder from Petrel – Miocene Storage Complex.

Zone	Layers
L_Miocene_SH	1-10
L_Miocene_A	11-30
AMPB_SAND	31-40
L_Miocene_B	41-60
L_Miocene_C	61-70
LMIO_INJ	71-90
LMIO_INJ_5	91-110
LMIO_INJ_4	111-130
LMIO_INJ_3	131-150
LMIO_INJ_6	151-170
LMIO_INJ_2	171-190
Anahuac	191-200

As described in previous section, the static model imported to CMG contained 288 x 314 x 200 cartesian grids (18.1 million of cells). In order to reduce computational time, a section of the model to the north was deactivated. The final simulation contains 288 × 285 × 200 cartesian grids and more than 16 million active cells.

5.11 Predictions of System Behavior

The simulated well rates and pressures are shown in Figure AoR-300, Figure AoR-301 and Figure AoR-302 . Wellhead pressures were calculated using a PROSPER-generated tubing table with 5.5-inch tubing. Table AoR-52 shows the average bottomhole for each stage at operative conditions.



Simulation results supported bottom-up, staged completions as an attractive completion strategy (Table AoR-53). The proposed completion design for each well is based on the overall forecasted sequestration volume, the injectivity of each well, and the availability of the pore space.

Table AoR-53: Stage injection, injection, and production rate for all the wells.



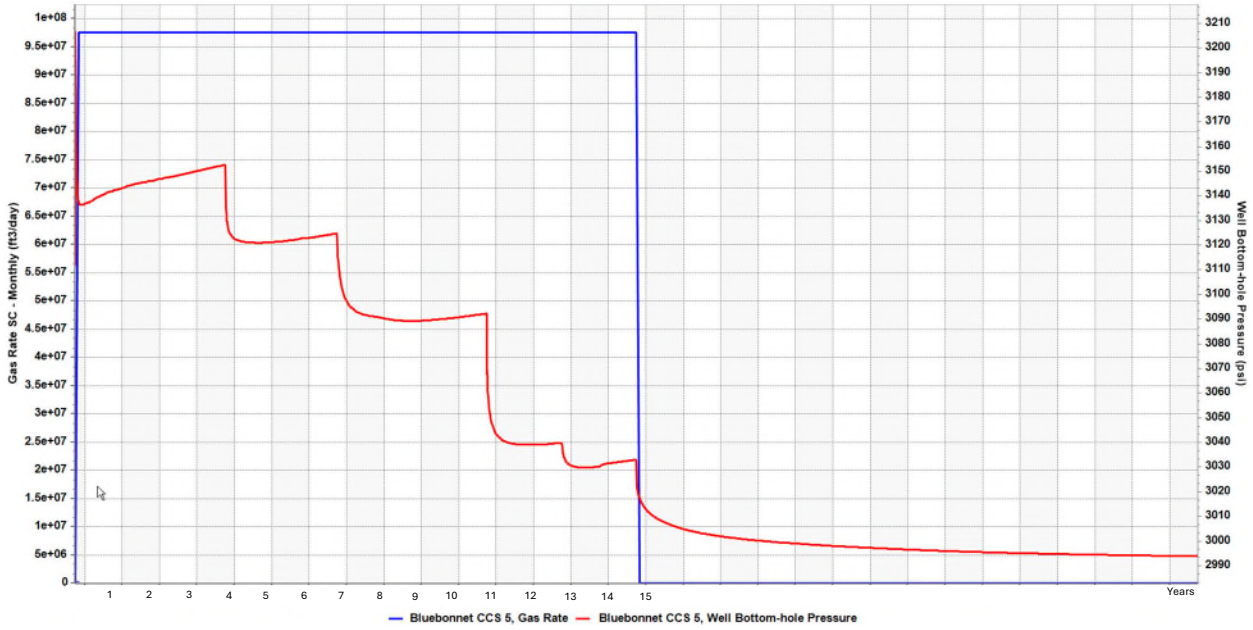


Figure AoR-300: Simulated well Bluebonnet CCS 5 gas injection rates and corresponding bottomhole pressures.

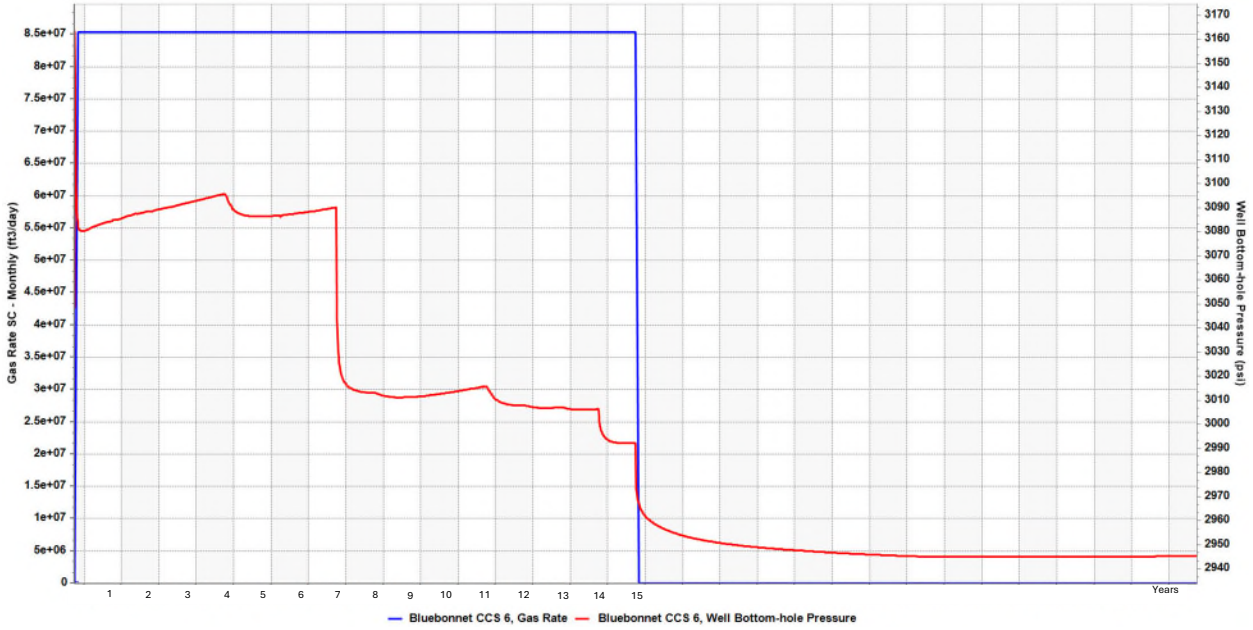


Figure AoR-301: Simulated well Bluebonnet CCS 6 gas injection rates and corresponding bottomhole pressures.

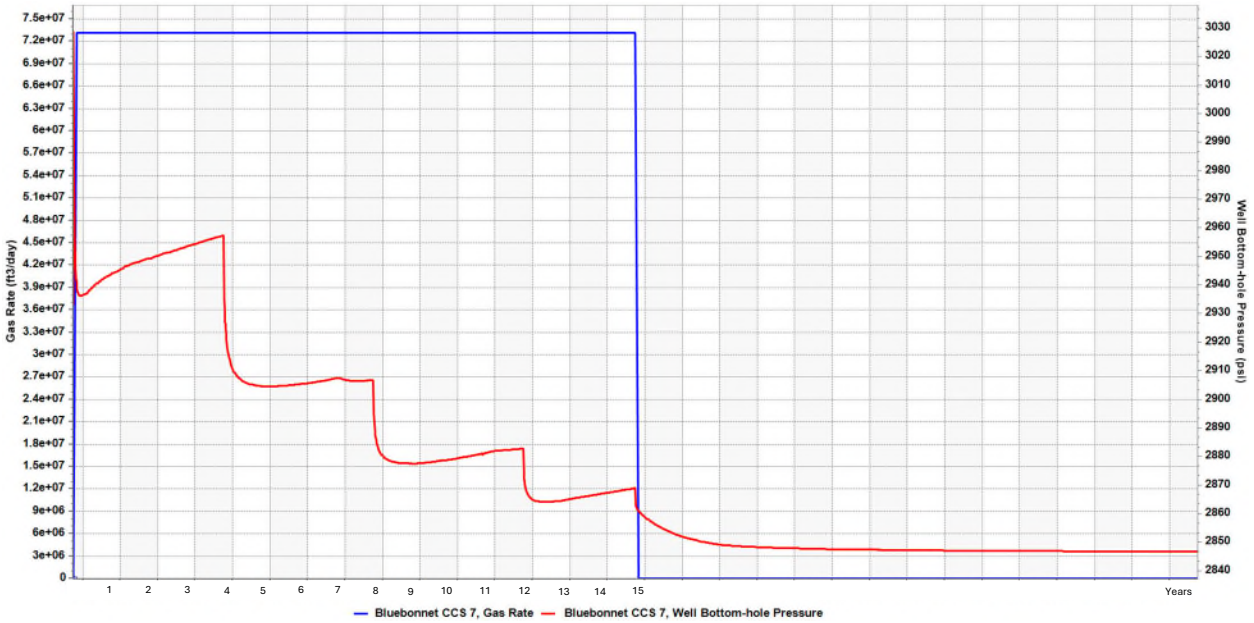


Figure AoR-302: Simulated well Bluebonnet CCS 7 gas injection rates and corresponding bottomhole pressures.

5.12 Model Calibration and Validation

5.12.1 Sensitivity to Input Parameters

Due to the uncertainties in some of site-specific pilot data used to calibrate the dynamic model, sensitivity of the results to subsurface input was explored. These subsurface uncertainties include vertical-to-horizontal permeability ratio (K_v/K_h), residual gas saturation (S_{gr}), permeability multiplier, faults transmissibility, rock compressibility, and size of the boundary aquifers.

Table AoR-54 summarizes the possible ranges of these subsurface inputs. The base case inputs are indicated in the left column. Many simulation runs were made by varying these parameters one at a time and plotting the results to see their impacts. The parameters used to compare the different sensitivity cases are reservoir pressure increase and CO_2 retention.

Table AoR-54: Simulation sensitivity cases.

Case	Parameter	Base Case	Sensitivity Values	
			High	Low
1	Boundary Extension	[redacted]		
2	Kv/Kh			
3	Fault Transmissibility Multiplier			
4	Residual Gas Saturation (Sgr)			
5	Rock Compressibility			
6	Permeability Multiplier			

Claimed as PBI

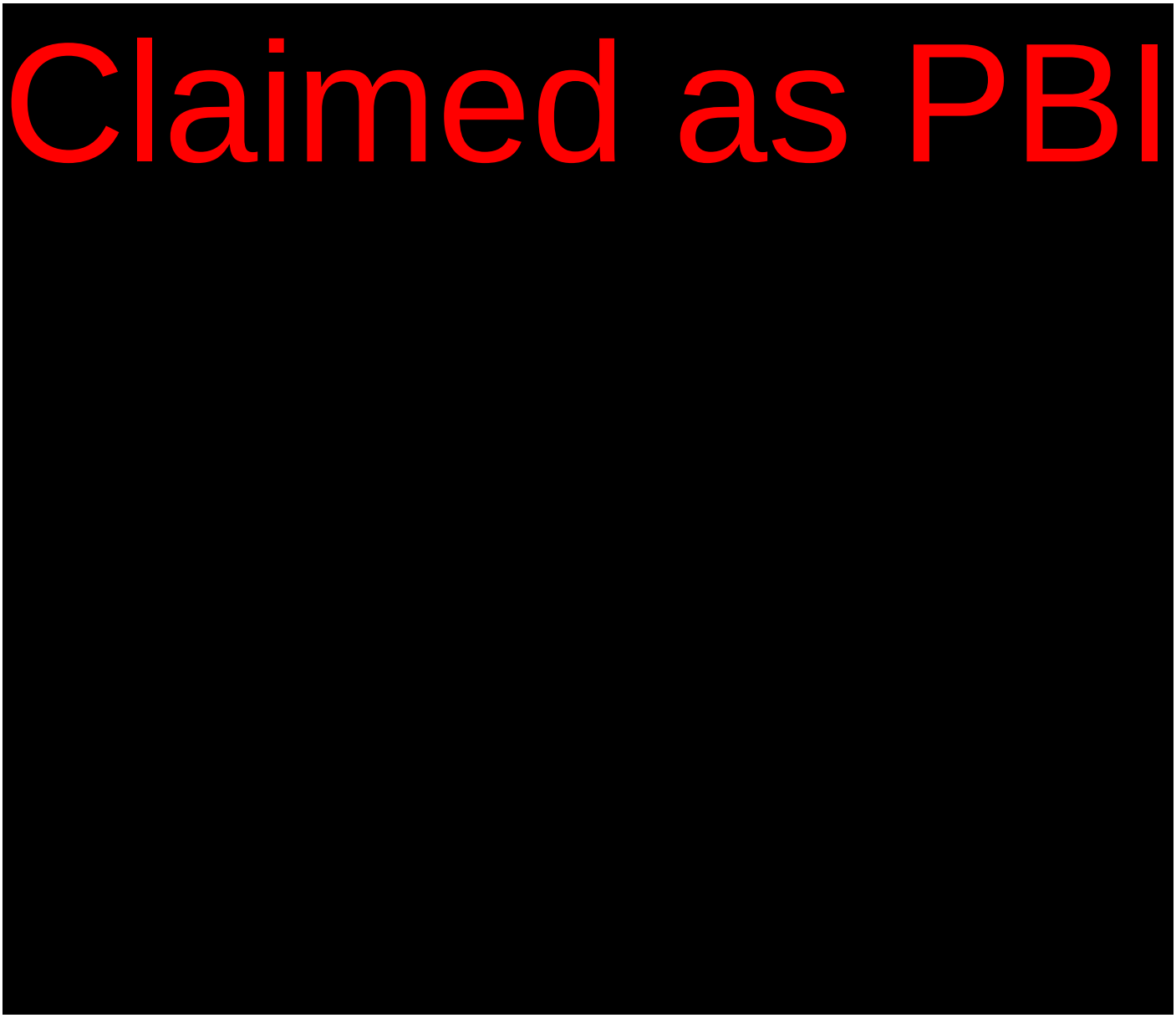
Figure AoR-303 to Figure AoR -308 shows the impact on the AoR delineation by each of the sensitivity's cases.

The highest changes in AoR occurs in the scenarios of low rock compressibility and permeability multiplier. Both scenarios are very unlikely for the Miocene storage complex based on the site-based data presented in previous sections and extensive literature of the Gulf Coast reservoirs.


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI

5.13 Area of Review (AoR)

5.13.1 Critical pressure calculations

Claimed as PBI [redacted].

Critical Pressure = MW x 0.052 x (TD_{perf}– 50) + GS –$\nabla P_{Reservoir}$ x TD_{perf} ... (Equation 11)

Gel Strength Pressure (GS) = A x Gel Strength x L_{Hole} / D_{Hole} …..…. (Equation 12)

MW: Mud weight (ppg)
TD_{perf}: Top of perforation depth (ft)
GS: Gel Strength Pressure (psi)
$\nabla P_{Reservoir}$: Reservoir Pressure Gradient (psi/ft)
A: Conversion factor (1/300)
Gel Strength (lbs/ft^2)
L_{Hole}: Length of the wellbore (ft)
D_{hole}: Diameter of the wellbore (inch)

5.13.2 AoR delineation

5.13.2.1 Critical pressure front

The maximum differential pressure occurs at year 4 of injection since the three wells, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7, are operating at a constant injection rate, in the same reservoir zone, simultaneously. The movement of the pressure front was evaluated at 5, 10, and 15 years after injection starts. The forecasted pressure increases in year 4 of the injection period is shown in Figure AoR-309. A critical pressure front of 110 psi for the Lower Miocene is projected onto the 2D areal map.

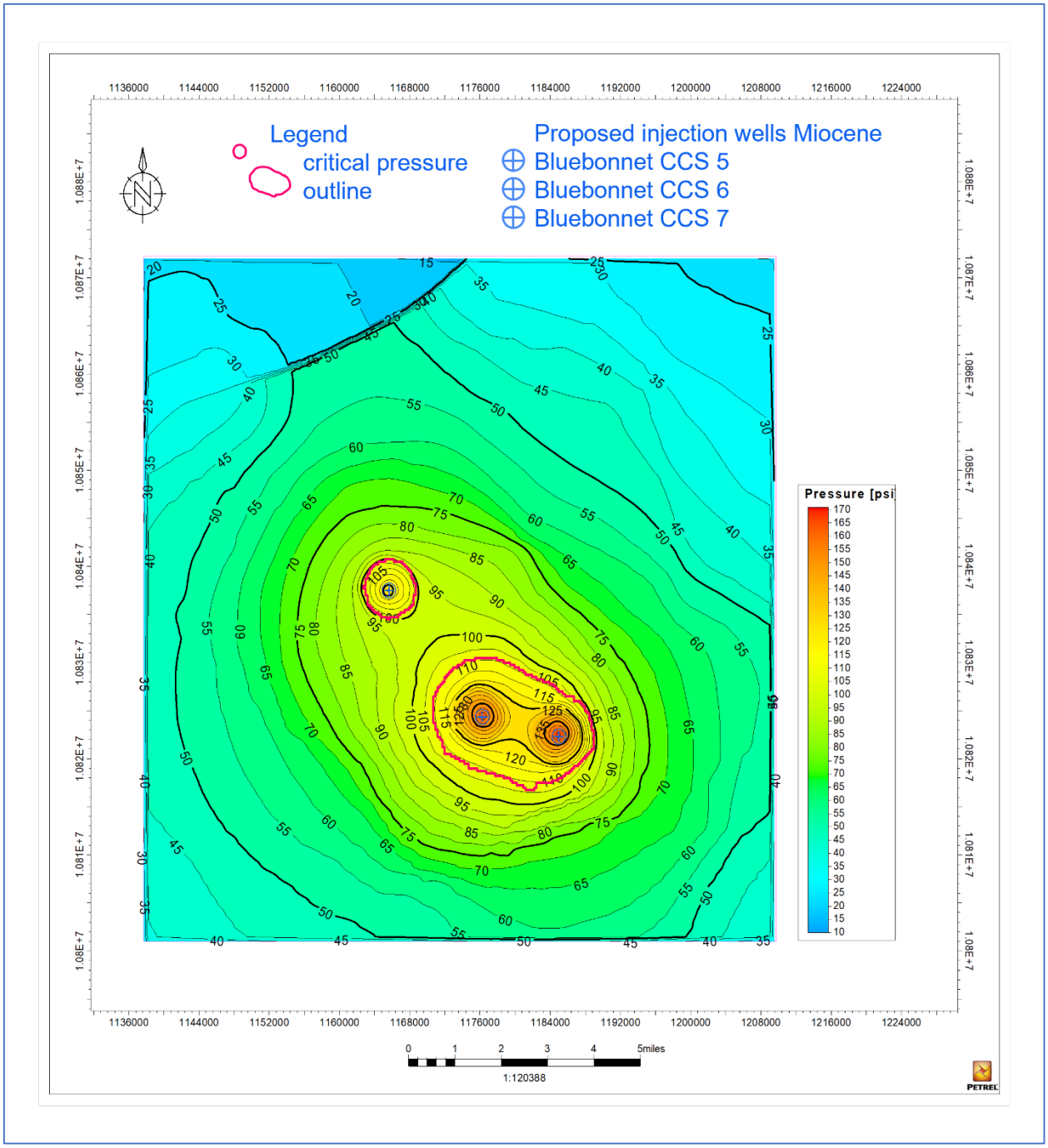


Figure AoR-309: View of highest pore-pressure increases when CCS 5, CCS 6, and CCS 7 are injecting in the same stage at the same time within the first 4 years of injection. Values displayed are pore-volume-weighted averages across the lowermost injection interval, which is opened first. The red polygon is the pressure front for the Miocene Formation after 4 years of injection when the highest pressure occurs because of the staged bottom-up completion strategy.

5.13.2.2 CO_2 plume extent

The CO_2 plume extend was simulated assuming 15 years of injection as described in the previous section. The Project simulated 50 years post-injection as well as 100 years post-injection. Plume tends to stabilize before the 50 years of post-injection period; however, the Project defined the 100-year plume outline to delineate the maximum extend of the CO_2 plume in the AoR as a conservative approach. The Project used a cut off of 3% CO_2 saturation as supported by the fluid substitution analysis provided in Section 8.0.

Figure AoR-310, Figure AoR-311, and Figure AoR-312 show CO_2 distribution at End of Injection, 50 years of post-injection, and 100 years post injection. The highest CO_2 saturation is around the wellbore and has moved up dip with time. Results suggested that CO_2 plume extents can be retained within the AoR and migration of CO_2 plume from 50 to 100 years is predicted to be minimal.

Figure AoR-313, Figure AoR-314, and Figure AoR-315 show the simulated CO_2 saturations along a north-south cross section through Bluebonnet CCS 5, CCS 6, and CCS 7 wells in year 15 after injection. The figure displays a desirable uniform CO_2 profile within the injection zone, effectively utilizing all intervals in the project's pore spaces. In the modeling exercises, such a profile has been achieved by employing the staged completions bottom up.

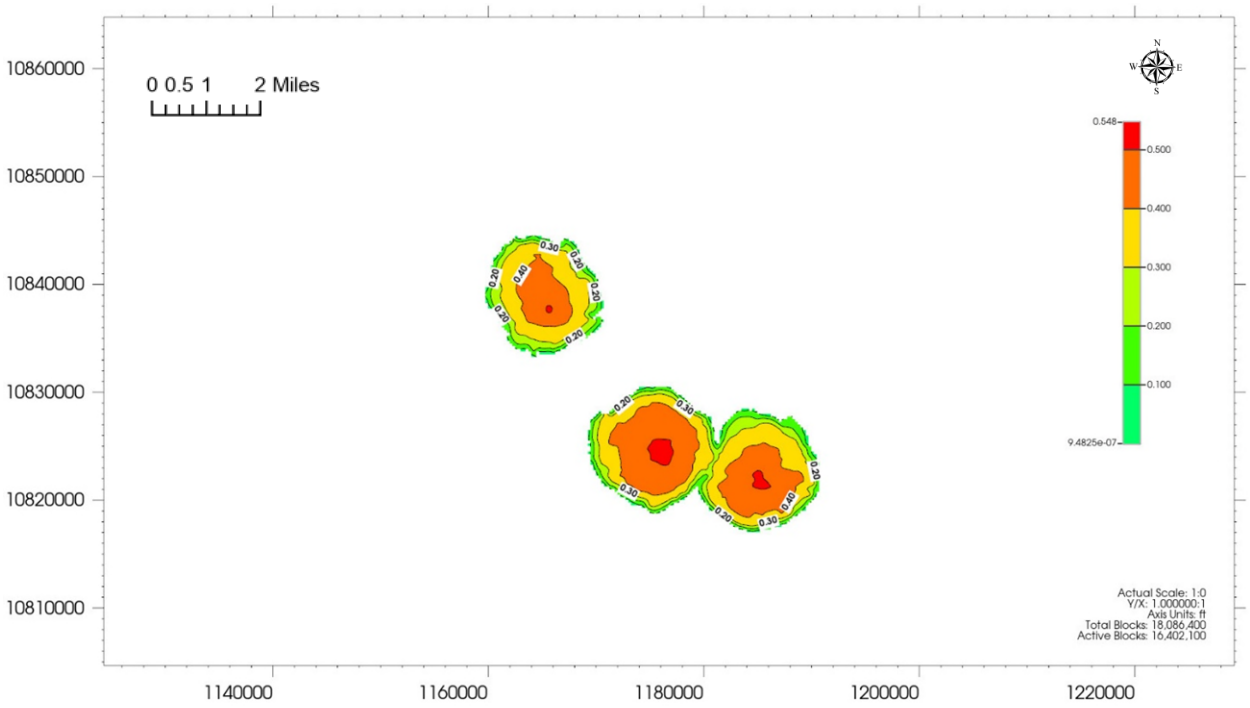


Figure AoR-310: CO_2 saturation map distribution after 73.2 million MT CO_2 injection in Lower Miocene at the End of Injection.

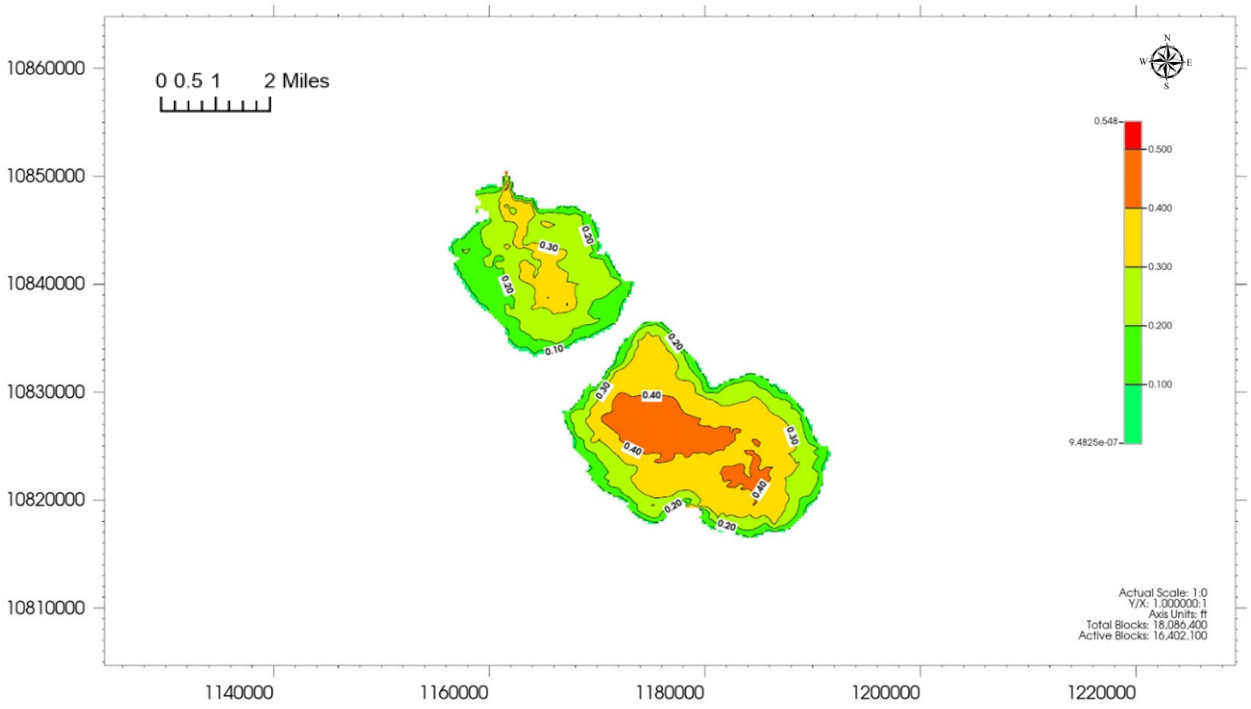


Figure AoR-311: CO_2 saturation map distribution after 73.2 million MT CO2 injection in Lower Miocene, after 50 years of post-injection.

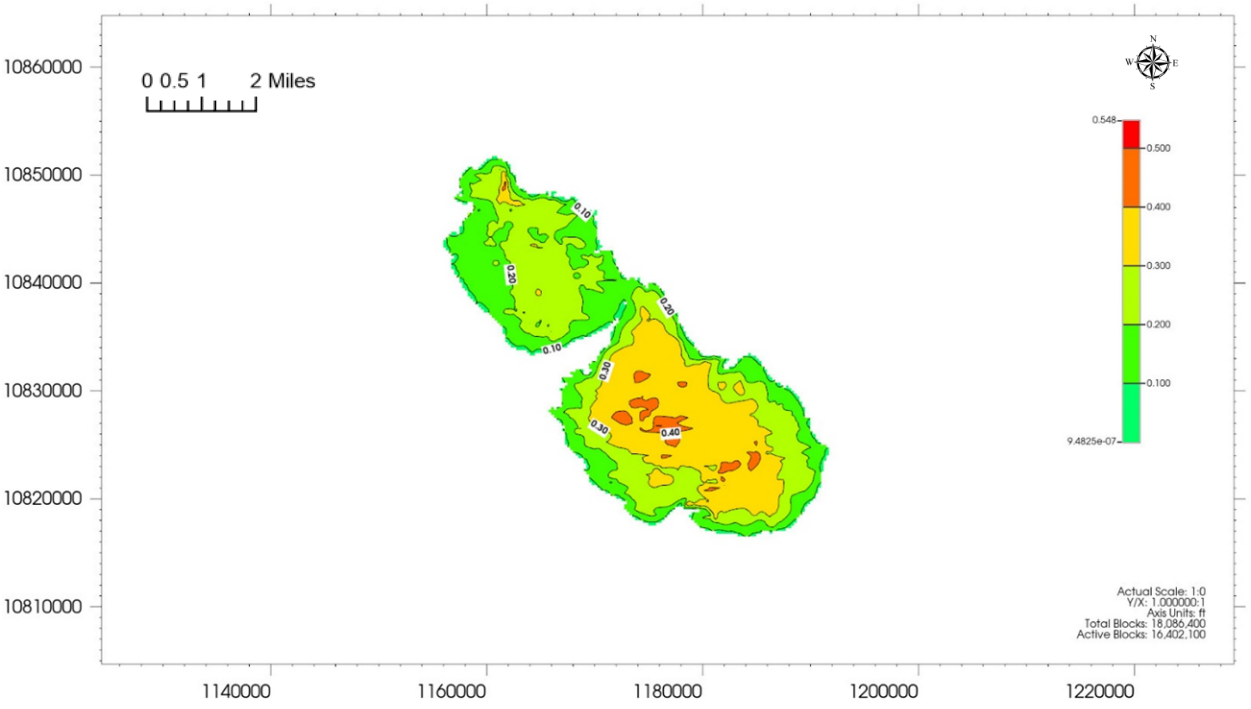


Figure AoR-312: CO_2 saturation map distribution after 73.2 million MT CO_2 injection in Lower Miocene, after 100 years of post-injection.

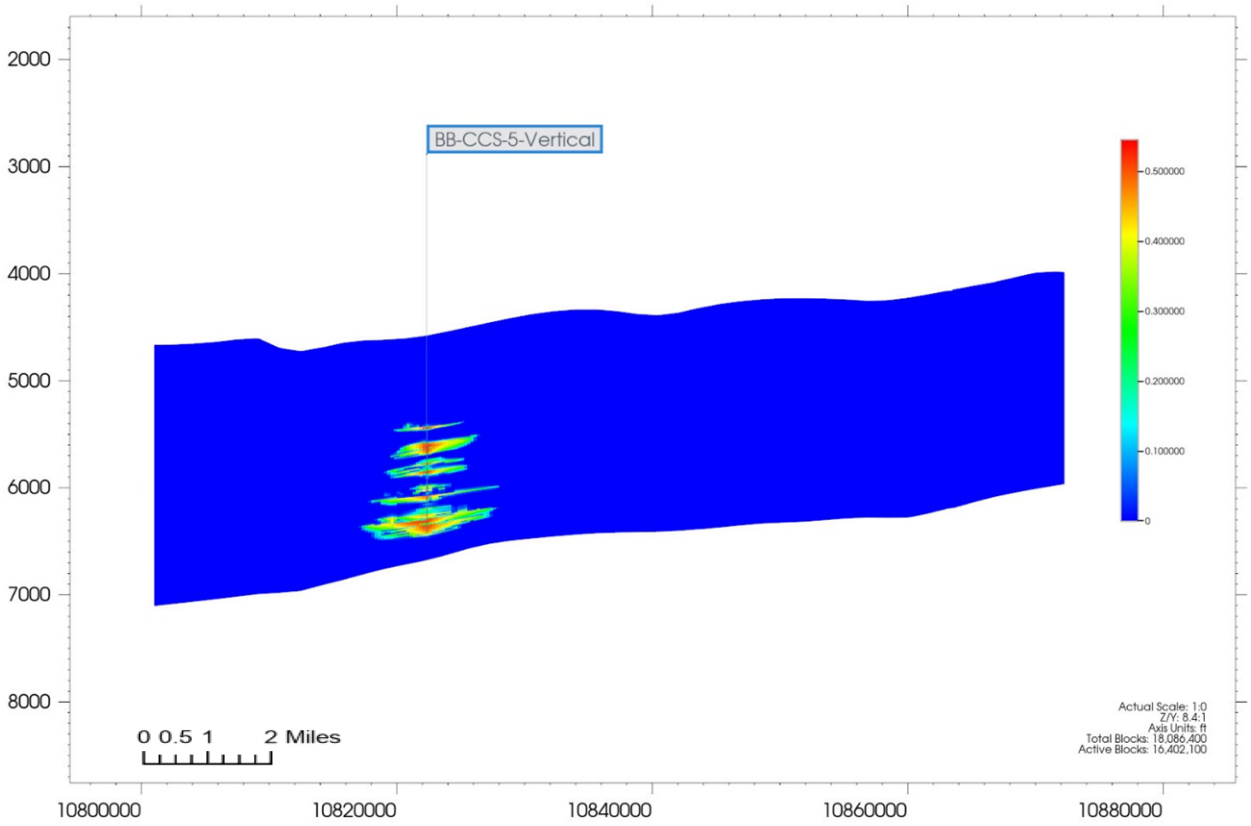


Figure AoR-313: North-south cross section through well CCS 5 showing simulated CO_2 saturation at year 15 after injection starts.

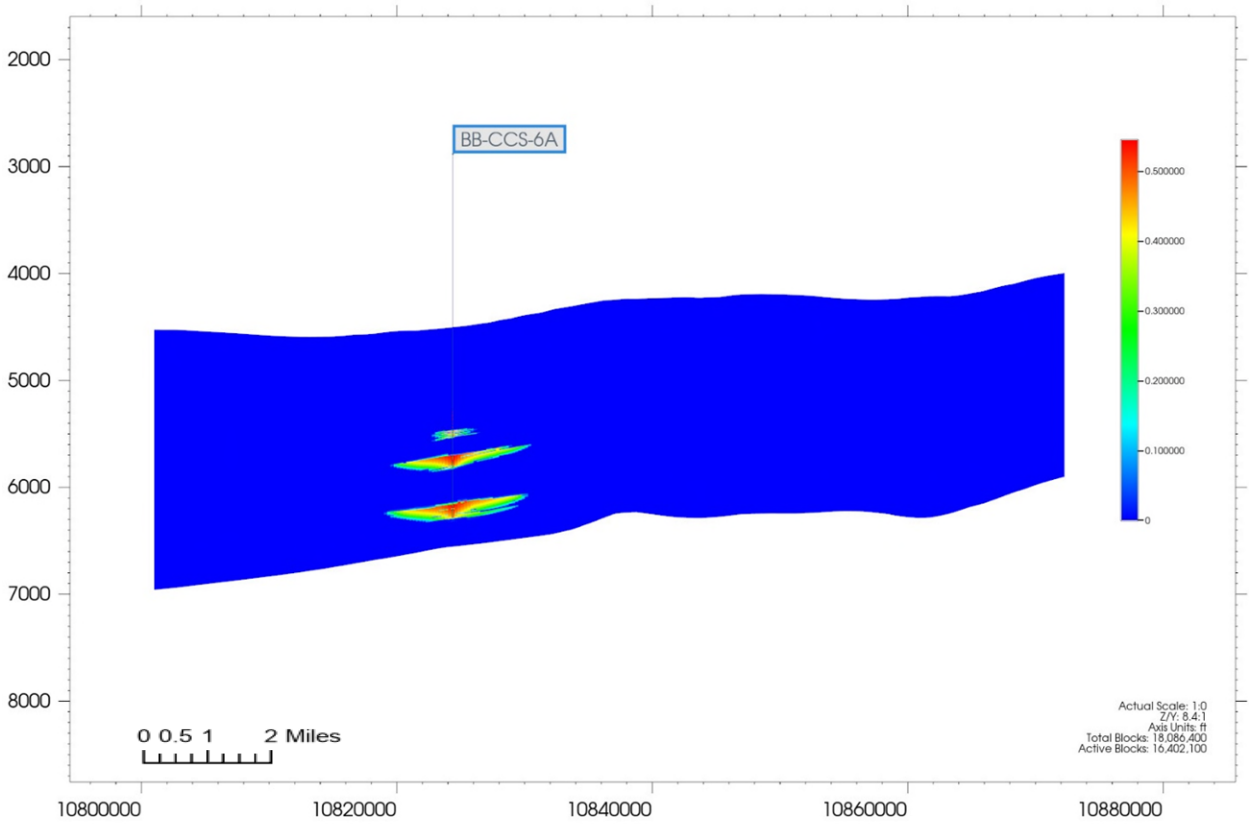


Figure AoR-314: North-south cross section through well CCS 6 showing simulated CO_2 saturation at year 15 after injection starts.

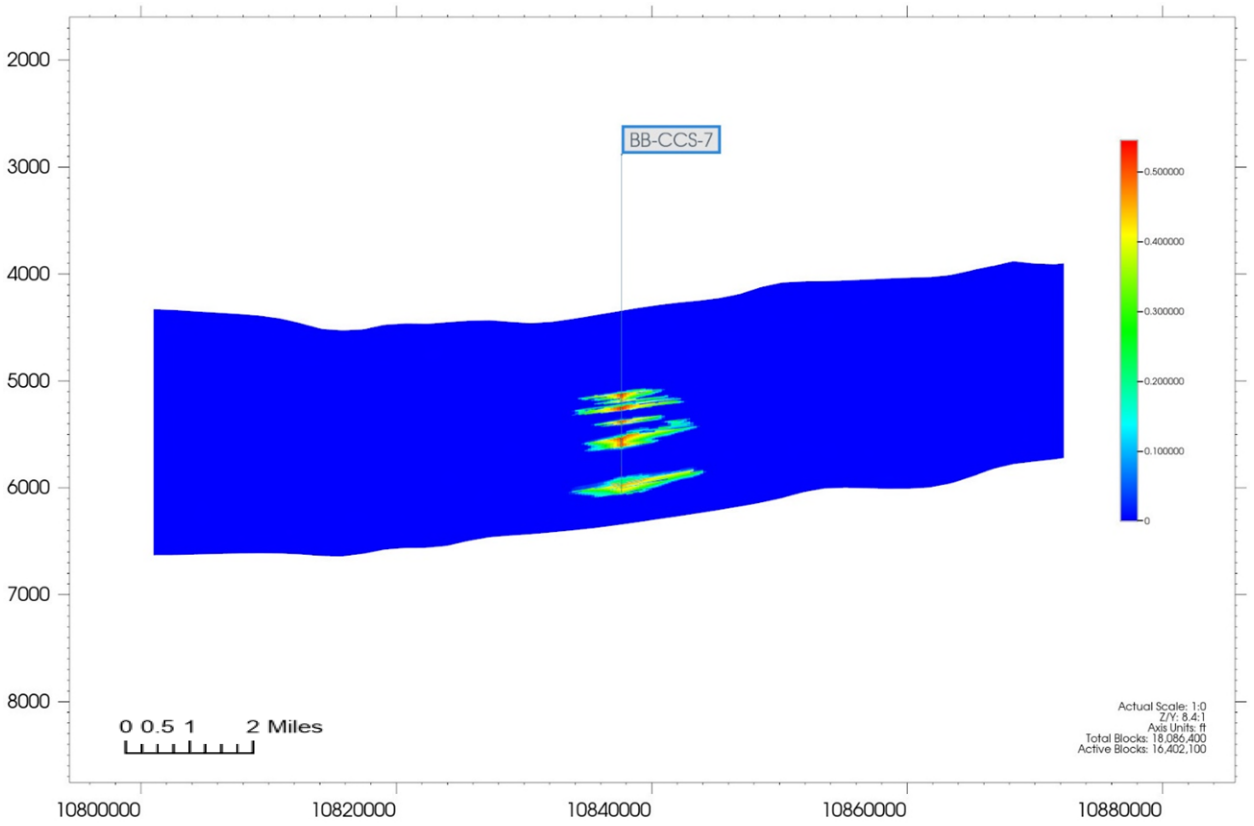


Figure AoR-315: North-south cross section through well CCS 7 showing simulated CO_2 saturation at year 15 after injection starts.

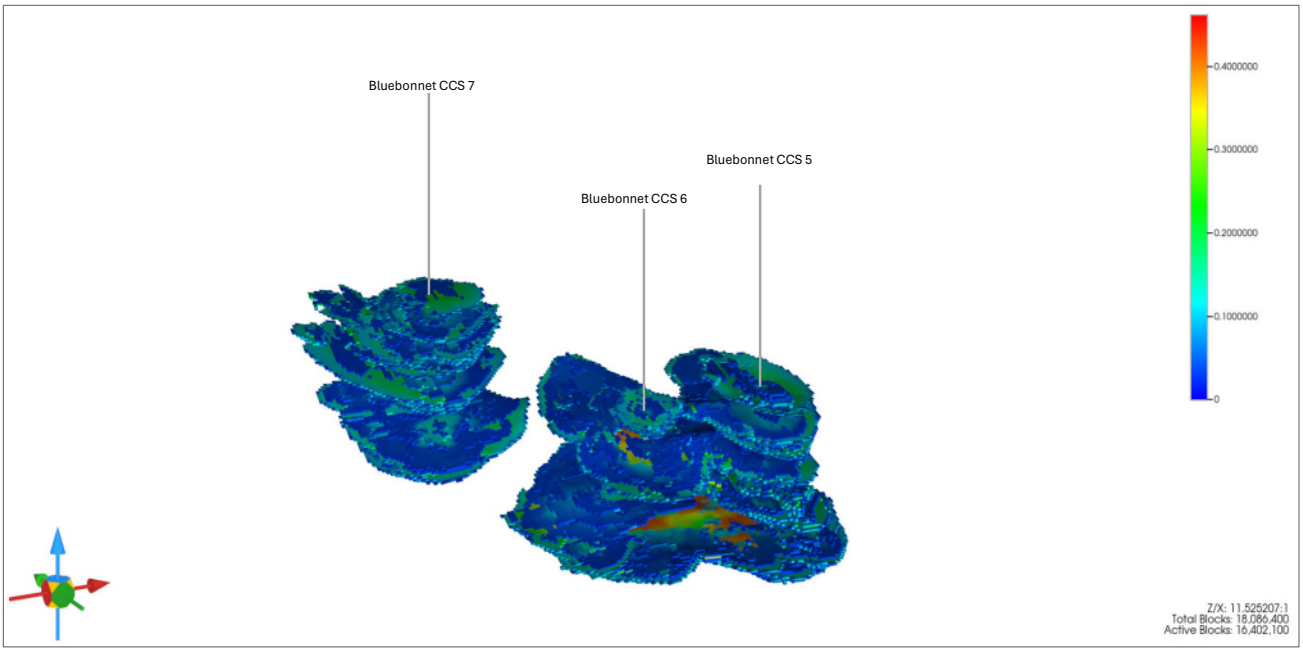


Figure AoR-316: 3D View of the CO_2 plumes for Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7.

5.14 Geochemical Modeling

Geochemical equilibrium and reactive-transport simulation modeling was conducted for the Lower Miocene confining and injection zones at Bluebonnet Sequestration Hub to evaluate site specific data acquired from the stratigraphic well. Two geochemical modeling studies were performed: (1) batch reactions with detailed geochemical equilibrium simulations and (2) reactive-transport and the multiphase flow simulations using the full-field model. Literature review for geochemical and reactive-transport modeling at carbon sequestration sites was described in detail in Section 4.11.1 of this document.

5.14.1 Geochemical Equilibrium Simulations

Geochemical equilibrium modeling was conducted using Geochemist's Workbench and the Lawrence Livermore National Laboratory thermodynamic database for aqueous, mineral, and gaseous interactions (Wolery 1992a; Wolery 1992b). The Tsonopoulos equation of state was used to improve the solubility calculation of gas at high pressures (Tsonopoulos, 1974, Tsonopoulos and Heidman, 1990).

The objective of this work is to identify primary chemical reactions (solid and aqueous phase) to be included into the reactive-transport simulations and provide initial assessment of CO_2 compatibility with rocks and fluids in the reservoir and confining zones. This modeling includes brines speciation, geochemical baseline prior injection, and CO_2 interaction with reservoir brine and minerals.

Table AoR-55 shows brine compositions for the reservoir and composite confining zone used in geochemical simulations. Dissolved constituents not shown in the table were not considered in geochemical models because their concentration was negligible or below detection limits. Trace metals (*e.g.*, arsenic, mercury, and lead) have negligible concentrations and were not tracked during modeling.

Table AoR-56 describes mineralogy used in geochemical equilibrium runs for the reservoir and confining zones. Values were obtained from XRD analysis of representative samples within each reservoir or confining system interval.

Table AoR-55: Brine chemical compositions used in geochemical and reactive-transport simulations – Lower Miocene

Name	Description	Units	Miocene Composite Confining Zone	Lower Miocene Injection Zone
Sample Depth	-	ft	Claimed as PBI	
Reservoir Pressure	-	psi		
Reservoir Temp	-	°F		
TDS	Sum of Ions	mg/L		
pH	Lab	SU		
Sodium	Na^+	mg/L		
Calcium	Ca^{2+}	mg/L		
Magnesium	Mg^{2+}	mg/L		
Potassium	K^+	mg/L		
Strontium	Sr^{2+}	mg/L		
Barium	Ba^{2+}	mg/L		
Silica	SiO_2 (aq)	mg/L		
Aluminum	Al^{3+}	mg/L		
Iron (total)	Fe^{2+}	mg/L		
Chloride	Cl^-	mg/L		
Total Alkalinity	Alkalinity	mg HCO_3^-/L		
Borate	$B(OH)_3^-$	mg/L		
Bromide	Br^-	mg/L		
Sulfate	SO_4^{2-}	mg/L		

Table AoR-56: Solid-phase mineralogy from RSWC XRD data used in geochemical equilibrium and reactive-transport simulations – Lower Miocene.

Mineral (wt%)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
Quartz	Claimed as PBI	
K-Feldspar		
Plagioclase		
Calcite		
Dolomite		
Pyrite		
Illite/Smectite		
Kaolinite		
Analcime		
Chlorite		

Although some chemical reactions are known to be time dependent, equilibrium assumption was first modeled to represent the most conservative approach. The equilibrium approach allows minerals to dissolve or precipitate instantaneously and achieve final stage of interaction with other solid phase and aqueous species. This approach can simulate expected late time fluid-rock interactions anticipated in permanent CO_2 storage.

The Wolery database was selected as the thermodynamic data and activity coefficient model for equilibrium and reactive-transport simulations. Although Pitzer virial model is known to be more suitable for brines with high ionic strength (above 1.0 M) at certain conditions, the extended Debye-Hückel equation ("Bdot" equation) is determined to be more suitable for the brines analyzed for this site. Besides the ion-size parameters, the extended terms based on ionic strength have been fit for main ions in chloride-dominated waters (Truesdell and Jones, 1974) such as calcium, magnesium, sulfate, potassium, and carbonate species. In addition, the Pitzer approach has limited parametrization for iron and aluminum species as pointed out by Krupka et al. (2010). These aqueous components are very important for brines in equilibrium with clay-type minerals because they modify the ions activity, having critical impact on minerals solubility product (Appelo and Postma, 2005).

For equilibrium simulations, a rock with porosity equal to 17% is assumed. Initial CO_2 concentration in the reservoir was retrieved using flashed gas composition and the fugacity was calculated at reservoir pressure and temperature. Calculated pre-injection fugacity is 0.009 and 0.006 atm for the Lower Miocene Confining Zone and Lower Miocene Injection Zone, respectively. Secondary mineral phases were included in the simulation even though they are not present in measured XRD data (e.g., dolomite, anhydrite, gypsum, barite, strontianite, and celestite) to evaluate their precipitation tendency. In addition, plagioclase is assumed to be anorthite phase.

Three geochemical scenarios were modeled: (1) fluid equilibrium without minerals present, (2) baseline (pre-injection) equilibrium modeling between existing formation fluids and mineralogy, and (3) equilibrium modeling of formations fully saturated with CO_2 to represent the most aggressive injection case. Table AoR-57 shows reservoir fluid equilibrium state for the confining and reservoir zones. Positive and negative saturation index numbers (SI) indicate supersaturated or undersaturated condition in relation to a mineral, respectively. Fluid equilibrium modeling can provide assurance of quality fluid analysis and insight to flow paths or potential commingling as minerals in equilibrium are assumed to be primary sources of dissolved ions in formation fluids. Lower Miocene Confining Zone results suggest formation fluids are in equilibrium with the formation mineralogy including barite and calcite. Lower Miocene Injection Zone fluids are in equilibrium with barite and calcite.

Modeled pH values are lower in comparison to laboratory measured values. This result can be explained by CO_2 exsolving from fluids exposed to atmospheric conditions during analysis. Even rapid laboratory analytical result in CO_2 loss prior to measurements, resulting in a shift to more basic conditions (Appelo and Postma, 2005, page 14). Here, the Lower Miocene Confining and Injection Zones show calculated pH values similar to those reported in the literature (Kharaka et al. 2009 and Xu et al., 2010).

Table AoR-57: Mineral saturation indexes and reservoir pH of formation waters in Lower Miocene Confining and Injections Zones prior to CO_2 injection (baseline reservoir condition).

Model Results (SI)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
pH (SU)	Claimed as PBI	
Anhydrite		
Barite		
Calcite		
Celestite		
Dolomite		
Gypsum		
Halite		
Illite		
Kaolinite		
K-Feldspar		
Plagioclase		
Quartz		
Strontianite		
Dawsonite		
Analcime		

Baseline (pre-injection) equilibrium modeling included the addition of formation mineralogy previously described in Table AoR-56. Overall, similar mineral stability tendency is observed for the Lower Miocene Confining and Injection Zones (Table AoR-58). Pre-injection, formation waters are saturated with respect to calcite, dawsonite, kaolinite, and K-feldspar and are predicted to precipitate at equilibrium. Calcite precipitation at equilibrium and associated removal of bicarbonate ions is likely the cause low pH values observed with fluid-rock equilibrium models. Clay minerals, including kaolinite, are highly sensitive to dissolved aluminum concentrations and values were reported below detection limit. Despite predicted kaolinite supersaturation, it is likely that both kaolinite and illite are stable at existing reservoir conditions considering kinetics of clay mineral precipitation. Quartz, pyrite, illite, and dolomite are considered stable phases initially present in the reservoir. Plagioclase is considered unstable at pre-injection reservoir conditions and predicted to be dissolve at existing reservoir conditions.

Table AoR-58: Mineral stability tendency and fluid pH of Lower Miocene Confining and Injections Zones in equilibrium with reservoir mineralogy.

Model Results (SI)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
pH (SU)	7.1	6.8
Fluid TDS	Minor increase	Minor decrease
Reservoir Porosity	Minor decrease	Minor decrease
Anhydrite	Dissolution	Dissolution
Barite	Stable	Stable
Calcite	Precipitation	Precipitation
Celestite	Dissolution	Dissolution
Dawsonite	Precipitation	Dissolution
Dolomite	Precipitation	Precipitation
Gypsum	Dissolution	Dissolution
Halite	Dissolution	Dissolution
Illite	Stable	Stable
Kaolinite	Precipitation	Precipitation
K-Feldspar	Precipitation	Precipitation
Plagioclase	Dissolution	Dissolution
Pyrite	Stable	Stable
Quartz	Stable	Stable
Strontianite	Minor precipitation	Minor precipitation
Analcime	Stable	Stable

Geochemical equilibrium modeling of formations fully saturated with CO_2 to simulate injection suggests CO_2 addition cause minor effects on mineral saturation states. CO_2 fugacity was assumed to be 1.26 and 1.67 for 100% CO_2 gas at Lower Miocene Confining and Injection Zone

temperatures and pressures, respectively. Table AoR-59 shows the mineral stability tendency after equilibration for each sample in the Lower Miocene Confining and Injection Zones.

Negligible changes for mineral saturation states were observed for most minerals when comparing results for existing (Table AoR-58) versus fully saturated (Table AoR-59). Values for pH are predicted to decrease approximately 1.5 SU. Minor precipitation of Dawsonite is predicted in Lower Miocene Confining and Injection Zones. Saturation with respect to illite is predicted to decrease at equilibrium; however, the mineral is relatively stable and minimal dissolution is predicted. Dolomite is considered stable and precipitation is suppressed due to slow reaction kinetics associated with dolomite. Therefore, quartz, pyrite, and dolomite likely remain the most stable phases initially present. Plagioclase dissolution will increase as larger amount of CO_2 dissolves in water shifting the equilibria to a more acidic environment. In addition, a substitution process occurs by precipitation of calcite and kaolinite; enhanced further under CO_2-saturated reservoir conditions. However, dynamics in the reservoir during injection are more complicated as reactions are time dependent and calcite likely dissolve first at lower pH, reprecipitating at later times (equilibrium conditions).

Lower Miocene Confining Zone results show minimal effects from saturation with 100% CO_2 and equilibrium conditions have a small (~1.5%) porosity loss due to high proportions of clay minerals and mineral reprecipitation in the pore space. This finding corroborates the assumption that CO_2 will not affect the confining system integrity as pointed out by Kharaka et al. (2009). It is important to highlight that further precipitation might provide a healing effect to microfracture that might have been formed due to pressure increase (*i.e.*, mechanical deformation), as proposed by Hangx et al. (2009), enhancing long-term integrity of the confining system.

Table AoR-59: Directional shift in mineral stability tendency and fluid pH of Lower Miocene Confining Zone and Injections Zones in equilibrium with reservoir mineralogy and saturated CO2.

Model Results (SI)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
pH (SU)	5.5	5.3
Fluid TDS	Minor increase	Minor decrease
Reservoir Porosity	Minor decrease	Minor decrease
Anhydrite	-	-
Barite	-	-
Calcite	Inc. precipitation	Inc. precipitation
Celestite	-	-
Dawsonite	Inc. precipitation	Inc. precipitation
Dolomite	-	-
Gypsum	-	-
Halite	-	-
Illite	Minor dissolution	Minor dissolution
Kaolinite	-	-
K-Feldspar	-	-
Plagioclase	Inc. dissolution	Inc. dissolution
Pyrite	-	-
Quartz	-	-
Strontianite	-	-
Analcime	Inc. dissolution	Inc. dissolution

5.14.2 Reactive-Transport Simulations

Reactive-transport simulations were conducted using CMG-GEM. This section provides an evaluation of geochemical influences on reservoir storage capacity and long-term trapping mechanisms. The extended Debye-Hückel equation ("Bdot") is used for consistency with geochemical equilibrium simulations. Quartz, calcite, plagioclase (anorthite), kaolinite, k-feldspar, illite, and dolomite are minerals considered in dynamic simulations. Minerals present in the XRD that resulted as non-reactive (e.g. pyrite) are not included in simulations and lumped with the quartz phase.

All mineral solubility reactions were simulated using the kinetics approach based on the transition state theory (TST). Activation energies, TST reaction rate constants, and equilibrium constants are retrieved from the literature (Palandri and Kharaka, 2004, Krupka et al. 2010, Jia et al. 2021, and Zhang et al. 2019). Mineral reactive surface area is considered one of the largest uncertainties for modeling kinetic reactions. Actual reactivity area values are assumed to be significantly lower in comparison to the conventional methods of surface area measurements (***e.g.***, BET adsorption

method). This is because certain pores are not expected to contact injected fluid due to preferential flow paths in porous media. For the current simulations, reactive surface area values were retrieved from Jia et al. (2021) and Zhang et al. (2019) and their values multiplied by 0.01 as recommended by Xu et al. (2010). For practical purposes, the final state of mineral stability is insensitive to the reactive surface area (hundreds of years after injection). However, as reactive surface area value increases, the simulation will reach the equilibrium condition faster. Thus, it allows the interpretation of how the long-term CO_2 storage affects reservoir properties within a reasonable computational time.

The effect of mineral dissolution and precipitation on porosity is also included to evaluate its impact on reservoir storage capacity. The model is based on the simple correlation that the amount of mineral change will directly impact the solid volume using the respective mineral mass, mineral molar weight, and mineral density to calculate the new void volume (porosity) over time. The modified Kozeny-Carman equation was included to model the effect of porosity changes in rock permeability.

The model is initialized into two regions, confining and reservoir, with each region having a distinct mineralogy and water chemical composition (Table AoR-55 and Table AoR-56). In total, twelve aqueous species were initialized in reservoir connate water and allowed to flow with aqueous phase in the reactive-transport simulations. The aqueous species modeled are $H_4SiO_4^0$, H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2^0, HCO_3^-, OH^-, CO_3^{2-}, and $CaOH^+$. The selection of aqueous complexes was based on the simulation results from geochemical equilibrium runs with minerals and CO_2. Aqueous species that were not originally in the complete water analysis were assumed to have trace concentration. The reservoir is allowed to equilibrate prior to simulation start. Preliminary reactive-transport simulation results are described below and multiple parameter sets are still being considered to understand current model observations and improve simulation runtimes.

Figure AoR-317, shows minimum value results for fluid pH values at end of the injection period, aggregated across all model layers. Reservoir fluid pH values pre- and post-injection are similar to values obtained from equilibrium modeling (Table AoR-58 and Table AoR-59).

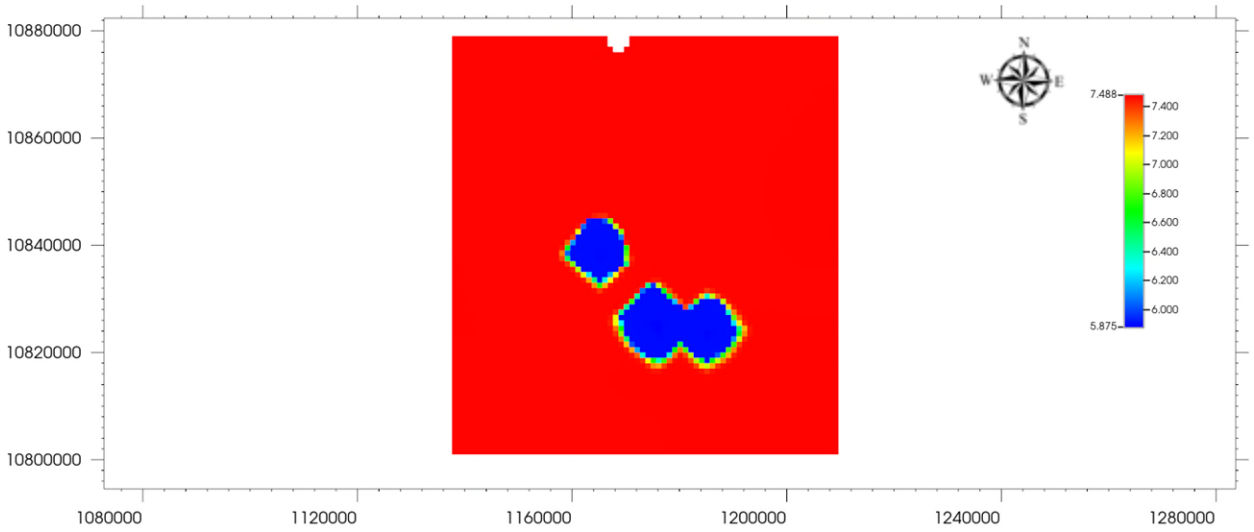


Figure AoR-317: Aggregate view for all model layers of minimum values for modeled fluid pH after cessation of CO_2 injection.

Figure AoR-318,shows reservoir mineral volume change for calcite, plagioclase, kaolinite, illite, k-feldspar, and dolomite upon cessation of injection. Dissolution of anorthite and calcite is observed during injection; however, molar changes are small due to minor proportions of calcite (1.2 mol %) in the Lower Miocene Injection Zone. Post-injection, it is expected that plagioclase continues to dissolve while calcite, kaolinite, and illite will precipitate (Xu et al., 2010, Hovorka et al. 2009). Kaolinite and minor illite precipitation are related to dissolution of plagioclase, which releases additional dissolved aluminum into formation waters.

Modeled porosity changes due to mineral dissolution and precipitation at end of the injection period are shown in Figure AoR-319 and Figure AoR-320. Negative and positive values represent the amount of increase and decrease from the initial porosity, respectively. Porosity increased a maximum of 0.3% in Lower Miocene Injection Zone through the end of injection. Porosity remained unchanged for the Lower Miocene Confining Zone due to the presence of low-permeability shales that prevent vertical upward migration of CO_2-saturated fluids. Reservoir porosity is expected to decrease over long post-injection timescales as calcite and kaolinite precipitate.

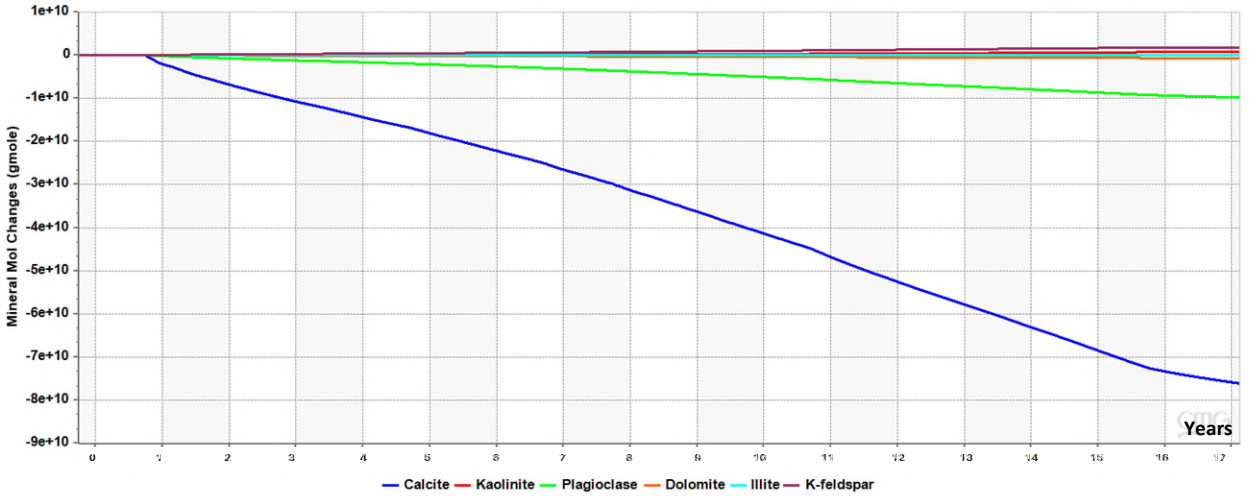


Figure AoR-318: Modeled molar change in minerals change through end of injection.

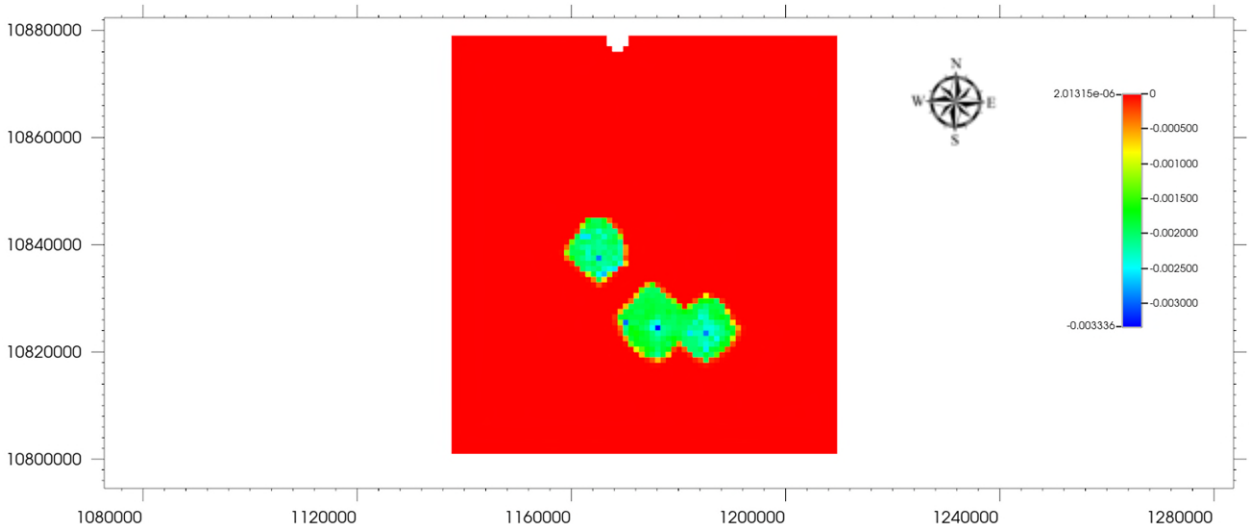


Figure AoR-319: Aggregate view for all model layers of modeled maximum porosity increase from mineral dissolution and precipitation upon cessation of injection.

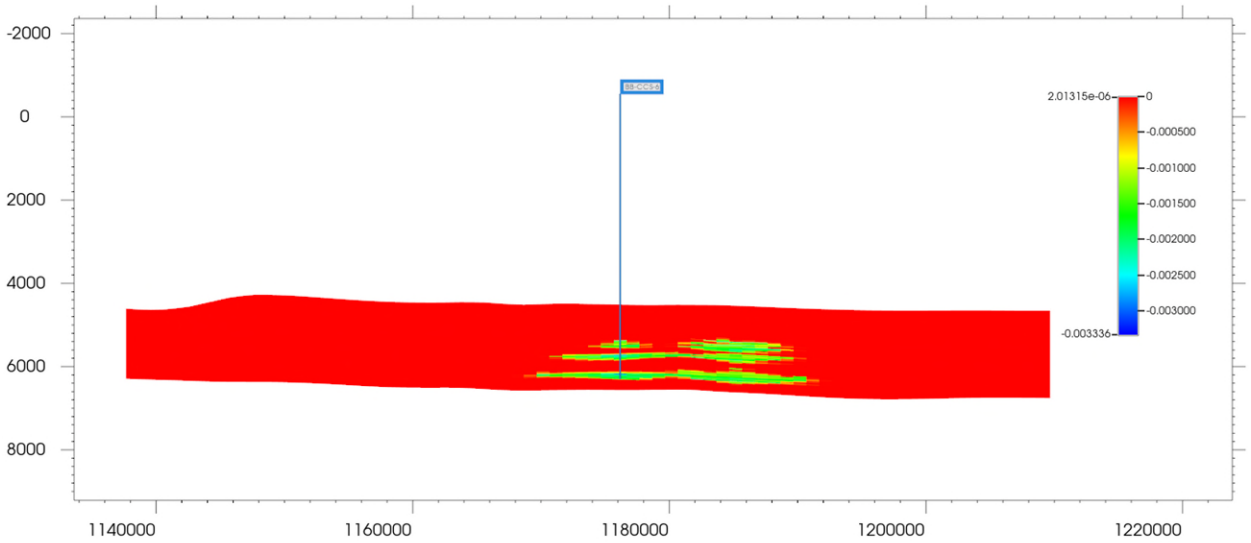


Figure AoR-320: Select E-W cross-section modeled porosity decrease from mineral dissolution and precipitation upon cessation of injection.

Modeled CO_2 trapping mechanisms (aqueous, dissolved in water, mineralization, super-critical mobile, and trapped in residual phase) are shown in Figure AoR-321. Results show primary trapping mechanisms of injected CO_2 at injection timescales is the super-critical phase as mobile and trapped CO_2. Mineral CO_2 storage is negative during injection due to calcite dissolution. Permanent sequestration of injected CO_2 as calcite is expected to occur over long post-injection timescales, eventually becoming a dominant trapping mechanism.

Compositional simulation commonly shows a larger CO_2 plume compared to reactive transport simulation. The reason for the reactive-transport simulations showing a smaller CO_2 plume, even with smaller pore volume, is due to part of the CO_2 being transferred from the super-critical state to two additional conditions that are not modeled using conventional runs: conversion in aqueous ions (*e.g.*, HCO_3^-) and precipitation as solid phase (*e.g.*, kaolinite, calcite). Thus, the compositional simulations (without geochemistry) typically provide the most conservative assessment of CO_2 plume extent.

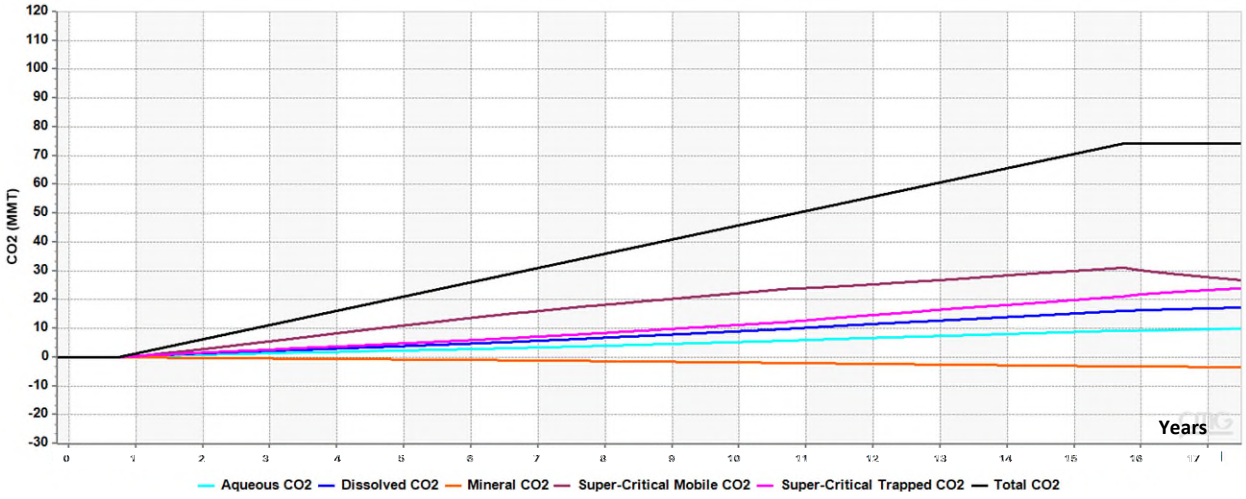


Figure AoR-321: CO_2 partitioning in reactive-transport model until cessation of injection.

6.0 Combined AoR – Oligocene & Miocene Storage Complex

For the Lower Miocene Confining Zone, the Miocene Composite Confining Zone as well as the base of USDW, the Frio/Hackberry AoR was merged with the Miocene AoR, as the confining zones are utilized for both storage complexes and also to capture the largest footprint to assess and mitigate any potential USDW contamination.



7.0 Fluid Substitution Study – Frio Injection Zone

An important aspect of all CCS projects is the demonstration of viable methods for monitoring of CO_2 plume development during injection, to ensure reservoir containment, and provide data necessary for dynamic model update(s). In high porosity saline aquifers, in-situ reservoir and elastic properties are amenable to robust detection of CO_2 using time-lapse geophysical methods sensitive to elastic property (bulk density and P-wave velocity) changes with increasing CO_2 saturation. The best-known example of this – from an offshore setting - is the Sleipner project in the North Sea (Dupuy et al. 2017); credible results from an active onshore sequestration site are known from the QUEST project in Alberta, Canada (Harvey et al. 2022). While Sleipner is a shallow reservoir and monitoring clearly benefits from high-quality repeat marine seismic data, similar opportunities are expected for geophysical monitoring in high porosity, acoustically 'soft' onshore reservoirs. Our feasibility modeling workflow makes no assumption about the monitoring method (3D and/or 2D surface seismic, in-well (DAS), cross-well, VSP, etc.) eventually selected, as the modeled response of expected changes due to increasing CO_2 saturation can be detected by all methods that respond to in-situ changes in acoustic impedance (density*P-wave velocity). The presence of a 'soft' fluid (CO_2) in a brine-saturated aquifer creates a significant change in acoustic impedance, which is readily detected with traditional geophysical methods sensitive to amplitude (density and Vp) and/or AVO (Vp and Vs) response due to fluid type and saturation changes.

Key elements of our feasibility modeling workflow are summarized in Figure 1. Additional comments about specific workflow elements are highlighted here for reference.

- Fluid properties. Brine acoustic properties are determined using extant (Batzle and Wang, 1992) geophysical properties model, with inputs Pressure (P), Temperature (T), and brine salinity (NaCl equivalent). Properties for CO_2 are also a function of P and T and are obtained using the Span and Wagner (1996) equation of state (EOS) model for pure CO_2. These estimates are made readily available using the convenient worksheet calculator provided by NIST(https://webbook.nist.gov/chemistry/fluid/).

- End-member elastic properties. Geophysical response in this Gulf Coast setting is controlled by the contrast between non-reservoir mudrock and reservoir (aquifer) wet sand. In a compaction setting, with normal pressure, elastic properties of both endmember lithologies is largely a function of effective stress, manifest as present-day burial depth. Acoustic impedance of both end-member rock types generally increases with depth in a monotonic and predictable manner. The contrast between end-member rock types is generally small, given the brine-saturated nature of the reservoir material.

- Reservoir rock physics model. An advocated approach to reservoir rock physics model development is applying model(s) tied to matrix composition, total porosity (petrophysical model and core-log calibration), and with an understanding of present-day (vertical) effective stress. The workflow ensures that core-log calibration done for petrophysical properties and geophysical measurements are compatible and enable full multi-physics integration. In the absence of core, the workflow is still able to deliver model-based geophysical calibration and well-base Close-the-Loop in uncored well control and further enabled by geological analog(s) with available core-based measurements.

- Fluid replacement modeling. Expected change in reservoir rock elastic properties (primarily Vp and bulk density) with an increasing volume of CO_2 is modeled using traditional (Gassmann) fluid replacement modeling (e.g., Wang, 2001) workflows. Following on extensive legacy lab-based studies and consistent with data included therein, the fluid mixing model is varied as a function of increasing CO_2 saturation. This has an important impact on modeled expectations for geophysical response in the reservoir, particularly at early (low) volumes of in-situ CO_2 saturation.

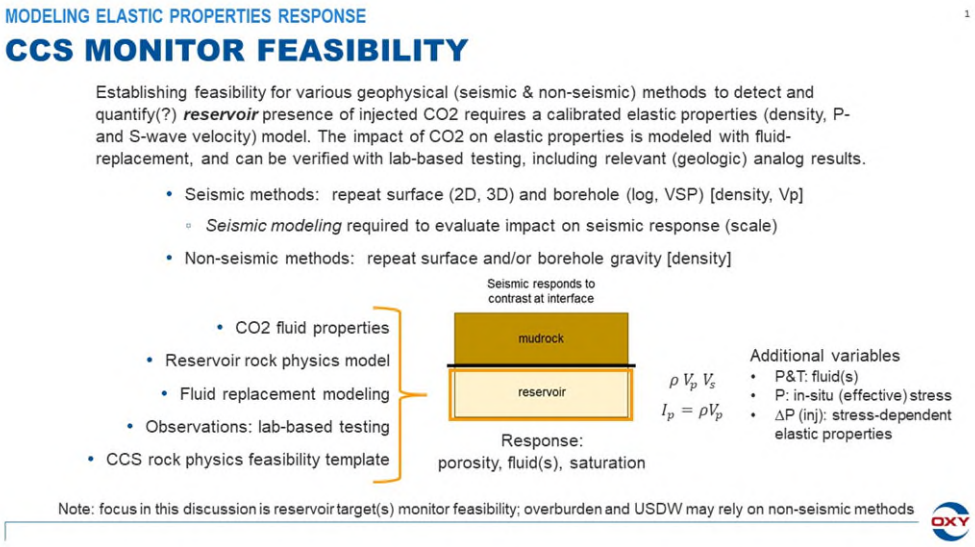


Figure AoR-323: Geophysical Modeling for CCS Monitor Feasibility – Workflow.

7.1 Challenges with Well-Based Forward Model(s).

The workflow depicted above follows established practice as commonly applied in traditional exploration and production studies where quantitative interpretation (QI) methods are used to exploit amplitude and/or Amplitude Versus Offset (AVO) signatures associated with potential oil and gas accumulations. Adaptations for modeling the behavior of CO_2 are minor and will be further detailed below.

Frequent challenges for site-specific well-based forward modeling in support of CCS site characterization may include one or more of the following.

- Legacy well control – data availability and quality. Well control associated with saline aquifer sequestration targets are frequently very limited in data and often further challenged with the quality of measured data. Borehole data quality may suffer in intervals drilled with limited hydrocarbon potential where drilling efficiency commonly takes priority. Similarly, actual petrophysical data acquisition is also limited so data common for extensive reservoir characterization (nuclear logs, cores, and fluid samples) or geophysical integration (acoustic log data, particularly shear velocity) are often unavailable. Rigorous

geophysical data quality control (QC) and synthetic log creation are often required to include geologically significant legacy well control.

- Pilot well control – Site-specific characterization. In nearly all potential CCS sites, one or more new pilot ('strat') wells are drilled with the intention of gathering detailed data necessary for quality 3D reservoir site characterization. New well control is often better borehole quality, but careful geophysical data QC will still be required. Acquisition of modern multimode acoustic log data affords the opportunity to gain high-quality P- and S-wave velocity data required for geophysical forward modeling but will also require careful post-processing (from waveform data) to ensure robust results. Recovered core and fluid samples will require additional time for analyses prior to core-log integration studies.

- Geophysical response modeling – With a local pilot well and detailed petrophysical reservoir characterization results, porosity and reservoir composition (e.g., core-log) are established and fluid sample(s) provide essential data for in-situ brine properties. The model's expected response can be forwarded to varied CO_2 presence (saturation, vertical extent in reservoir) using fluid replacement modeling. An important limitation in this workflow, not a function of data quality or availability, is the non-unique geophysical response to varied combinations of CO_2 saturation and thickness. In addition, the detailed vertical resolution afforded by wellbore measurements will be optimistic when compared to expectations from 2D/3D geophysical monitoring, where vertical resolution will be less and controlled by actual frequency content of the monitor data. Careful handling of well data with a view to eventual geophysical resolution (wavelet frequency) is essential to the feasibility modeling workflow. Including a range of expected geophysical 'noise' for monitor data is important for ensuring that reliable estimates of dynamic plume detection and resolution are made during feasibility modeling.

7.2 Well-based Geophysical Response Modeling

In this section, the geophysical modeling workflow described above will be applied to data gathered in the Encanto 01 pilot well. The project team worked closely with Petrophysics during the data evaluation and integration phase. The geophysical response modeling described here is fully aligned with petrophysical characterization results and relies on application of key core data to constrain various input parameters in modeling the expected reservoir geophysical response.

The focus of the discussion and all associated modeling described here is taken from the Frio 'Mid' interval in Encanto 01, for which conventional core (Core-6) was recovered, and from associated analyses for calibration and validation of key reservoir properties. Well-based results will also be included from the top of the immediately underlying Frio 'Lower' reservoir as additional evidence of the effectiveness of the well-based forward modeling workflow. In a subsequent section, comments will be provided on the expected geophysical response for other (deeper) Frio age reservoir intervals in the Encanto 01 well.

7.3 Petrophysical Reservoir Characterization

Well data from Encanto 01 are all acquired from a wellbore drilled with oil-based mud (OBM). Hole conditions were variable but generally good; minimal geophysical log QC was made to the recorded bulk density log and only in non-reservoir (mudrock) intervals. All multimode acoustic log data have been post-processed from the original raw waveform data to ensure that high-quality P- and S-wave velocities are available. Geophysical QC workflows using a variety of relevant models for shale (mudrock) and sand (wet) support the viability of the assembled density and velocity (Vp and Vs) data set.

Conventional core recovered from the Frio target reservoir provided essential routine core analysis (RCA) data to enable reservoir petrophysics model calibration (core-log). Core-log alignment was made using GR recorded on the recovered core. Key measured data included porosity (at simulated net confining stress) and grain density. Additional measurements of reservoir composition (X-ray diffraction) provide vital data on mineralogy (including non-quartz minerals) present in the Frio target reservoir; compositional data yield estimated grain density values in very good agreement with core-measured values.

7.4 Geophysical Fluid Properties

Fluid properties required for fluid replacement modeling include density and (adiabatic) bulk modulus. These properties for brine and CO_2 are a function of Pressure (P) and Temperature (T), and, in the case of brine, also the salinity. Local Frio reservoir P and T were estimated from regional well control including in-situ formation pressure obtained from wireline formation test (WFT) tool measurements. Fluid properties used in subsequent modeling are given in Table AoR-60.

Table AoR-60: Geophysical fluid properties – Encanto 01.

Encanto 01: Frio Mid-Lower (P = 3,500 psi; T = 175 F)	
Fluid	Claimed as PBI
Brine	
CO_2	

7.5 Reservoir Rock Physics Model

To model the expected change in elastic properties within the reservoir due to increased presence of CO_2, an approach was adopted that relies on a model-based relationship between the (total) porosity and dry-rock moduli (bulk and shear) of the reservoir frame. This robust workflow is suitable for use in a variety of theoretical and/or heuristic rock physics model(s) and is directly tied to core-calibrated reservoir properties (porosity and grain mineralogy), benefits from integration of well-specific and/or geologically sensible analog measurements of geophysical properties (Vp and Vs) and creates an interpretive framework where dry-rock modulus diagnostics

can be applied (Kittridge, 2006). Further support in model validation results from the iterative application of a well-based petrophysical Close-the-Loop (CtL) workflow, which provides in-situ model validation when compared to measured density and velocity log data (see Figure AoR-324).

The Frio reservoir section in Encanto 01 is a high porosity (27-32 pu) sand. Measured velocity data suggest the reservoir framework is very poorly consolidated. An appropriate public-domain model was applied for this loosely consolidated reservoir tied to framework grain composition (see below), in-situ effective stress, and total porosity. Well-measured Vp and Vs data, along with local core-measured (stress-dependent) velocities, further supported with geologically analogous core measured velocities, yield a core-calibrated model for the local Frio reservoir section. A petrophysical CtL workflow was then applied to further validate consistency between petrophysical properties (porosity and grain composition) and measured Vp and Vs. A simple empirical model for high-porosity wet sands provides additional validation of shear velocity integrity (Vernik & Kachanov, 2010).



**Figure Ao
Depth (2) For
Petrophysic
(6) P-wav**

7.6 Fluid replacement modeling

Establishing a basis for understanding the expected geophysical response to injected CO_2 in a brine-saturated reservoir relies on fluid replacement modeling to estimate expected changes in compressional velocity, using the Gassmann model (see Wang [2001] for a complete description

of the model). The geophysical fluid properties of CO_2 (Table AoR-60) cause a reduction in reservoir P-wave velocity as the saturation increases, making traditional geophysical methods sensitive to amplitude (P-wave velocity and bulk density) suitable for time-lapse detection and characterization of the evolving CO_2 plume. The change in saturated bulk density is a simple volumetric mixing model that accounts for changes in fluid density with increasing CO_2 saturation. While S-wave velocity is also sensitive to the change in saturated bulk density, the focus here was on the change in P-wave velocity, expected to be significant and amenable to geophysical detection.

Experience in the field, supported by legacy laboratory data (Gist 1994) and recent modeling work (Papageorgiou et al. 2016), demonstrates that applying the fluid mixing model, particularly at low (< 10%) CO_2 saturation, is important in estimating expected response. At higher CO_2 saturation, 'traditional' Wood's model (isostress) is applied to estimate the bulk modulus of the mixed fluid. A traditional volumetric mixing equation calculates the density of the fluid mixture. Specific CO_2 saturation cases were modeled to establish feasibility, using the well-defined reservoir fluid properties (Table AoR-60). Results for the fluid mixture replacement modeling are shown in Figure AoR-325.

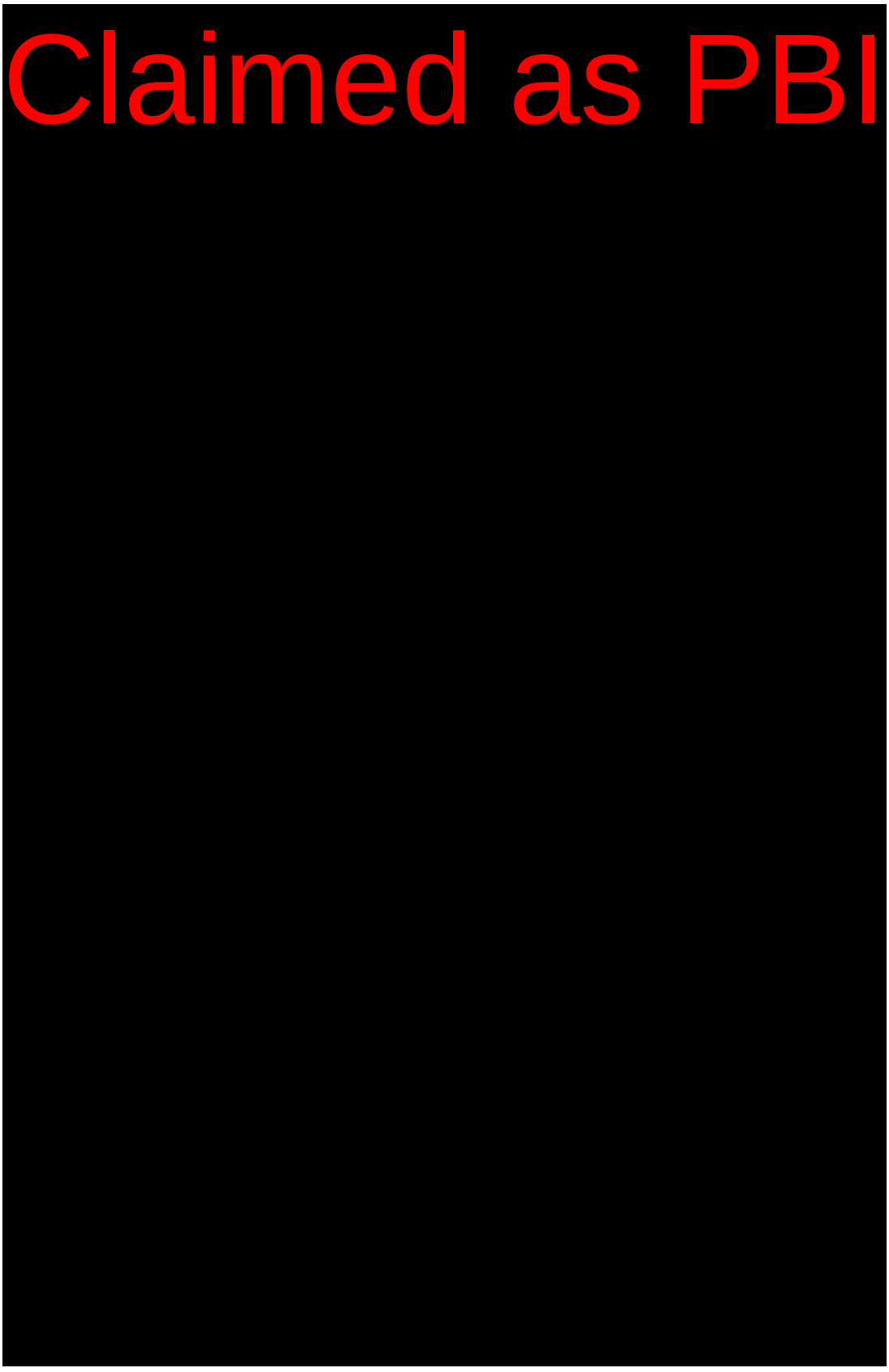


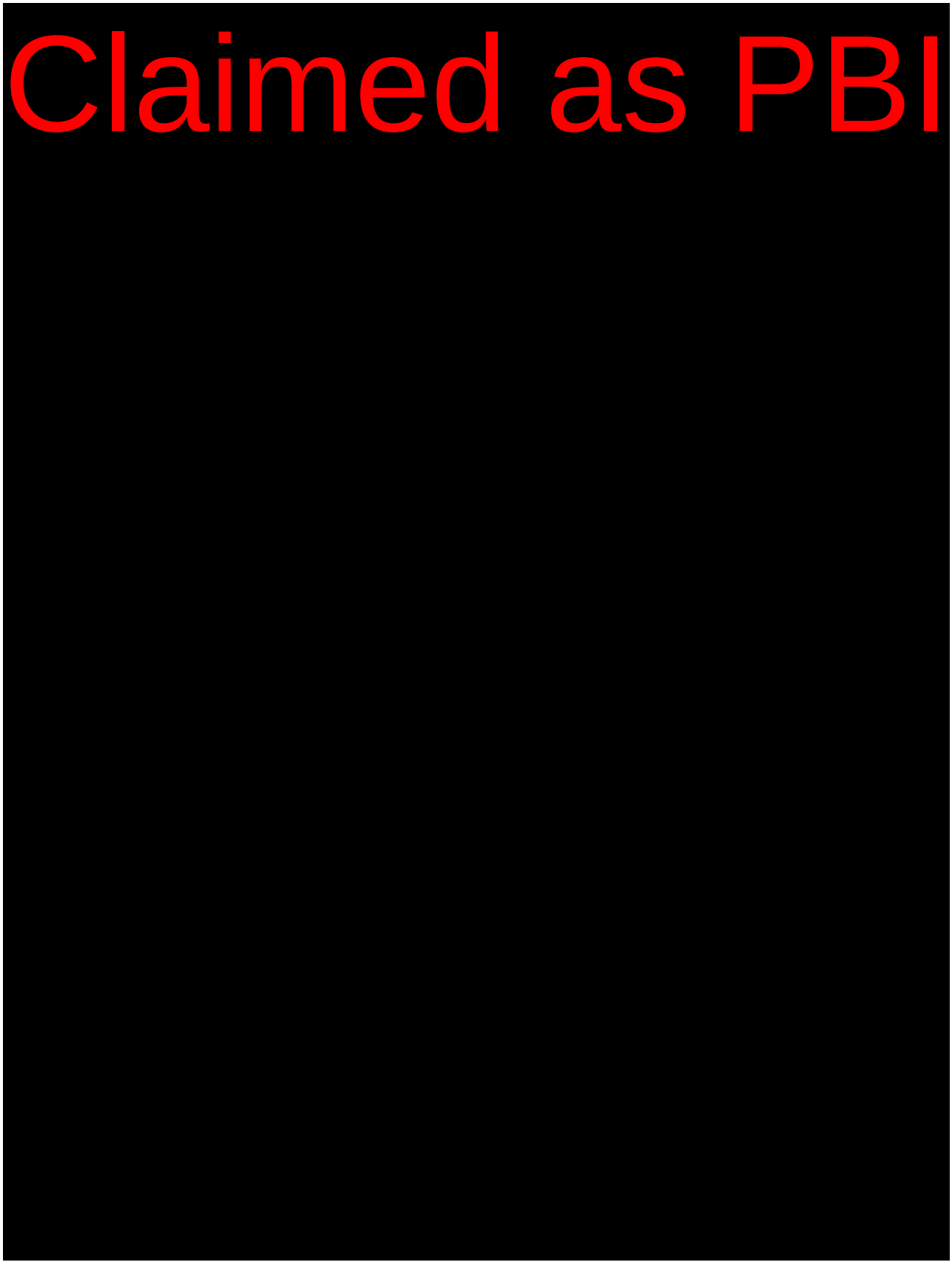
Remaining input properties and parameters required for Gassmann fluid replacement modeling are noted here. Porosity is the total porosity from well log (core-calibrated). The matrix grain properties (grain density and grain bulk modulus) are based on reservoir composition as determined by XRD, using constant values based on Mid Frio conventional core data. Results for modeling in specific layers from Mid Frio and upper portion of Lower Frio are shown in Figure AoR-326.

7.7 Feasibility for geophysical monitoring – Frio Reservoir

The well-based fluid replacement model scenarios provide a log-scale vertical resolution image of expected changes in P-velocity and P-impedance (density*Vp). Geophysical monitor methods will all operate at a resolution (vertical) that is less than that seen at well log scale. An estimate of geophysical resolution is made using an appropriate up-scaling (filter) Backus average that ensures both bulk density and P-velocity bed boundaries are consistent. Expected changes in P-impedance are estimated by comparing fluid-replacement scenarios to the original in-situ (Sw 100%) starting point (Figure AoR-326).

Observations from the modeled replacement scenarios (Figures AoR-326 and AoR-327) suggest that clear geophysical identification of CO_2 would be expected for saturation greater than [redacted] The target Frio reservoir sands are high porosity and very loosely consolidated (grain-to-grain contacts and no cement), and are, therefore, very responsive to increasing CO_2 saturation. The impedance changes when compared to the low contrast in-situ wet reservoir sands will make geophysical monitoring very effective in this reservoir.


Claimed as PBI


Claimed as PBI

The feasibility modeling of the Frio (Mid and Lower) interval provides clear evidence that robust geophysical monitoring is expected that will enable time-lapse characterization of plume development. Some cautionary notes should be noted on the feasibility workflow applied in this reservoir example.

- Fluid mixing model. As noted in the previous section, different fluid mixing models are applied at low Claimed as PBI [redacted] based on published laboratory and modeling studies. The choice of mixing model change at Claimed as PBI [redacted] is supported by available public-domain laboratory experiments in similar (high-porosity) loosely-consolidated reservoir sands.

- Saturation change. The current modeling addresses saturation change only. It is expected that any changes in reservoir pressure (increase) due to injection, which would decrease in-situ (vertical) effective stress in the reservoir, would further increase the current modeled change in P-velocity.

- Geophysical resolution – saturation vs. thickness. The fluid replacement model scenarios included here put a constant saturation of CO_2 in all reservoir layers defined in each Frio (Mid and Lower) zone. During injection and migration, it is likely that the reservoir layers would develop variable thickness and saturation layers over time. The geophysical resolution is not expected to be able to distinguish a thin interval of high CO_2 saturation versus a thick(er) interval of low(er) saturation.

8.0 Fluid Substitution Study – Miocene Injection Zone

8.1 Well-based Geophysical Response Modeling.

In this section, the geophysical modeling workflow is applied to data gathered in the Encanto 01 pilot well. Working closely with Petrophysics during the data evaluation and integration phase, the geophysical response modeling described here is fully aligned with petrophysical characterization results and relies on application of key core data to constrain various input parameters in the modeling of expected reservoir geophysical response.

The focus of the discussion and all associated modeling described here is taken from the Lower Miocene injection interval in Encanto 01, where conventional core (Core-3) and associated analyses for calibration and validation of key reservoir properties have been recovered. As the Encanto 01 well is outside the dynamic model plume, scCO2 saturation taken from the dynamic model (year-5 injection) was used in a similar reservoir quality (porosity) reservoir. The average scCO2 saturation is the pore volume weighted (petrophysical) average.



8.2 Geophysical Fluid Properties

Fluid properties required for fluid replacement modeling include density and (adiabatic) bulk modulus. These properties for brine and scCO2 are a function of Pressure (P) and Temperature (T), and in the case of brine, also the salinity. Local Lower Miocene reservoir P and T were estimated from regional well control including in-situ formation pressure obtained from Wireline Formation Test (WFT) tool measurements. Fluid properties used in subsequent modeling are given in Table AoR-61.

Table AoR-61: Geophysical fluid properties – Encanto 01.

Encanto 01: Lower Miocene (P = 2,500 psi; T = 150 F)	
Fluid	Claimed as PBI
Brine	
CO2	

8.3 Fluid replacement modeling

Establishing a basis for understanding the expected geophysical response to injected scCO2 in a brine saturated reservoir relies on fluid replacement modeling to estimate expected changes in compressional velocity, using the Gassmann model (see Wang [2001] for a complete description of the model). The geophysical fluid properties of scCO2 cause a reduction in reservoir P-wave

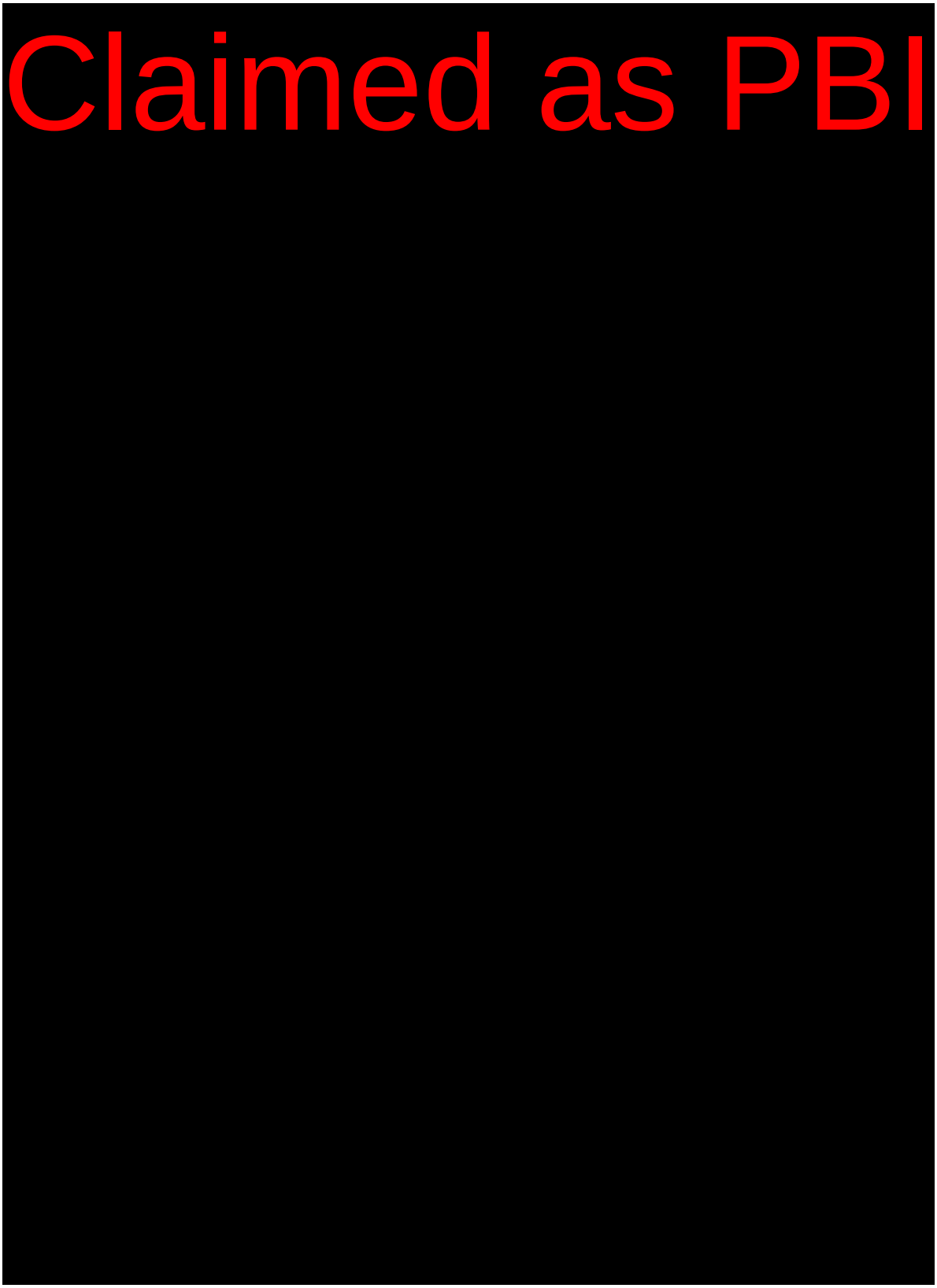
velocity as the saturation increases, making traditional geophysical methods sensitive to amplitude (P-wave velocity and bulk density) suitable for time-lapse detection and characterization of the evolving scCO2 plume. The change in saturated bulk density is a simple volumetric mixing model that accounts for changes in fluid density with increasing scCO2 saturation. While S-wave velocity is also sensitive to the change in saturated bulk density, focus here is on the change in P-wave velocity, expected to be significant and amenable to geophysical detection.

Remaining input properties and parameters required for Gassmann fluid replacement modeling are noted here. Porosity is the total porosity from well log (core-calibrated). The matrix grain properties (grain density and grain bulk modulus) are based on reservoir composition as determined by XRD; using constant values based on Lower Miocene conventional core data.

8.4 Feasibility for geophysical monitoring – Lower Miocene Reservoir

The well-based fluid replacement model scenarios provide a log-scale vertical resolution image of expected changes in P-velocity and P-impedance (density*Vp). Geophysical monitor methods will all operate at a (vertical) resolution that is less than that seen at well log scale. An estimate of geophysical resolution is made using an appropriate up-scaling (filter) Backus average that ensures both bulk density and P-velocity bed boundaries are consistent. Expected changes in P-impedance are estimated by comparing fluid-replacement scenarios to the original in-situ (Sw 100%) starting point (Figure AoR-329).

Observations from the modeled replacement scenarios suggest that a clear geophysical identification of scCO2 would be expected at year 5 (saturation 0.17 – 0.26 v/v). The target Lower Miocene reservoir sands are high porosity and very loosely consolidated (grain-to-grain contacts and no cement), and are therefore, very responsive to increasing scCO2 saturation. The impedance changes (generally > 8% across reservoir injection interval) when compared to the low contrast in-situ wet reservoir sands will make geophysical monitoring very effective in this reservoir.



Figure

9.0 Corrective Action

9.1 Tabulation of wells within the AoR

Pursuant to 40 CFR §146.82(a)(4). 40 CFR §146.82(a), 40 CFR §146.84(c)(2), and 40 CFR §146.84(d), an exhaustive search using multiple methods is required to identify artificial penetrations (APs) in the Area or Review (AoR). The Bluebonnet Sequestration Hub, LLC, used the following methods when evaluating the area:

- Public records searches
    - Texas Railroad Commission (TRRC) online records search and interactive Geographic Information System (GIS) viewer. (https://rrc.texas.gov/resource-center/research/gis-viewer)
    - Texas Railroad Commission (TRRC) microfilm/Hardcopy records search.
    - Texas Bureau of Economic Geology (BEG) database. (https://coastal.beg.utexas.edu/continuum/#!/)
    - Texas Commission on Environmental Quality (TECQ) online records.
    - Texas Water Development Board (TWDB) online records.
    - Texas Department of Licensing and regulation (TDLR) online records.
    - Texas General Land Office (GLO) database. (https:?/gisweb.glo.texas.gov/glomapjs/index.html)
    -
- Third-party well databases licensed by Oxy Low Carbon Ventures, LLC.

- Review of historical aerial photos licensed by Bluebonnet.
- Aerial Magnetic Survey acquired by Bluebonnet in 2025 (Appendix F).

The proposed AoR represents approximately 22 square miles of extension (combination of pressure front at 15 and 20 years of injection and CO_2 plume at 100 years post injection) and includes 29 legacy oil and gas wells and 39 water wells (excluding Bluebonnet USDW 01), according to the records obtained from the public records and private databases. Bluebonnet USDW 01 well was reported originally as a water well through TWDB with the permit number 668850 but was later converted to an aquifer monitoring well and reported in TRRC database with the API 42071326720000. The locations of these wells are shown in Figure AoR-330 (oil and gas wells) and Figure AoR-331 (water wells). The area is dedicated mostly to farming and recreational activities. Oil and gas development is present in areas outside of the AoR; however, exploration activities in the proposed AoR have not proved to be economical, as all the legacy wells were classified as dry holes.

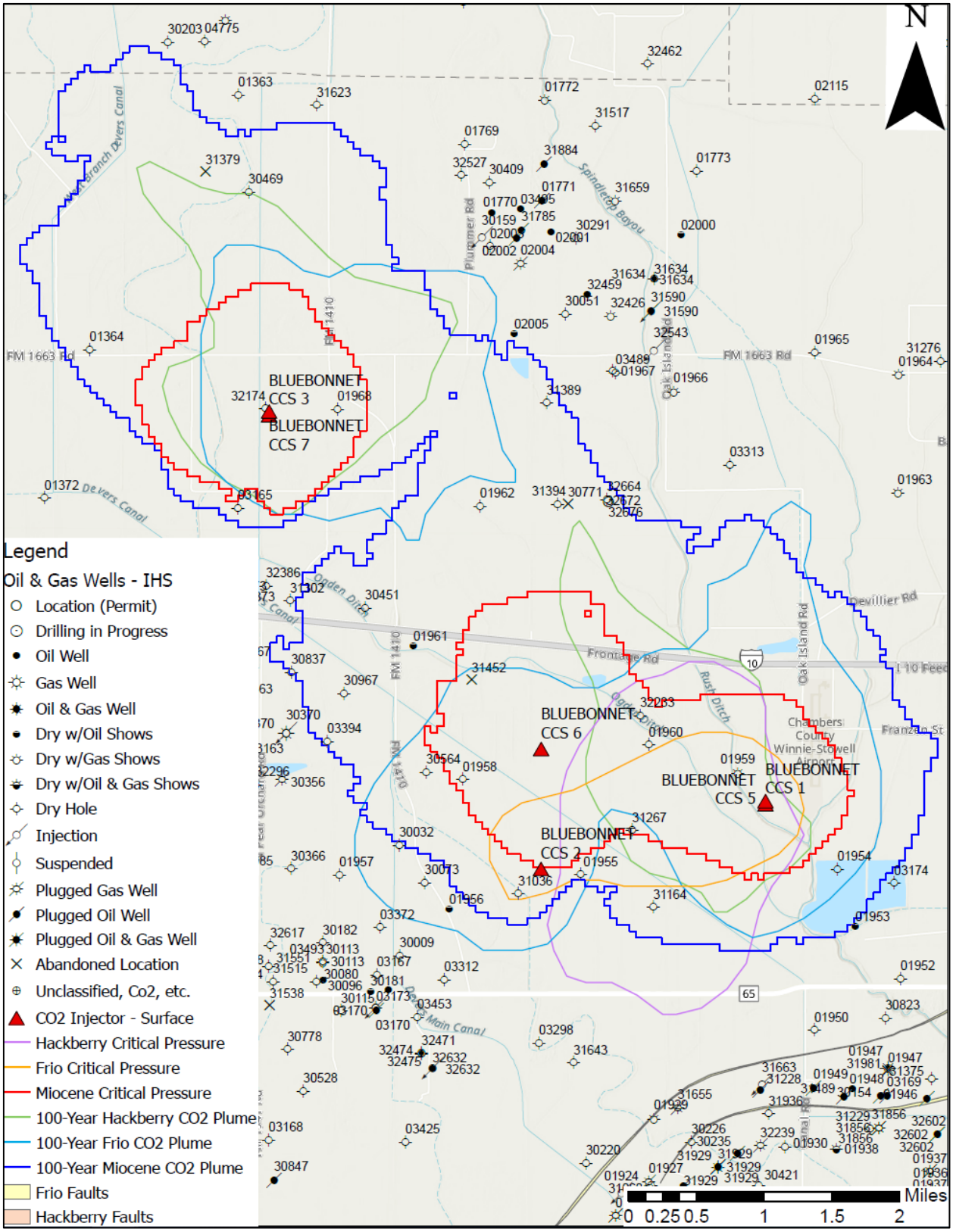


Figure AoR-330: Oil and gas wells and deep penetrations in the Area of Review.



Figure AoR-331: Water well distribution in the Area of Review.

9.1.1 Oil and Gas Wells Within the AoR

As outlined in the previous section, there are 29 oil and gas wells within the AoR, identified through both public and private databases (Table AoR 62). During the research and evaluation of these wells/deep penetrations, some discrepancies were noted between the TRRC, BEG, GLO, and IHS databases. To verify the locations, the files for each well were obtained from TRRC offices, and the plats were compared with the positions presented in the maps and viewers. In addition to reviewing databases and microfilms, Bluebonnet conducted a Magnetic Survey over the AoR in 2025 to validate the locations and eliminate the possibility of unreported wells that could pose a leakage risk. Furthermore, Bluebonnet licensed historical imagery to aid in the identification of well locations.

The reconciliation of the different well databases, imagery, films, plats and data from the Magnetic Survey is summarized as follows (for additional information please refer to appendix F of the AoR):

- API (42071019540000) - Well is not shown in TRRC viewer or BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using information from IHS and GLO as well. The magnetic survey validated the well location with a minimum displacement to the south-west.
- API (42071019550000) - Well is not shown in TRRC viewer. Location was confirmed with paper files obtained from TRRC files. Reported using data from IHS, BEG and GLO as well. The magnetic survey validated the location of the well.
- API (42071019560000) - Well is not shown in BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using data from IHS, TRRC, and GLO. The magnetic survey validated the location of the well. Aerial imagery from 1970 confirmed the location of the well.
- API (42071019580000) - Location was confirmed with paper files obtained from TRRC files. Reported using information from BEG, IHS, TRRC and GLO. The magnetic survey validated the location of the well.
- API (42071019590000) - Well is not shown in BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using data from IHS, TRRC, and GLO. The magnetic survey validated the location of the well.
- API (42071019600000) - The well location in BEG and IHS align, but do not correspond with the TRRC or the plat. Additionally, the TRRC and the plat information themselves are not in agreement. The GLO database has reported the well based on the plat information. A magnetic survey did not identify an existing well at the reported locations, and aerial imagery from 1941 did not reveal a clearly defined path. The project will proceed with an additional ground survey to definitively rule out the presence of the legacy well.
- API (42071019610000) – Well is not shown in BEG Viewer. Reported using data from IHS, TRRC, and GLO. The magnetic survey validated the location of the well.

- API (42071019620000) – Location was reported using data from TRRC, GLO, BEG and IHS. Aerial imagery from 1960 validated the well location. The magnetic survey validated the well location.
- API (42071019680000) – Location was reported using data from TRRC, and while IHS and BEG are aligned, there is a discrepancy regarding the location and plat information on GLO. The Magnetic survey has confirmed that the well's location matches the GLO coordinates.
- API (42071031650000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location. The project will conduct additional on the ground survey due to the proximity of the well to surface structures.
- API (42071033940000) – Well is not shown in TRRC viewer or BEG Viewer. The well coordinates are consistent with both the GLO and IHS records. The magnetic survey indicates that the well location is slightly displaced to the southeast from the GLO coordinates.
- API (42071300320000) - Well is not shown in TRRC viewer or BEG Viewer. The well coordinates align with both the GLO and IHS records. The magnetic survey and aerial images from 1969 confirm the well coordinates as GLO.
- API (42071300730000) – Well is not shown in BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using information from TRRC, GLO and IHS. The magnetic survey and the aerial imagery from 1970 validated the reported well location.
- API (42071304510000) – Location was reported using data from TRRC, GLO, BEG and IHS. Aerial imagery from 1978 validated the well location. The magnetic survey validated the well location.
- API (42071305640000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.
- API (42071304690000) – Well is not shown in BEG Viewer. The well is reported using data from TRRC, GLO and IHS. The magnetic survey shows interference with the pipeline and the Project will conduct an on-ground survey to validate well location.
- API (42071308370000) – The well is not displayed in BEG. The well's data, sourced from TRRC and GLO, reveals discrepancies in the coordinates when compared to IHS records. Both the magnetic survey and aerial imagery have confirmed the well's location as per the data from GLO and TRRC.
- API (42071309670000) – The well is not displayed in BEG. Reported using information from TRRC, GLO and IHS. The magnetic survey and the aerial imagery from 1979 validated the reported well location.
- API (42071310360000) – The well is not displayed in BEG. Reported using information from TRRC, GLO and IHS. The magnetic survey and the aerial imagery from 1980 validated the reported well location.

- API (42071311640000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey and the aerial imagery from 1982 validated the well location.
- API (42071312670000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey and the aerial imagery from 1982 validated the well location.
- API (42071313890000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.
- API (42071313940000) – The well is not displayed in BEG. Reported using information from TRRC, GLO and IHS. The magnetic survey validated the reported location.
- API (42071321740000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.
- API (42071322330000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.

Table AoR-62: Oil and Gas wells within the AoR (Source IHS Database for coordinates).



9.1.2 Water Wells Within the AoR

The thirty-nine water wells identified from databases and reports within the AoR are listed in Table AoR-63 (excluding Bluebonnet USDW 01). All the wells targeted the Chicot aquifer. These wells are dedicated to domestic use, stock, rig supply, and groundwater monitoring activities. The measured depths range from 122 ft to 500 ft. None of these forty wells penetrated the injection zone or the confining zone. None of the wells require corrective action.

In addition to reviewing databases and microfilm, Bluebonnet conducted interviews with several landowners in the area. Through these interviews, eight additional water wells were identified that lacked reporting numbers or documentation, yet are being utilized as water supply for domestic purposes or irrigation (Table AoR 64). These wells are shallow, targeting freshwater zones between 50-500 feet, and none of them penetrated the injection or confining zones.

Table AoR-63: Water wells within the AoR.




Claimed as PBI


Claimed as PBI

Claimed as PBI

Table AoR-64: Additional Water Wells within the AoR.

Claimed as PBI

9.1.3 Wells Penetrating the Confining Zone Within the AoR

The 29 oil and gas wells within the Area of Review (AoR) are listed in Table AoR-62. Twenty-six of these wells were drilled through the Confining Zone into the Miocene and Frio formations.

The Drought 1 well (API 42071013640000) was drilled to a depth of 1,200 ft and did not penetrate the Confining Zone, therefore no corrective action is required.

The Bluebonnet USDW 01 well (API 42071326720000), originally drilled as a water well and later converted to an above confining zone/USDW monitoring well, targeted the base of the USDW water, reaching a total depth (TD) of 1,630 ft. The well was plugged back to 1,410 ft and completed with a gravel packed screen from 1,370 ft to 1,420 ft. No corrective action is required.

The Bluebonnet USDW 8 well (API 42071326760000) was drilled to 2,950 ft to core the shale intervals described in the composite confining zone. The well was plugged back to 1,050 ft and completed above the base of the USDW. No corrective action is needed.

Sixteen of the 29 oil and gas wells identified in the AoR were abandoned open hole, while nine ran intermediate casing through the proposed storage complex to reach the deepest formation.

The Encanto 01 well (API 42071326640000) was drilled as a stratigraphic well in support of this project and will be converted to a monitoring well before the start of injection. The well is currently temporarily abandoned.

9.2 Plan for Site Access

The project wells and wells in the remediation plan are located inside the area proposed for the Bluebonnet Hub. Bluebonnet has acquired the rights to access the Bluebonnet Hub project area and the various well locations via agreements with the surface owners.

9.3 Corrective Action Schedule

A detailed analysis was performed to evaluate the risk and timing of the plume and/or pressure front reaching each of the wells inside the AoR, relative to the project schedule, to propose corrective actions and a timeline for these procedures. Schematics and proposed repairs for each well that penetrates the seal or injection formations are included in Appendix C of this document.

The analysis was divided into two main categories to assess the risk and mitigations, based on the possible mechanism of failure:

1) **CO_2 plume corrosive effect and contamination of USDW aquifer.** The analysis focused on potential leakage paths from the injection zone that could endanger the USDW for those wells that are projected to be exposed to the CO_2 plume. The lack of proper isolation, cement degradation by carbonic acid, mechanical barrier failures, and micro-annulus or casing corrosion are some of the situations that increase the risk of brine/CO_2 leaks.

2) **Pressure front effect with brine contamination from deeper saline reservoirs to USDW aquifers.** This category includes wells that were not projected to be in contact with the CO_2 plume but are inside the simulated pressure front. In this scenario, the wells were evaluated for proper hydraulic isolation between the injection zone and USDW. The degradation or corrosion of cement, tubulars, and tools is not considered a high-risk scenario in this category.

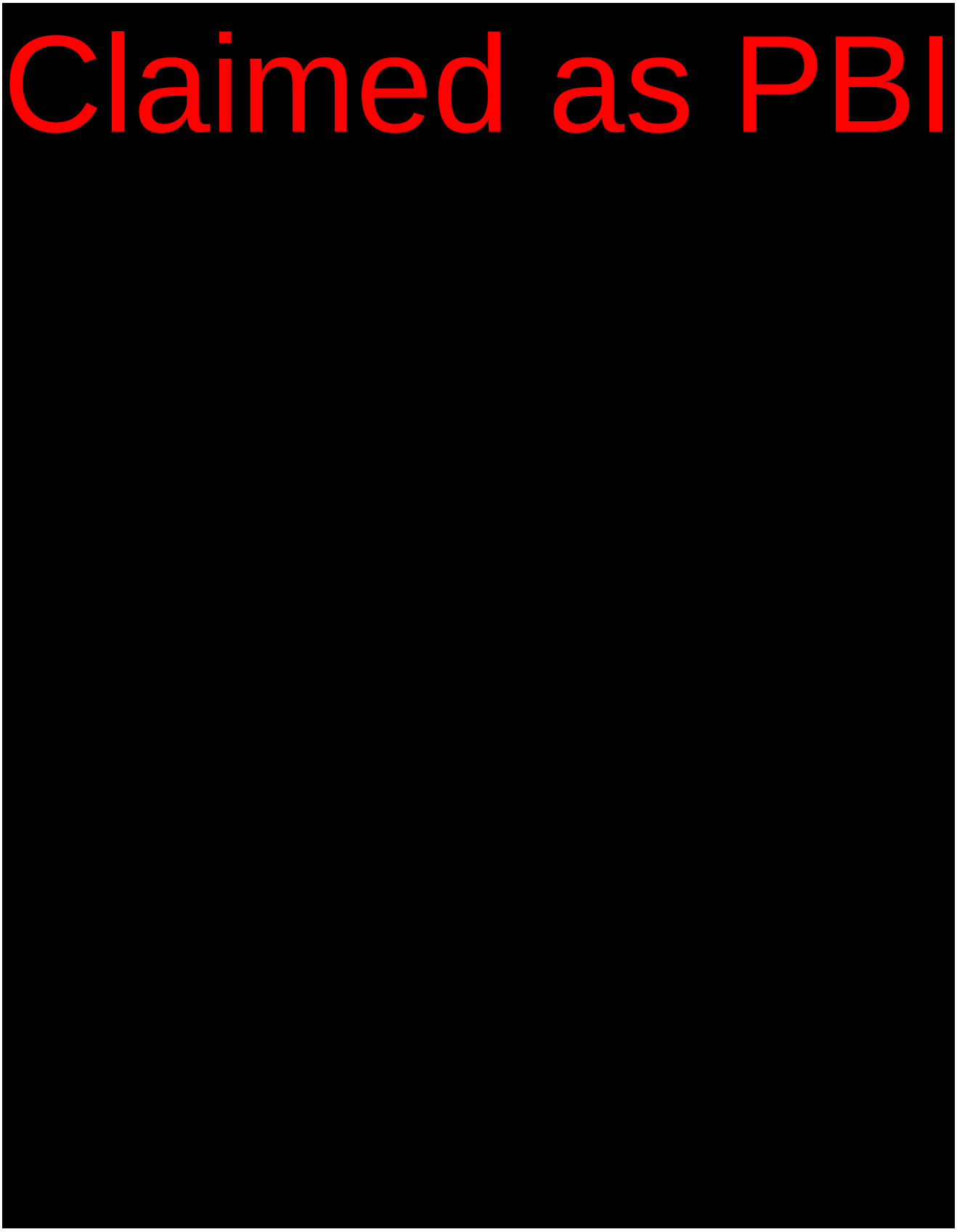
The study was also divided into time periods from initial injection to 100 years post-injection in order to propose the schedule and approach for the corrective actions.

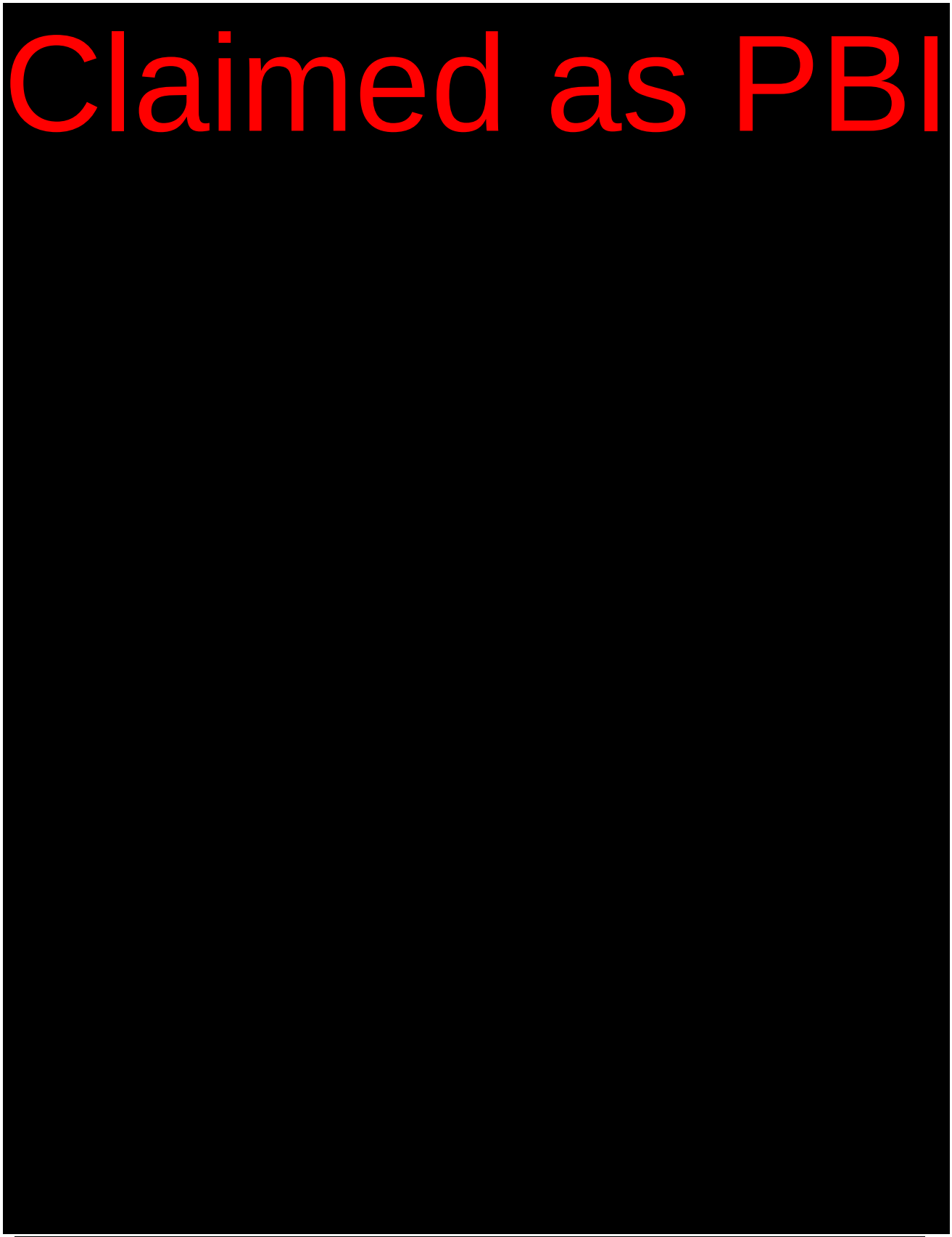
From the individual well analysis, 25 of the 29 wells were identified as requiring remedial actions to isolate the injection zone properly from the confining zone and USDW zones. These wells are listed in Table AoR-65, along with the main mechanism of failure and proposed schedule. Although the Magnetic Survey has not identified Trinity Rice 1 well within the project area, it has nonetheless been included in the financial assurance and risk evaluation for the ERRP. The project plans to conduct additional on-the-ground surveys to definitively rule out this well as a potential leak path.

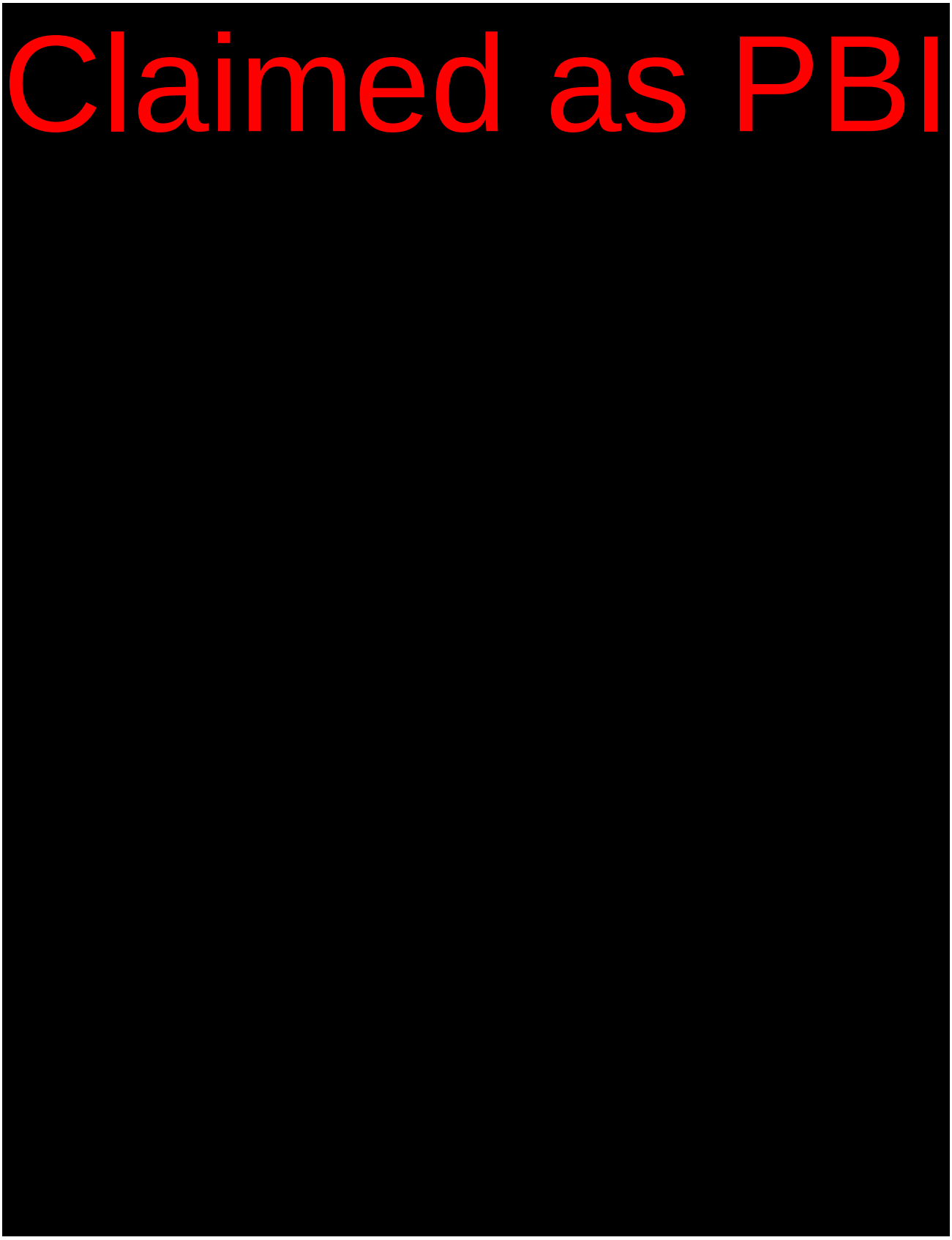
Table AoR-65: Wells to be remediated in the proposed AoR.

API Number	Lease Name	Well No	Status	Failure Mechanism	Total Depth (ft)	Schedule
42071019540000	J W Garth Jr Etal	1	Dry & Abandoned	CO2 Plume	9,012	Year 0
42071019550000	Drought H P	1	Dry & Abandoned	CO2 Plume	9,505	Year 0
42071019560000	Garth Brothers	1	D&A-O	CO2 Plume	9,250	Year 0
42071019580000	Sterrett Eat Fred R	1	Dry & Abandoned	CO2 Plume	9,550	Year 0
42071019590000	Wm Doornbos Etal	1	Dry & Abandoned	CO2 Plume	9,025	Year 0
42071019600000	Trinity Rice	1	Dry & Abandoned	CO2 Plume	8,019	Year 0
42071019680000	Simon Walter	1	Dry & Abandoned	CO2 Plume	7,788	Year 0
42071031650000	C H Lanz	1	Dry & Abandoned	CO2 Plume	7,629	Year 0
42071305640000	M E Hunter	1	Dry & Abandoned	CO2 Plume	12,665	Year 0
42071310360000	Garth	1	Dry & Abandoned	CO2 Plume	11,000	Year 0
42071321740000	Holter Et Al	1	Dry & Abandoned	CO2 Plume	11,000	Year 0
42071322330000	Doornbos	1	Dry & Abandoned	CO2 Plume	10,800	Year 0
42071300320000	Earl Cooper Etal	1	Dry & Abandoned	CO2 Plume	9,500	Year 5

API Number	Lease Name	Well No	Status	Failure Mechanism	Total Depth (ft)	Schedule
42071300730000	Garth Co	3	Dry & Abandoned	CO2 Plume	9,265	Year 5
42071312670000	Doornbos Willim Etl	1	Dry & Abandoned	CO2 Plume	18,950	Year 5
42071019610000	Ogden L G Etal	1	D&A-O	CO2 Plume	9,617	Year 10
42071019620000	Debellvue Mrs Maria	1	Dry & Abandoned	CO2 Plume	9,348	Year 15
42071033940000	O C Devillier Jr	1	Dry & Abandoned	CO2 Plume	9,317	Year 15
42071304510000	O C Devillier	4	Dry & Abandoned	CO2 Plume	12,215	Year 15
42071304690000	Beaumnt Rc Mll	1	Dry & Abandoned	CO2 Plume	9,008	Year 15
42071308370000	O C Devillier	6	Dry & Abandoned	CO2 Plume	10,993	Year 15
42071309670000	Devillier O C	7	Dry & Abandoned	CO2 Plume	11,270	Year 15
42071311640000	Garth	1	Dry & Abandoned	CO2 Plume	16,000	Year 15
42071313890000	Simon S E	1	Junked & Abandoned	CO2 Plume	9,119	Year 15
42071313940000	Devillier L C	1	Dry & Abandoned	CO2 Plume	9,300	Year 15


Claimed as PBI


Claimed as PBI


Claimed as PBI

10.0 Reevaluation Schedule and Criteria

10.1 AoR Reevaluation Cycle

The Bluebonnet Sequestration Hub, LLC will reevaluate the AoR every five years at a minimum during the injection and post-injection phases. In addition, monitoring and operational data will be reviewed periodically by the Bluebonnet technical team during the injection and post-injection phases.

Activities to be performed during reevaluation include reviewing and analyzing available monitoring and operational data and comparing it to the dynamic simulation forecast to assess whether the predicted CO_2 plume migration is consistent with the actual data. This includes data from the CO_2 injector wells, monitoring wells, geophysical surveys, and other sources. The monitoring activities to be conducted are described in the Testing and Monitoring Plan of this permit and PISC and Closure Plan.

Specific steps of this review and analysis include:

- Reviewing collected data on the position of the CO_2 plume and pressure front. This data will be collected from the CO_2 injector wells, monitoring wells, and near-surface monitoring systems as well as geophysical surveys as described in the testing and monitoring plan.

- Reviewing water chemistry monitoring data taken in the Bluebonnet USDW monitoring wells and verify that there is no evidence of CO_2 or brines that represent an endangerment to any USDWs.

- Reviewing operating data (e.g., injection rates and pressures) and verify consistency with the inputs used in the most recent modeling effort. History-match the numerical simulation model with operational data for well performance.

- Reviewing any geologic data acquired since the last modeling effort (e.g., additional site characterization performed and updates of petrophysical properties from core analysis). Identify whether any new data is materially different from the modeling inputs and assumptions.

- Comparing the results of computational modeling used for AoR delineation to the monitoring data collected. Monitoring data will be used to history-match the computational model and validate that the model provides an accurate representation of the storage site and can be used as a proxy to determine the plume's properties and size. The degree of accuracy is demonstrated by comparing monitoring data with the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to represent the storage site accurately.

If the collected data is consistent with model inputs and/or if the model forecast has not materially changed after the incorporation of such data, no update to the AoR will be needed. In this case, a report will be prepared to demonstrate that, based on the monitoring and operating data, no reevaluation of the AoR is needed. This report will include the data and results demonstrating that no changes are necessary.

If material changes in site conditions or operating parameters have occurred or if data indicates that the actual plume or pressure front may extend beyond the modeled plume and pressure front, the AoR will be re-delineated. Steps to re-delineate the AoR include:

- Revising the site conceptual model based on the new site characterization, operational, or monitoring data.
- Calibrating and history-matching the model in order to minimize the differences between monitoring data and model simulations.
- Performing the AoR delineation method as described in the AoR Delineation section of this AoR and Corrective Action Plan.
- Reviewing wells in any newly identified areas of the AoR and applying corrective action to deficient wells, if needed. Specific steps include:
    - Identifying any new wells within the AoR. Evaluate the status and records for wells that were not evaluated previously and provide description of each well including well type, construction, date drilled, location, depth, and record of plugging and/or completion.
    - Determining which wells in the newly delineated AoR are constructed or plugged/abandoned in a manner that could be a risk for endangering USDWs.
    - Performing or scheduling corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs using materials compatible with CO_2.
- Preparing a report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to the EPA within one year of the reevaluation and will include maps that highlight similarities and differences with previous AoR delineations.
- Updating the AoR and Corrective Action Plan to reflect the revised AoR along with other related project plans, as needed.

10.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled AoR reevaluations will be based on quantitative and material changes of the monitoring and operative parameters in CO_2 injectors, monitoring wells, seismometer networks, and geophysical surveys that could indicate that the actual plume and pressure front may extend

beyond the area modeled or outside the proposed storage complex. These changes might include, but not be limited to the following:

- **Pressure:** Changes in injection pressure that are excessive and unexpected in timing or magnitude from those predicted by the model.
- **RST Saturation:** Increases in CO_2 saturation in monitoring wells that indicate an earlier breakthrough of CO_2.
- **Deep Groundwater Constituent Concentrations:** Unexpected changes in fluid constituent concentrations that indicate movement of CO_2 or brine into or above the confining zone.
- **Exceeding Fracture Pressure Conditions:** Pressure in injection wells exceeding 90% of the geologic formation fracture pressure.
- **Compromise in Injection Well Mechanical Integrity:** A significant change in annular pressure for the injection well or abnormal reading of temperature in the fiber optic cable that indicates a loss of mechanical integrity or a failed mechanical integrity test (MIT) in an injector or monitoring wells.
- **Induced Seismicity Monitoring:** Seismic monitoring data that indicates reactivation of a fault or structures due to pressurization of the reservoir because of the CO_2 injection. The project will review the monitoring data to discard naturally occurring events not related to the injection.

The Bluebonnet Sequestration Hub, LLC will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, the Project will perform the steps described in the 10.1 AoR Reevaluation Cycle.

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells.

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

	Surface Coordinates		Bottom Hole Coordinates	
Well Name	Latitude (NAD27)	Longitude (NAD27)	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442	29.808132	-94.437235
Bluebonnet CCS 2	29.804552	-94.463937	29.806641	-94.469059
Bluebonnet CCS 3	29.852812	-94.498078	29.848655	-94.495108
Bluebonnet CCS 5	29.812133	-94.436456	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078	29.853222	-94.498078

Bluebonnet Sequestration Hub, LLC will be building the Bluebonnet Sequestration Hub (Bluebonnet Hub or the project) where it will construct CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, according to the procedures below. The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, and pressure control systems, amongst others.

2.0 Overview

This Construction Plan sets forth the operational parameters and material selection requirements to provide mechanical integrity, minimize potential endangerment of the Underground Sources of Drinking Water (USDW), and optimize operation during the life of the project. While this Construction Details Plan describes the intended procedures for drilling and construction of the project, changes to the plan may be required based on technical, operational, or safety conditions encountered during the development and execution. The project team will notify the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director if substantial deviations from this plan are required.

As mentioned, the Bluebonnet Sequestration Hub, LLC will drill six new CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS

6, and Bluebonnet CCS 7. These wells will target the Oligocene and Miocene formations, specifically the Lower Miocene, Frio, and Hackberry sands.

Oxy Low Carbon Ventures, LLC, the parent company of Bluebonnet Sequestration Hub, LLC, drilled one stratigraphic well, Encanto 01, in the Bluebonnet Hub in 2022-2023. This well has been used to obtain site-based information and additional characterization to complement the geological and numerical simulation models. The Encanto 01 stratigraphic well was designed with the goal of being converted into an in-zone monitoring well to track the CO_2 plume extension and pressure front in the Frio and Miocene formations, as described in the Testing and Monitoring Plan.

Bluebonnet Sequestration Hub LLC drilled the Bluebonnet USDW 1 well in 2024 to characterize the shallow aquifers. Subsequently, in 2025, the Bluebonnet USDW 8 well was drilled to obtain whole core and sidewall core samples from the intershales predominant within the Miocene Composite Confining Zone.

Additionally, the project plans to drill two new in-zone monitoring wells in Frio/Miocene injection zone to directly monitor the injection targets (IZM FM), one in-zone monitoring well in the Lower Miocene injection zone (IZM M), six additional USDW/ Above Confining Zone (ACZ) monitoring wells (targeting the shallowest zone above the confining zone that was defined by the project as the deepest USWD), two water production wells in the Frio injection zone to manage increases in the reservoir pressure, and one water disposal well.

Since the shallowest above-confining zone has been defined as the base of the USDW, the USDW monitoring wells will track the quality of the water and variations in geochemistry in the USDW. These shallow water wells will be produced and sampled based on the requirements described in the Testing and Monitoring Plan presented in this application.

Location, well schematics, and construction details for the in-zone monitoring wells, above confining zone/USDW monitoring wells, water production wells, and water disposal well are included in the Testing and Monitoring Plan of this application.

3.0 Design Considerations for CO_2 Injector Wells

Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 are designed to maximize the rate of injection and reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the frac gradient. A nodal analysis using PROSPER software performed sensitivities on the tubing size, rate of erosion, stresses, operating pressures, and potential movement of the tubulars. The injection rate will continue to be refined as the project acquires, processes, evaluates, and interprets additional data.

Well materials and equipment were selected based on the maximum operating conditions expected during the life of the well and compatibility with the expected CO_2 stream, to ensure mechanical integrity and reliability of the system during the life of the project.

The selected design provides enough clearance to deploy pressure and temperature gauges on the tubing and continuous surveillance of external mechanical integrity through an external fiber optic cable.

During the design process, the project team integrated years of experience and data collected by Oxy (the parent company of Bluebonnet Sequestration Hub, LLC) as a CO_2 operator in enhanced oil recovery (EOR) fields, with the expertise of worldwide-recognized providers of tubulars, cementing services companies, and downhole and surface equipment manufacturers, amongst others, to complete the final design of the CO_2 injectors.

The operating conditions expected during the life of the CO2 injector wells are shown in Table CON-1.Table CON-2, Table CON-3, Table CON- 4, Table CON- 5, and Table CON- 6. Table CON-7 shows the CO_2 specifications of the Bluebonnet Hub.

Table CON-1: Operating design parameters for Bluebonnet CCS 1.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top - bottom (ft)	Claimed as PBI		
Perforation interval TVD[2], top - bottom (ft)			
Maximum injection rate (metric tonnes per day)			
Wellhead surface injection pressure at maximum injection rate (psig)			
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)			
Surface temperature (°F)			
Bottom hole temperature (°F) (top perfs)			
Operating injection rate (metric tonnes per day)			
Operating wellhead surface injection pressure (psig)			
Minimum annulus/tubing differential pressure (psig)			

(1) MD: Measured Depth
(2) TVD: True Vertical Depth

Table CON-2: Operating design parameters for Bluebonnet CCS 2.

Parameter/Completion	Completion 1	Completion 2
Perforation interval MD[1], top - bottom (ft)	Claimed as PBI	
Perforation interval TVD[2], top - bottom (ft)		
Maximum injection rate (metric tonnes per day)[3]		
Wellhead surface injection pressure at maximum injection rate (psig)		
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)		
Surface temperature (°F)		
Bottomhole temperature (°F) (top perfs)		
Operating injection rate (average) (metric tonnes per day)		
Operating wellhead surface injection pressure (psig)		
Minimum annulus/tubing differential pressure (psig)		

Table CON-3: Operating design parameters for Bluebonnet CCS 3.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top - bottom (ft)	Claimed as PBI		
Perforation interval TVD[2], top - bottom (ft)			
Maximum injection rate (metric tonnes per day)[3]			
Wellhead surface injection pressure at maximum injection rate (psig)			
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)			
Surface temperature (°F)			
Bottom hole temperature (°F) (top perfs)			
Operating injection rate (average) (metric tonnes per day)			
Operating wellhead surface injection pressure (psig)			
Minimum annulus/tubing differential pressure (psig)			

Table CON- 4: Operating design parameters for Bluebonnet CCS 5.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4	Completion 5
Perforation interval MD[1], top - bottom (ft)	Claimed as PBI				
Maximum injection rate (metric tonnes per day)[3]					
Wellhead surface injection pressure at maximum injection rate (psig)					
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)					
Surface temperature (°F)					
Bottom hole temperature (°F) (top perfs)					
Operating injection rate (average) (metric tonnes per day)					
Operating wellhead surface injection pressure (psig)					
Minimum annulus/tubing differential pressure (psig)					

Table CON- 5: Operating design parameters for Bluebonnet CCS 6.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top - bottom (ft)	Claimed as PBI		
Maximum injection rate (metric tonnes per day)[3]			
Wellhead surface injection pressure at maximum injection rate (psig)			
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)			
Surface temperature (°F)			
Bottom hole temperature (°F) (top perfs)			
Operating injection rate (average) (metric tonnes per day)			
Operating wellhead surface injection pressure (psig)			
Minimum annulus/tubing differential pressure (psig)			

Table CON- 6: Operating design parameters for Bluebonnet CCS 7.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4
Perforation interval MD[1], top - bottom (ft)	Claimed as PBI			
Maximum injection rate (metric tonnes per day)[3]				
Wellhead surface injection pressure at maximum injection rate (psig)				
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)				
Surface temperature (°F)				
Bottom hole temperature (°F) (top perfs)				
Operating injection rate (average) (metric tonnes per day)				
Operating wellhead surface injection pressure (psig)				
Minimum annulus/tubing differential pressure (psig)				

Table CON-7: CO_2 Specification for Bluebonnet Hub.

Claimed as PBI

4.0 Well Design Bluebonnet CCS 1 - CO_2 Injector Well

The Bluebonnet CCS 1 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-1, Figure CON-2, and Figure CON-3 show the proposed well schematics for Bluebonnet CCS 1 original completion, first recompletion, and second recompletion, respectively.

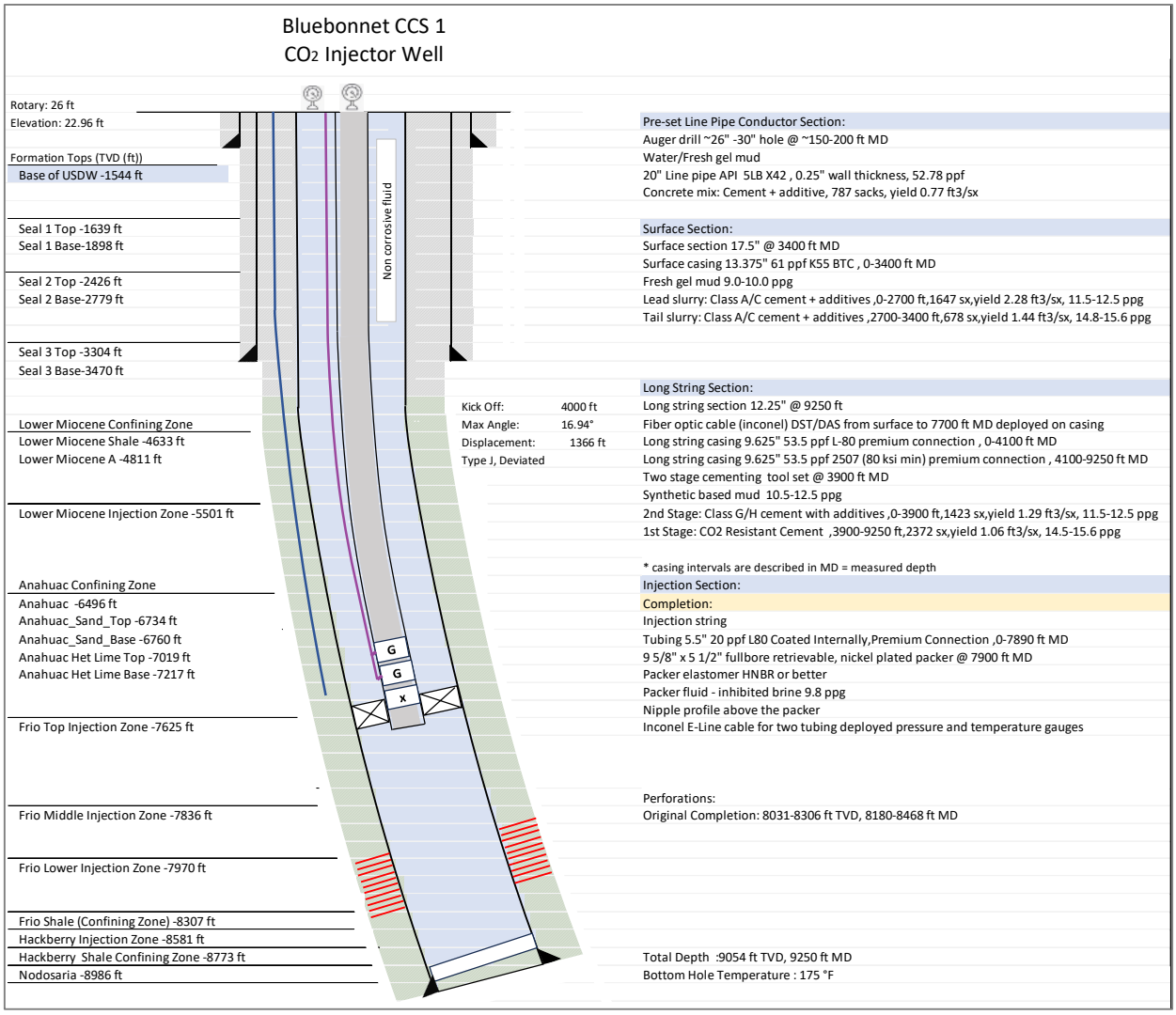


Figure CON-1: Bluebonnet CCS 1 well schematic – original completion.

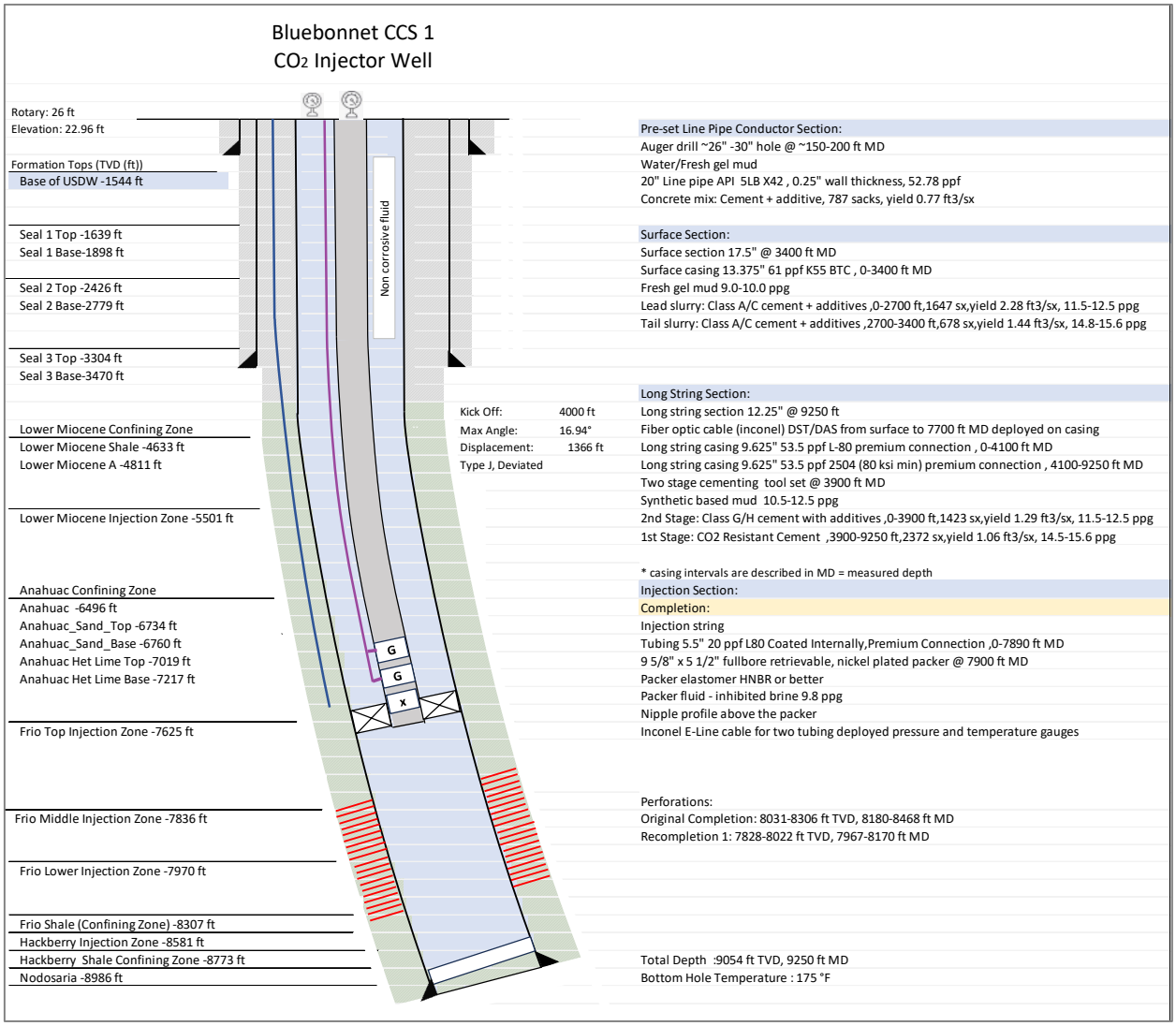


Figure CON-2: Bluebonnet CCS 1 well schematic – first recompletion.

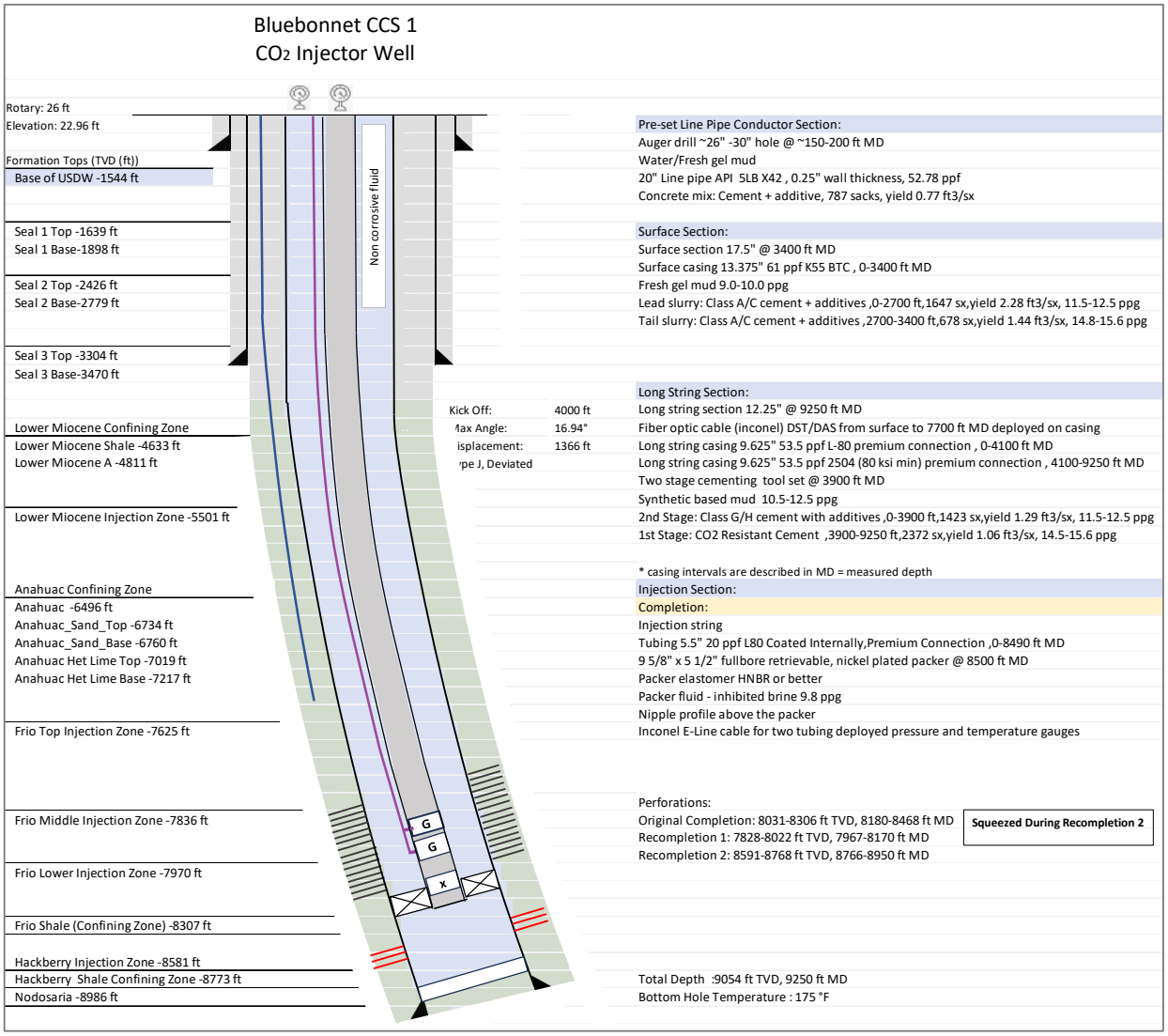


Figure CON-3: Bluebonnet CCS 1 well schematic – second recompletion.

4.1 Design Overview Bluebonnet CCS 1

4.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

4.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,400 ft to cover the base of the USDW, estimated at 1,544 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with a conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

4.1.3 Long String Section

Bluebonnet CCS 1 will be drilled directionally in a “J” type profile, with the kickoff point planned at 4,000 ft TVD, a maximum angle of 16.94°, and 1,366 ft displacement. The detailed trajectory is provided in Table CON-8.

A 12 ¼ in. directional wellbore will be drilled from 3,400 ft to total depth (MD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustical sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing

job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and pack off. The team will then install the rest of the wellhead to prepare for completion operations.

4.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5 ½-in. tubing and packer completion will be run to approximately 7,900 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

4.2 Directional Plan Bluebonnet CCS 1

Table CON-8 summarizes the proposed trajectory for Bluebonnet CCS 1.

Table CON-8: Bluebonnet CCS 1 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
0	0	0	0	-48.96	0	0	0
4000	0	0	4000	3951.04	0	0	0
4050	0.75	191.42	4050	4001.04	-0.32	-0.06	0.33
4100	1.5	191.42	4099.99	4051.03	-1.28	-0.26	1.31
4150	2.25	191.42	4149.96	4101	-2.89	-0.58	2.94
4200	3	191.42	4199.91	4150.95	-5.13	-1.04	5.23
4250	3.75	191.42	4249.82	4200.86	-8.02	-1.62	8.18
4300	4.5	191.42	4299.69	4250.73	-11.54	-2.33	11.77
4350	5.25	191.42	4349.51	4300.55	-15.71	-3.17	16.02
4400	6	191.42	4399.27	4350.31	-20.51	-4.14	20.92
4450	6.75	191.42	4448.96	4400	-25.95	-5.24	26.48
4500	7.5	191.42	4498.57	4449.61	-32.03	-6.47	32.68

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
4550	8.25	191.42	4548.1	4499.14	-38.75	-7.83	39.53
4600	9	191.42	4597.54	4548.58	-46.1	-9.31	47.03
4650	9.75	191.42	4646.87	4597.91	-54.08	-10.92	55.17
4700	10.5	191.42	4696.09	4647.13	-62.7	-12.66	63.96
4750	11.25	191.42	4745.19	4696.23	-71.94	-14.53	73.39
4800	12	191.42	4794.16	4745.2	-81.82	-16.52	83.47
4850	12.75	191.42	4843	4794.04	-92.32	-18.65	94.19
4900	13.5	191.42	4891.7	4842.74	-103.45	-20.89	105.54
4950	14.25	191.42	4940.24	4891.28	-115.2	-23.27	117.53
5000	15	191.42	4988.62	4939.66	-127.58	-25.77	130.15
5050	15.75	191.42	5036.83	4987.87	-140.57	-28.39	143.41
5100	16.5	191.42	5084.86	5035.9	-154.18	-31.14	157.3
5129.57	16.94	191.42	5113.18	5064.22	-162.52	-32.82	165.81
5150	16.94	191.42	5132.72	5083.76	-168.36	-34	171.76
5200	16.94	191.42	5180.55	5131.59	-182.64	-36.89	186.33
5250	16.94	191.42	5228.38	5179.42	-196.93	-39.77	200.9
5300	16.94	191.42	5276.21	5227.25	-211.21	-42.66	215.47
5350	16.94	191.42	5324.04	5275.08	-225.49	-45.54	230.04
5400	16.94	191.42	5371.87	5322.91	-239.78	-48.42	244.62
5450	16.94	191.42	5419.7	5370.74	-254.06	-51.31	259.19
5500	16.94	191.42	5467.53	5418.57	-268.34	-54.19	273.76
5550	16.94	191.42	5515.36	5466.4	-282.62	-57.08	288.33
5600	16.94	191.42	5563.19	5514.23	-296.91	-59.96	302.9
5650	16.94	191.42	5611.02	5562.06	-311.19	-62.85	317.47
5700	16.94	191.42	5658.85	5609.89	-325.47	-65.73	332.05
5750	16.94	191.42	5706.68	5657.72	-339.76	-68.62	346.62
5800	16.94	191.42	5754.51	5705.55	-354.04	-71.5	361.19
5850	16.94	191.42	5802.34	5753.38	-368.32	-74.39	375.76
5900	16.94	191.42	5850.17	5801.21	-382.61	-77.27	390.33
5950	16.94	191.42	5898	5849.04	-396.89	-80.16	404.9
6000	16.94	191.42	5945.82	5896.86	-411.17	-83.04	419.47
6050	16.94	191.42	5993.65	5944.69	-425.46	-85.92	434.05
6100	16.94	191.42	6041.48	5992.52	-439.74	-88.81	448.62
6150	16.94	191.42	6089.31	6040.35	-454.02	-91.69	463.19
6200	16.94	191.42	6137.14	6088.18	-468.31	-94.58	477.76
6250	16.94	191.42	6184.97	6136.01	-482.59	-97.46	492.33
6300	16.94	191.42	6232.8	6183.84	-496.87	-100.35	506.9
6350	16.94	191.42	6280.63	6231.67	-511.15	-103.23	521.47
6400	16.94	191.42	6328.46	6279.5	-525.44	-106.12	536.05

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
6450	16.94	191.42	6376.29	6327.33	-539.72	-109	550.62
6500	16.94	191.42	6424.12	6375.16	-554	-111.89	565.19
6550	16.94	191.42	6471.95	6422.99	-568.29	-114.77	579.76
6600	16.94	191.42	6519.78	6470.82	-582.57	-117.66	594.33
6650	16.94	191.42	6567.61	6518.65	-596.85	-120.54	608.9
6700	16.94	191.42	6615.44	6566.48	-611.14	-123.42	623.48
6750	16.94	191.42	6663.27	6614.31	-625.42	-126.31	638.05
6800	16.94	191.42	6711.1	6662.14	-639.7	-129.19	652.62
6850	16.94	191.42	6758.93	6709.97	-653.99	-132.08	667.19
6900	16.94	191.42	6806.76	6757.8	-668.27	-134.96	681.76
6950	16.94	191.42	6854.59	6805.63	-682.55	-137.85	696.33
7000	16.94	191.42	6902.42	6853.46	-696.84	-140.73	710.9
7050	16.94	191.42	6950.25	6901.29	-711.12	-143.62	725.48
7100	16.94	191.42	6998.08	6949.12	-725.4	-146.5	740.05
7150	16.94	191.42	7045.91	6996.95	-739.68	-149.39	754.62
7200	16.94	191.42	7093.74	7044.78	-753.97	-152.27	769.19
7250	16.94	191.42	7141.56	7092.6	-768.25	-155.16	783.76
7300	16.94	191.42	7189.39	7140.43	-782.53	-158.04	798.33
7350	16.94	191.42	7237.22	7188.26	-796.82	-160.92	812.9
7400	16.94	191.42	7285.05	7236.09	-811.1	-163.81	827.48
7450	16.94	191.42	7332.88	7283.92	-825.38	-166.69	842.05
7500	16.94	191.42	7380.71	7331.75	-839.67	-169.58	856.62
7550	16.94	191.42	7428.54	7379.58	-853.95	-172.46	871.19
7600	16.94	191.42	7476.37	7427.41	-868.23	-175.35	885.76
7650	16.94	191.42	7524.2	7475.24	-882.52	-178.23	900.33
7700	16.94	191.42	7572.03	7523.07	-896.8	-181.12	914.91
7750	16.94	191.42	7619.86	7570.9	-911.08	-184	929.48
7800	16.94	191.42	7667.69	7618.73	-925.37	-186.89	944.05
7850	16.94	191.42	7715.52	7666.56	-939.65	-189.77	958.62
7900	16.94	191.42	7763.35	7714.39	-953.93	-192.66	973.19
7950	16.94	191.42	7811.18	7762.22	-968.21	-195.54	987.76
7966	16.94	191.42	7827	7778.04	-972.94	-196.49	992.58
8000	16.94	191.42	7859.01	7810.05	-982.5	-198.42	1002.33
8050	16.94	191.42	7906.84	7857.88	-996.78	-201.31	1016.91
8100	16.94	191.42	7954.67	7905.71	-1011.06	-204.19	1031.48
8150	16.94	191.42	8002.5	7953.54	-1025.35	-207.08	1046.05
8200	16.94	191.42	8050.33	8001.37	-1039.63	-209.96	1060.62
8250	16.94	191.42	8098.16	8049.2	-1053.91	-212.85	1075.19
8300	16.94	191.42	8145.99	8097.03	-1068.2	-215.73	1089.76

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
8350	16.94	191.42	8193.82	8144.86	-1082.48	-218.62	1104.33
8400	16.94	191.42	8241.65	8192.69	-1096.76	-221.5	1118.91
8450	16.94	191.42	8289.48	8240.52	-1111.05	-224.39	1133.48
8500	16.94	191.42	8337.31	8288.35	-1125.33	-227.27	1148.05
8550	16.94	191.42	8385.13	8336.17	-1139.61	-230.16	1162.62
8600	16.94	191.42	8432.96	8384	-1153.9	-233.04	1177.19
8650	16.94	191.42	8480.79	8431.83	-1168.18	-235.92	1191.76
8700	16.94	191.42	8528.62	8479.66	-1182.46	-238.81	1206.34
8750	16.94	191.42	8576.45	8527.49	-1196.74	-241.69	1220.91
8800	16.94	191.42	8624.28	8575.32	-1211.03	-244.58	1235.48
8850	16.94	191.42	8672.11	8623.15	-1225.31	-247.46	1250.05
8900	16.94	191.42	8719.94	8670.98	-1239.59	-250.35	1264.62
8950	16.94	191.42	8767.77	8718.81	-1253.88	-253.23	1279.19
9000	16.94	191.42	8815.6	8766.64	-1268.16	-256.12	1293.76
9050	16.94	191.42	8863.43	8814.47	-1282.44	-259	1308.34
9100	16.94	191.42	8911.26	8862.3	-1296.73	-261.89	1322.91
9150	16.94	191.42	8959.09	8910.13	-1311.01	-264.77	1337.48
9200	16.94	191.42	9006.92	8957.96	-1325.29	-267.66	1352.05
9250	16.94	191.42	9054.75	9005.79	-1339.58	-270.54	1366.62

4.3 Casing, Tubing and Completion Design Bluebonnet CCS 1

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-9 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-9: Minimum safety factors for tubular design – Bluebonnet CCS 1.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,400	1.18	1.04	2.09	1.30
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.06	2.44	2.27	2.00
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-9,250	1.89	1.11	3.29	1.41
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-7,900	2.52	1.29	1.94	1.39

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document. Safety factors for the second recompletion events are similar that the ones presented in Table CON-9.

Figure CON-4 shows the design limits envelope for the 5 ½-in. injection tubing used to validate the selection of the material. The analysis was developed with WELLCAT™ software from Landmark.

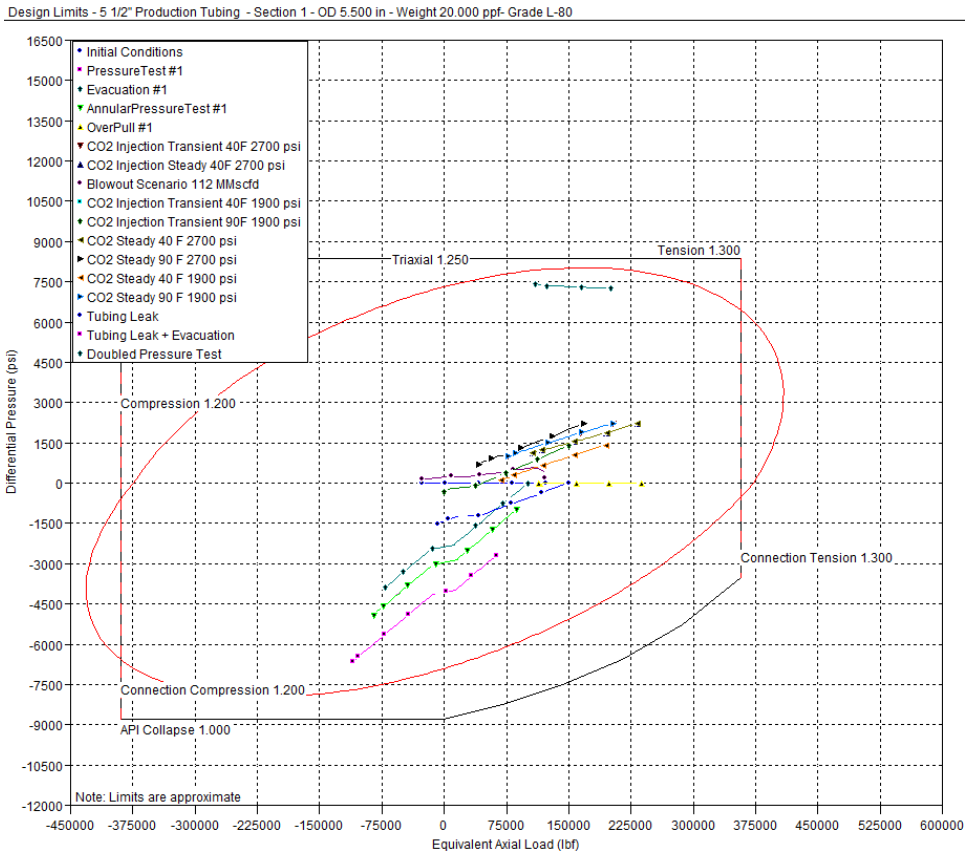


Figure CON-4: Bluebonnet CCS 1 injection tubing design limits.

A summary of the loads used in the simulation of the tubing with WELLCAT^{TM} is provided in Attachment E of this Injection Well Construction Plan.

The tables listed below provide further details regarding the Bluebonnet CCS 1 well. Table CON-10 contains the open hole diameters and intervals, Table CON-11 lists the casing specifications, Table CON-12 details the conductor material, and Table CON-13 details the casing material properties for Bluebonnet CCS 1.

Table CON-10: Open hole diameters and intervals - Bluebonnet CCS 1.

Name	Depth Interval (ft)	Open hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,400	17 ½	Cover USDW
Long String Section	3,400 to 9,250	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,544 ft TVD.

Table CON-11: Casing specifications - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,400	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 9,250	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-12: Conductor material properties - Bluebonnet CCS 1.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-13: Casing material properties - Bluebonnet CCS 1.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 61 ppf K55 BTC	0 to 3,400	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 9,250	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-14 and Table CON-15 contain the upper completion specifications for the original completion and first and second recompletions. Table CON-16 shows the specification of the 5 ½ in. tubing.

Table CON-14: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 7,890	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-15: Tubing material properties – second recompletion - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 8,490	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-16: Tubing material properties - Bluebonnet CCS 1.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-17 shows the specifications of the injection packer.

Table CON-17: Packer specifications - Bluebonnet CCS 1.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

4.4 Cementing Program Bluebonnet CCS 1

Table CON-18 shows the cementing program details.

Table CON-18: Cementing program - Bluebonnet CCS 1.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,647	2.28	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,413	1.29	50%
	CO_2-Resistant Cement	3,900 to 9,250	14.5-15.6	2,372	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

Details on cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

4.5 Centralization Program Bluebonnet CCS 1

4.5.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

4.5.2 Long String Casing

Approximately 130-135 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

4.6 Fluids Program Bluebonnet CCS 1

Table CON-19 shows the mud program details for Bluebonnet CCS 1.

Table CON-19: Mud program - Bluebonnet CCS 1.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,400	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,400–9,250	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

4.7 Wellhead Schematic Bluebonnet CCS 1

Figure CON-5 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 1 well. Details on the blowout preventors (BOP) and wellhead design are included in Appendix C.



4.8 Bluebonnet CCS 1 Procedure

4.8.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

4.8.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi, BOPE to 3,000 psi.

4.8.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry as per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

4.8.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

5.0 Well Design Bluebonnet CCS 2 - CO_2 Injector Well

The Bluebonnet CCS 2 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-6 and Figure CON-7 show the proposed well schematic for Bluebonnet CCS 2 original completion and recompletion, respectively.

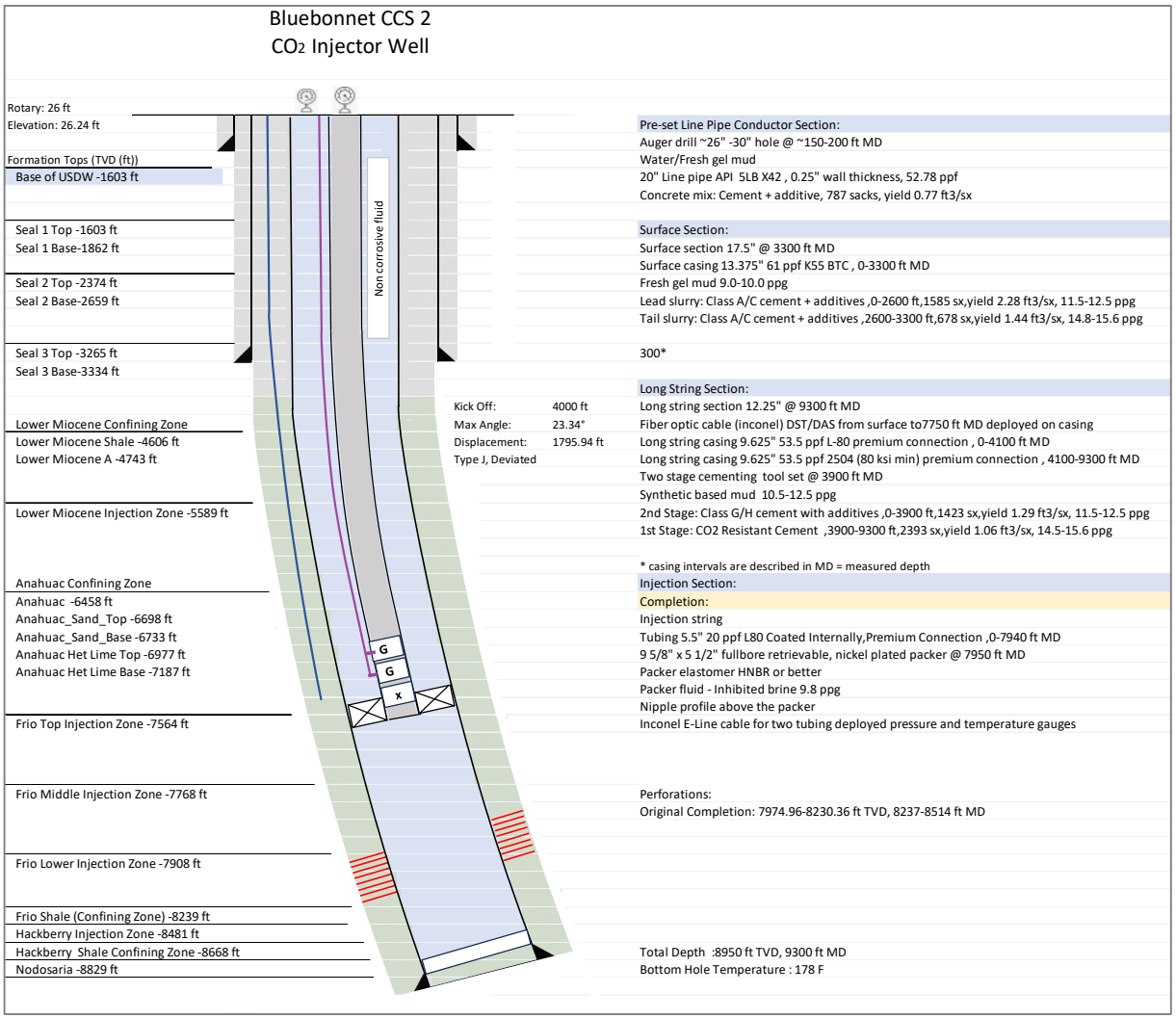


Figure CON-6: Bluebonnet CCS 2 well schematic – original completion.

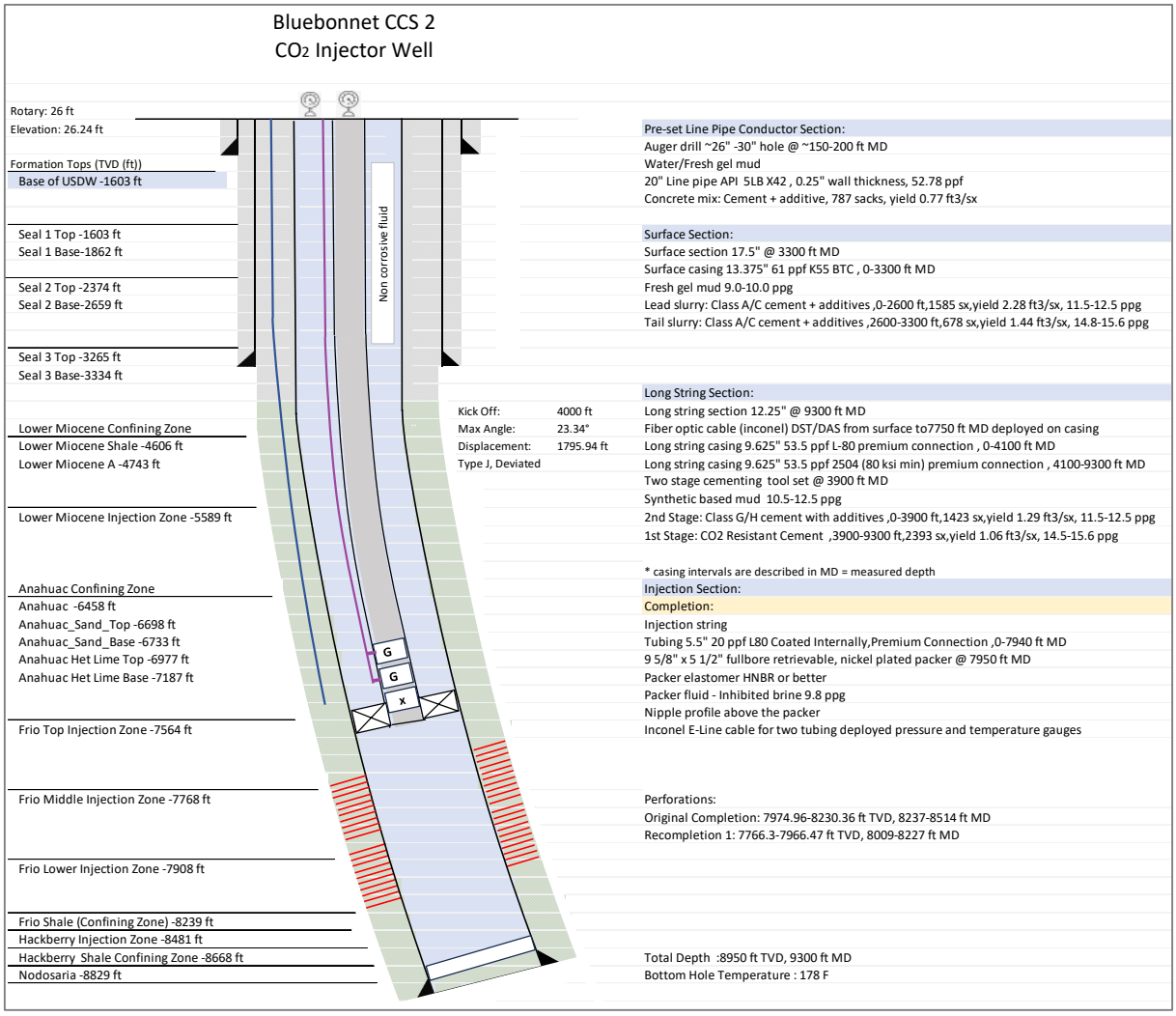


Figure CON-7: Bluebonnet CCS 2 well schematic – recompletion.

5.1 Design Overview Bluebonnet CCS 2

5.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,603 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

5.1.3 Long String Section

Bluebonnet CCS 2 will be drilled directionally in a “J” type profile, with the kickoff point planned at 4,000 ft TVD, a maximum angle of 23.34°, and 1,795 ft displacement. The detailed trajectory is provided in Table CON-17.

A 12 ¼ in. directional wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The

depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and pack off. The team will install the rest of the wellhead to prepare for completions operations.

5.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5 ½-in. tubing and packer completion will be run to approximately 7,950 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

5.2 Directional Plan Bluebonnet CCS 2

Table CON-20 summarizes the proposed trajectory for Bluebonnet CCS 2.

Table CON-20: Bluebonnet CCS 2 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
0	0	0	0	-52.25	0	0	0
4000	0	0	4000	3947.75	0	0	0
4050	0.75	295.79	4050	3997.75	0.14	-0.29	0.33
4100	1.5	295.79	4099.99	4047.74	0.57	-1.18	1.31
4150	2.25	295.79	4149.96	4097.71	1.28	-2.65	2.94
4200	3	295.79	4199.91	4147.66	2.28	-4.71	5.23
4250	3.75	295.79	4249.82	4197.57	3.56	-7.36	8.18
4300	4.5	295.79	4299.69	4247.44	5.12	-10.6	11.77
4350	5.25	295.79	4349.51	4297.26	6.97	-14.43	16.02
4400	6	295.79	4399.27	4347.02	9.1	-18.84	20.92
4450	6.75	295.79	4448.96	4396.71	11.52	-23.84	26.48
4500	7.5	295.79	4498.57	4446.32	14.22	-29.42	32.68

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
4550	8.25	295.79	4548.1	4495.85	17.2	-35.59	39.53
4600	9	295.79	4597.54	4545.29	20.46	-42.34	47.03
4650	9.75	295.79	4646.87	4594.62	24	-49.68	55.17
4700	10.5	295.79	4696.09	4643.84	27.83	-57.59	63.96
4750	11.25	295.79	4745.19	4692.94	31.93	-66.08	73.39
4800	12	295.79	4794.16	4741.91	36.32	-75.16	83.47
4850	12.75	295.79	4843	4790.75	40.98	-84.8	94.19
4900	13.5	295.79	4891.7	4839.45	45.92	-95.03	105.54
4950	14.25	295.79	4940.24	4887.99	51.13	-105.82	117.53
5000	15	295.79	4988.62	4936.37	56.63	-117.19	130.15
5050	15.75	295.79	5036.83	4984.58	62.39	-129.13	143.41
5100	16.5	295.79	5084.86	5032.61	68.43	-141.63	157.3
5150	17.25	295.79	5132.71	5080.46	74.75	-154.7	171.81
5200	18	295.79	5180.36	5128.11	81.34	-168.33	186.95
5250	18.75	295.79	5227.81	5175.56	88.19	-182.52	202.71
5300	19.5	295.79	5275.05	5222.8	95.32	-197.27	219.09
5350	20.25	295.79	5322.07	5269.82	102.72	-212.58	236.09
5400	21	295.79	5368.86	5316.61	110.38	-228.43	253.7
5450	21.75	295.79	5415.43	5363.18	118.31	-244.84	271.93
5500	22.5	295.79	5461.74	5409.49	126.5	-261.8	290.76
5550	23.25	295.79	5507.81	5455.56	134.96	-279.3	310.19
5556.05	23.34	295.79	5513.37	5461.12	136	-281.45	312.59
5600	23.34	295.79	5553.72	5501.47	143.57	-297.13	330
5650	23.34	295.79	5599.63	5547.38	152.19	-314.97	349.81
5700	23.34	295.79	5645.54	5593.29	160.81	-332.81	369.62
5750	23.34	295.79	5691.45	5639.2	169.43	-350.64	389.43
5800	23.34	295.79	5737.35	5685.1	178.05	-368.48	409.24
5850	23.34	295.79	5783.26	5731.01	186.67	-386.32	429.05
5900	23.34	295.79	5829.17	5776.92	195.28	-404.15	448.86
5950	23.34	295.79	5875.08	5822.83	203.9	-421.99	468.67
6000	23.34	295.79	5920.99	5868.74	212.52	-439.83	488.48
6050	23.34	295.79	5966.89	5914.64	221.14	-457.66	508.29
6100	23.34	295.79	6012.8	5960.55	229.76	-475.5	528.1
6150	23.34	295.79	6058.71	6006.46	238.38	-493.34	547.91
6200	23.34	295.79	6104.62	6052.37	247	-511.17	567.72
6250	23.34	295.79	6150.53	6098.28	255.62	-529.01	587.53
6300	23.34	295.79	6196.44	6144.19	264.23	-546.85	607.34
6350	23.34	295.79	6242.34	6190.09	272.85	-564.68	627.15
6400	23.34	295.79	6288.25	6236	281.47	-582.52	646.96

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
6450	23.34	295.79	6334.16	6281.91	290.09	-600.36	666.77
6500	23.34	295.79	6380.07	6327.82	298.71	-618.19	686.58
6550	23.34	295.79	6425.98	6373.73	307.33	-636.03	706.39
6600	23.34	295.79	6471.89	6419.64	315.95	-653.87	726.2
6650	23.34	295.79	6517.79	6465.54	324.56	-671.71	746.01
6700	23.34	295.79	6563.7	6511.45	333.18	-689.54	765.82
6750	23.34	295.79	6609.61	6557.36	341.8	-707.38	785.63
6800	23.34	295.79	6655.52	6603.27	350.42	-725.22	805.44
6850	23.34	295.79	6701.43	6649.18	359.04	-743.05	825.25
6900	23.34	295.79	6747.33	6695.08	367.66	-760.89	845.06
6950	23.34	295.79	6793.24	6740.99	376.28	-778.73	864.87
7000	23.34	295.79	6839.15	6786.9	384.9	-796.56	884.68
7050	23.34	295.79	6885.06	6832.81	393.51	-814.4	904.49
7100	23.34	295.79	6930.97	6878.72	402.13	-832.24	924.3
7150	23.34	295.79	6976.88	6924.63	410.75	-850.07	944.11
7200	23.34	295.79	7022.78	6970.53	419.37	-867.91	963.92
7250	23.34	295.79	7068.69	7016.44	427.99	-885.75	983.73
7300	23.34	295.79	7114.6	7062.35	436.61	-903.58	1003.54
7350	23.34	295.79	7160.51	7108.26	445.23	-921.42	1023.35
7400	23.34	295.79	7206.42	7154.17	453.84	-939.26	1043.16
7450	23.34	295.79	7252.33	7200.08	462.46	-957.09	1062.97
7500	23.34	295.79	7298.23	7245.98	471.08	-974.93	1082.78
7550	23.34	295.79	7344.14	7291.89	479.7	-992.77	1102.59
7600	23.34	295.79	7390.05	7337.8	488.32	-1010.61	1122.4
7650	23.34	295.79	7435.96	7383.71	496.94	-1028.44	1142.21
7700	23.34	295.79	7481.87	7429.62	505.56	-1046.28	1162.02
7750	23.34	295.79	7527.77	7475.52	514.18	-1064.12	1181.83
7793.81	23.34	295.79	7568	7515.75	521.73	-1079.74	1199.19
7800	23.34	295.79	7573.68	7521.43	522.79	-1081.95	1201.64
7850	23.34	295.79	7619.59	7567.34	531.41	-1099.79	1221.45
7900	23.34	295.79	7665.5	7613.25	540.03	-1117.63	1241.26
7950	23.34	295.79	7711.41	7659.16	548.65	-1135.46	1261.07
8000	23.34	295.79	7757.32	7705.07	557.27	-1153.3	1280.88
8050	23.34	295.79	7803.22	7750.97	565.89	-1171.14	1300.69
8100	23.34	295.79	7849.13	7796.88	574.51	-1188.97	1320.5
8150	23.34	295.79	7895.04	7842.79	583.12	-1206.81	1340.31
8200	23.34	295.79	7940.95	7888.7	591.74	-1224.65	1360.12
8250	23.34	295.79	7986.86	7934.61	600.36	-1242.48	1379.93
8300	23.34	295.79	8032.77	7980.52	608.98	-1260.32	1399.74

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
8350	23.34	295.79	8078.67	8026.42	617.6	-1278.16	1419.55
8400	23.34	295.79	8124.58	8072.33	626.22	-1295.99	1439.36
8450	23.34	295.79	8170.49	8118.24	634.84	-1313.83	1459.17
8500	23.34	295.79	8216.4	8164.15	643.46	-1331.67	1478.98
8550	23.34	295.79	8262.31	8210.06	652.07	-1349.51	1498.79
8600	23.34	295.79	8308.21	8255.96	660.69	-1367.34	1518.6
8650	23.34	295.79	8354.12	8301.87	669.31	-1385.18	1538.41
8700	23.34	295.79	8400.03	8347.78	677.93	-1403.02	1558.22
8750	23.34	295.79	8445.94	8393.69	686.55	-1420.85	1578.03
8800	23.34	295.79	8491.85	8439.6	695.17	-1438.69	1597.84
8850	23.34	295.79	8537.76	8485.51	703.79	-1456.53	1617.65
8900	23.34	295.79	8583.66	8531.41	712.4	-1474.36	1637.46
8950	23.34	295.79	8629.57	8577.32	721.02	-1492.2	1657.27
9000	23.34	295.79	8675.48	8623.23	729.64	-1510.04	1677.08
9050	23.34	295.79	8721.39	8669.14	738.26	-1527.87	1696.89
9100	23.34	295.79	8767.3	8715.05	746.88	-1545.71	1716.7
9150	23.34	295.79	8813.2	8760.95	755.5	-1563.55	1736.51
9200	23.34	295.79	8859.11	8806.86	764.12	-1581.38	1756.32
9250	23.34	295.79	8905.02	8852.77	772.74	-1599.22	1776.13
9300	23.34	295.79	8950.93	8898.68	781.35	-1617.06	1795.94

5.3 Casing, Tubing and Completion Design Bluebonnet CCS 2

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-21 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-21: Minimum safety factors for tubular design - Bluebonnet CCS 2.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 68.0 ppf, K-55	Buttress	0-3,300	1.18	1.06	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.06	2.44	2.52	2.07
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-9,300	1.89	1.12	3.5	1.44
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-7,950	2.52	1.29	2.04	1.4

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 2 well. Table CON-22 contains the open hole diameters and intervals, Table CON-23 lists the casing specifications, Table CON-24 details the conductor material, and Table CON-25 details the casing material properties.

Table CON-22: Open hole diameters and intervals - Bluebonnet CCS 2.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 9,300	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,603 ft TVD.

Table CON-23: Casing specifications - Bluebonnet CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 9,300	9 ⅝	8.535	8.379	53.5	2507 Min. 80 ksi	Premium

Table CON-24: Conductor material properties - Bluebonnet CCS 2.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-25: Casing material properties - Bluebonnet CCS 2.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 9,300	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-26 contains the upper completion specifications for the original completion. Table CON-27 shows the specification of the 5 ½ in. tubing.

Table CON-26: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 7,940	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-27: Tubing material properties - Bluebonnet CCS 2.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-28 shows the specifications of the injection packer.

Table CON-28: Packer specifications - Bluebonnet CCS 2.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

5.4 Cementing Program Bluebonnet CCS 2

Table CON-29 shows the cementing program details.

Table CON-29: Cementing program - Bluebonnet CCS 2.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,600	11.5-12.5	1,585	2.28	100%
	Class A/C cement with additives	2,600 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,423	1.29	50%
	CO_2-Resistant Cement	3,900 to 9,300	14.5-15.6	2,393	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

Details on cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

5.5 Centralization Program Bluebonnet CCS 2

5.5.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

5.5.2 Long String Casing

Approximately 130-135 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

5.6 Fluids Program Bluebonnet CCS 2

Table CON-30 shows the mud program details for Bluebonnet CCS 2.

Table CON-30: Mud program - Bluebonnet CCS 2.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,300	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

5.7 Wellhead Schematic Bluebonnet CCS 2

Figure CON-8 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 2 well. Details on blowout preventors (BOP) and wellhead design are included in Appendix C.



5.8 Bluebonnet CCS 2 Procedure

5.8.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

5.8.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

5.8.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing per program, coordinating running speed with the fiber optic installation.
- Once on the bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

5.8.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

6.0 Well Design Bluebonnet CCS 3 - CO_2 Injector Well

The Bluebonnet CCS 3 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-9, Figure CON-10, and Figure CON-11 show the proposed well schematics for the Bluebonnet CCS 3 original completion and recompletions, respectively.

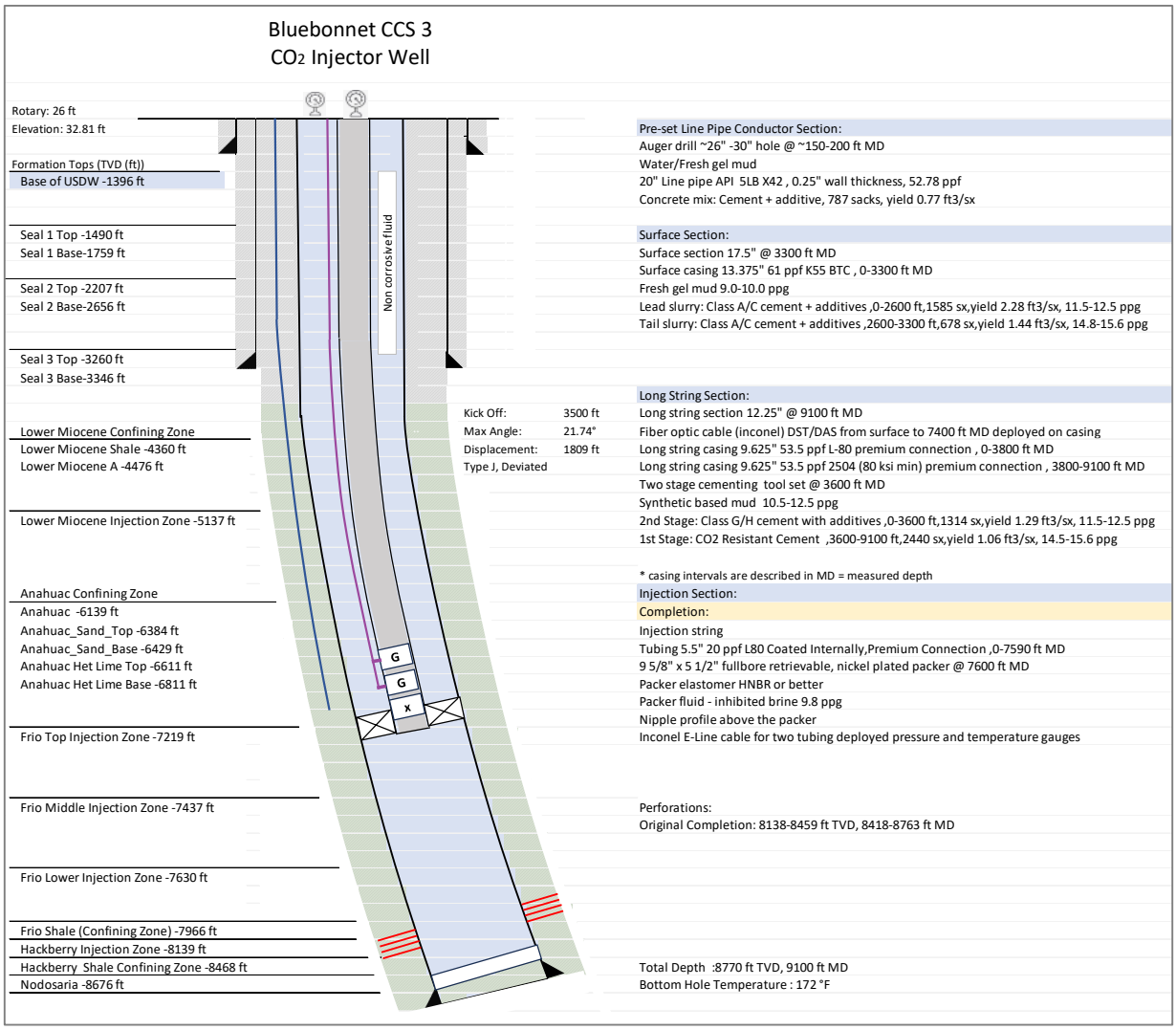


Figure CON-9: Bluebonnet CCS 3 well schematic – original completion.

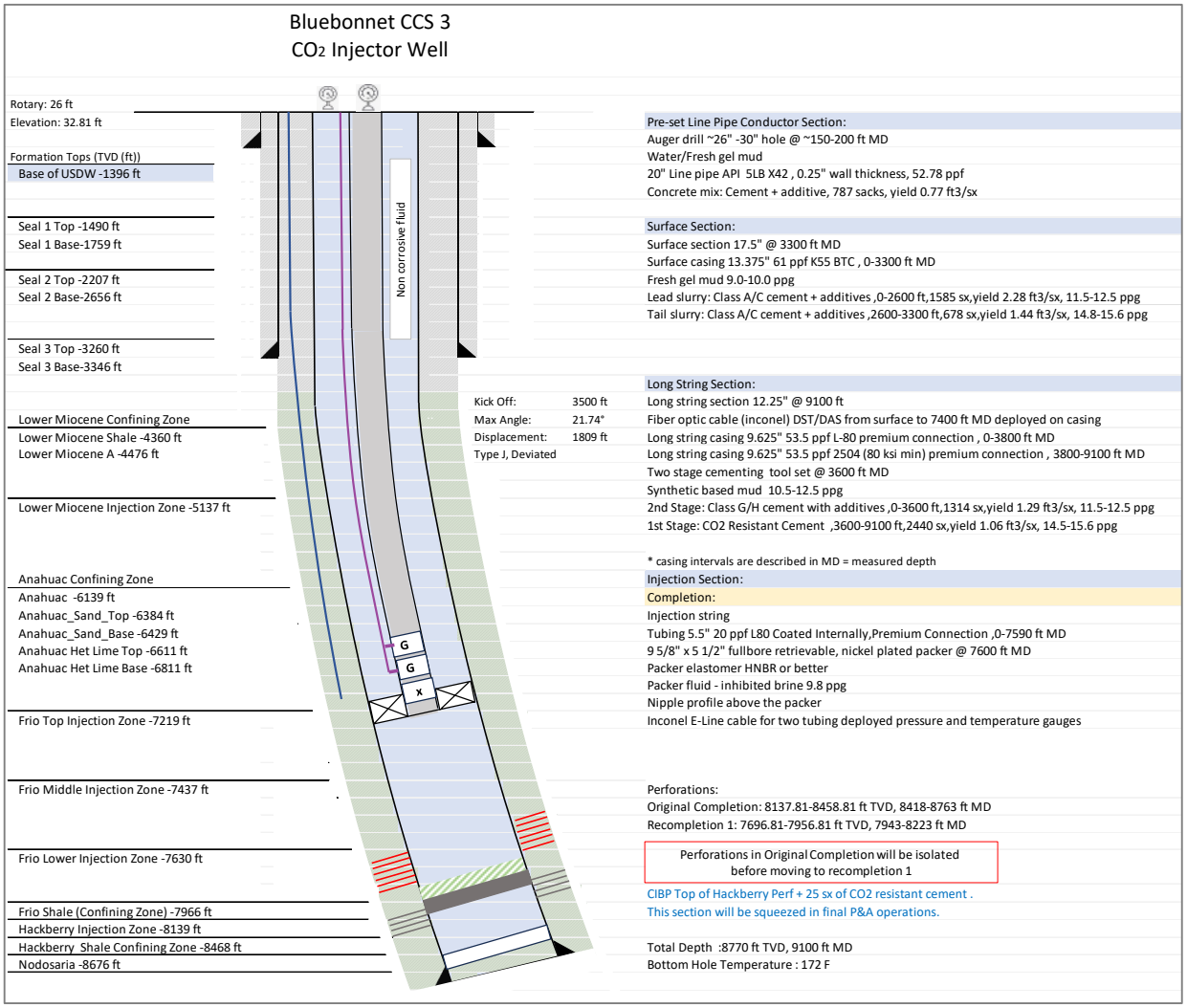


Figure CON-10: Bluebonnet CCS 3 well schematic – first recompletion.

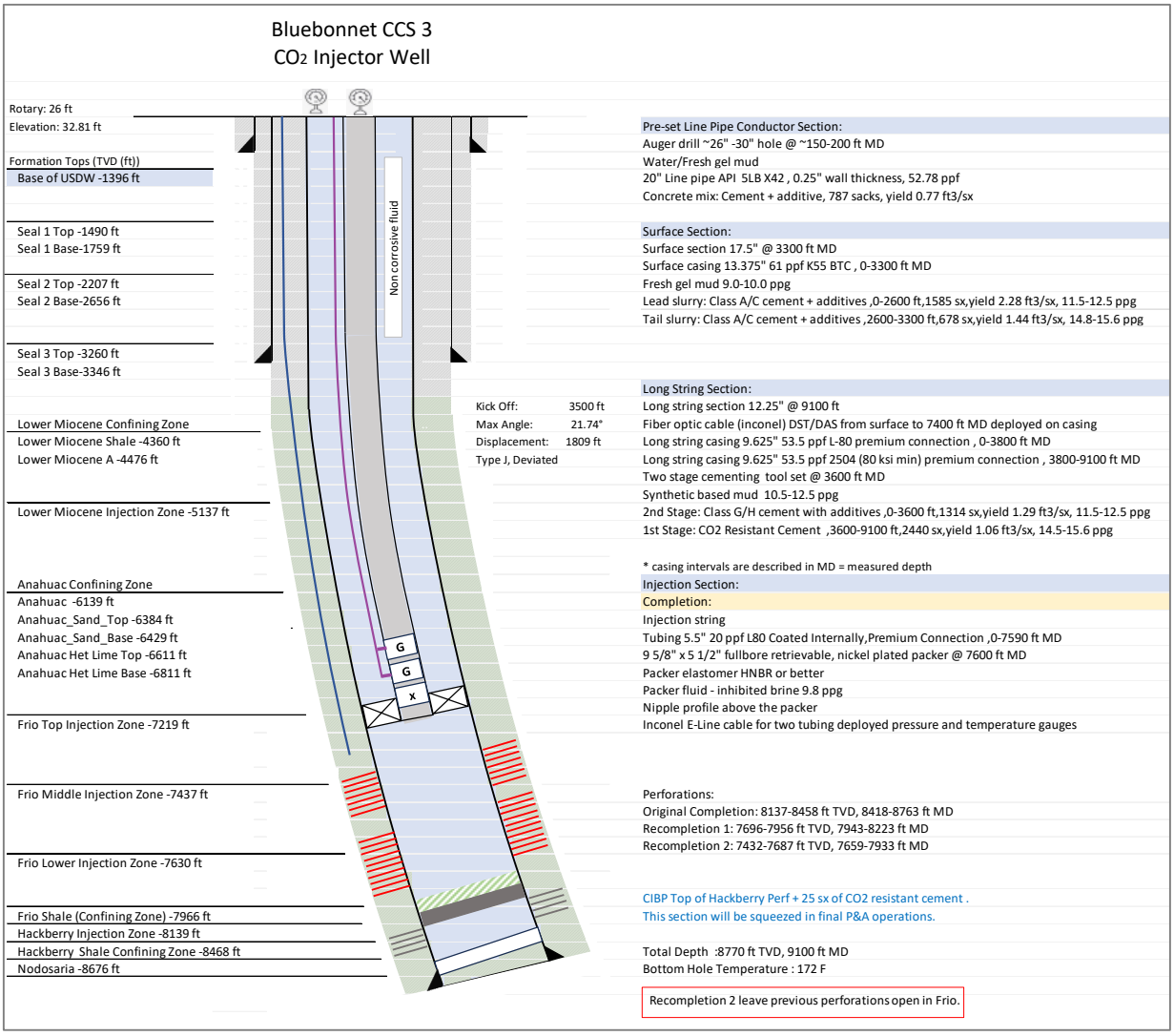


Figure CON-11: Bluebonnet CCS 3 well schematic – second recompletion.

6.1 Design Overview Bluebonnet CCS 3

6.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

6.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,396 ft TVD, and provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

6.1.3 Long String Section

Bluebonnet CCS 3 will be drilled directionally in a “J” type profile, with the kickoff point planned at 3,500 ft TVD, a maximum angle of 21.74°, and 1,809 ft displacement. The detailed trajectory is provided in Table CON-31.

A 12 ¼ in. directional wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

6.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5 ½-in. tubing and packer completion will be run to approximately 7,600 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

6.2 Directional Plan Bluebonnet CCS 3

Table CON-31 summarizes the proposed trajectory for Bluebonnet CCS 3.

Table CON-31: Bluebonnet CCS 3 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
0	0	0	0	-58.81	0	0	0
3500	0	0	3500	3441.19	0	0	0
3550	0.75	148.83	3550	3491.19	-0.28	0.17	0.33
3600	1.5	148.83	3599.99	3541.18	-1.12	0.68	1.31
3650	2.25	148.83	3649.96	3591.15	-2.52	1.52	2.94
3700	3	148.83	3699.91	3641.1	-4.48	2.71	5.23
3750	3.75	148.83	3749.82	3691.01	-7	4.23	8.18
3800	4.5	148.83	3799.69	3740.88	-10.08	6.09	11.77
3850	5.25	148.83	3849.51	3790.7	-13.71	8.29	16.02
3900	6	148.83	3899.27	3840.46	-17.9	10.83	20.92
3950	6.75	148.83	3948.96	3890.15	-22.65	13.7	26.48
4000	7.5	148.83	3998.57	3939.76	-27.96	16.91	32.68
4050	8.25	148.83	4048.1	3989.29	-33.82	20.46	39.53
4100	9	148.83	4097.54	4038.73	-40.24	24.34	47.03
4150	9.75	148.83	4146.87	4088.06	-47.21	28.55	55.17

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
4200	10.5	148.83	4196.09	4137.28	-54.73	33.1	63.96
4250	11.25	148.83	4245.19	4186.38	-62.8	37.99	73.39
4300	12	148.83	4294.16	4235.35	-71.42	43.2	83.47
4350	12.75	148.83	4343	4284.19	-80.59	48.75	94.19
4400	13.5	148.83	4391.7	4332.89	-90.3	54.62	105.54
4450	14.25	148.83	4440.24	4381.43	-100.56	60.83	117.53
4500	15	148.83	4488.62	4429.81	-111.37	67.36	130.15
4550	15.75	148.83	4536.83	4478.02	-122.71	74.22	143.41
4600	16.5	148.83	4584.86	4526.05	-134.59	81.41	157.3
4650	17.25	148.83	4632.71	4573.9	-147.01	88.92	171.81
4700	18	148.83	4680.36	4621.55	-159.96	96.76	186.95
4750	18.75	148.83	4727.81	4669	-173.45	104.91	202.71
4800	19.5	148.83	4775.05	4716.24	-187.47	113.39	219.09
4850	20.25	148.83	4822.07	4763.26	-202.01	122.19	236.09
4900	21	148.83	4868.86	4810.05	-217.08	131.31	253.7
4949.52	21.74	148.83	4914.98	4856.17	-232.52	140.64	271.75
4950	21.74	148.83	4915.43	4856.62	-232.67	140.74	271.93
5000	21.74	148.83	4961.87	4903.06	-248.52	150.32	290.45
5050	21.74	148.83	5008.31	4949.5	-264.37	159.91	308.97
5100	21.74	148.83	5054.75	4995.94	-280.22	169.5	327.49
5150	21.74	148.83	5101.2	5042.39	-296.07	179.08	346.02
5200	21.74	148.83	5147.64	5088.83	-311.92	188.67	364.54
5250	21.74	148.83	5194.08	5135.27	-327.76	198.25	383.06
5300	21.74	148.83	5240.52	5181.71	-343.61	207.84	401.58
5350	21.74	148.83	5286.97	5228.16	-359.46	217.43	420.1
5400	21.74	148.83	5333.41	5274.6	-375.31	227.01	438.63
5450	21.74	148.83	5379.85	5321.04	-391.16	236.6	457.15
5500	21.74	148.83	5426.3	5367.49	-407.01	246.19	475.67
5550	21.74	148.83	5472.74	5413.93	-422.85	255.77	494.19
5600	21.74	148.83	5519.18	5460.37	-438.7	265.36	512.71
5650	21.74	148.83	5565.62	5506.81	-454.55	274.94	531.24
5700	21.74	148.83	5612.07	5553.26	-470.4	284.53	549.76
5750	21.74	148.83	5658.51	5599.7	-486.25	294.12	568.28
5800	21.74	148.83	5704.95	5646.14	-502.1	303.7	586.8
5850	21.74	148.83	5751.4	5692.59	-517.94	313.29	605.32
5900	21.74	148.83	5797.84	5739.03	-533.79	322.87	623.85
5950	21.74	148.83	5844.28	5785.47	-549.64	332.46	642.37
6000	21.74	148.83	5890.72	5831.91	-565.49	342.05	660.89
6050	21.74	148.83	5937.17	5878.36	-581.34	351.63	679.41

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
6100	21.74	148.83	5983.61	5924.8	-597.19	361.22	697.93
6150	21.74	148.83	6030.05	5971.24	-613.03	370.81	716.46
6200	21.74	148.83	6076.5	6017.69	-628.88	380.39	734.98
6250	21.74	148.83	6122.94	6064.13	-644.73	389.98	753.5
6300	21.74	148.83	6169.38	6110.57	-660.58	399.56	772.02
6350	21.74	148.83	6215.82	6157.01	-676.43	409.15	790.54
6400	21.74	148.83	6262.27	6203.46	-692.28	418.74	809.07
6450	21.74	148.83	6308.71	6249.9	-708.12	428.32	827.59
6500	21.74	148.83	6355.15	6296.34	-723.97	437.91	846.11
6550	21.74	148.83	6401.6	6342.79	-739.82	447.49	864.63
6600	21.74	148.83	6448.04	6389.23	-755.67	457.08	883.15
6650	21.74	148.83	6494.48	6435.67	-771.52	466.67	901.68
6700	21.74	148.83	6540.92	6482.11	-787.37	476.25	920.2
6750	21.74	148.83	6587.37	6528.56	-803.21	485.84	938.72
6800	21.74	148.83	6633.81	6575	-819.06	495.43	957.24
6850	21.74	148.83	6680.25	6621.44	-834.91	505.01	975.76
6900	21.74	148.83	6726.7	6667.89	-850.76	514.6	994.29
6950	21.74	148.83	6773.14	6714.33	-866.61	524.18	1012.81
7000	21.74	148.83	6819.58	6760.77	-882.46	533.77	1031.33
7050	21.74	148.83	6866.02	6807.21	-898.3	543.36	1049.85
7100	21.74	148.83	6912.47	6853.66	-914.15	552.94	1068.37
7150	21.74	148.83	6958.91	6900.1	-930	562.53	1086.9
7200	21.74	148.83	7005.35	6946.54	-945.85	572.12	1105.42
7250	21.74	148.83	7051.8	6992.99	-961.7	581.7	1123.94
7300	21.74	148.83	7098.24	7039.43	-977.55	591.29	1142.46
7350	21.74	148.83	7144.68	7085.87	-993.39	600.87	1160.98
7400	21.74	148.83	7191.12	7132.31	-1009.24	610.46	1179.51
7450	21.74	148.83	7237.57	7178.76	-1025.09	620.05	1198.03
7500	21.74	148.83	7284.01	7225.2	-1040.94	629.63	1216.55
7550	21.74	148.83	7330.45	7271.64	-1056.79	639.22	1235.07
7600	21.74	148.83	7376.89	7318.08	-1072.64	648.8	1253.59
7650	21.74	148.83	7423.34	7364.53	-1088.48	658.39	1272.11
7661.48	21.74	148.83	7434	7375.19	-1092.12	660.59	1276.37
7700	21.74	148.83	7469.78	7410.97	-1104.33	667.98	1290.64
7750	21.74	148.83	7516.22	7457.41	-1120.18	677.56	1309.16
7800	21.74	148.83	7562.67	7503.86	-1136.03	687.15	1327.68
7850	21.74	148.83	7609.11	7550.3	-1151.88	696.74	1346.2
7900	21.74	148.83	7655.55	7596.74	-1167.73	706.32	1364.72
7950	21.74	148.83	7701.99	7643.18	-1183.57	715.91	1383.25

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
8000	21.74	148.83	7748.44	7689.63	-1199.42	725.49	1401.77
8050	21.74	148.83	7794.88	7736.07	-1215.27	735.08	1420.29
8100	21.74	148.83	7841.32	7782.51	-1231.12	744.67	1438.81
8150	21.74	148.83	7887.77	7828.96	-1246.97	754.25	1457.33
8200	21.74	148.83	7934.21	7875.4	-1262.82	763.84	1475.86
8250	21.74	148.83	7980.65	7921.84	-1278.66	773.42	1494.38
8300	21.74	148.83	8027.09	7968.28	-1294.51	783.01	1512.9
8350	21.74	148.83	8073.54	8014.73	-1310.36	792.6	1531.42
8400	21.74	148.83	8119.98	8061.17	-1326.21	802.18	1549.94
8450	21.74	148.83	8166.42	8107.61	-1342.06	811.77	1568.47
8500	21.74	148.83	8212.87	8154.06	-1357.91	821.36	1586.99
8550	21.74	148.83	8259.31	8200.5	-1373.75	830.94	1605.51
8600	21.74	148.83	8305.75	8246.94	-1389.6	840.53	1624.03
8650	21.74	148.83	8352.19	8293.38	-1405.45	850.11	1642.55
8700	21.74	148.83	8398.64	8339.83	-1421.3	859.7	1661.08
8750	21.74	148.83	8445.08	8386.27	-1437.15	869.29	1679.6
8800	21.74	148.83	8491.52	8432.71	-1453	878.87	1698.12
8850	21.74	148.83	8537.97	8479.16	-1468.84	888.46	1716.64
8900	21.74	148.83	8584.41	8525.6	-1484.69	898.04	1735.16
8950	21.74	148.83	8630.85	8572.04	-1500.54	907.63	1753.69
9000	21.74	148.83	8677.29	8618.48	-1516.39	917.22	1772.21
9050	21.74	148.83	8723.74	8664.93	-1532.24	926.8	1790.73
9100	21.74	148.83	8770.18	8711.37	-1548.09	936.39	1809.25

6.3 Casing, Tubing and Completion Design Bluebonnet CCS 3

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-32 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-32: Minimum safety factors for tubular design - Bluebonnet CCS 3.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,300	1.18	1.08	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,800	2.06	2.63	2.56	2.06
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,800-9,100	1.90	1.14	3.56	1.47
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-7,600	2.56	1.32	2.09	1.44

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 3 well. Table CON-33 contains the open hole diameters and intervals, Table CON-34 lists the casing specifications, Table CON-35 details the conductor material, and Table CON-36 details the casing material properties.

Table CON-33: Open hole diameters and intervals - Bluebonnet CCS 3.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 9,100	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,396 ft TVD.

Table CON-34: Casing specifications - Bluebonnet CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,800	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,800 to 9,100	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-35: Conductor material properties - Bluebonnet CCS 3.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-36: Casing material properties - Bluebonnet CCS 3.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,800	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,800 to 9,100	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,600 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-37 contains the upper completion specifications for the original completion and recompletions. Table CON-38 shows the specification of the 5 ½ in. tubing.

Table CON-37: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 7,590	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-38: Tubing material properties - Bluebonnet CCS 3.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-39 shows the specifications of the injection packer.

Table CON-39: Packer specifications - Bluebonnet CCS 3.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

6.4 Cementing Program Bluebonnet CCS 3

Table CON-40 shows the cementing program details.

Table CON-40: Cementing program - Bluebonnet CCS 3.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,600	11.5-12.5	1,585	2.28	100%
	Class A/C cement with additives	2,600 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,800	11.5-12.5	1,314	1.29	50%
	CO_2-Resistant Cement	3,800 to 9,100	14.5-15.6	2,440	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,600 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

6.5 Centralization Program Bluebonnet CCS 3

6.5.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

6.5.2 Long String Casing

Approximately 130-135 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the

field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,600 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

6.6 Fluids Program Bluebonnet CCS 3

Table CON-41 shows the mud program details for Bluebonnet CCS 3.

Table CON-41: Mud program - Bluebonnet CCS 3.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

6.7 Wellhead Schematic Bluebonnet CCS 3

Figure CON-12 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 3 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.



6.8 Bluebonnet CCS 3 Procedure

6.8.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

6.8.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting, and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

6.8.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

6.8.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

7.0 Well Design Bluebonnet CCS 5 - CO_2 Injector Well

The Bluebonnet CCS 5 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-13 shows the proposed well schematic for the Bluebonnet CCS 5 original completion.

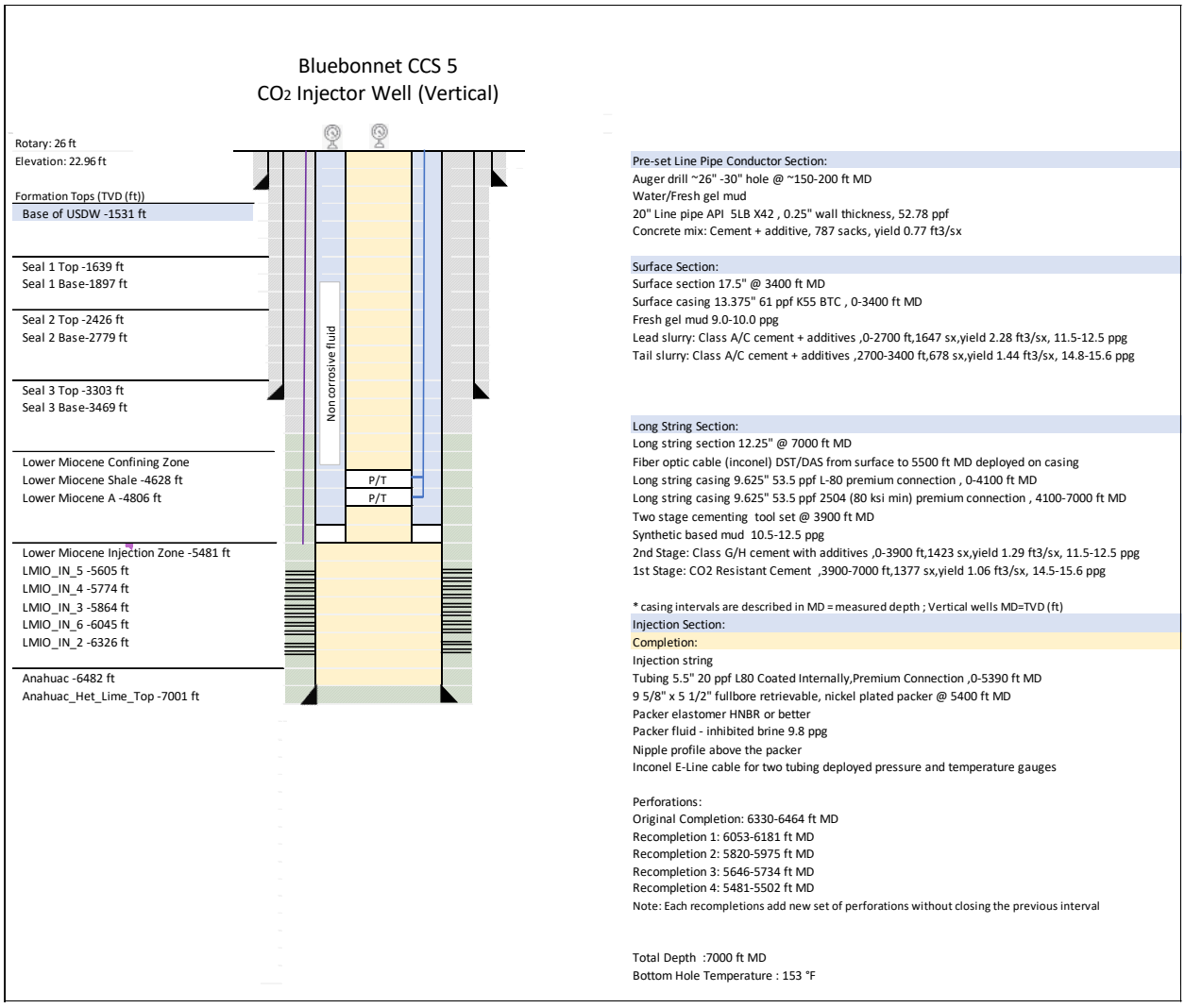


Figure CON-13: Bluebonnet CCS 5 well schematic.

7.1 Design Overview Bluebonnet CCS 5

7.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

7.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,400 ft to cover base of the USDW, estimated at 1,531 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

7.1.3 Long String Section

A 12 ¼ in. vertical wellbore will be drilled from 3,400 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

7.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5 ½-in. tubing and packer completion will be run to approximately 5,400 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

7.2 Casing, Tubing and Completion Design Bluebonnet CCS 5

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-42 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-42: Minimum safety factors for tubular design - Bluebonnet CCS 5.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,400	1.18	1.35	2.51	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.07	2.45	3.05	2.17
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-7,000	1.98	1.44	4.63	1.85
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,400	2.57	1.49	2.41	1.63

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCAT^{TM} evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 5 well. Table CON-43 contains the open hole diameters and intervals, Table CON-44 lists the casing specifications, Table CON-45 details the conductor material, and Table CON-46 details the casing material properties.

Table CON-43: Open hole diameters and intervals - Bluebonnet CCS 5.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,400	17 ½	Cover USDW
Long String Section	3,400 to 7,000	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,531 ft TVD.

Table CON-44: Casing specifications - Bluebonnet CCS 5.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,400	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 7,000	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-45: Conductor material properties - Bluebonnet CCS 5.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-46: Casing material properties - Bluebonnet CCS 5.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,400	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 7,000	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-47 contains the upper completion specifications for the original completion and recompletions. Table CON-38 shows the specification of the 5 ½ in. tubing.

Table CON-47: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 5.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,390	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-48: Tubing material properties - Bluebonnet CCS 5.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-49 shows the specifications of the injection packer.

Table CON-49: Packer specifications - Bluebonnet CCS 5.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

7.3 Cementing Program Bluebonnet CCS 5

Table CON-50 shows the cementing program details.

Table CON-50: Cementing program - Bluebonnet CCS 5.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,627	2.28	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,423	1.29	50%
	CO_2-Resistant Cement	3,900 to 7,000	14.5-15.6	1,377	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

7.4 Centralization Program Bluebonnet CCS 5

7.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

7.4.2 Long String Casing

Approximately 100-105 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the

field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

7.5 Fluids Program Bluebonnet CCS 5

Table CON-51 shows the mud program details for Bluebonnet CCS 5.

Table CON-51: Mud program - Bluebonnet CCS 5.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

7.6 Wellhead Schematic Bluebonnet CCS 5

Figure CON-14 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 5 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.



7.7 Bluebonnet CCS 5 Procedure

7.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

7.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.

- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.

- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

7.7.3 Long String Section

- Perform apre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.

- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

7.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.

- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

8.0 Well Design Bluebonnet CCS 6 - CO_2 Injector Well

The Bluebonnet CCS 6 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-15 shows the proposed well schematic for the Bluebonnet CCS 6 original completion.

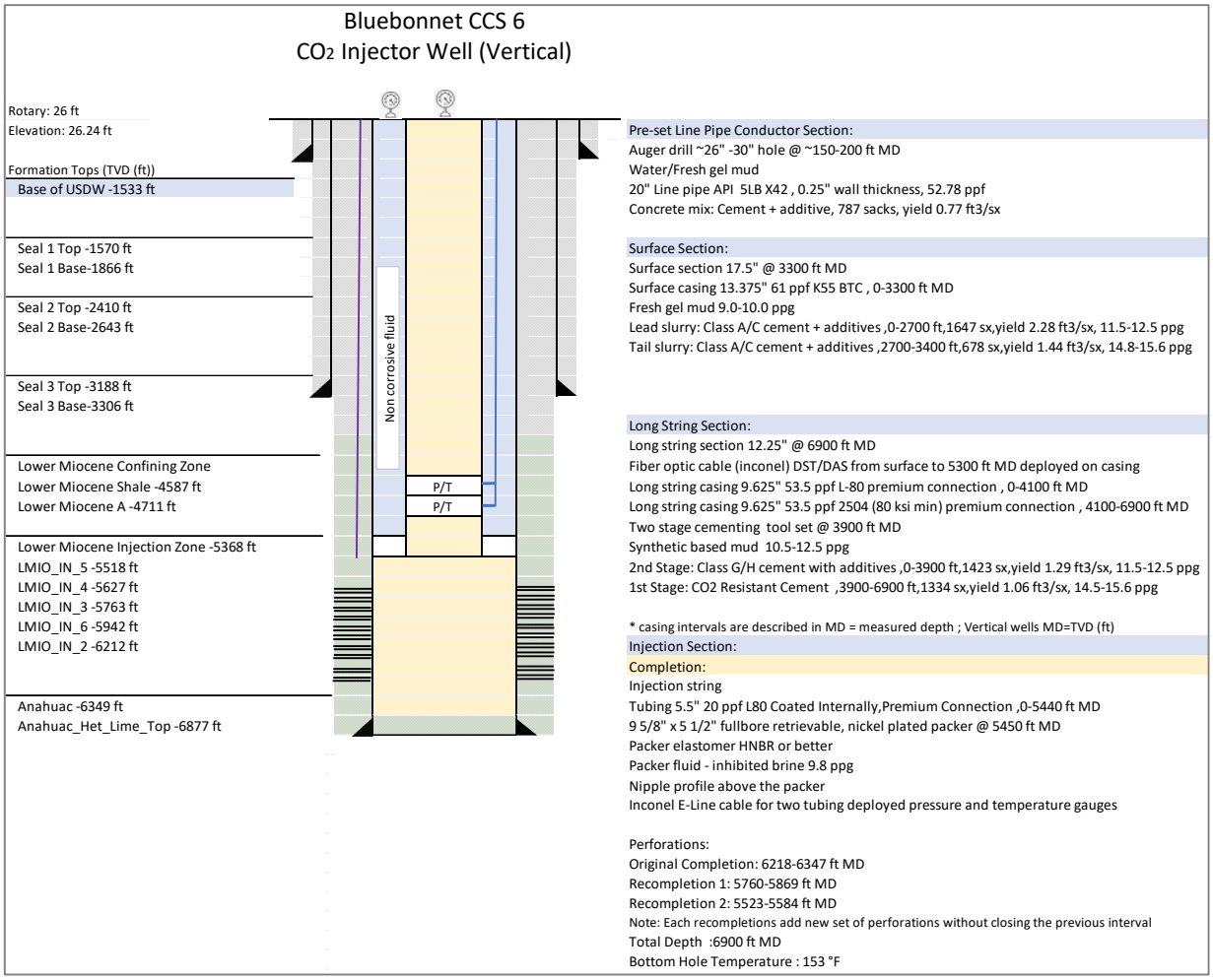


Figure CON-15: Bluebonnet CCS 6 well schematic.

8.1 Design Overview Bluebonnet CCS 6

8.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

8.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,533 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

8.1.3 Long String Section

A 12 ¼ in. vertical wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

8.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5 ½-in. tubing and packer completion will be run to approximately 5,450 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

8.2 Casing, Tubing and Completion Design Bluebonnet CCS 6

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-52 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-52: Minimum safety factors for tubular design - Bluebonnet CCS 6.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,300	1.18	1.37	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.07	2.45	3.09	2.18
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-6,900	1.99	1.46	4.66	1.88
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,450	2.57	1.49	2.41	1.63

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 6 well. Table CON-53 contains the open hole diameters and intervals, Table CON-54 lists the casing specifications, Table CON-55 details the conductor material, and Table CON-56 details the casing material properties.

Table CON-53: Open hole diameters and intervals - Bluebonnet CCS 6.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 6,900	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,533 ft TVD.

Table CON-54: Casing specifications - Bluebonnet CCS 6.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 6,900	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-55: Conductor material properties - Bluebonnet CCS 6.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-56: Casing material properties - Bluebonnet CCS 6.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 6,900	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-57 contains the upper completion specifications for the original completion and recompletions. Table CON-58 shows the specification of the 5 ½ in. tubing.

Table CON-57: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 6.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,440	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-58: Tubing material properties - Bluebonnet CCS 6.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-59 shows the specifications of the injection packer.

Table CON-59: Packer specifications - Bluebonnet CCS 6.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

8.3 Cementing Program Bluebonnet CCS 6

Table CON-60 shows the cementing program details.

Table CON-60: Cementing program - Bluebonnet CCS 6.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,647	2.28	100%
	Class A/C cement with additives	2,700 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,423	1.29	50%
	CO_2-Resistant Cement	3,900 to 6,900	14.5-15.6	1,334	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

8.4 Centralization Program Bluebonnet CCS 6

8.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

8.4.2 Long String Casing

Approximately 100-105 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

8.5 Fluids Program Bluebonnet CCS 6

Table CON-61 shows the mud program details for Bluebonnet CCS 6.

Table CON-61: Mud program - Bluebonnet CCS 6.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

8.6 Wellhead Schematic Bluebonnet CCS 6

Figure CON-16 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 6 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.



8.7 Bluebonnet CCS 6 Procedure

8.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

8.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.

- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

8.7.3 Long String Section

- Perform pre-section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.

- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.

- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

8.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.

- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

9.0 Well Design Bluebonnet CCS 7 - CO_2 Injector Well

The Bluebonnet CCS 7 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-17 shows the proposed well schematic for the Bluebonnet CCS 7 the original completion.

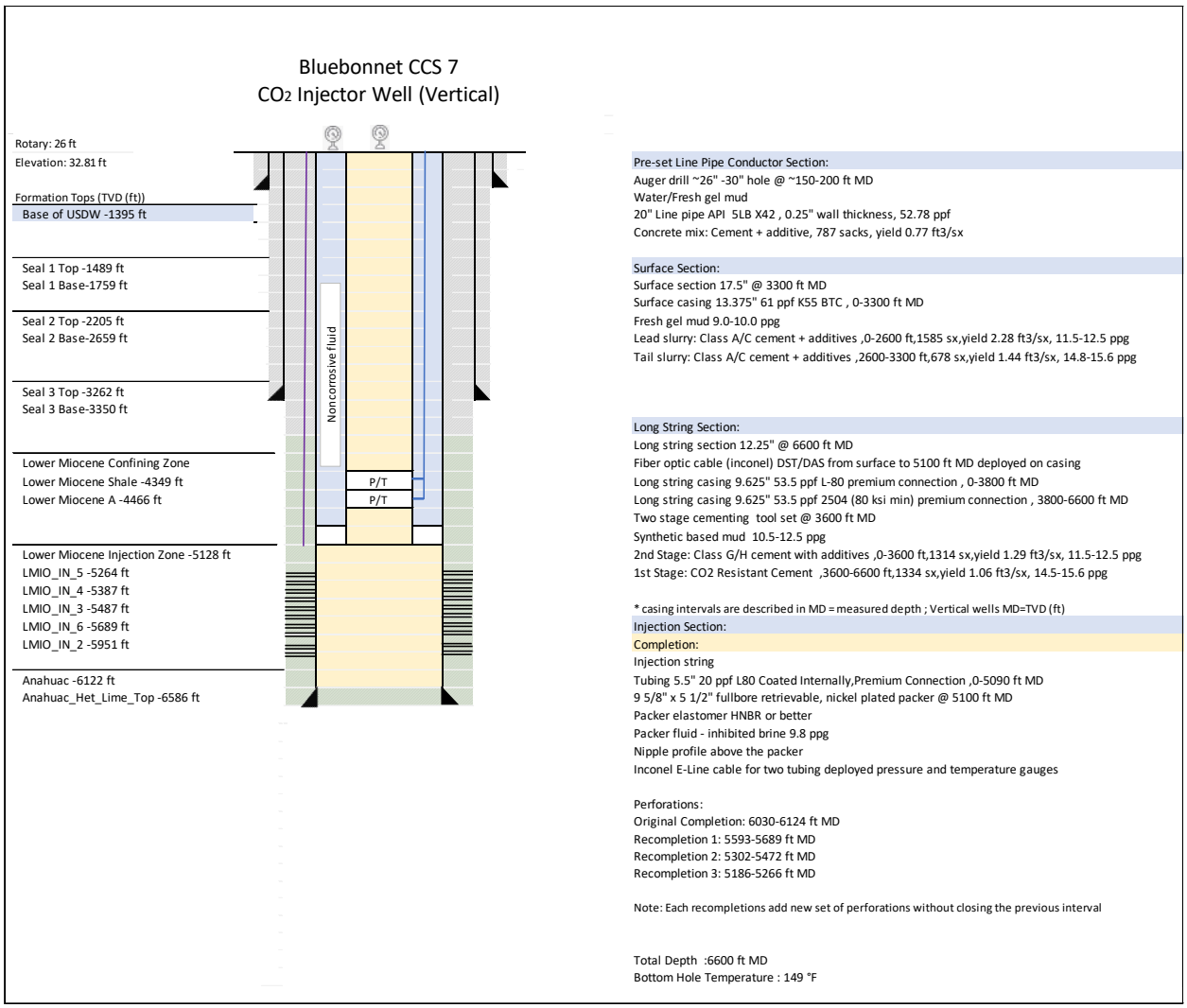


Figure CON-17: Bluebonnet CCS 7 well schematic.

9.1 Design Overview Bluebonnet CCS 7

9.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

9.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,395 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

9.1.3 Long String Section

A 12 ¼ in. vertical wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

9.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5 ½-in. tubing and packer completion will be run to approximately 5,100 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

9.2 Casing, Tubing and Completion Design Bluebonnet CCS 7

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-62 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-62: Minimum safety factors for tubular design - Bluebonnet CCS 7.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,300	1.18	1.59	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,800	2.08	2.65	3.19	2.18
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,800-6,600	2.00	1.52	4.77	1.97
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,100	2.57	1.53	2.48	1.67

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 7 well. Table CON-63 contains the open hole diameters and intervals, Table CON-64 lists the casing specifications, Table CON-65 details the conductor material, and Table CON-46 details the casing material properties.

Table CON-63: Open hole diameters and intervals - Bluebonnet CCS 7.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 6,600	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,395 ft TVD.

Table CON-64: Casing specifications - Bluebonnet CCS 7.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,800	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,800 to 6,600	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-65: Conductor material properties - Bluebonnet CCS 7.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-66: Casing material properties - Bluebonnet CCS 7.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,800	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,800 to 6,600	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,600 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-67 contains the upper completion specifications for the original completion and recompletions. Table CON-68 shows the specification of the 5 ½ in. tubing.

Table CON-67: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 7.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,090	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-68: Tubing material properties - Bluebonnet CCS 7.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-69 shows the specifications of the injection packer.

Table CON-69: Packer specifications - Bluebonnet CCS 7.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

9.3 Cementing Program Bluebonnet CCS 7

Table CON-70 shows the cementing program details.

Table CON-70: Cementing program - Bluebonnet CCS 7.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,600	11.5-12.5	1,585	2.28	100%
	Class A/C cement with additives	2,600 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,600	11.5-12.5	1,314	1.29	50%
	CO_2-Resistant Cement	3,600 to 6,600	14.5-15.6	1,334	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,600 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

9.4 Centralization Program Bluebonnet CCS 7

9.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

9.4.2 Long String Casing

Approximately 95-100 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

9.5 Fluids Program Bluebonnet CCS 7

Table CON-71 shows the mud program details for Bluebonnet CCS 7.

Table CON-71: Mud program - Bluebonnet CCS 7.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

9.6 Wellhead Schematic Bluebonnet CCS 7

Figure CON-18 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 7 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.



9.7 Bluebonnet CCS 7 Procedure

9.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

9.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.

- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

9.7.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and the casing slips and test the correct function of the tools.
- Rig up the spooler and the equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

9.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

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C. STIMULATION PLAN

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (°) (NAD27)	Longitude (°) (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.82 (a)(9), this CO_2 Injection Well Stimulation Plan describes the operations that Bluebonnet Sequestration Hub, LLC would execute in the CO_2 Injector Wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CC7 to enhance or regain injection capabilities.

Stimulation and cleanouts to enhance or regain the injection potential of the Lower Miocene, Frio and Hackberry Sandstones in the CO_2 Injector Wells include coil tubing cleanouts, stick pipe cleanouts, matrix acid stimulation, sand control and water flushes.

The need for stimulation and cleanouts will be determined once the characterization data from the Bluebonnet Sequestration Hub is completed, and the wells are available and have been evaluated (i.e., results of geophysical logs, core analyses, and hydrogeologic testing and operating conditions).

Bluebonnet Sequestration Hub, LLC will notify and submit the proposed stimulation or cleanout procedures in writing to the Underground Injection Control (UIC) Program Director at least 30 days in advance of performing the stimulation or workover in accordance with 40 CFR. § 146.91(d)(1) and 40 CFR § 146.91(d)(2). Bluebonnet Sequestration Hub, LLC will carry out the stimulation or cleanout according to the EPA approved procedures. The procedures will describe all fluids being pumped and demonstrate that there will be no loss of containment due to the stimulation.

While this CO_2 Injection Well Stimulation Plan sets forth the intended procedures for stimulation of the injection wells at the Bluebonnet Sequestration Hub, changes to the plan may be required based on technical, operational, or safety conditions encountered during operations. Bluebonnet

Sequestration Hub, LLC will notify the UIC Program Director if substantial deviations from this Plan are required.

2.0 Stimulation and Cleanout Procedures

If injection rates decline below or injection pressures increase above expected values during the project's life, the Bluebonnet Hub will investigate the cause to determine if a stimulation or cleanout may be required. Investigation activities include, without limitation, the following:

- Logging operations, including but not limited to, evaluation of the injection profile, mechanical spinner surveys, caliper logging, gauge runs, downhole camera investigation, distributed temperature sensing (DTS), distributed acoustic sensing (DAS), tracers and injection profile logging (IPL), etc.

- Collecting downhole samples when necessary or feasible with wireline, slickline, or coiled tubing conveyed sampling equipment, to be followed by analytical testing, as appropriate to determine remediation options.

The equipment to implement the stimulation procedures or cleanouts include, but is not limited to, coil tubing units, workover units, snubbing units, pumping units, wireline, and slickline, amongst others.

The following are standard procedures for matrix acid stimulations, water flush, and sand and solids clean out.

2.1 Matrix Acid Stimulation

- The maximum bottom hole pressure is 90% of the injection zone fracture pressure. Job will be pumped below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.
- Verify acid blend is correct before pumping.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Spot in acid pump truck, acid transport, and frac tanks.
4. Hook up tubing and pressure test lines to 5,000 psi.
5. Open well and pump pre-flush.
6. Pump acid blend.
7. Pump flush and close in well.
8. Rig down tubing.
9. Open injection line and resume injection.

2.2 Water Flush Treatment

- The maximum bottom hole pressure is 90% of the injection zone fracture pressure. Job will be pumped below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Spot in pump truck and frac tanks.
4. Hook up tubing and pressure test lines to 5,000 psi.
5. Open well.
6. Pump water with additives.
7. Close in well.
8. Rig down tubing.
9. Open injection line and resume injection.

2.3 Coil Tubing Cleanout

- The maximum bottom hole pressure is 90% of injection zone fracture pressure. The job will be performed below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up coil tubing unit.
4. Kill well, or if well is dead, pump buffer fluid.
5. Make up bottom hole assembly (BHA).
6. Run in hole (RIH) with BHA to just above top perforation.
7. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
8. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
9. Pull out of hole with coil tubing and BHA.
10. Rig down coil tubing unit.
11. Open injection line and resume injection.

2.4 Stick Pipe Cleanout

- The maximum bottom hole pressure is 90% of injection zone fracture pressure. The job will be performed below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well and nipple up the blowout preventors (BOPs).
5. Make up bit on work string.
6. Run in hole (RIH) with bit to just above top perforation.
7. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
8. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
9. Pull out of hole with work string and bit. Lay down same.
10. Nipple down the BOPs.
11. Rig down pulling unit.
12. Open injection line and resume injection.

2.5 Sand Control

The requirement for sand control in Bluebonnet Class VI wells is very dependent upon the level of sand consolidation that is experienced during initial completion operations. Highly unconsolidated sand has an elevated risk of slumping or sloughing into the wellbore following perforating operations, during well intervention due to swabbing and surging forces, and during operations from pressure changes resulting from change in operating conditions.

1. Chemical consolidation

- Chemical treatment techniques are sometimes employed for sand control. These processes are designed to produce a chemical reaction with the formation sand for the purpose of inhibiting its mobility. Resin consolidation is the most common process and involves injecting chemical into the unconsolidated formation to provide grain-to-grain cementation creating a strong consolidated matrix that is subsequently flushed to clear the pore spaces and retain the best possible permeability.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well and nipple up the blowout preventors (BOPs).
5. Make up bit on work string.
6. Run in hole (RIH) with bit to just above top perforation.

7. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
8. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
9. Pull out of hole with work string and bit.
10. Pick up straddle packer assumbly and run in hole and isolate problem interval.
11. Establish injection rate then perform chemical squeeze followed by curing time.
12. Flush the perfs clean then pull out of hole and lay down tools.
13. Nipple down the BOPs.
14. Rig down pulling unit.
15. Open injection line and resume injection

2. Standalone Wire Wrapped or Premium Screen

- Conventional wire-wrapped or premium screens can be used stand-alone to control formation sand in cased holes. This type of design is most effective with medium to coarse grained, moderately uniform sands that will quickly build up a high permeability zone in the annular space between the casing and screen.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well, nipple down inj tree and flowlines and nipple up the blowout preventors (BOPs).
5. Pull out of hole with tubing and packer.
6. Make up bit on work string.
7. Run in hole (RIH) with bit to just above top perforation.
8. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
9. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
10. Pull out of hole with work string and bit.
11. Pick up sand screens and packer and RIH and set screens across perfs.
12. POOH with workstring.
13. Pick up and RIH with packer and tubing.
14. Set packer, land tubing
15. Nipple down the BOPs.
16. Nipple up Inj tree and flowlines.
17. Rig down pulling unit.
18. Open injection line and resume injection

3. Cased Hole Gravel Pack

Cased hole gravel packs are commonly used completion techniques where sized gravel is pumped into the wellbore and placed/ squeezed between the installed sandscreen and the formation matrix to produce a sand retention and filtration media. Prior to gravel placement large hole perforating charges are used to bypass the formation damage zone created during the drilling and cementing operation.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well, nipple down inj tree and flowlines and nipple up the blowout preventors (BOPs).
5. Pull out of hole with tubing and packer.
6. Make up bit on work string.
7. Run in hole (RIH) with bit to just above top perforation.
8. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
9. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
10. Pull out of hole with work string and bit.
11. Pick up sand screens, packer and gravel packing tools and RIH and set screens across perfs.
12. Pump and squeeze gravel pack into perforations, filling the annulus space and taking fluid returns back up the annulus.
13. Unsting out of packer assembly and POOH with workstring.
14. Pick up and RIH with packer and tubing.
15. Set packer, land tubing
16. Nipple down the BOPs.
17. Nipple up Inj tree and flowlines.
18. Rig down pulling unit.
19. Open injection line and resume injection

The proposed procedures could be modified to adjust to the actual condition of the well when the treatment is executed.

3.0 Stimulation and Cleanouts Fluids

At the Bluebonnet Hub, the project team may use acid blends for matrix stimulation or perforation cleanouts that are typical of the industry. These include, but are not limited to, mixtures of acetic, hydrochloric, hydrofluoric, and/or other organics acids. These blends have been historically proven to remove near-wellbore damage caused by mineral scales, drilling muds, completion fluids, and clay fines while minimizing negative impacts to permeability.

There is also potential for near-wellbore halite precipitation in the CO_2 Injector Wells, which may require remediation by periodic flushes with less saline water.

During the characterization of the site, the project team identified that the Frio and Hackberry injection zones tend to produce sand due to the unconsolidated condition of these formations. The project team plans to incorporate preventive and correctives cleanouts, as described in the previous section. During cleanout operations, the project team may use brines that might include a KCL and/or NACL solution to control the well along with a gelling additive to increase viscosities in the fluids and remove the sand from the wellbore.

All chemical treatments will be evaluated and selected for compatibility with the formation and installed equipment downhole.

Additives may be utilized with the stimulation fluids to aid matrix stimulation while mitigating corrosion of tubulars and potential damage to the sequestration zone. These additives include, but are not limited to, corrosion or acid inhibitors, scale inhibitors, clay stabilizers, biocides, demulsifiers, chelating agents, mutual solvents, iron sequestrants, retarders, and/or surfactants.

Brines and gelling additives will be included during wellbore cleanouts to improve efficiency while cleaning solids out of the wellbores.

Compatibility of these additives and stimulation fluids, with the installed tubulars and reservoir, will be confirmed prior to their use in any stimulation activities.

4.0 Ensuring Containment

Except during stimulation, the project team will ensure that injection pressure does not exceed 90 percent of the fracture pressure on the injection zone(s) to ensure that the injection will not initiate new fractures or propagate existing fractures in the injection zones(s). In no case will the injection pressure initiate fractures in the confining zones(s) or cause the movement of injected or formation fluids that endanger the USDW, 40 CFR §146.88 (a).

The injection pressure will be monitored continuously during stimulation operations. Chemicals and fluids used during stimulation or cleanouts will be selected to ensure no damage in downhole equipment and formation(s).

D. PRE-INJECTION/ PRE-OPERATIONAL TESTING PLAN

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4.0 Pre-Injection Test Plan – Water Production Wells 17
5.0 Pre-Injection Test Plan – Water Disposal Well 19
6.0 Pre-Injection Test Plan – Above-Confining-Zone/USDW Monitoring Wells 20
7.0 Pre-Injection Test Plan – Miocene Composite Confining Zone Monitoring Wells 20

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contact: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
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Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.87, this plan describes the testing and logging activities proposed by Bluebonnet Sequestration Hub, LLC for the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, as well as the monitoring wells, water producer wells, and a water disposal well planned for the Bluebonnet Hub.

These testing and logging activities are restricted to the drilling, completion, and pre-injection phases of the project. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring Plan along with other non-well related pre-injection baseline activities, such as geophysical and geochemical monitoring.

As required by 40 CFR §146.87, all pre-injection testing procedures for logging, sampling, and testing will be submitted to the Underground Injection Control (UIC) Director for review. The results and data collected during the testing, sampling, and logging operations will be documented in a report and submitted to the UIC Director after the procedures are completed, but before the start of the CO_2 injection operations.

The Bluebonnet Sequestration Hub, LLC will notify the UIC director at least 30 days prior to conducting the tests. Notice and the opportunity to witness these test/logs shall be provided to the UIC Director at least 48 hours in advance of the given procedure.

A table of the wells described in this document is shown in Table POT-1.

Table POT-1: Bluebonnet Sequestration Hub wells.



(1) ACZ: Above Confining Zone
(2) USDW: Underground Source of Drinking Water

Figure POT-1 and Figure POT-2 show the location of the CO_2 injection wells, in-zone monitoring wells, Miocene Composite Confining Zone monitoring wells, water production wells, water disposal well, and USDW monitoring wells as proposed in the Bluebonnet Hub.

Well diagrams for the CO_2 Injection wells listed in Table POT-1 are presented in the Injector Wells Construction Details Plan of this permit. Well diagrams for the monitoring wells, water production wells, and water disposal well are presented in the Testing and Monitoring Plan.

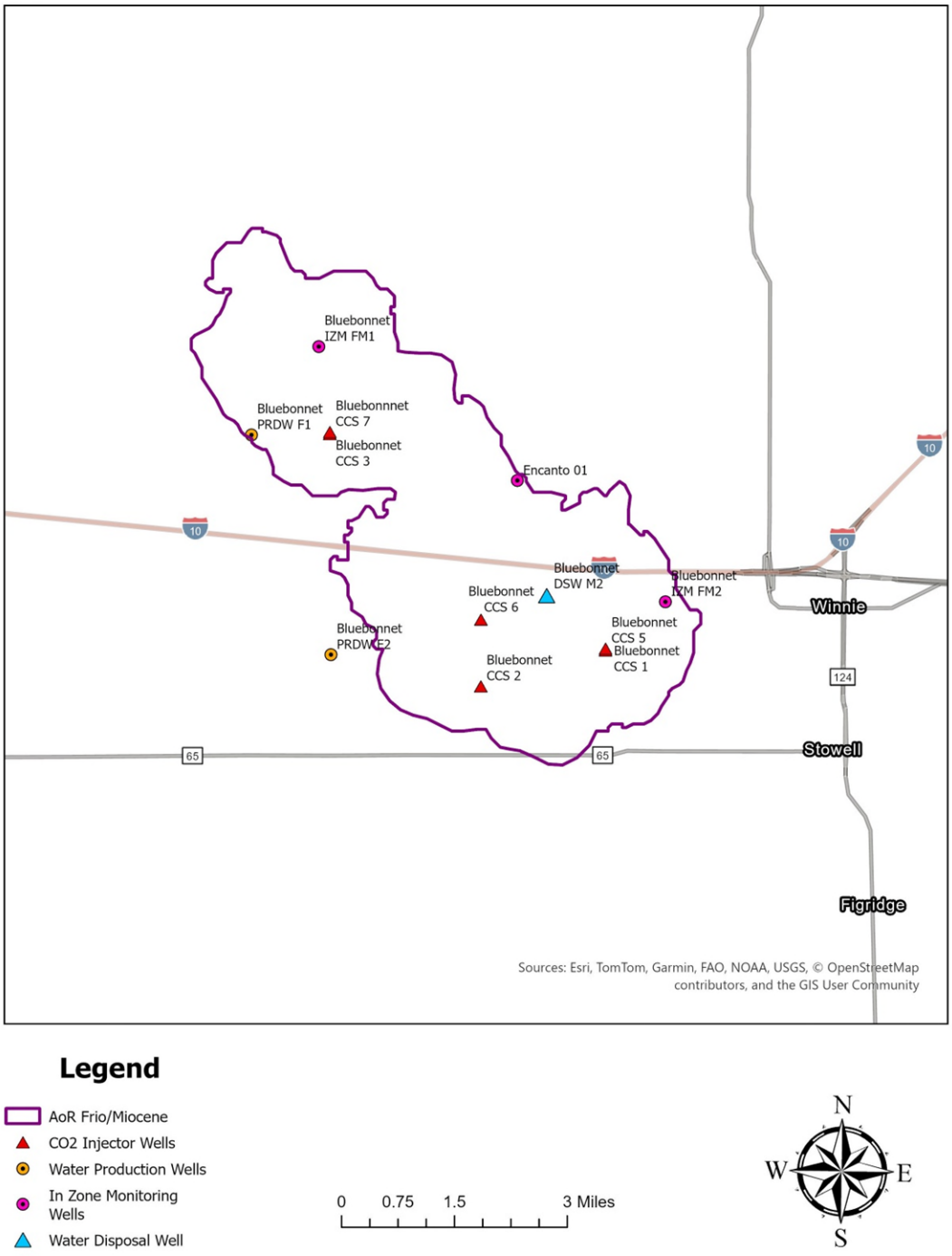


Figure POT-1: Location of CO_2 injector wells, in-zone monitoring wells, water production wells, and water disposal wells for the Bluebonnet Sequestration Hub.

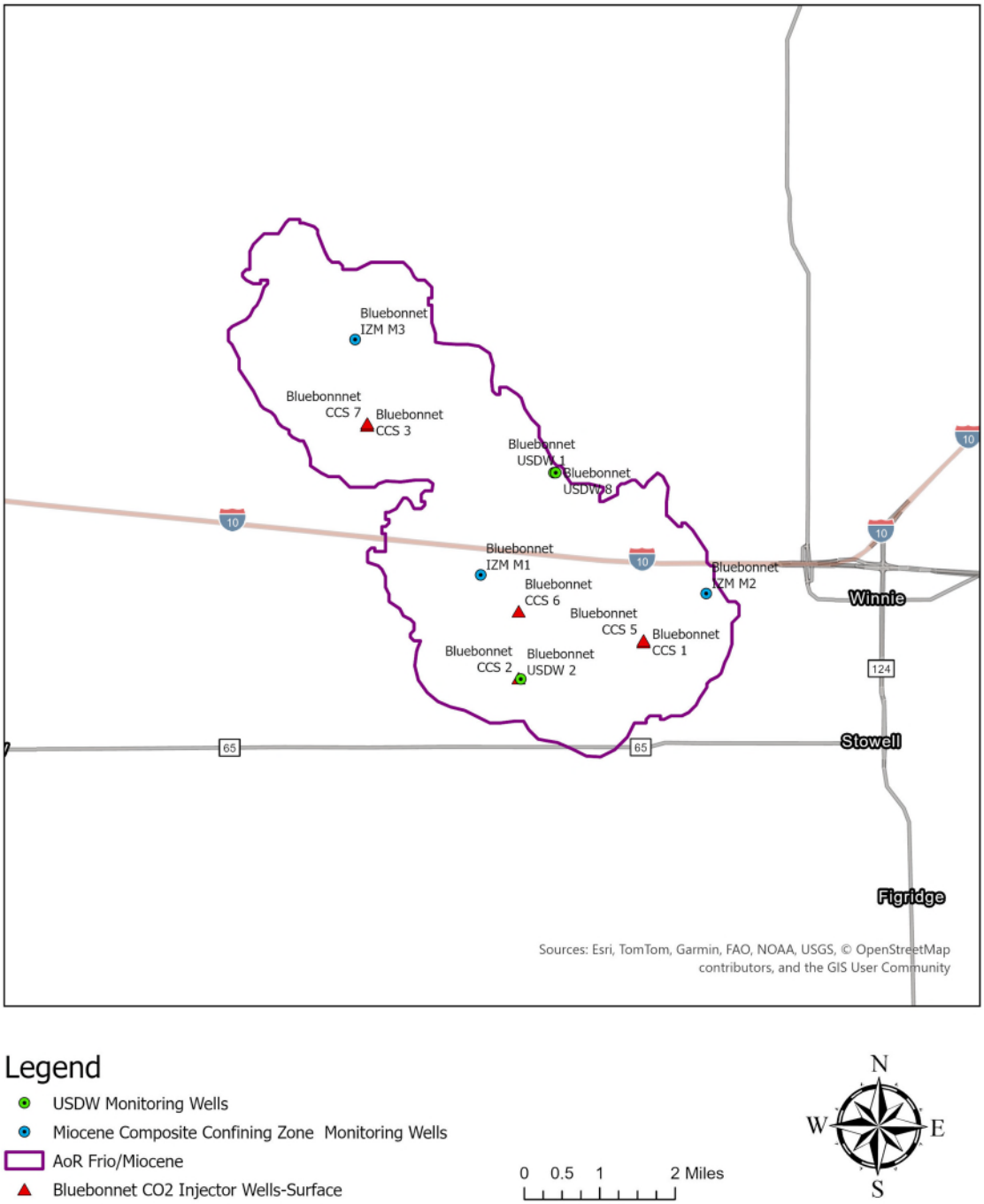


Figure POT-2: Location of CO2 injector wells, Miocene Composite Confining Zone monitoring wells and above-confining-zone/USDW monitoring wells for the Bluebonnet Sequestration Hub.

The Bluebonnet Sequestration Hub, LLC will construct six new CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CC 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, targeting injection in the Lower Miocene, Frio, and Hackberry sands.

In addition to the injectors, the project will construct two new in-zone monitoring wells (Bluebonnet IZM FM1 and Bluebonnet IZM FM2) and will recomplete the stratigraphic well Encanto 01.

Oxy Low Carbon Ventures, LLC, the parent company of Bluebonnet Sequestration Hub, LLC, drilled the Encanto 01 stratigraphic well in 2022 and acquired advanced geophysical logs as well as 204 ft of full core and 22 sidewall cores (SWC). The project also performed step rate and falloff tests in the prospect reservoirs and leak-off tests in the proposed confining zones. The results and a summary of the data acquisition program for Encanto 01 are shown in Appendix A in the AoR attachment. In May 2024, Encanto 01 was reentered to collect additional water samples from the Frio reservoir. The Encanto 01 stratigraphic well was temporarily abandoned and will be re-completed as an in-zone monitoring well for the project.

The project plans to construct two water producer wells (Bluebonnet PRDW F1 and Bluebonnet PRDW F2) to extract water from the Frio formation as a technique to control the pressure front during the injection phase. These wells will be completed with pressure and temperature sensors downhole and pressure and temperature sensors on the surface.

The project defines the above-confining zone as the first permeable zone above the Miocene Composite Confining Zone. This first permeable formation is the base of the USDW as characterized by Encanto 01 stratigraphic well and mapped laterally though the storage complex.

In May 2024, the project drilled Bluebonnet USDW 1, targeting the shallow aquifers from the surface to 1,500 ft. The main objective of this well was to validate the base of the USDW and determine the water composition of the different flow units as part of the site characterization and baseline for injection operations. The detailed data acquired during Bluebonnet USDW 1 construction is provided in Appendix B in the AoR attachment. Bluebonnet USDW 1 will be used as monitoring well for the shallow aquifer to monitor changes in water composition during the injection and post-injection phases of the project.

In May 2025, the project drilled the Bluebonnet USDW 8 well, targeting the Miocene Composite Confining Zone intershales from the surface to a depth of 2,750 feet. The primary objective of this well was to acquire whole core samples (79 feet) and sidewall cores (35) from the intershales to further characterize the Miocene Composite Confining Zone and conduct sealing capabilities studies. The detailed data collected during the construction of Bluebonnet USDW 8 is currently being integrated and will be included as an appendix to the AoR. Additionally, Bluebonnet USDW 8 will serve as a monitoring well for the shallow aquifer, allowing us to track changes in water composition during both the injection and post-injection phases of the project. The project plans to construct one additional above-confining-zone/USDW monitoring wells (Bluebonnet USDW 2) and three Miocene Composite Confining Zone monitoring wells (Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3). These wells will be used to track changes in pressure, temperature as well as in water composition of the base of the USDW and within the Miocene Composite Confining Zone across the Hub.

The project also plans to drill one water disposal well (Bluebonnet DSW M2) targeting the sands of the Miocene formation above the Lower Miocene Confining Zone. This well will be used to dispose of the water extracted from the Frio formation as well as fluid generated during the construction and operation of the Bluebonnet site.

2.0 Pre-Injection Test Plan – CO_2 Injector Wells

The following tests and logs will be run during drilling, casing installation, and completion of the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 injector wells in accordance with the testing required under 40 CFR §146.87(a), (b), (c), (d), and (e).

The CO_2 injection well testing program includes a combination of advanced logging, sidewall coring, fluid sampling, and formation hydrogeologic testing. This program is complemented with an extensive data acquisition program executed in the Encanto 01 stratigraphic well, as well as the data acquisition planned in the additional monitoring wells, water producer wells, and water disposal well.

The pre-operational testing program will measure the depth, fluid salinity, thickness, mineralogy, lithology, porosity, and permeability information of the injection zone, overlying confining zone, and other relevant geologic formations. This data acquisition program will be used to determine conformance with the injection well construction requirements and to establish accurate baseline data for future monitoring activities.

TablesPOT-2 and Table-3 list the logs, tests, and surveys proposed for the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells to comply with 40 CFR §146.87 (a).

Table POT-2: Logging, testing, and surveying plan for CO_2 injector wells – Part 1[(40 CFR 146.87 (a))].

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Open Hole Logs, Surveys, and Sampling During Construction							
Deviation survey [40 CFR §146.87 (a) (1)] – Every 100 ft while drilling, as a minimum	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline - Spontaneous Potential – Surface Casing [40 CFR §146.87 (a) (2) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Correlation log, volume of shale indicator, estimate salinity
Wireline - Resistivity – Surface Casing [40 CFR §146.87 (a) (2) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Fluid identification, estimate salinity, correlation log
Wireline - Density/neutron – Surface Casing [40 CFR §146.87 (a) (3) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Estimate porosity, mineralogical characterization.
Wireline - Sonic dipolar –Surface Casing [40 CFR §146.87 (a) (3) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - High-definition image – Surface Casing [40 CFR §146.87 (a) (3) (i)]	800 to 3,400 ft	800 to 3,300 ft	800 to 3,300 ft	n/a	800 to 3,300 ft	n/a	Identify fracture, structural information, minimum stress orientation
Wireline - Caliper – Surface Casing [40 CFR §146.87 (a) (2) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Identify borehole enlargement and calculate cement volume.

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Open Hole Logs, Surveys, and Sampling During Construction							
Wireline - Resistivity – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Fluid identification, estimate salinity, correlation log
Wireline - Caliper – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Define stratigraphy, correlation log, shale indicator
Wireline - Magnetic resonance image – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Estimate porosity, pore size distribution, permeability index
Wireline - Sonic dipolar – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - Spectral gamma ray – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Define uranium-rich formation, clay indicator
Wireline - Density / neutron – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Estimate porosity, mineralogical characterization.
Wireline - High-definition image – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Identify fracture, structural information, minimum stress orientation.

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Open Hole Logs, Surveys, and Sampling During Construction							
Wireline - Litho-scanner or equivalent – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Identify mineralogy.
Wireline - Formation pressure measurement – Long String Casing – Depths to be selected after drilling	5 points upper Miocene, 3-6 points in Lower Miocene Sands, 3-6 points in Frio Sands, 1-2 points in Hackberry Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands, 3-6 points in Frio Sand	5 points upper Miocene, 3-6 points in Lower Miocene Sands, 3-6 points in Frio Sands, 1-2 points in Hackberry Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands	Measure formation pressure.
Wireline - Mini Frac with MDT Tool in Confining Zones – Long String Casing	Upper Miocene Shales. Lower Miocene. Anahuac	Upper Miocene Shales. Lower Miocene. Anahuac	Upper Miocene Shales. Lower Miocene. Anahuac	n/a	Upper Miocene Shales. Lower Miocene	n/a	Measure frac gradient in the confining zones.
Mud Logging	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.

Table POT-3: Logging, testing and surveying plan for CO_2 injector wells – Part 2 [(40 CFR 146.87 (a))].

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Cased Hole Logs and Surveys Before Injection							
CBL-VDL-USIT-CCL - Surface Casing [40 CFR §146.87 (a)(2) (ii) - The surface cement log is run while running open hole logs in long string.	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Cement bond, casing integrity. Validate external mechanical integrity
CBL-VDL-USIT-CCL - Long string casing [40 CFR §146.87 (a)(3) (ii)] – The well is logged during completions operations.	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long string casing [40 CFR §146.87 (a)(4) (i)]	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long-string, and packer.
Wireline - Activate pulsed neutron, through tubing – Long string casing [40 CFR §146.87 (a)(4) (ii)]	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long string casing [40 CFR §146.87 (a)(4) (iv)]	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.
Fiber Optic - DTS survey – Long-string casing [40 CFR §146.87 (a)(4) (iii)]	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Measure the temperature profile on the well from the surface to the top of perforation. Define baseline for monitoring mechanical integrity.

Notes: Logging depths will be adjusted when the wells are drilled.

The long string sections of Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 will be drilled with synthetic based mud to ensure well stability while drilling, logging, and cementing. Therefore, spontaneous potential logs will not be possible to acquire. However, the project proposes additional new generation logs to improve reservoir and confining zone characterizations as described in Table POT-2 above.

The project will not collect full core while drilling the long string section in Bluebonnet CCS 01, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7**.** Only sidewall cores will be collected, as allowed by 40 CFR §146.87 (b). The project team will also collect water samples in the injection zones as shown in Table POT-4.

As part of the data acquisition program for the Bluebonnet Hub, the project acquired reservoir pressure and water samples in 2022 for the Miocene formation in Encanto 01 stratigraphic well as well as for the Frio formation. The water samples were deemed contaminated for the Frio reservoir. In 2024, the project re-entered Encanto 01 and collected four fluid samples from the Frio formation.

In 2024, the project also drilled water well Bluebonnet USWD 1 to acquire water samples in the first and second permeable zone below the shallowest seal, defined as the base of the USDW. In Bluebonnet USDW 1, water samples were collected at the base of the USDW and at the freshwater sands as part of the characterization. A detailed description of the baselines and data collected in Bluebonnet USDW 1 are provided in the AoR attachment in Appendix A.

Table POT-4: Sidewall Cores and Water Sampling for CO_2 Injector Wells (40 CFR 146.87 (b)).

Method	Interval (ft)	Samples	Purpose
Bluebonnet CCS 1 and Bluebonnet CCS 3			
Open Hole – Wireline - Sidewall core samples	Upper Miocene Shales, Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac, Frio Injection Zone, Frio Confining Zone, Hackberry Injection Zone.	20-35 samples at depths to be determined once the well is drilled.	Define porosity and permeability, mineralogy, CO_2 compatibility
Open Hole – Wireline - water samples	Injection zones: Frio and Hackberry	3-5 water samples. Depth to be defined once the well is drilled.	Define fluid temperature, formation pressure, water composition, pH, conductivity, mobility.
Bluebonnet CCS 2			
Open Hole – Wireline - Sidewall core samples	Upper Miocene Shales, Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac, Frio Injection Zone, Frio Confining Zone	20-35 samples at depths to be determined once the well is drilled.	Define porosity and permeability, mineralogy, CO_2 compatibility
Open Hole – Wireline - water samples	Injection zones: Frio	3-5 water samples. Depth to be defined once the well is drilled.	Define fluid temperature, formation pressure, water composition, pH, conductivity, mobility.
Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7			
Open Hole – Wireline - Sidewall core samples	Upper Miocene Shales, Lower Miocene Confining Zone, Lower Miocene Injection Zone	15-20 samples at depths to be determined once the well is drilled.	Define porosity and permeability, mineralogy, CO_2 compatibility
Open Hole – Wireline - water samples	Injection zones: Lower Miocene	3-5 water samples. Depth to be defined once the well is drilled.	Define fluid temperature, formation pressure, water composition, pH, conductivity, mobility.

The project team will record the fluid temperatures and reservoir pressures obtained from the wireline tool while taking the pressure points and water samples (40 CFR §146.87 (c)). The project team also plans to install downhole gauges that will allow us to determine original pressure and temperature at the top of the perforations.

The project team plans to perform the following analysis in the sidewall cores collected from CO_2 injection wells listed in Table POT-5.

Table POT-5: Core analysis to be performed in the rotary sidewall cores (RSWC) samples from CO_2 injector wells.

RSWC Testing
Standard CT scans
High Resolution Core Photography
X-ray Fluorescence
X-ray Diffraction - Bulk and Clay Analysis
Porosity and Permeability @ Net Confining Stress
Laser Particle Size Analysis
Thin Section Petrography
SEM (Scanning Electron Microscopy)
Source Rock Pyrolysis
Mercury Injection Capillary Pressure
High Resolution CT scans
CO_2 Threshold Entry Pressure

The project team will send the water samples to a third-party lab for a complete analysis, including pH, conductivity, major cations, major anions, trace metals, dissolved gases, density, and TDS, amongst others. Table POT-6 shows the minimum analytics to be characterized in the downhole water samples (40 CFR §146.87 (d)(3) and 40 CFR §146.87 (c)).

Table POT-6: Analyses and methods for water samples testing in the reservoir and overburden.

Parameter	Analytical Method
Cations: Al, Ba, B, Cd, Ca, Cu, Cr, Fe, Pb, Li, Mg, Mn, Ni, P, K, Si, Na Sr, Zn	ICP-OES, EPA Method 6010d, ICP-MS Method 200.8 or equivalent
Other Metals: As, U, Co, Se, Pb, Mo, V	ICP-MS Method 200.8 or equivalent
Mercury	EPA 245.7 CVAA, or equivalent
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-, $NO2^-$	Ion Chromatography, EPA Method 300.1 or similar
Carbonate, bicarbonate and hydroxide	Titration, ASTM D3875.
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C, ASTM D5907 or equivalent
Water Density	ASTM D5057, ASTM D4052 or equivalent
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of DIC in Water	Gas Bench and CF-IRMS for $^{13/12}C$
Radiocarbon 14C of DIC in Water	AMS for ^{14}C
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, ASTM 1945D, RSK 175 or equivalent
pH (lab)	ASTM D1293, EPA 150.23 or equivalent
Temperature (lab)	ASTM 2550
Conductivity (lab)	ASTM D1125
Conductivity (field)	EPA 120.1
ICP-OES = inductively coupled plasma optic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; GC/MS = gas chromatography–mass spectrometry; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: Cold Vapor Atomic Absorption; DIC: Dissolved Inorganic Carbon	

The static fluid level of the injection zones will be determined after well completion during the step rate test, injectivity tests, and falloff tests (40 CFR §146.87 (c)). The Bluebonnet Sequestration Hub, LLC will not acquire fluid samples though the open hole DST, by performing a pump off or swabbing after the well is completed, due to the potential for sand production when negative drawdown is applied to the reservoir, which could damage the well.

To comply with 40 CFR §146.87(d), the data to be acquired in the proposed Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 injection wells will include logging, formation pressure testing in the injection zones, mini frac test in the confining zones, rotary sidewall core sampling and analyses, and hydrogeologic testing to determine the physical and chemical characteristics of the injection and confining zones. This data will allow calibration of the data acquired in 2022 in the Encanto 01 stratigraphic test well during the initial site characterization and will further serve as a baseline prior to commencing CO_2 injection.

Upon completion and prior to injection in the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells, the project team will conduct the tests described in Table POT-7 to verify hydrogeologic characteristics of the injection zone, define fracture pressure for the injection zone, and identify the maximum parameters for injection **(**40 CFR 146.87 (d) (1) and 40 CFR 146.87 (e))**.**

Table POT-7: Step rate test, injectivity test, and falloff test in CO_2 injectors.

Method	Comments
Step Rate Test (SRT) (Injection Target)	Determine the fracture pressure in the injection zone and define the rate of injection for the injectivity and falloff test.
Injectivity Test (Injection Target)	Evaluate injectivity on the well.
Pressure Falloff Test (Injection Target)	Determine transmissibility, skin factor, and well flowing and static pressures.

3.0 Pre-Injection Test Plan – In-Zone Monitoring Wells

3.1 In Zone Monitoring Wells – Bluebonnet IZM FM1 and Bluebonnet IZM FM2.

Bluebonnet IZM FM1 and Bluebonnet IZM FM2 will be new wells drilled as part of the project. Table POT-8 shows the proposed logging, survey, and mud log sampling for these wells.

Table POT-8: Logging, survey and sampling for in-zone monitoring wells.

Method	Interval (ft)		Purpose
	Bluebonnet IZM FM1	Bluebonnet IZM FM2	
Open Hole Logs, Surveys and Sampling During Construction			
Deviation Survey - every 100 ft while drilling as a minimum	Surface to TD	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline - Spontaneous Potential – Surface Casing	Surface to 3,300 ft	Surface to 3,400 ft	Correlation log, volume of shale indicator, estimate salinity.
Wireline - Resistivity – Surface Casing	Surface to 3,300 ft	Surface to 3,400 ft	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Surface Casing	Surface to 3,300 ft	Surface to 3,400 ft	Identify borehole enlargement and calculate cement volume.
Wireline - Resistivity – Long String Casing	3,300 ft to TD	3,400 ft to TD	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Long String Casing	3,300 ft to TD	3,400 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	3,300 ft to TD	3,400 ft to TD	Define stratigraphy, correlation log, shale indicator.
Wireline -Sonic Dipolar – Long String Casing	3,300 ft to TD	3,400 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Density/Neutron – Long String Casing	3,300 ft to TD	3,400 ft to TD	Estimate porosity, mineralogical characterization.
Mud Logging	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and Surveys Before Injection			
CBL-VDL-USIT-CCL –Surface Casing - Surface casing will be logged while running open-hole logs in long string section.	Surface to 3,300 ft	Surface to 3,400 ft	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long String Casing - Long string casing will be logged during well completion.	Surface to TD.	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline - Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	Surface to TD	CO_2 saturation, baseline for monitoring.

Method	Interval (ft)		Purpose
	Bluebonnet IZM FM1	Bluebonnet IZM FM2	
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.
Fiber Optic - DTS Survey – Long String Casing	Surface to TD	Surface to TD	Measure temperature profile on the well from the surface to the top of the perforation. Define baseline for monitoring mechanical integrity.

Notes: Logging depths will be adjusted when the wells are drilled.

Original pressure and temperature in the reservoir will be measured with a downhole gauge installed in the tubing ported to the reservoir below the packer.

3.2 Encanto 01 – Recompletion as an In Zone Monitoring Well

As described in the previous section, the Encanto 01 stratigraphic well will be recompleted as an in-zone monitoring well. In addition to the data acquired during the stratigraphic campaign in 2022 and during the re-entry in May 2024, the well will be tested for mechanical integrity after the recompletion. A pulse neutron baseline will be acquired as well. Table POT-9 shows the logs and tests that will be performed during and after the recompletion of the well.

Table POT-9: Cased hole logs for Encanto 01.

Cased Hole Logs During and After Recompletion as an In-Zone monitoring well		
Method	**Interval (ft)**	**Purpose**
CBL-VDL-USIT-CCL - Long String Casing.	The log will be run after recompletion to validate the quality of the squeeze job proposed.	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline – Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.

The original pressure and temperature in the reservoir will be measured with a downhole gauge installed in the tubing ported to the reservoir below the packer.

4.0 Pre-Injection Test Plan – Water Production Wells

Bluebonnet PRDW F1 and Bluebonnet PRDW F2 will be new wells drilled as part of the project to withdraw water from the Frio Injection target as a technique to manage the pressure increases

in the reservoir. Table POT-10 shows the proposed logging, survey, and mud log sampling for these wells.

Table POT-10: Logging, survey, and sampling for water production wells.

Method	Interval (ft)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey - Every 100 ft while drilling, as a minimum.	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline- Spontaneous Potential – Surface Casing	Surface to 3,200 ft	Correlation log, volume of shale indicator, estimate salinity.
Wireline –Resistivity – Surface Casing	Surface to 3,200 ft	Fluid identification, estimate salinity, correlation log.
Wireline – Caliper – Surface Casing	Surface to 3,200 ft	Identify borehole enlargement and calculate cement volume.
Wireline –Resistivity – Long String Casing	3,200 ft to TD	Fluid identification, estimate salinity, correlation log.
Wireline – Caliper – Long String Casing	3,200 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	3,200 ft to TD	Define stratigraphy, correlation log, shale indicator.
Wireline - Sonic Dipolar – Long String Casing	3,200 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Density/Neutron – Long String Casing	3,200 ft to TD	Estimate porosity, mineralogical characterization.
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and surveys Before Injection		
CBL-VDL-USIT-CCL –Surface Casing - Surface casing will be logged while running open hole logs in the long string section.	Surface to 3,200 ft	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long String Casing - Long string casing will be logged during well completion.	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline – Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.

Note: Logging depths will be adjusted when the wells are drilled.

The original pressure and temperature in the reservoir zone will be measured with a downhole sensor, as part of the downhole completion.

5.0 Pre-Injection Test Plan – Water Disposal Well

The project plans to drill one new Class I well in order to dispose of the water production from the Frio Injection Zone, as well as the fluids generated or used during the construction and operation of the Hub. Bluebonnet DSW M2 will be the well, targeting the upper Miocene Sands located above the Lower Miocene Confining Zone. Table POT-11 shows the proposed logging, survey, and mud log sampling for this well.

Table POT-11: Logging, survey, and sampling for water disposal well.

Method	Bluebonnet DSW M2	
	Interval (ft)	Purpose
Deviation survey – Every 100 ft while drilling as a minimum.	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline- Spontaneous Potential – Surface Casing	Surface to 2,300 ft	Correlation log, volume of shale indicator, estimate salinity.
Wireline –Resistivity – Surface Casing	Surface to 2,300 ft	Fluid identification, estimate salinity, correlation log.
Wireline - Density/Neutron – Surface Casing	Surface to 2,300 ft	Estimate porosity, mineralogical characterization.
Wireline - Sonic Dipolar –Surface Casing	Surface to 2,300 ft	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Caliper – Surface Casing	Surface to 2,300 ft	Identify borehole enlargement and calculate cement volume.
Wireline- Resistivity – Long String Casing	2,300 ft to TD	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Long String Casing	2,300 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	2,300 ft to TD	Define stratigraphy, correlation log, shale indicator.
Wireline - Magnetic Resonance Image – Long String Casing	2,300 ft to TD	Estimate porosity, pore size distribution, permeability index.
Wireline -Sonic dipolar – Long String Casing	2,300 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Spectral Gamma Ray – Long String Casing	2,300 ft to TD	Define uranium rich formation, clay indicator.
Wireline - Density/Neutron – Long String Casing	2,300 ft to TD	Estimate porosity, mineralogical characterization.
Wireline - High-Definition Image – Long String Casing	2,300 ft to TD	Identify fracture, structural information, minimum stress orientation.
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and Surveys Before Injection	Surface to 2,300 ft	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long string casing– The well is logged during completions operations.	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.

Method	Bluebonnet DSW M2	
	Interval (ft)	Purpose
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string casing and packer.
Wireline - Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.

Note: Logging depths will be adjusted when the wells are drilled.

The original pressure and temperature in the reservoir will be measured with a downhole gauge installed in the tubing ported to the reservoir below the packer.

6.0 Pre-Injection Test Plan – Above-Confining-Zone/USDW Monitoring Wells

Bluebonnet USDW 1 and Bluebonnet USDW 8 were completed to monitor the sands below and above the base of the USWD respectively. Bluebonnet USDW 2 will be used to monitor changes in pressure and the water composition of the USDW. Table POT-12 shows the proposed logging and survey for this well.

Table POT-12: Logging, survey, and sampling for above-confining-zone/USDW monitoring wells.

Method	Interval (ft)	Purpose
Open Hole Logs, Surveys, and Sampling During Construction		
Wireline- Spontaneous Potential – Surface Casing	Surface to TD	Correlation log, volume of shale indicator, estimate salinity.
Wireline –Resistivity – Surface Casing	Surface to TD	Fluid identification, estimate salinity, correlation log.

Note: Details, tools, and procedures for the logging, sampling and tests are described in the QASP attachment to this permit.

7.0 Pre-Injection Test Plan – Miocene Composite Confining Zone Monitoring Wells

Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3 will be used to monitor changes in pressure, temperature and the water composition within the Miocene Composite Confining Zone. Table POT-13 shows the proposed logging and survey for these wells.

Table POT-13: Logging, survey, and sampling for Miocene Composite Confining Zone Monitoring Wells.

Method	Interval (ft)			Purpose
	Bluebonnet IZM M1	**Bluebonnet IZM M2**	**Bluebonnet IZM M3**	
Open Hole Logs, Surveys and Sampling During Construction				
Deviation Survey - every 100 ft while drilling, or during completion	Surface to TD	n/a	n/a	Define well trajectory, displacement, and tortuosity.
Wireline - Spontaneous Potential – Surface Casing	Surface to 1,600 ft	n/a	n/a	Correlation log, volume of shale indicator, estimate salinity.
Wireline - Resistivity – Surface Casing	Surface to 1,600 ft	n/a	n/a	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Surface Casing	Surface to 1,600 ft	n/a	n/a	Identify borehole enlargement and calculate cement volume.
Wireline - Resistivity – Long String Casing	1,600 ft to TD	Surface to TD	Surface to TD	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Long String Casing	1,600 ft to TD	n/a	n/a	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	1,600 ft to TD	Surface to TD	Surface to TD	Define stratigraphy, correlation log, shale indicator.
Wireline -Sonic Dipolar – Long String Casing	1,600 ft to TD	n/a	n/a	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Density/Neutron – Long String Casing	1,600 ft to TD	n/a	n/a	Estimate porosity, mineralogical characterization.
Mud Logging	Surface to TD (every 30 ft)	n/a	n/a	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and Surveys Before Injection				
CBL-VDL-USIT-CCL – Surface Casing - Surface casing will be logged while running open-hole logs in long string section.	Surface to 1,600 ft	n/a	n/a	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long String Casing - Long string casing will be logged during well completion.	1,600 to TD.	n/a	n/a	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	n/a	n/a	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline - Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	n/a	n/a	CO_2 saturation, baseline for monitoring.

Method	Interval (ft)			Purpose
	Bluebonnet IZM M1	**Bluebonnet IZM M2**	**Bluebonnet IZM M3**	
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	n/a	n/a	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.
Fiber Optic - DTS Survey – Long String Casing	Surface to TD	n/a	n/a	Measure temperature profile on the well from the surface to the top of the perforation. Define baseline for monitoring mechanical integrity.

E. INJECTION WELL OPERATING CONDITIONS

E.1 Injection Well Operating Conditions - Bluebonnet CCS 1

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1.

Table OP-1: Injection well operating conditions.

Parameter/Completion (TVD ft)	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top-bottom (ft)	8,180-8,468	7,967-8,468	8,766-8,950
Perforation interval TVD[2], top-bottom (ft)	8,031-8,306	7,828-8,306	8,591-8,768
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	1,370
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500	1,300-1,900
Maximum bottom hole pressure at 90% of frac gradient ([redacted] at top of perforations (psig)	5,495	5,355	5,880
Maximum bottom hole pressure at 90% of frac gradient ([redacted]) at bottomhole gauge (psig)	5,405	5,335	5,795
Bottomhole gauge depth MD/TVD (ft)	7,900/7,763	7,900/7,763	8,500/8,337
Operating injection rate (metric tonnes per day)	5,480	5,480	1,370
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100	1,300-1,900
Minimum annulus/tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	16	14	2.5

(1) MD: measured depth.
(2) TVD: true vertical depth.
(3) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

1.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 1 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01, performed in 2023. Analysis of the well test in the stratigraphic well in the Lower Frio formation shows a fracture gradient of [redacted]. The Hackberry Injection Zone was also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of [redacted] was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Claimed as PBI

The downhole gauge for injection pressure monitoring will be located at approximately 7,763 ft TVD during Completion 1 and Completion 2. For Completion 3, the gauges will be at 8,337 ft TVD. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Claimed as PBI

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

1.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The main pipeline design pressure is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 1 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 1 wellhead will be between 1,200 and 2,100 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,500 psig at the maximum injection rate proposed, with wellhead pressure setpoints of 2,650 and 2,850 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

1.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long-string casing and tubing was estimated as follows:

DP (psi) = max bottom hole pressure during injection – hydrostatic pressure in annulus +100 psi

Calculated at packer depth.

1.4 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2: Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

1.5 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the Bluebonnet Hub will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below, in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,500 psig, measured at the wellhead.
(4) The planned injection rates are shown in Table OP-3.

Table OP-3: Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	24	40
2,740	24	50
3,616	24	60
4,548	24	70
4,932	24	80
5,206	24	90
5,480	24	100

(5) The injection rates will be controlled with variable-frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.
(b) The permittee will notify the agency within 24 hours of the determination.
(c) The permittee will consult with the agency before initiating any further injection.

E.2 Injection Well Operating Conditions - Bluebonnet CCS 2

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion (TVD ft)	Completion 1	Completion 2
Perforation interval MD[1], top-bottom (ft)	8,237-8,514	8,009-8,514
Perforation interval TVD[2], top-bottom (ft)	7,974-8,230	7,766-8,230
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (Claimed as PBI) at top of perforations (psig)	5,455	5,315
Maximum bottomhole pressure at 90% of frac gradient (Claimed as PBI) at bottomhole gauge (psig)	5,370	5,295
Bottomhole gauge depth MD/TVD (ft)	7,950/7,711	7,650/7,711
Operating injection rate (average) (metric tonnes per day)	4,660	4,660
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100
Minimum annulus /tubing differential pressure (psig)	100	100
Total volume injected (millions of tonnes)	13.6	11.9

(1) MD: measured depth.
(2) TVD: true vertical depth.
(3) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

1.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 2 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of Claimed as PBI

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Claimed as PBI

The downhole gauge for injection pressure monitoring will be located at approximately 7,711 ft TVD during Completion 1 and Completion 2. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Claimed as PBI

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

1.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 2 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 2 wellhead will be between 1,200 and 2,100 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,500 psig at the maximum injection rate, with wellhead pressure setpoints of 2,650 and 2,850 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

1.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing was estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi

Calculated at packer depth.

1.4 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semi-annually
Description of any event that triggers a shutoff device and the response taken	Semi-annually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semi-annually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

1.5 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and

methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,500 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	24	40
2,740	24	50
3,616	24	70
4,548	24	80
4,660	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:
    (a) The instantaneous shut-in pressure (ISIP) will be measured.
    (b) The permittee will notify the agency within 24 hours of the determination.

(c) The permittee will consult with the agency before initiating any further injection.

E.3 Injection Well Operating Conditions- Bluebonnet CCS 3

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top-bottom (ft)	8,418-8,763	7,943-8,223	7,659-8,223
Perforation interval TVD[2], top-bottom (ft)	8,138-8,459	7,697-7,957	7,433-7,957
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (Claimed as PBI) at top of perforations (psig)	5,570	5,265	5,085
Maximum bottomhole pressure at 90% of frac gradient (Claimed as PBI at bottomhole gauge (psig)	5,315	5,160	5,065
Bottomhole gauge depth MD/TVD (ft)	7,600/7,376	7,600/7,376	7,600/7,376
Operating injection rate (average) (metric tonnes per day)	3,840	3,840	2,740
Operating wellhead surface injection pressure (psig)	1,000-1,800	1,000-1,800	1,000-1,600
Minimum annulus /tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	11.2	11.2	5

(1) MD: measured depth.
(2) TVD: true vertical depth.
(3) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

1.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 3 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of Claimed as PBI The Hackberry Injection zone was also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of Claimed as PBI was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Claimed as PBI

The downhole gauge for injection pressure monitoring will be located at approximately 7,376 ft TVD during Completion 1, Completion 2, and Completion 3. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Claimed as PBI

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

1.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 3 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 3 wellhead will be between 1,000 and 1,800 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,500 psig at the maximum injection rate, with wellhead pressure setpoints of 2,600 and 2,750 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

1.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi Calculated at packer depth.

1.4 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

1.5 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,500 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,500	24	40
1,900	24	50
2,690	24	70
3,070	24	80
3,840	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the

injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.
(b) The permittee will notify the agency within 24 hours of the determination.
(c) The permittee will consult with the agency before initiating any further injection.

E.4 Injection Well Operating Conditions - Bluebonnet CCS 5

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4	Completion 5
Perforation interval MD, top-bottom (ft)	6,330-6,464	6,053-6,181	5,820-5,975	5,646-5,734	5,481-5,502
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient ([redacted] at top of perforations (psig)	4,330	4,140	3,980	3,860	3,750
Maximum bottomhole pressure at 90% of frac gradient ([redacted]) at bottomhole gauge (psig)	4,025	3,925	3,845	3,780	3,725
Bottomhole gauge depth MD (ft)	5,400	5,400	5,400	5,400	5,400
Operating injection rate (average) (metric tonnes per day)	5,095	5,095	5,095	5,095	5,095
Operating wellhead surface injection pressure (psig)	1,000-1,500	1,000-1,500	1,000-1,500	1,000-1,500	1,000-1,500
Minimum annulus /tubing differential pressure (psig)	100	100	100	100	100
Total volume injected (millions of tonnes)	7.44	5.58	7.44	3.72	3.72

(1) MD: measured depth.
(2) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

1.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 5 well is 90% of the fracture propagation pressure of the Frio

injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of Claimed as PBI The Lower Miocene and Hackberry injection zones were also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of Claimed as PBI was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Claimed as PBI

The downhole gauge for injection pressure monitoring will be located at approximately 5,400 ft MD during Completion 1, Completion 2, Completion 3, Completion 4 and Completion 5. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Claimed as PBI

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

1.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 5 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 5 wellhead will be between 1,000 and 1,500 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,200 psig at the maximum injection rate, with wellhead pressure setpoints of 2,250 and 2,300 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

1.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi
Calculated at packer depth.

1.4 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

1.5 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,600	24	30
2,200	24	40
2,750	24	50
3,300	24	60
3,850	24	70
4,400	24	80
4,950	24	90
5,494	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

    (a) The instantaneous shut-in pressure (ISIP) will be measured.
    (b) The permittee will notify the agency within 24 hours of the determination.
    (c) The permittee will consult with the agency before initiating any further injection.

E.5 Injection Well Operating Conditions Bluebonnet CCS 6

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD, top-bottom (ft)	6,218-6,347	5,760-5,869	5,523-5,584
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient ([redacted]) at top of perforations (psig)	4,250	3,940	3,780
Maximum bottomhole pressure at 90% of frac gradient ([redacted]) at bottomhole gauge (psig)	4,000	3,840	3,755
Bottomhole gauge depth MD (ft)	5,450	5,450	5,450
Operating injection rate (average) (metric tonnes per day)	4,465	4,465	4,465
Operating wellhead surface injection pressure (psig)	950-1,500	950-1,500	950-1,500
Minimum annulus /tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	11.41	11.41	1.63

(1) MD: measured depth.
(2) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

1.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 6 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of [redacted] The Lower Miocene and Hackberry Injection zone were also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of [redacted] psi/ft was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Claimed as PBI

The downhole gauge for injection pressure monitoring will be located at approximately 5,450 ft TVD during Completion 1, Completion 2, and Completion 3. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Claimed as PBI

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

1.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 6 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 6 wellhead will be between 950 and 1,500 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,200 psig at the maximum injection rate, with wellhead pressure setpoints of 2,250 and 2,300 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

1.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi Calculated at packer depth.

1.4 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

1.5 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the Project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,500	24	30
1,900	24	40
2,400	24	50
2,900	24	60
3,350	24	70
3,900	24	80
4,300	24	90
4,794	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the

injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.
(b) The permittee will notify the agency within 24 hours of the determination.
(c) The permittee will consult with the agency before initiating any further injection.

E.6 Injection Well Operating Conditions - Bluebonnet CCS 7

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4
Perforation interval MD, top-bottom (ft)	6,030-6,124	5,593-5,689	5,302-5,472	5,186-5,266
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient ([redacted]) at top of perforations (psig)	4,125	3,825	3,630	3,550
Maximum bottomhole pressure at 90% of frac gradient ([redacted]) at bottomhole gauge (psig)	3,820	3,665	3,560	3,520
Bottomhole gauge depth MD (ft)	5,100	5,100	5,100	5,100
Operating injection rate (average) (metric tonnes per day)	3,808	3,808	3,808	3,808
Operating wellhead surface injection pressure (psig)	900-1,300	900-1,300	900-1,300	900-1,300
Minimum annulus /tubing differential pressure (psig)	100	100	100	100
Total volume injected (millions of tonnes)	5.56	5.56	5.56	4.17

(1) MD: measured depth.
(2) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

1.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 7 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of [redacted] The Lower Miocene and Hackberry injection zones were also tested in 2023 in the stratigraphic well. The test reached the maximum

injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of Claimed as PBI was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Claimed as PBI

The downhole gauge for injection pressure monitoring will be located at approximately 5,100 ft MD during Completion 1, Completion 2, Completion 3, and Completion 4. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Claimed as PBI

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

1.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 7 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 7 wellhead will be between 900 and 1,300 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,200 psig at the maximum injection rate, with wellhead pressure setpoints of 2,200 and 2,300 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

1.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as

proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi Calculated at packer depth.

1.4 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

1.5 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,100 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,250	24	30
1,650	24	40
2,100	24	50
2,500	24	60
2,900	24	70
3,300	24	80
3,712	24	90
4,125	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:
    (a) The instantaneous shut-in pressure (ISIP) will be measured.
    (b) The permittee will notify the agency within 24 hours of the determination.
    (c) The permittee will consult with the agency before initiating any further injection.

F. TESTING AND MONITORING PLAN

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the project)
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

This Testing and Monitoring Plan describes how the Bluebonnet Sequestration Hub, LLC, will monitor the Bluebonnet Hub pursuant to 40 CFR §146.90. In addition to demonstrating that the wells are operating as planned, the CO_2 plume and pressure front are moving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDWs), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

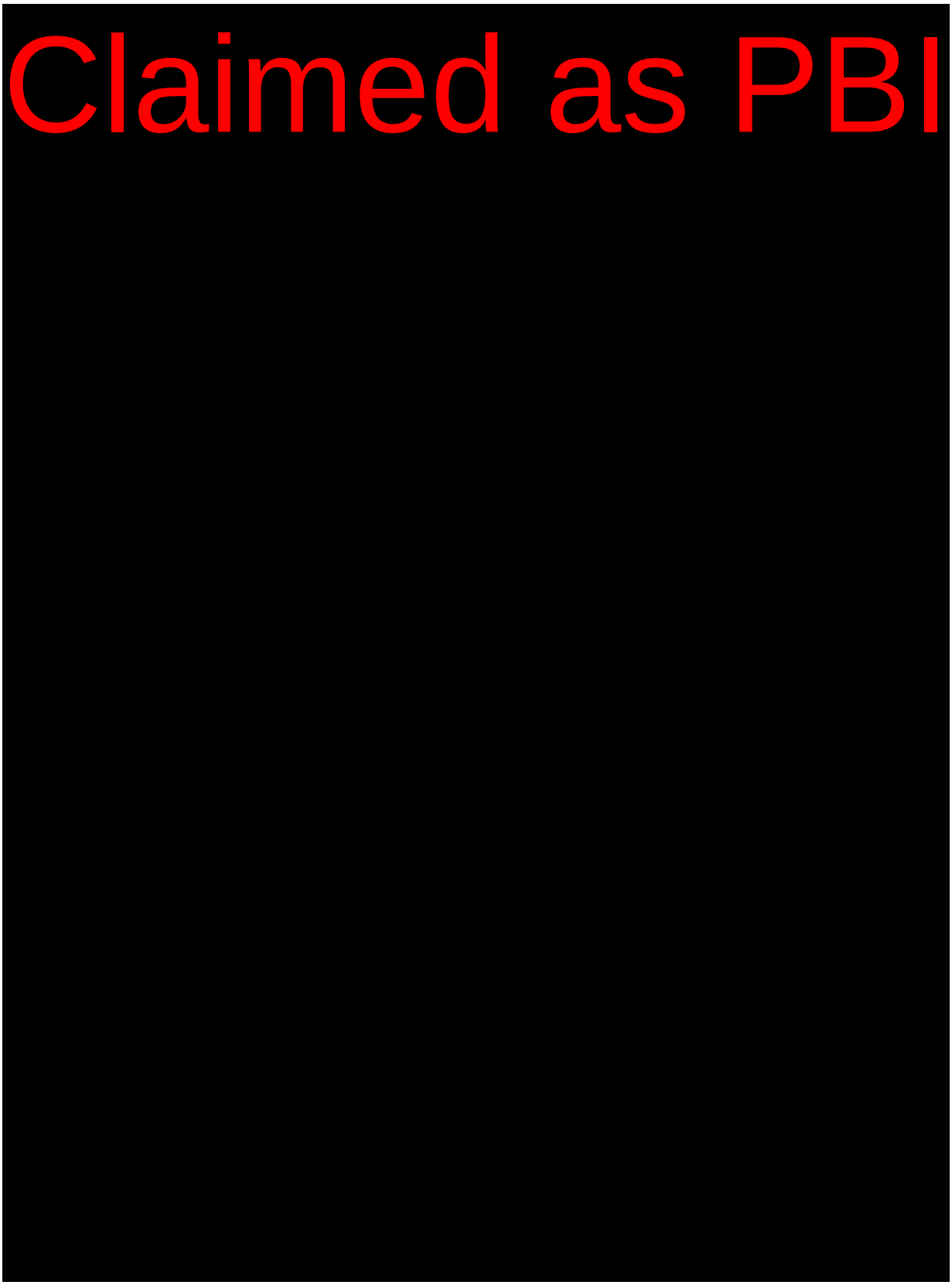
Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan attached to this application.

2.0 Overall Strategy and Approach of the Testing and Monitoring Plan

The testing and monitoring plan is designed to detect unforeseen CO_2 and/or brine leakage out of the injection zone that could endanger the USDW, migrate to a different stratus, or create a risk to human health or the environment.

This monitoring plan was tailored based on a qualitative risk assessment of the site that also was used to inform the Emergency and Remedial Response Plan for the Bluebonnet Hub. Table TM-1 summarizes the residual risk ranking, assuming the proposed controls and mitigations of the project design and monitoring plan are in place.

Table TM-1: Risk ranking for Bluebonnet Hub evaluation.



Several components are integrated into the master monitoring plan for the Bluebonnet Hub, which are classified in the following categories:

1. Operational testing and monitoring during injection.
2. Mechanical integrity testing.
3. Groundwater quality and geochemical monitoring.
4. CO_2 plume and pressure-front tracking.
5. Near-surface and surface monitoring.
6. Induced seismicity.

Table TM-2 summarizes the different methods proposed to monitor the AoR, including the CO_2 plume and pressure front from the CO_2 injection wells proposed at the Bluebonnet Hub: Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7.

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan.

Ct	Description	Method	Location	Pre-Injection		Injection Period
1	Operational testing and monitoring during injection.	Carbon Dioxide Stream Analysis.	Sampling point upstream CO_2 Injector wells	n/a		Quarterly
		Measurement of injection pressure and temperature on surface - surface transducers	Flow line of CO_2 Injector wells	n/a		Continuously
		Measurement of casing-tubing annular pressure in surface- surface transducers	Wellhead of CO_2 Injector wells	n/a		Continuously
		Measurement of rate and injection volume in surface - coriolis flow meter	Flow Line CO_2 Injector wells	n/a		Continuously
		Measurement of casing-tubing annular pressure above packer- donwhole gauges	Downhole CO_2 Injector wells	n/a		Continuously
		Measurement of pressure and temperature at top of the perforations - downhole gauges	Downhole CO_2 Injector wells	n/a		Continuously
		Automatic surface shut off devices.	Flow Line CO_2 Injector wells	n/a		Continuously
		Corrosion coupons analysis.	Upstream CO_2 Injector wells	n/a		Quarterly
		Pressure Fall Off test	CO_2 Injector Well		x	Every 5 years
		Measurements of tubing pressure and temperature on surface- Surface transducers	Wellhead of IZM and USDW wells	n/a		Continuously
		Measurement of downhole conditions - Downhole sensors and Gauges	Completion of IZM and USDW wells	n/a		Continuously
		Visual inspections and handheld monitors (LEL, H2S, CO_2)	General facilities		x	Weekly
		Leak detection and repair (LDAR) program using Optical Gas Imaging cameras , handheld during inspections	General facilities	n/a		Quarterly

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan (continued).

Ct	Description	Method	Location	Pre-Injection		Injection Period
2	Mechanical Integrity testing.	Ultrasonic cement evaluation , CBL, VDL	CO_2 injector wells		x	
		Ultrasonic cement evaluation , CBL, VDL	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1		x	
		Ultrasonic casing inspection log	CO_2 injector wells		x	During workover or well maintenance
		Pulse neutron log	CO_2 injector wells		x	Annually
		DTS fiber alongside the casing to the top of the perforations	CO_2 injector wells		x	Continuously
		DTS fiber alongside the casing to total depth.	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1		x	Continuously
		Pulse neutron, temperature log,or electromagnetic log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01		x	Every 5 years or during planned maintenance or workover activities if fibers fails or its not installed. Event triggered by other monitoring results.
		Annular pressure test	CO_2 injector wells		x	After every WO
		Annular pressure test	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01 Bluebonnet IZM M1			Annually

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan (continued).

Ct	Description	Method	Location	Pre-Injection		Injection Period
3	Ground water quality and geochemical monitoring	Water sampling and testing in USDW monitoring wells.	USDW wells	Bluebonnet USDW 1 Baseline. Quarterly min 1 year before injection.		Quarterly sample first 2 years of injection. Semi-annually from year 3 to end of injection.
		Water sampling and testing in the Miocene Composite Confining Zone	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3		x	Quarterly sample the first 2 years of injection. Semi-annually from year 3 to end of injection.
		Water sampling and testing in legacy shallow fresh aquifer water wells.	Legacy water wells	Quarterly samples from selected wells for minimum 1 year before injection.		Quarterly sample first 2 years of injection. As needed based on other monitoring tools.
		Measurement of pressure and temperature downhole in USDW - Downhole Gauges	USDW wells		x	Continuously
		Measurement of pressure and temperature downhole in the Miocene Composite Confining Zone- Downhole Gauges	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3		x	Continuously
		Isotopic fingerprinting of water in shallow aquifers, overburden, and injection targets	USDW, IZM M and CO_2 injector wells	Initial samples before injection during well construction .		

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan (continued).

Ct	Description	Method	Location	Pre-Injection		Injection Period
4	Carbon Dioxide Plume and Pressure Front Tracking	Timed lapsed Pulse Neutron Log for CO_2 plume tracking	CO_2 injector		x	Annually for the CO_2 injectors. Event triggered in the IZM wells based on other monitoring techniques.
		Measurement of pressure and temperature in the reservoir - Downhole gauges	CO_2 injectors Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01			Continuously
		3D surface seismic survey - baseline	AoR		x	
		2D time lapsed surface seismic survey	AoR		x	Every 5 years
		3D time-lapsed VSP	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 6 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1		x	Annually until plume extend beyond detection.
5	Near Surface & Surface	Airborne electromagnetic survey	AoR		x	
		Airborne magnetic survey	AoR		x	
		Process-based soil gas approach	AoR	Minimum(1) year characterization		Quarterly
		Isotopic fingerprinting of the soil gas	AoR	Minimum(1) year characterization		If required to compliment other methods
		Atmospheric CO_2 sensors in wellhead.	CO_2 injector wells			Continuously
		Atmospheric CO_2 sensors in wellhead.	IZM FM wells			Continuously
6	Induced Seismicity	Surface seismometers network	AoR	Minimum (1) year baseline		Continuously

The methodology and frequency of testing and monitoring methods are expected to change throughout the project. Pre-injection monitoring and testing will focus on establishing baselines and ensuring that the site is ready to receive injected CO_2. Injection phase monitoring will be focused on collecting data that will be used to calibrate models and ensure the containment of CO_2. Post-injection phase monitoring and testing is designed to demonstrate CO_2 plume stabilization and ensure containment.

The proposed testing and monitoring plan will collect sufficient geospatial and monitoring data to validate the numerical simulation model, inform operational decisions on the quantity and rate of CO_2 injected, and trigger corrective or preventive maintenance actions, amongst others, to operate the site as designed, efficiently and safely. The monitoring results will allow the project to reevaluate the AoR and show that there is no endangerment to the USDW.

These methods and their applications in the proposed monitoring plan are discussed in the following sections. Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

The testing and monitoring plan will be reviewed at least once every five years and will be amended, if necessary, to ensure monitoring and storage performance is achieved and new technologies are appropriately incorporated. 40 CFR §146.90 (j).

2.1 Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for testing and monitoring activities, required pursuant to 146.90(k), is provided as a separate document in this permit.

2.2 Reporting Procedures

The Bluebonnet Sequestration Hub, LLC, will report the results of all testing and monitoring activities to Texas rail Road Commission in compliance with the requirements under 40 CFR 146.91.

3.0 Well Monitoring Network Design

Bluebonnet Sequestration Hub, LLC, plans to drill six CO_2 injection wells: Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, as part of the field development plan for the Bluebonnet Hub. The monitoring program proposed is designed based on the modeled CO_2 plume extension and propagation of the pressure front for the six wells injecting simultaneously according to the AoR delineation process to account for the maximum AoR extension and pressure impact. The injection schedule and field development plan might be adjusted based on the availability of CO_2.

The proposed monitoring plan includes a layout of three in zone (reservoir) monitoring wells, (Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Encanto 01), three monitoring wells within the Miocene Composite Confining Zone (Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet

IZM M3), and three USWD monitoring wells (Bluebonnet USDW 1, Bluebonnet USDW 2, and Bluebonnet USDW 8).

The project team plans to drill two water production wells, Bluebonnet PRDW F1 and Bluebonnet PRDW F2, to extract formation water from the Frio Injection Zone as a technique to control reservoir pressure. The project team plans to permit one water disposal well, Bluebonnet DSW M2, to reinject the water produced from the Frio formation to the shallow sands of the Miocene, above the Lower Miocene Confining Zone. Figure TM-1 and Figure TM-2 show the location of the monitoring wells relative to the CO_2 injection wells and predicted AoR and the legacy wells.

Table TM-3: Monitoring Wells Bluebonnet Hub.

Well Name & No	API No./Well ID	Purpose	Total Depth TVD (ft)	Date Drilled
Bluebonnet IZM FM1	TBD	Monitoring Frio and Hackberry Injection Zones	8,400	TBD
Bluebonnet IZM FM2	TBD	Monitoring Frio and Hackberry Injection Zones	9,000	TBD
Encanto 01	071-32664	Monitoring Lower Miocene Injection Zone	PBTD: 8,560 TD: 8,581	02/10/2023
Bluebonnet IZM M1	TBD	Monitoring Miocene Composite Confining Zone – Permeable formation between Seal 2 and Seal 3	2,900	TBD
Bluebonnet IZM M2	TBD	Monitoring Miocene Composite Confining Zone – Permeable formation between Seal 1 and Seal 2	2,000	TBD
Bluebonnet IZM M3	TBD	Monitoring Miocene Composite Confining Zone – Permeable formation between Seal 1 and Seal 2	1,900	TBD
Bluebonnet USDW 1	071-32672	Monitoring USDW zone	1,420	06/25/2024
Bluebonnet USDW 2	TBD	Monitoring USDW zone	1,500	TBD
Bluebonnet USDW 8	071-32676	Monitoring USDW zone	PBTD: 1,050 TD: 2,750	05/09/2025

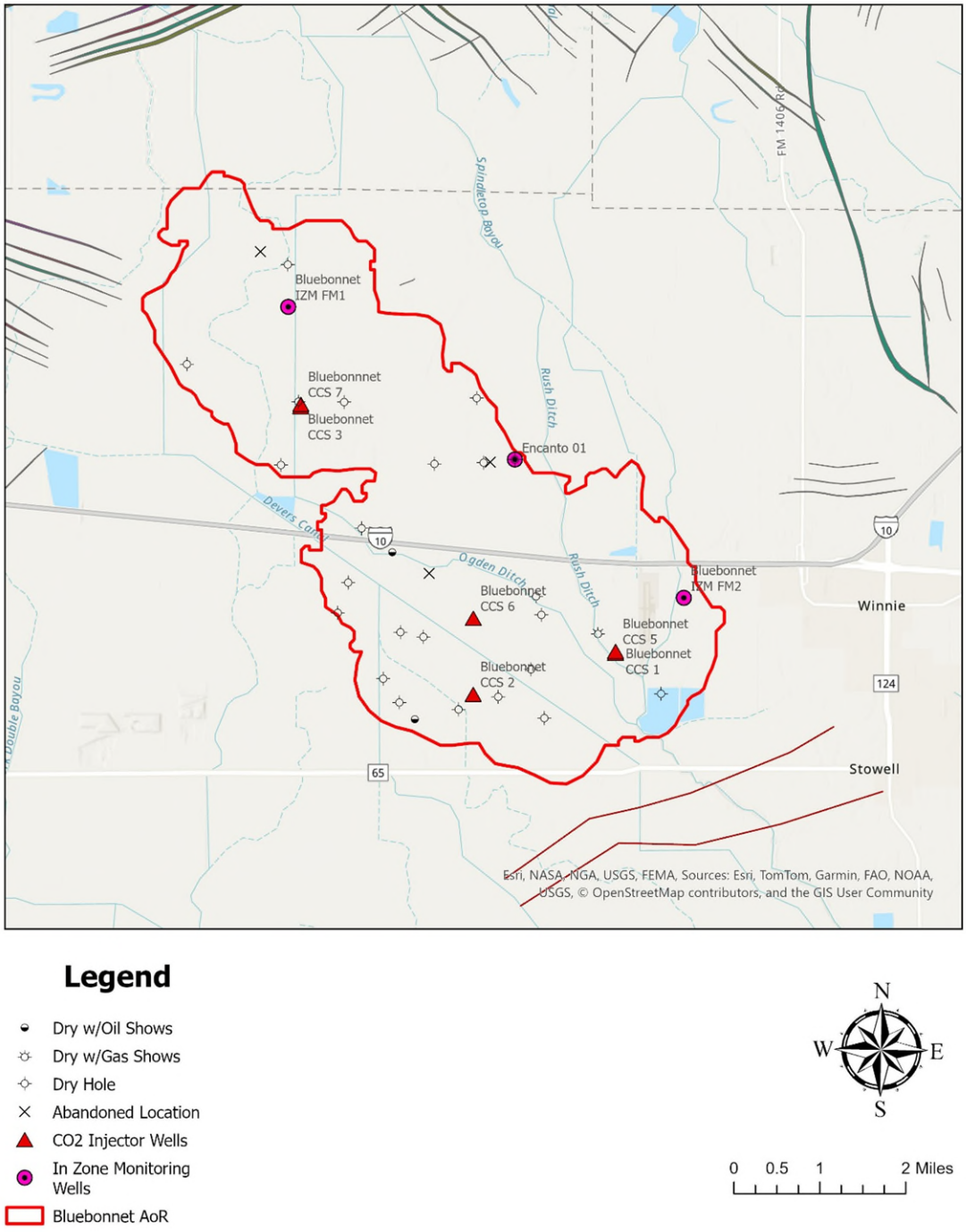


Figure TM-1: Location and layout of in-zone monitoring wells relative to the CO_2 injector wells, legacy wells and the predicted AoR.

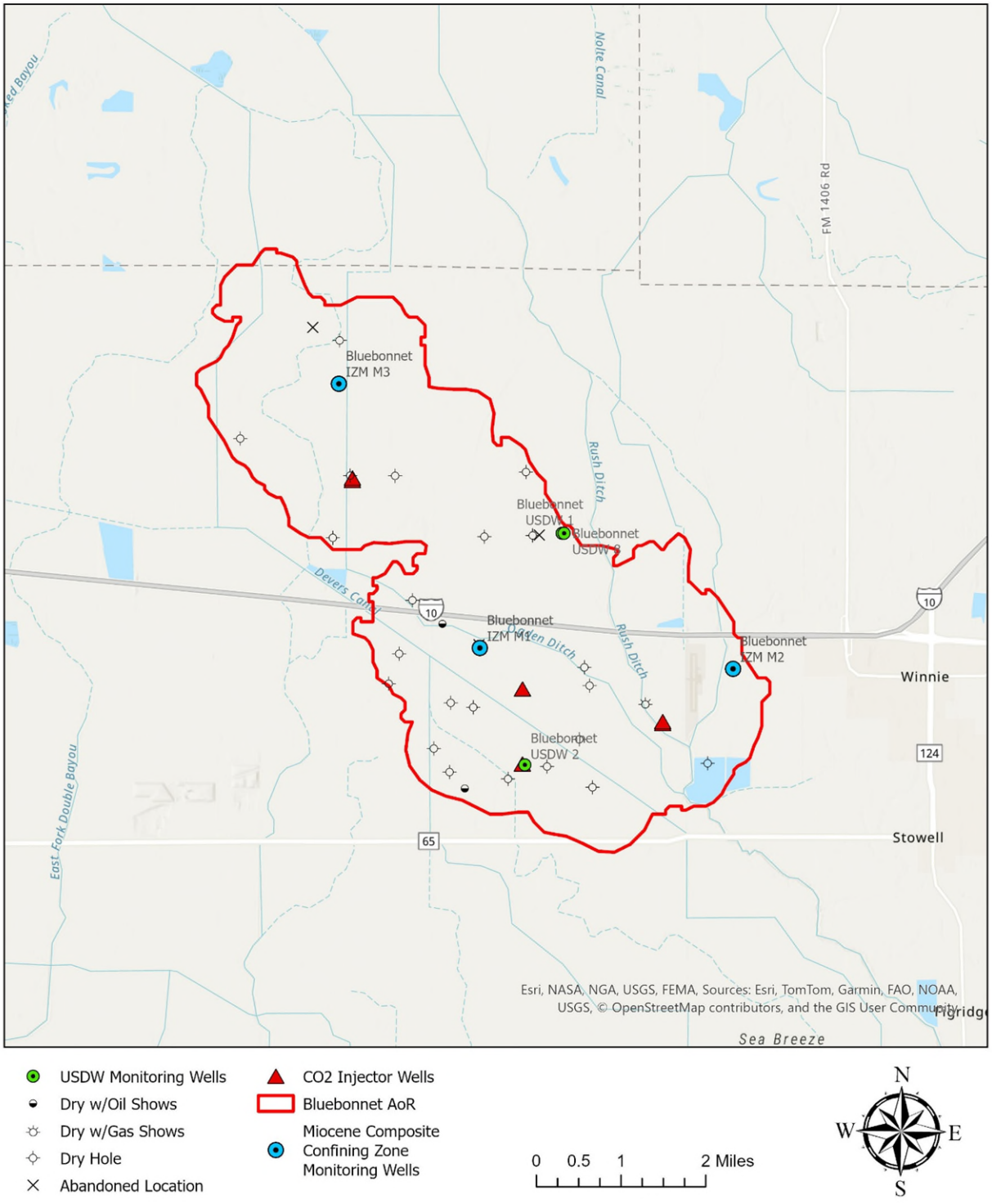


Figure TM-2: Location and layout of the legacy wells, USDW monitoring wells and Miocene Composite Confining Zone monitoring wells relative to the CO_2 injector wells and the predicted AoR.

The well locations show the approximate position of the CO_2 injector and monitoring wells. The exact locations might have a slight variation depending on the final design of the surface pads as well as the negotiations with the landowners when the locations are surveyed.

3.1 CO_2 Injector Wells (CCS)

The CO_2 injection wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 are designed to maximize CO_2 injection rates and operate the site efficiently. The wells will be equipped with surface and downhole sensors to track reservoir behavior in real time, allowing the project team to validate the predictions of the numerical simulation model and optimize injection parameters.

The implementation of a pulse neutron/saturation log will evaluate the mechanical integrity of the CO_2 injection wells and provide information about the vertical conformance of the injected CO_2 in the injection zone and validate containment.

The project plans to install fiber optic alongside each CO_2 injection well from surface to top of the perforations to track in real time the vertical conformance of the CO_2 near the wellbore to identify any potential migration paths. The fiber will be used from the beginning of the injection period to image the development of the CO_2 plume in 3D and validate the containment of CO_2 in the injection zones.

Details of the well construction and proposed schematics of the CO_2 injectors are included in the Injector Wells Construction Details Plan of this application.

3.2 In-Zone Monitoring Wells (IZM)

The location and completion design of the in-zone monitoring wells was defined with the objective of tracking the early development of the pressure front as it precedes the movement of the plume, to allow for history-matching of the model. The wells were located strategically to mitigate the main risks identified during the evaluation of the site and comply with 40 CFR §146.90 requirements. These areas included highly populated areas, faults, and high density of legacy wells, amongst others.

The in-zone monitors well locations and completions (Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Encanto 01) allow for the tracking of movement of the CO_2 plume through pressure and temperature matching, from early stages to the end of the injection period. Bluebonnet IZM FM1 and Bluebonnet IZM FM2 will be equipped with DTS/DAS fiber optics alongside the casing to support the acquisition of 3D vertical seismic profile (VSP) surveys, as further described in this document. If the surface seismometer network (described in the next sections) detects any activity related to induced seismicity due to the injection, these wells can acquire real time acoustic data to track downhole micro seismicity.

3.2.1 Bluebonnet IZM FM1

The Bluebonnet IZM FM1 will be drilled before the CO_2 injection on the Bluebonnet CCS 3 or the Bluebonnet CCS 7 wells starts or shortly thereafter. The well location was selected to track CO_2 movement and development of the pressure front to the northwest section of the AoR. This well will be located strategically in the updip direction and preferential path of the plume development. The well will serve to calibrate the simulation model and provide the capability to image the CO_2 plume with a 3D VSP, utilizing the fiber optic cable to be installed in the well, covering a radius 0.5 mile around the monitoring well to predict CO_2 plume migration rates.

The well will be completed in the Hackberry and Frio Injection Zones [~7,243-8,250 ft total vertical depth (TVD)] and will be equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow for tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

Since the well will be drilled from the surface to the Hackberry Confining Zone, it will enable tracking any changes in CO_2 saturation around the wellbore, not only for the Frio and Hackberry Injection Zones, but also for the Lower Miocene Injection Zone and overburden.

If the surface seismometer network (described in the next sections) detects any activity that could be related to induced seismicity from CO_2 injection, the Bluebonnet IZM FM1 has the capability to acquire real-time acoustic data to track downhole micro seismicity.

The proposed schematic for this well is presented in Figure TM-3.

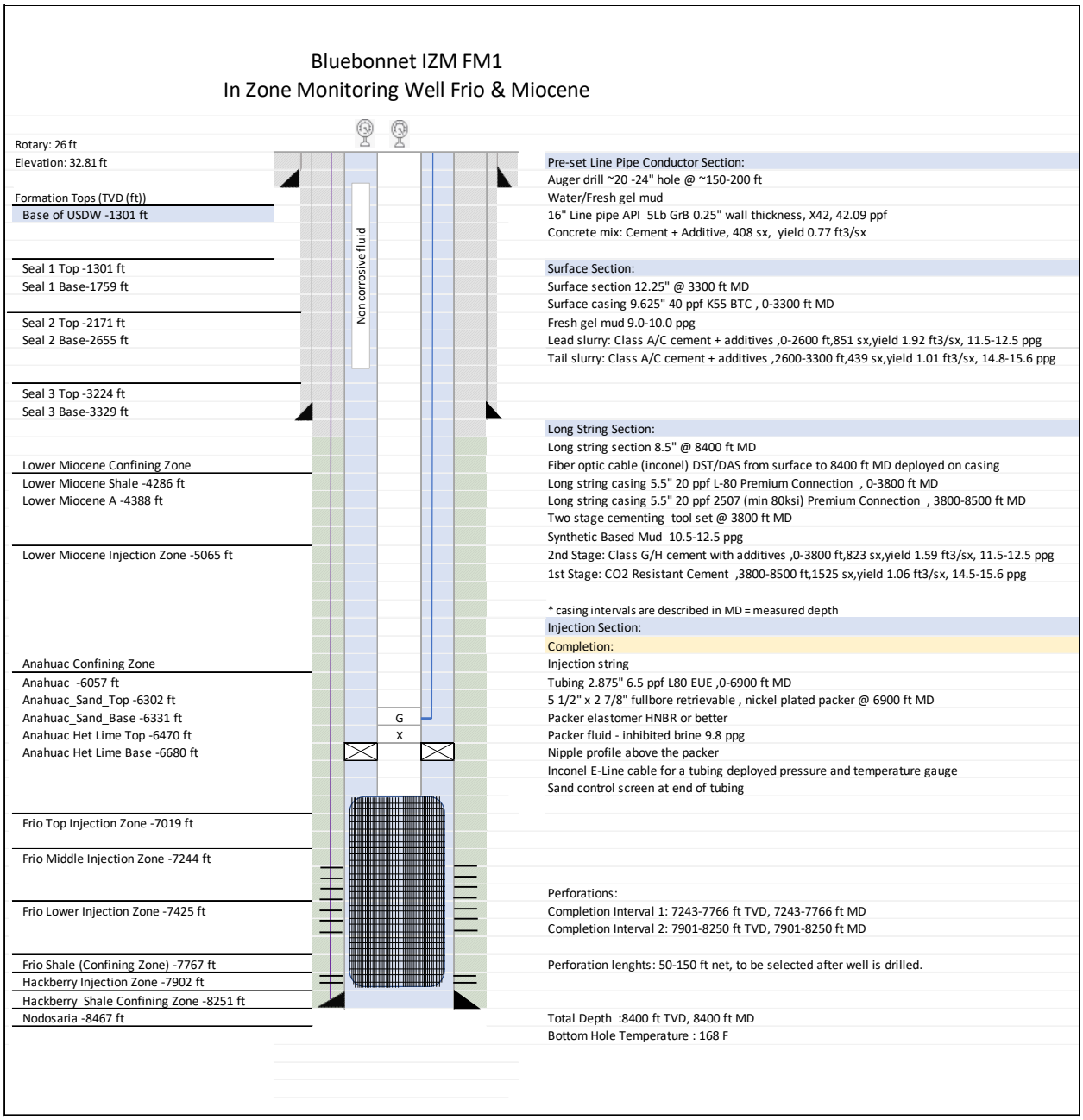


Figure TM-3: Well design and schematic for Bluebonnet IZM FM1.

3.2.2 Bluebonnet IZM FM2

The Bluebonnet IZM FM2 will be drilled before CO_2 injection starts on Bluebonnet CCS 1 or Bluebonnet CCS 5, or shortly thereafter. The well location was selected to track the development of the CO_2 plume and pressure front towards the east of the AoR. The east section of the plume will be near the town of Winnie, Texas, including the Winnie airport. The well will be on the border of the CO_2 plume and placed strategically to track any abnormal development of the plume eastward.

The well will be completed in the Hackberry and Frio Injection Zones (~7,824-8,790 ft TVD) and equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow to tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

Since the well will be drilled from surface to the Hackberry Confining Zone, it will enable tracking any changes in CO_2 saturation around the wellbore, not only for the Frio and Hackberry Injection zones, but also for the Lower Miocene Injection Zone and overburden.

The well will be equipped with a fiber optic cable alongside the casing, providing the capability to image the CO_2 plume with a 3D VSP and covering a radius 0.5 mile around the monitoring well, to predict CO_2 plume migration rates.

If the surface seismometer network (described in the next sections) detects any activity that could be related to induced seismicity from injection, then Bluebonnet IZM FM2 can acquire real-time acoustic data to track downhole micro seismicity with the fiber optic cable installed in the well.

The proposed schematic for this well is presented in Figure TM-4.

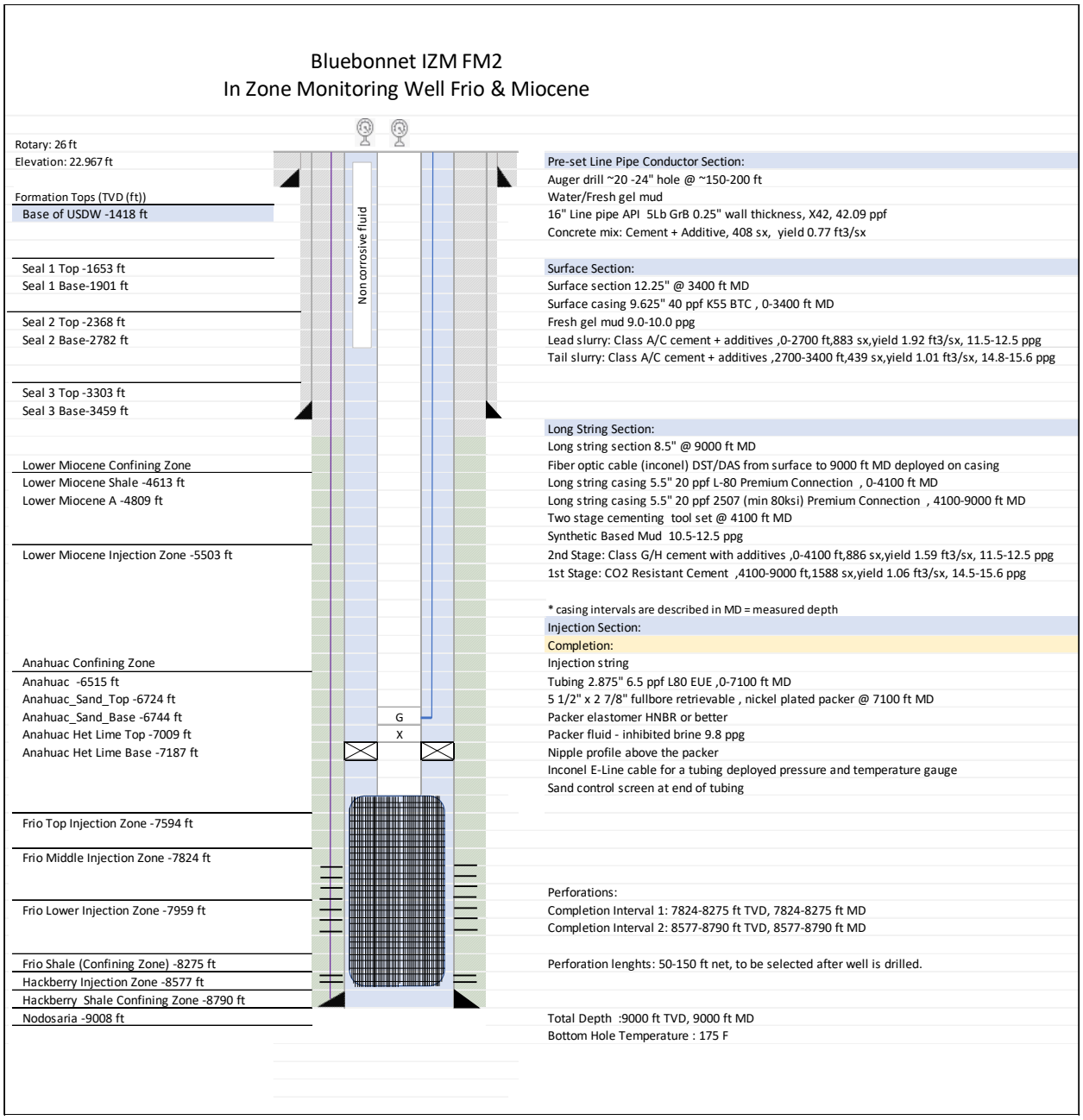


Figure TM-4: Well design and schematic for Bluebonnet IZM FM2.

3.2.3 Encanto 01

The Encanto 01 well was drilled in 2022 as part of the stratigraphic well campaign to acquire site-based data for the project and is temporarily abandoned, pending recompletion as part of the project's monitoring network. The well is strategically placed to track any potential migration in the field to the north of the Bluebonnet CCS 2 and Bluebonnet CCS 6 injection wells and will provide monitoring capabilities to track the pressure and temperature changes in the shallowest permitted reservoir interval in the AoR. The well will be completed in the Lower Miocene Injection Zone.

The proposed schematic for this well is presented in Figure TM-5.

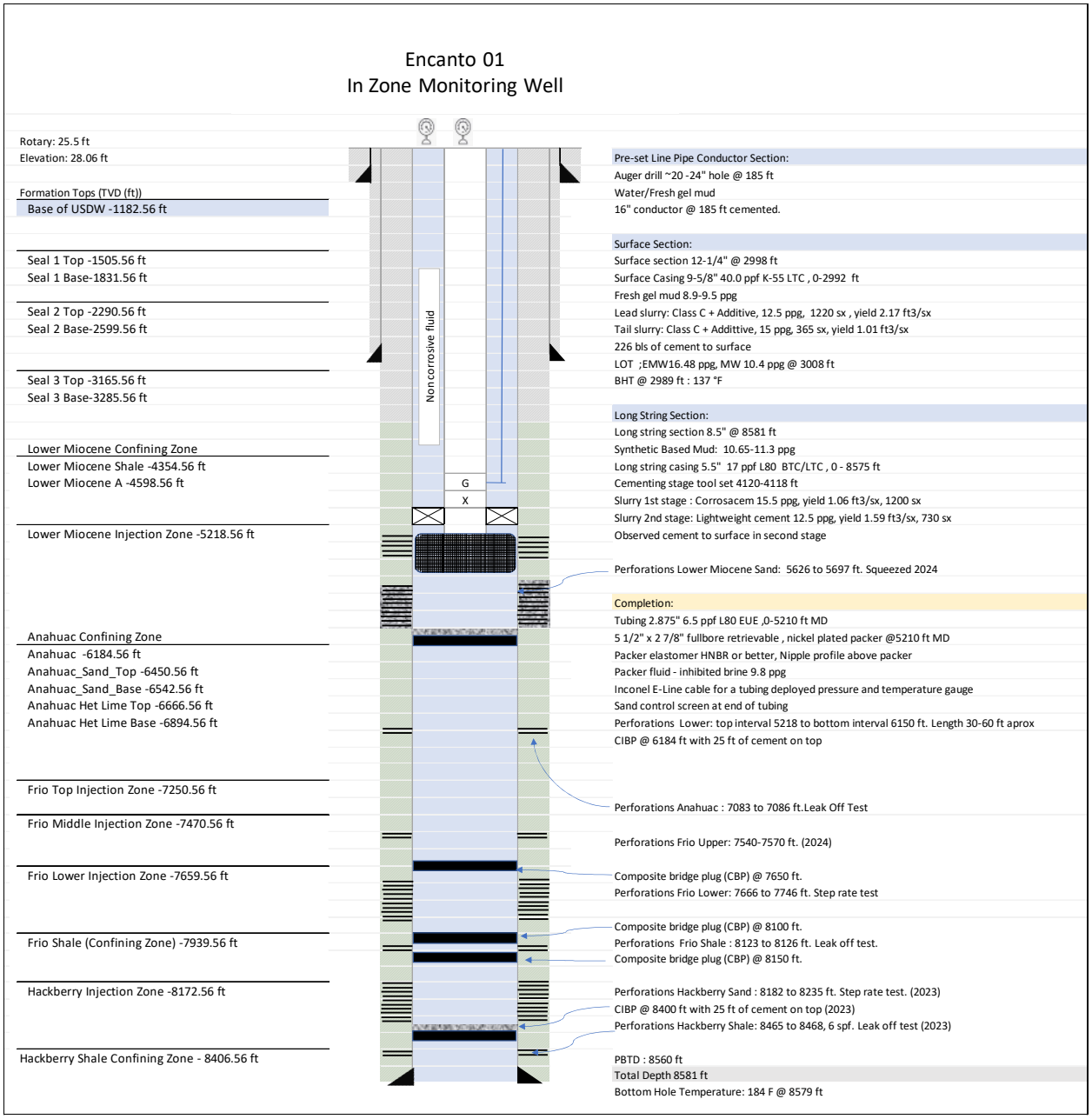


Figure TM-5: Well design and schematic for Encanto 01.

3.3 Miocene Composite Confining Zone Monitoring Wells

Bluebonnet plans to drill three monitoring wells withing the Miocene Composite Confining Zone—Bluebonnet IZM M1, Bluebonnet IZM M2, and Bluebonnet IZM M3. These wells will provide continuous pressure and temperature monitoring, as well as periodic geochemical sampling, within the permeable intervals located between the shallowest injection zone (Lower Miocene Injection Zone) and the base of the underground source of drinking water (USDW). The monitoring program is designed to detect potential changes in formation pressure, temperature or fluid chemistry and to provide early indication of any unexpected vertical fluid migration.

3.3.1 Bluebonnet IZM M1

The location of Bluebonnet IZM M1 was selected to monitor pressure, temperature, and geochemical changes within the permeable interval located between Seal 2 and Seal 3 of the Miocene Composite Confining Zone. The well will be equipped with a fiber-optic cable installed along the casing, providing the capability to conduct three-dimensional vertical seismic profiling (3D VSP) and image the CO_2 plume within an approximately 0.5-mile radius of the well. The completion will also include permanent downhole pressure and temperature gauges to provide continuous, real-time monitoring of changes within the monitored aquifer.

If the surface seismometer network (described in the next sections) detects any activity that could be related to induced seismicity from CO_2 injection, then the Bluebonnet IZM M1 can acquire real-time acoustic data to track downhole micro seismicity with the fiber optic cable installed in the well.

The proposed schematic for this well is presented in Figure TM-6.

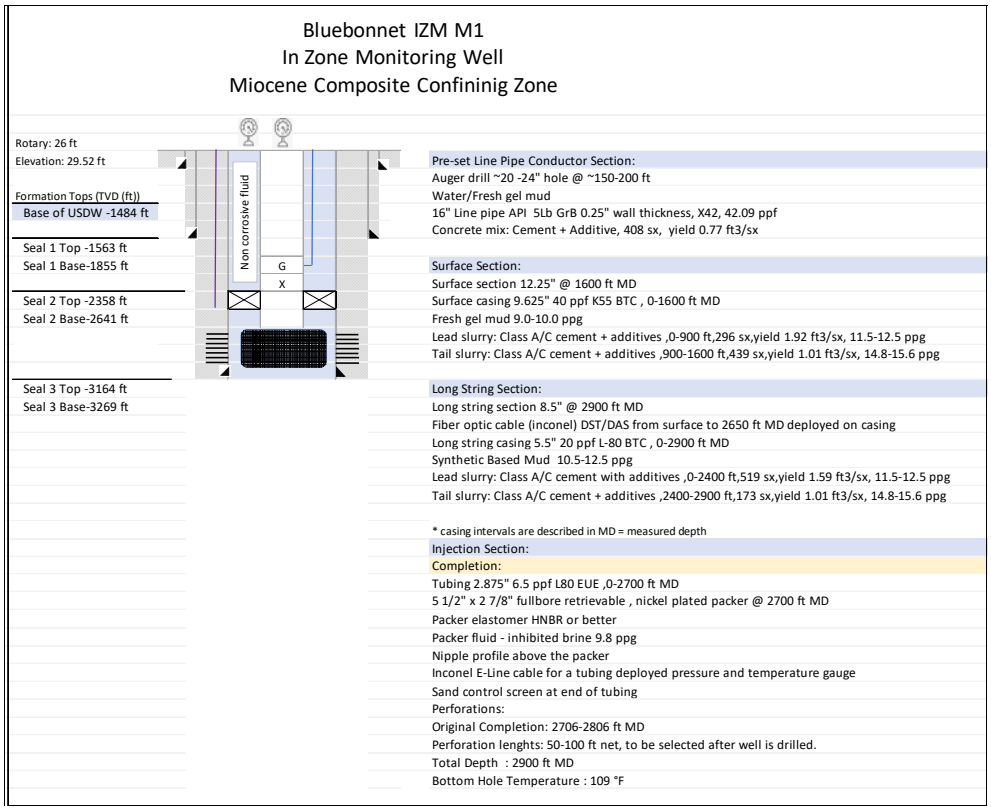


Figure TM-6: Well design and schematic for Bluebonnet IZM M1.

3.3.2 Bluebonnet IZM M2 and Bluebonnet IZM M3

Bluebonnet IZM M2 and Bluebonnet IZM M3 are designed to monitor the permeable interval immediately below Seal 1 within the Miocene Composite Confining Zone. Each well will be equipped with permanent downhole pressure and temperature gauges to provide continuous monitoring of formation conditions. The wells will also include water-sampling capabilities to support periodic geochemical analyses and identify potential changes in groundwater composition. The proposed schematic for these well are presented in Figure TM-7 and Figure TM-8.

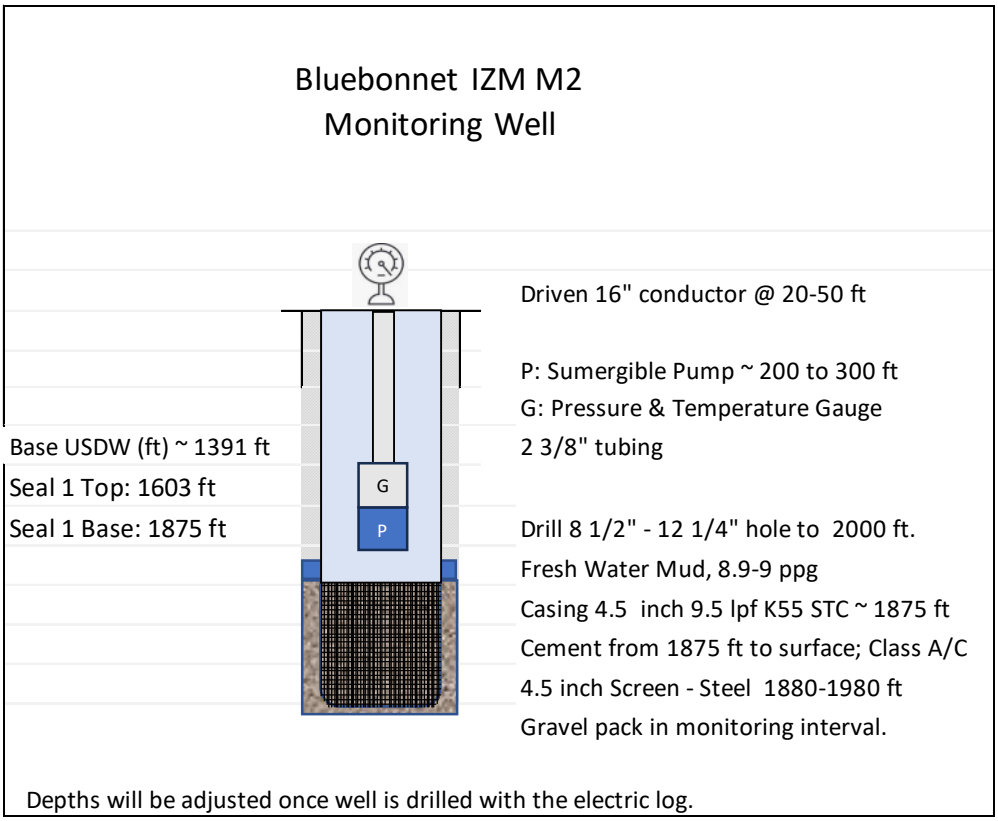


Figure TM-7: Well design and schematic for Bluebonnet IZM M2.

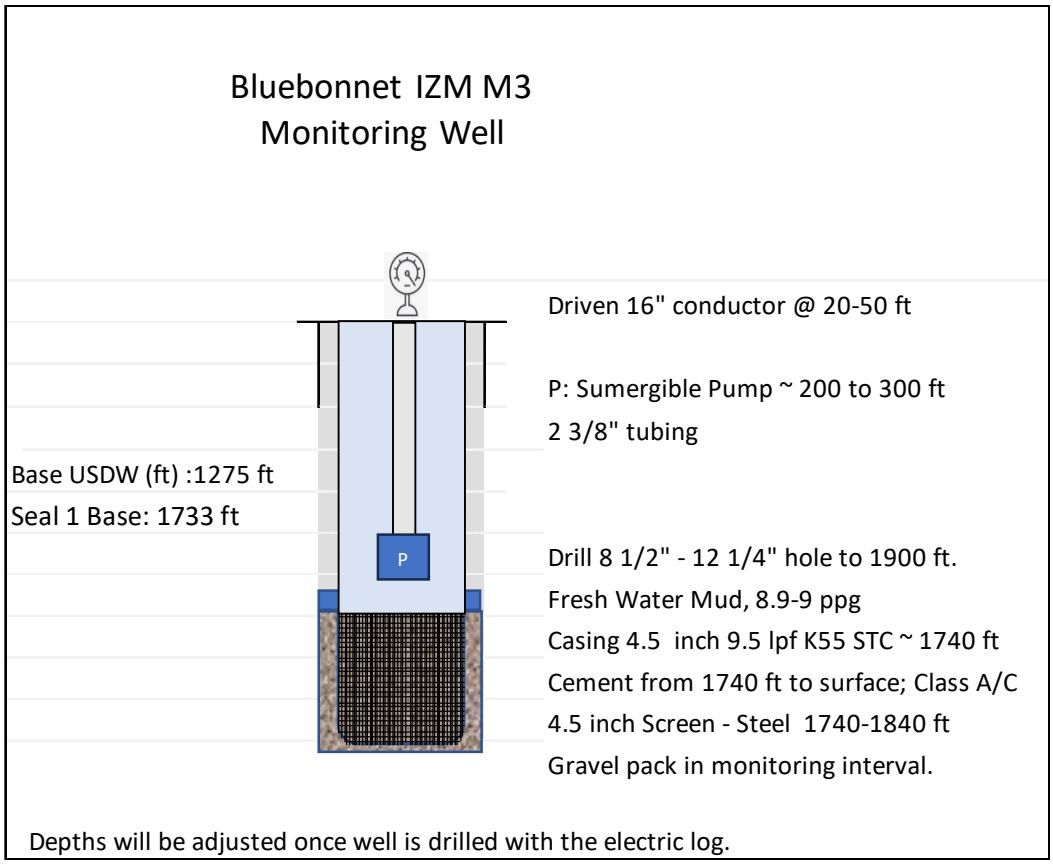


Figure TM-8: Well design and schematic for Bluebonnet IZM M3.

3.4 ACZ/USDW Monitoring Wells

The project team drilled the Bluebonnet USDW 1 well in 2024 with the objective of characterizing the shallow aquifers and validating the base of the USDW. The well was drilled to 1,630 ft. Electric logs were run and water samples were collected to be used in the delineation of the AoR. The lower section of the well was abandoned from 1,420 ft to 1,630 ft with a cement plug and the well was completed in the sand below the base of USDW.

In 2025, the project team undertook the drilling of the Bluebonnet USDW 8 at the same location as the Encanto 01 well, with the primary objective of obtaining cores from the intershales situated within the Miocene Composite Confining Zone. The team successfully acquired 79 feet of whole cores and 35 sidewall cores. The well was drilled to a depth of 2,750 feet and subsequently plugged back to 1,050 feet.

In addition to Bluebonnet USDW 1 and Bluebonnet USDW 8, the project team plans to construct one additional USDW monitoring well, Bluebonnet USDW 2, to closely monitor the USDW by acquiring water samples and monitoring real time pressure and temperature. Bluebonnet USDW 2 will be drilled to the base of the USDW and completed in the lowest-most sand. The wells USDW monitoring wells will be equipped with pressure and temperature sensors at the surface and downhole.

Figure TM-9 to Figure TM-11 show the as build and proposed construction for the USDW monitoring wells.

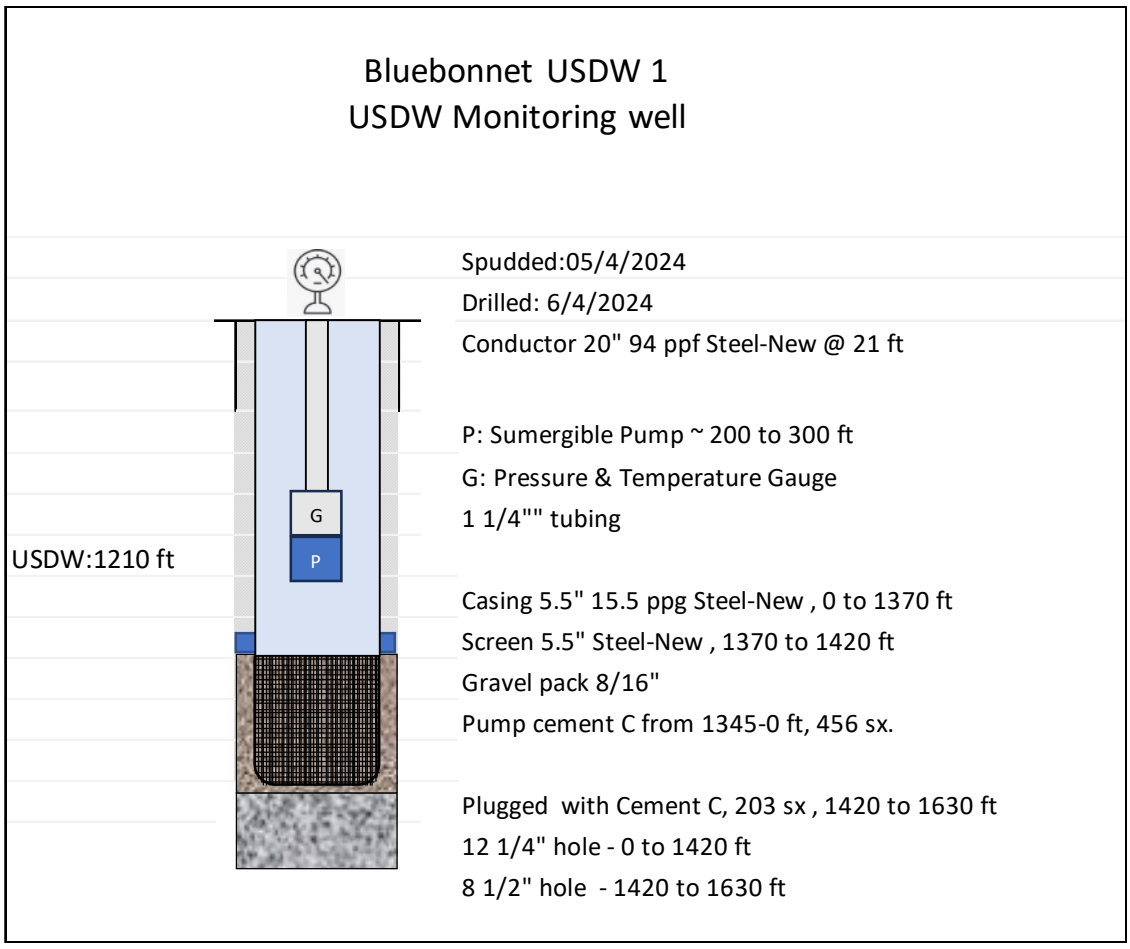


Figure TM-9: Well design and schematic for Bluebonnet USDW 1.

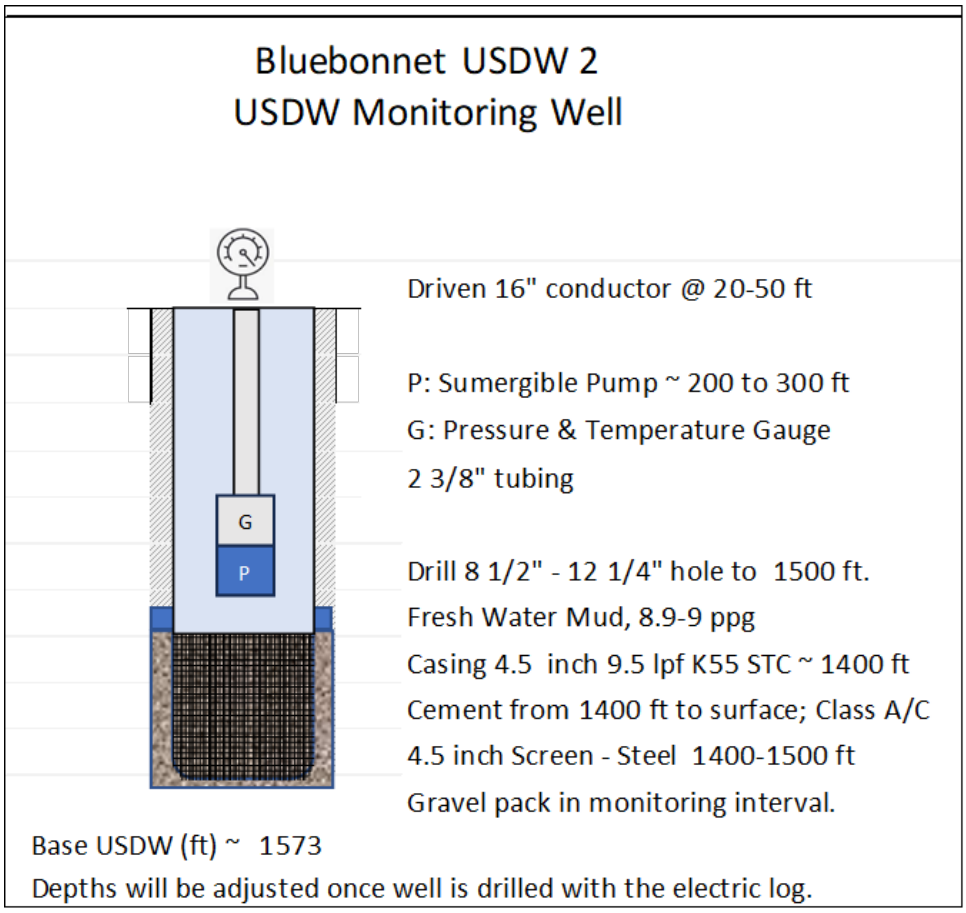


Figure TM-10: Well design and schematic for Bluebonnet USDW 2.

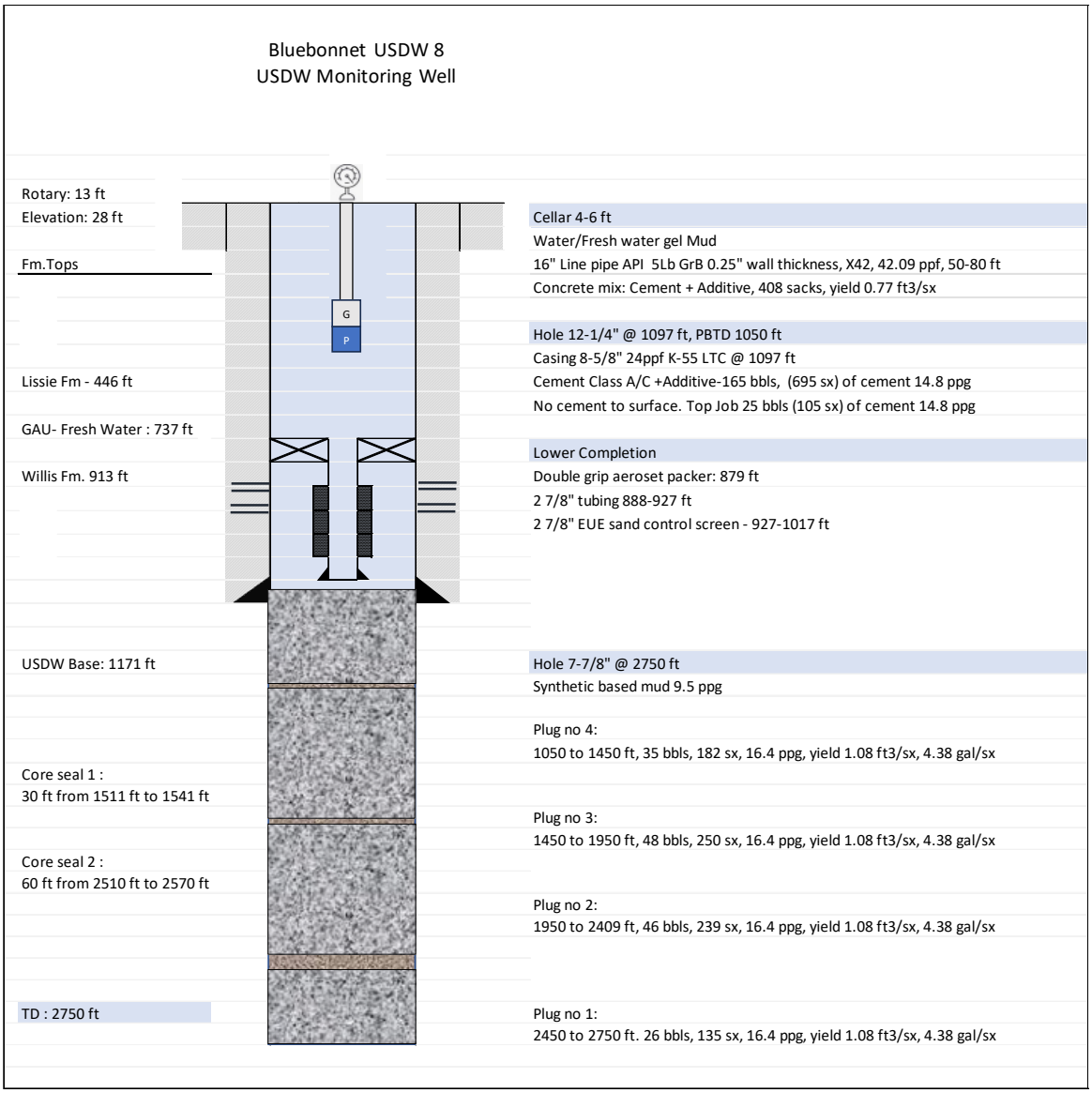


Figure TM-11: Well design and schematic for Bluebonnet USDW 8.

4.0 Operational Testing and Monitoring During Injection

4.1 CO_2 Stream Analysis

Pursuant to 40 CFR 146.90(a), during the operation period, Bluebonnet Sequestration Hub, LLC, will analyze the CO_2 stream for its chemical and physical characteristics.

4.1.1 Sampling Location and Frequency

The CO_2 stream sampling will occur quarterly during operation either upstream or downstream of the custody transfer flowmeter that measures the flow rate of the injectant at the site. Multiple samples will be acquired during the startup period of the project (first injection) to validate that the CO_2 stream complies with the required minimum specifications. After the startup period, a sample will be taken 3 months after the start of injection, at 6 months, at 9 months, and at 12 months, as a minimum frequency, continuing every quarter. The sampling period could be increased and slightly shifted in timing, depending on the operations.

The project has developed a minimum standard CO_2 specification, as shown in Table TM-4, to be enforced with the emitters and distribution channels that control the quality of the CO_2 injected at the site. The project will install a gas analyzer at the custody transfer meter located in the sequestration site to monitor CO_2 quality continuously before it is distributed to each well in the site, to detect any major deviation from the contractual specifications. The project could require additional components to be limited and analyzed based on final contractual terms with the emitters.

Table TM-4: CO_2 Stream specifications.



The CO_2 composition will be monitored continuously at each receipt point into the pipeline network along with at the delivery point to the sequestration site. In addition, samples will be collected and analyzed periodically at each receipt point and delivery point.

If the inline analyzers or sample results indicate a deviation from the CO_2 specification, the sampling frequency for the relevant receipt point(s) will be increased until the sampling results return to normal for a specified period.

If the CO_2 delivered to a receipt point does not meet the CO_2 specification, the project team will notify the CO_2 source facility and either shut in the source facility or increase the sample frequency, depending on the risk associated with the out-of-specification component.

If a CO_2 source facility is shut in, offtake will only resume from that facility once it has demonstrated the resumption of in-specification product for an agreed period between 12 and 48 hours.

4.1.2 Analytical parameters

The Bluebonnet Sequestration Hub, LLC, will analyze the CO_2 for the constituents identified in Table TM-5 as a minimum (but not limited to) requirement.

Table TM-5: CO_2 stream analysis.



The project team may deem it necessary to test additional elements to ensure the CO_2 delivered to the Bluebonnet Hub complies with contractual specifications.

Isotopes will be analyzed during the first year of operation and after any major change of CO_2 source composition to fingerprint the stream.

4.1.3 Sampling Methods

A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed. All sample containers will be labeled with durable labels and indelible markings. A unique identification number and sampling date will be recorded on the sample containers. The sample containers will be sent to the third-party authorized laboratory contracted for testing.

Sampling procedures will follow the third-party authorized laboratory protocols to ensure the sample is representative of the injectant and samples will be processed, packaged, and shipped to the contracted laboratory, following standard sample handling and chain-of-custody guidance. Sampling methods are described in the QASP.

4.1.4 Laboratory to be Used/Chain-of-Custody and Analysis Procedures

The samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Analytic methods and chain-of-custody procedures are described in the QASP.

4.2 Monitoring and Recording of Operating Parameters in CO_2 Injector Wells

The Bluebonnet Sequestration Hub, LLC, will install and use continuous recording devices to monitor injection pressure, rate, and volume, including the pressure on the annulus between the tubing and long string casing and the temperature of the injected stream in the CO_2 injector wells (Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7) as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

The project will record any changes in annular fluid volumes during daily or weekly inspections, as needed. Additionally, the project plans to install a downhole gauge above the packer, ported to the annulus, to track in real time changes of pressure above the packer in the annulus.

Injection operations will be continuously monitored and controlled by the operations staff, using the process control system. The system will continuously monitor, control, record, and set alarms for critical system parameters of pressure, temperature, and flow rate.

The process control system will limit maximum flow according to the operation parameters for each well.

The system will initiate a shutdown if specified control parameters deviate from the intended operating range and will allow for remote shutdown under emergency conditions. Trend analysis will help evaluate the performance (e.g., drift) of the instruments, suggesting the need for maintenance or calibration.

4.2.1 Monitoring Location and Frequency

Real-time monitoring activities will begin during the startup of the wells for first injection. The injection pressure and temperature will be continuously measured at the surface via real-time pressure and temperature (P/T) instruments installed in the CO_2 injection line near the interface with the wellhead. The pressure will be measured by an electronic pressure transducer with analog output mounted on the CO_2 line associated with the injection well. The temperature will be measured by an electronic temperature transducer mounted in the CO_2 line near the pressure transducer, with both transducers mounted near the wellhead.

The flow rate of CO_2 injected into the well will be measured by flowmeter skids with a Coriolis type flowmeter in the CO_2 injection line near the interface with the wellhead. Piping and valving will be configured to permit flowmeter calibration/verification. The flow transmitter will be connected to a remote terminal unit (RTU) on the flowmeter skid.

A P/T gauge will be installed downhole as part of the upper completion and will be ported into the tubing to continuously measure CO_2 injection pressure and temperature at the reservoir. The downhole gauges will be the point of compliance for maintaining injection pressure below 90% of formation fracture pressure and for evaluating the reservoir performance and history-matching the operation with the projection of the model.

If the downhole gauge stops working between scheduled maintenance events, then the surface pressure limit approved for this permit will be used as a backup until the downhole gauge is repaired or replaced. For calibration purposes, in lieu of removing the injection tubing, the accuracy of the downhole gauges will be demonstrated by using a second pressure gauge with current certified calibration lowered into the well at the same depth as the permanent downhole gauge.

Electronic pressure and temperature transducers will be used to continuously monitor the pressure and temperature of the annulus between the tubing and long-string casing at the surface. Gauges and sensors will be connected to the automation system to provide continuous data analysis and alarms for malfunctioning events when the values deviate from the intended operating range.

A minimum of 100 psi differential will be maintained across the packer with the addition of packer fluid volume. Changes in pressure will be noted by the operator in the field and recorded in the project well databases daily. A pressure gauge and temperature sensor will be installed downhole as part of the upper completion and will be ported into the annulus above the packer to continuously measure the pressure in the annular space and identify any potential loss of mechanical integrity. If a major variation of pressure is observed in the annular gauges (surface/downhole), then the field operator will proceed to troubleshoot the well.

A fiber optic cable will be attached along the side of the casing and a distributed temperature sensing (DTS) interrogator will be installed on the surface, which will provide a distributed temperature profile while injecting. This system will continuously record the temperature to assist in monitoring the CO_2 behavior and identifying any unforeseen mechanical integrity issue in the well.

Automated shutoff devices will be installed at each exit of the flowlines in the wellhead and will be connected to the control system. If the operational parameters deviate from the program operational limits, the system will send an alarm to the operators to evaluate and correct the situation, which might include starting the shutdown protocol if the parameter exceeds the maximum operating limits [40 CFR 146.88 (e)(2)]. The Bluebonnet Sequestration Hub, LLC, will perform the activities identified in Table TM-6 to monitor operational parameters. All monitoring will take place at the locations and frequencies shown in the table.

Table TM-6: Monitoring devices, locations, and frequencies for continuous monitoring during injection operations in the CO_2 injector wells.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection Pressure	Pressure Transducer	Flowline close to the wellhead	1 sec	15 sec
Injection Rate	Coriolis Meter	Flowline into the wellhead	1 min	1 hr
Injection Volume	Coriolis Meter	Flowline into the wellhead	15 sec	15 sec
Injection Temperature	Temperature Transducer	Flowline close to the wellhead	1 sec	15 sec
Surface Annular Pressure	Pressure Transducer	Wellhead Injector	1 sec	15 sec
Annulus Volume	Calibrates Surface Tank	Wellhead	Daily	Daily
Downhole Annular Pressure and Temperature	Pressure Gauges, Temperature Sensor	Deployed in tubing ported to annular above packer	15 sec	30 sec
Distributed Temperature Profile	Fiber Optic + DTS Interrogator	Alongside long string	10 min	30 min
Downhole Injection Pressure and Temperature	Pressure Gauges, Temperature Sensor	Deployed in tubing ported to tubing above packer	15 sec	30 sec
Automatic Surface Shutoff Devices	Electric Actuated Valve	Each exit of the flowline in the wellhead	n/a	n/a

4.2.2 Monitoring Devices Description and Technical Specifications

Technical specifications for the tools to use for real-time data acquisition, monitoring, and shut down are described in the QASP.

4.3 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), the Bluebonnet Sequestration Hub, LLC, will monitor well 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.

The Bluebonnet Sequestration Hub, LLC, will monitor corrosion using coupons and collect samples according to the description below. The project team will complement the corrosion coupons with casing inspection logs, visual inspection of the facilities, a robust leak detection and repair program, the use of optical gas imaging cameras (OGI), and the data collected in real time from the fiber optic cable installed in the injector wells.

During well material selection, the Bluebonnet Sequestration Hub, LLC, simulated the chemical reactions of the selected material, formation waters, and proposed CO_2 stream at downhole conditions. The project team proceeded to test the selected metallurgy to the maximum limits of the specification and operating parameters to validate the correct selection for downhole materials that will be exposed to the injection stream and formation waters.

4.3.1 Monitoring Location and Frequency

Table TM-7: Monitoring location and frequency of corrosion coupon testing.

Tool	Location	Pre-Injection	Injection
Corrosion coupons	Flowline CO_2 stream	n/a	Quarterly

4.3.2 Corrosion Coupon Analysis Description

Samples of selected materials in the wells and facilities (coupons) will be exposed to the injected CO_2 stream and monitored for signs of corrosion to verify that the selected materials meet the minimum standards for material strength and performance and to identify well maintenance needs.

Coupons shall be collected and sent quarterly to a third-party company for analysis, conducted in accordance with NACE Standard SP-0775-2018-SC, to determine and document corrosion wear rates based on mass loss. The project will begin corrosion coupon monitoring after the start of injection and will continue quarterly until the end of injection period.

Table TM-8: Summary of methods to evaluate corrosion coupons.

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

NACE SP0775-2018-SC: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations

Table TM-9: List of equipment with materials of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Long String Casing – CO_2 Injector Well (above injection zone)	Carbon Steel L80
Long String Casing – CO_2 Injector Well (injection zone)	CRA 2507 min 80 ksi
Tubing (Internally Coated) – CO_2 Injector Well	Carbon Steel L80
Wellhead – CO_2 Injector Well (no CO_2 wetted areas)	Carbon Steel DD specification
Injection Tree and Tubing Hanger – CO_2 Injector Well	Sour Service - HH specifications
Packers – CO_2 Injector Well & In-Zone Monitoring Wells	Nickel-Plated
Long String Casing –-Confining Zone/USDW Monitoring Wells	Carbon Steel L80
Long String Casing –In Zone Monitoring Wells (above injection zones)	Carbon Steel L80
Long String Casing –In Zone Monitoring Wells (Injection zones) . With the exception of Encanto 01	CRA 2507 min 80 ksi
Tubing – In-Zone Monitoring Wells	Carbon Steel L80
Wellhead and Tree – In-Zone Monitoring Wells	Carbon Steel DD specification

4.4 Visual Inspection and Leak Detection and Repair (LDAR) Program using Optical Gas Imaging Camera (OGI)

The project will perform visual inspection of the facilities and wells as part of the maintenance and mechanical integrity program, as summarized in Table TM-10. Inspection will start from the commissioning date and will continue weekly after the site is injecting steadily. Leak detection and repair (LDAR) field inspections will be performed quarterly after the start of injection and continue until injection ceases, using optical gas imaging (OGI) cameras.

During visual inspections, the field operator will be provided with handheld devices to measure explosive gases, H_2S, and CO_2 as part of the safety requirements of the site.

Table TM-10: Monitoring locations and frequency of visual inspections and LDAR program.

Tool	Location	Pre-Injection	Injection
Leak detection and repair (LDAR) program using optical gas imaging cameras, handheld during inspections	Surface facilities and wellheads	n/a	Quarterly
Visual inspections and handheld monitors (LEL, $H2_S$, CO_2)	Surface facilities and wellheads	Before start of injection	Weekly

Notes:

1. Multiple inspections using OGI cameras will be performed during the startup of the well (first injection) after authorization to inject is received and will continue quarterly as minimum frequency during the injection period.

4.5 Pressure Falloff Testing in CO_2 Injector Wells

The Bluebonnet Sequestration Hub, LLC, will perform pressure falloff tests in the CO_2 injection wells during the injection phase as described below to meet the requirements of 40 §CFR 146.90(f).

4.5.1 Testing Location and Frequency

Pressure falloff testing will be conducted upon completion of the injection well to characterize reservoir hydrogeologic properties, aquifer response model characteristics, and changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior.

Pressure falloff testing will be conducted in the CO_2 injection wells at least once every five years during injection for the AoR until the wells are plugged. The objective of the periodic pressure falloff testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect the well or reservoir performance.

4.5.2 Testing Details

Detailed procedure and analytics proposed for the falloff test are described in the QASP.

4.6 Tracking and Recording Pressure and Temperature in In-Zone Monitoring Wells

The Bluebonnet Sequestration Hub, LLC, will continuously measure pressure and temperature in the in-zone monitoring wells at the surface via real-time P/T instruments installed in the wellhead. Table TM-11 summarizes the monitoring locations of P/T gauges and frequency of testing.

A pressure and temperature (P/T) gauge will be installed downhole as part of the upper completion and will be ported into the tubing to continuously measure pressure and temperature in the reservoir. These measurements will allow the project team to calibrate and verify the model, improve predictive capability for confirming CO_2 containment, and evaluate the development of the pressure front.

Since the changes in reservoir pressure precede the movement of the CO_2 plume, in-zone monitoring wells will provide data to history-match the model and calibrate the response expected from the reservoir regarding the development of pressure front and CO_2 plume migration.

Table TM-11: Monitoring locations and frequency of pressure and temperature measurement in in-zone monitoring wells.

Tool	Location	Pre-Injection	Injection	Min. Sampling Frequency	Min. Recording Frequency
Surface P/T transducers	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	n/a	Continuously	1 sec	15 sec
Downhole P/T gauges	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	n/a	Continuously	15 sec	30 min

In the event the downhole sensor fails before a planned well maintenance operation, the project will continue monitoring the pressure with the surface transducers and might implement measurement of fluid levels in the well to calculate the bottomhole pressure while the equipment is replaced and repaired. The project team might install temporary pressure gauges in the well and limit the collection of data to one sample per day.

4.7 Tracking and Recording Pressure and Temperature in Miocene Composite Confining Zone monitoring wells.

The project team plans to install P/T sensors in the Miocene Composite Confining Zone monitoring wells, Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3. These sensors and gauges will be included as part of the upper completion.

In the event the downhole sensor fails before a planned well maintenance operation, the project team will continue monitoring the pressure with the surface transducers and might implement measurement of fluid levels in the well to calculate the bottomhole pressure while the equipment is replaced and repaired.

Table TM-12 summarizes the monitoring locations and frequency of pressure and temperature tracking on the Miocene Composite Confining Zone monitoring wells.

Table TM-12: Monitoring locations and frequency of pressure and temperature measurements in Miocene Composite Confining Zone monitoring wells.

Tool	Location	Pre-Injection	Injection	Min. Sampling Frequency	Min. Recording Frequency
Surface Pressure and Temperature Transducers	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	n/a	Continuously	1 sec	15 sec
Downhole P/T Gauges	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	n/a	Continuously	15 sec	30 min

4.8 Tracking and Recording Pressure in ACZ/USDW Monitoring Wells

The Bluebonnet Sequestration Hub, LLC, will continuously measure pressure and temperature in the USDW monitoring wells at the surface via real-time P/T instruments installed in the wellhead.

The project team plans to install P/T gauges in the upper completion of the USDW monitoring wells to track changes in the downhole conditions.

4.8.1 Monitoring Location and Frequency

Table TM-13: Monitoring locations and frequency of pressure and temperature measurement for USDW monitoring wells.

Tool	Location	Pre-Injection	Injection	Min. Sampling Frequency	Min. Recording Frequency
Surface P/T transducers	Bluebonnet USDW 1 Bluebonnet USDW 2 Bluebonnet USDW 8	n/a	Continuously	1 sec	15 sec
Downhole P/T gauges	Bluebonnet USDW 1 Bluebonnet USDW 2 Bluebonnet USDW 8	n/a	Continuously	15 sec	30 min

5.0 Mechanical Integrity Testing

5.1 External Mechanical Integrity Testing

The Bluebonnet Sequestration Hub, LLC, will perform a cement logging evaluation with one or more of the following tools to validate zonal isolation between the injection zones, confining and dissipation zones, and overburden formations after installation of the long string casing during construction of the CO_2 injector and in-zone monitoring wells [40 CFR 146.87 (a)(2)(ii) 40 CFR 146.87 (a)(3)(ii)]:

a) Cement bond logging
a) Ultrasonic cement evaluation tool
a) Variable density log (VDL)

The project team will run a pulse neutron log (PNL) in the CO_2 injection wells after initial installation of the completion equipment, and at least once a year to evaluate external mechanical integrity (40 CFR 146.89(c) and 40 CFR 146.90(e)).

The project team will install a fiber optic cable alongside the long-string casing in the CO_2 injection wells with the capability of continuously monitoring temperature changes from the top of the perforations to the surface, exceeding the requirements in 40 CFR 146.89(e) and 40 CFR 146.90(e).

Additionally, during well maintenance operations or workovers for the CO_2 injection well, an ultrasonic casing inspection tool will be run to evaluate casing thickness and conditions.

The project team will run a PNL in the in-zone monitoring wells after initial installation of the completion equipment to set the baseline for mechanical integrity evaluation as well as for CO_2 plume tracking in the reservoir if required.

The project team will also install a fiber optic cable alongside the casing in the in-zone monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2, and the Miocene Composite Confining Zone monitoring well Bluebonnet IZM M1, that will allow tracking of mechanical integrity in real time as well as changes in reservoir and overburden conditions.

If a fiber optic cable fails in any of the in-zone monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2, or Bluebonnet IZM M1 the project team will run one of the following tools at least every five years or during well maintenance operations or workovers to evaluate external mechanical integrity:

a) Pulse neutron through tubing
b) Electromagnetic casing inspection log
c) Temperature log

For Encanto 01 stratigraphic well which does not have fiber optic cable installed on the long string, the project team will run one of the following tools at least every five years or during planned well maintenance or workover activities to demonstrate external mechanical integrity:

a) Pulse neutron through tubing
b) Electromagnetic casing inspection log
c) Temperature log

5.1.1 Testing Location and Frequency

Table TM-14 below provides a summary of the external mechanical integrity tools.

Table TM-14: Corrosion monitoring and surface leak detection tools.

Tool	Location	Pre-Injection	Injection
USIT, CBL, VDL	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1	After long-string installation before completion	If required by future operations.
Pulse Neutron	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	After completion installation or before injection to set baseline.	Once a year.
Pulse neutron, temperature log, or electromagnetic log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01 Bluebonnet IZM M1	After completion installation or before injection to set baseline.	Every 5 years or during planned maintenance or workover activities. Event triggered by other monitoring results.
DTS survey	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	Before injection as baseline	Continuously
DTS survey	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1	Before injection as baseline	Continuously

5.1.2 Testing Details

The logging industry has made impressive advancements in tools that provide images of and data identifying the quality of the cement bond behind the casing after cementing jobs are complete. The casing inspection tool and multi-finger calipers can provide information about ovality, collapse, and/or damage in the casing, as well as estimations of wall thickness to evaluate wearing and corrosion effects.

The most advanced tools can evaluate up to five concentric tubulars to measure changes in thickness that could be related to corrosion or wearing effects.

The tools described below are readily available technologies on the market and the basis of the project's master monitoring program for mechanical integrity. No specific provider has been selected. In the future, new technologies or tools may be proposed for further discussion with regulators.

5.1.2.1 Cement Bond Log and Variable Density Log

Cement bond log (CBL) is a basic method to evaluate cement quality in the annulus. It is an acoustic wave measurement. The tool usually includes a transmitter and receiver, separated by 3 ft. The acoustic wave is emitted by the transmitter, propagated down and across the annulus, and recorded by the receiver. The attenuation of the wave is analyzed to interpret the bonding behind the pipe. Signal coming from a properly cemented casing will be more attenuated than the signal coming from a poorly cemented one.

The arriving signal recorded by the receiver is a mixed signal coming from casing, cement, mud, and formations. Each signal has its own pathway because they travel at different velocities through each medium. The signal through the casing is the fastest, as sound travels the quickest through steel. As a result, it is the first signal detected on the receiver. The second signal most likely to arrive is the signal through the formation and last one is the drilling fluid signal because sound travels slower in a liquid.

Variable density log (VDL) is commonly used as an adjunct to the cement bond log and offers better insights with its interpretation. In most cases, micro annulus and fast-formation-arrival effects can be identified using this additional display.

Figure TM-12 and Figure TM-13 show examples of CBL and VDL output.

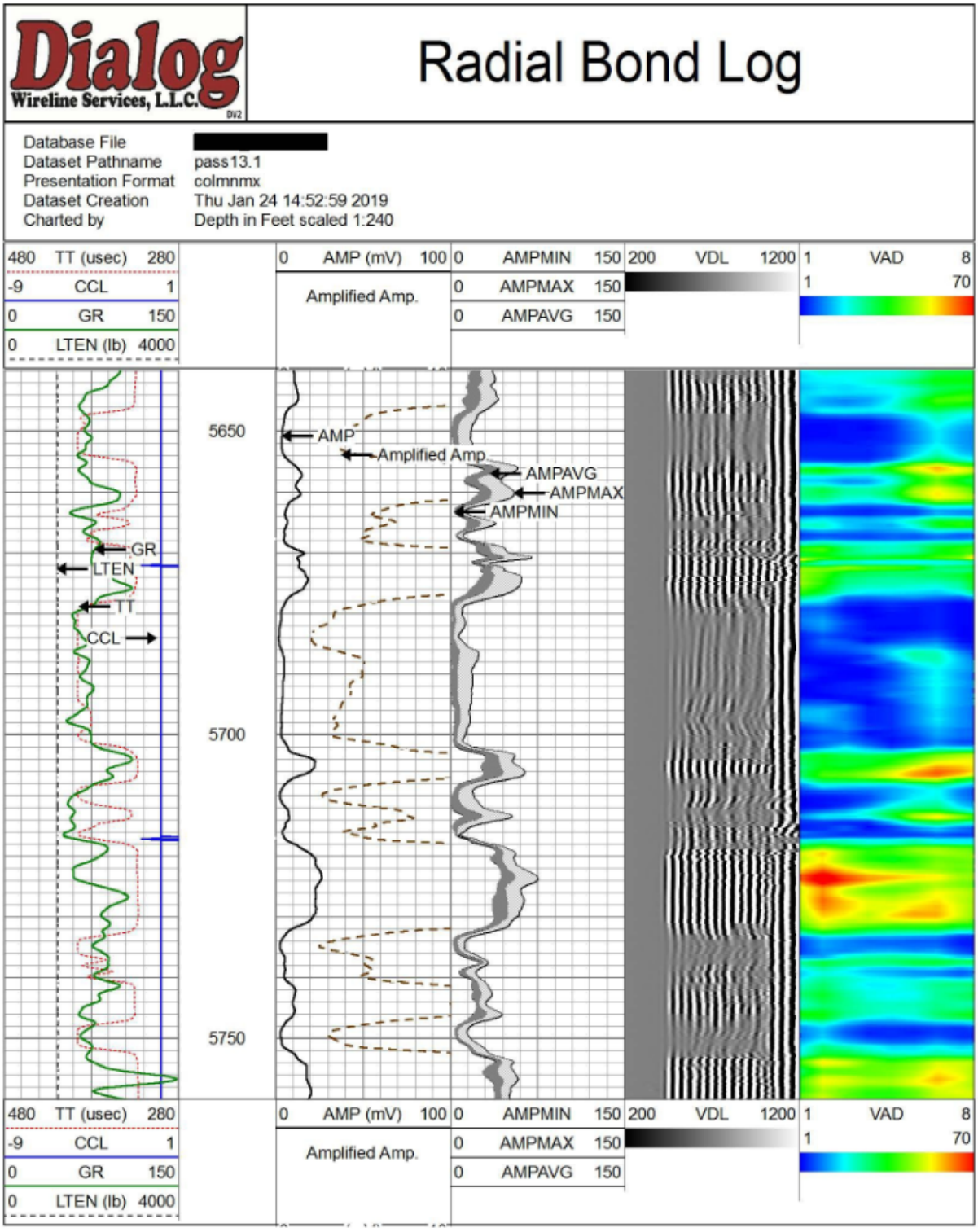


Figure TM-12: CBL and VDL example from dialog wireline services web page.

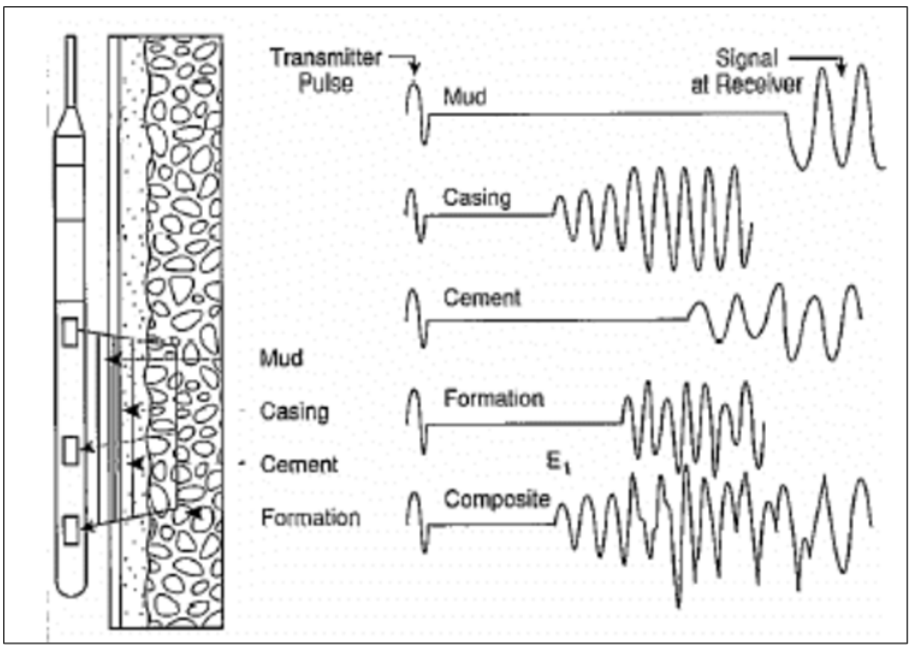


Figure TM-13: Signal received by CBL-VDL.

5.1.2.2 Ultrasonic Cement and Casing Evaluation Tools

USIT (SLB technology) is an example of an ultrasonic imager that delivers an accurate, comprehensive, and high-resolution confirmation of the pipe-to-cement bond quality and downhole pipe condition in real time. Casing inspection and monitoring applications include corrosion detection, identification of internal and external damage or deformation, and casing thickness analysis for collapse and burst pressure calculations.

The rate of decay of the waveforms received indicates the quality of the cement bond at the cement-casing interface and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. The resulting 360° data coverage enables evaluation of the quality of the cement bond and determination of both the internal and external condition of the casing.

Isolation Scanner™ (SLB Technology) is a combination of independent measurements that fully characterizes the annular environment, differentiating low-density solids from liquids to distinguish lightweight and contaminated cements from liquids. Its azimuthal coverage provides results around the entire circumference of the casing, pinpointing any channels in the cement and confirming the effectiveness of the annular barrier for zonal isolation.

The Isolation Scanner™ tool also identifies corrosion or drilling-induced wear through measurement of the inside diameter and thickness of the casing. The flexural wave measurement produces entirely new information from the third-interface echoes (TIEs) between the annulus and borehole or outer casing. The TIEs image the borehole shape, define the position of the casing within the borehole or outer casing, and image the outer string to reveal corrosion and damage.

5.1.2.3 Distributed Temperature Sensing

Distributed temperature sensing (DTS) technology uses fiber optic sensor cables, typically several kilometers in length, that function as linear temperature sensors. The result is a continuous temperature profile along the entire length of the sensor cable. DTS uses the Raman effect to measure temperature. An optical laser pulse sent through the fiber results in some scattered light reflecting to the transmitting end, where the information is analyzed. The intensity of the Raman scattering is a measure of the temperature along the fiber. The Raman anti-Stokes signal changes its amplitude significantly with changing temperature, while the Raman Stokes signal is relatively stable. The position of the temperature reading is determined by measuring the arrival timing of the returning light pulse like a radar echo.

The fiber optic cable is run alongside the casing as an umbilical and is protected with clamps and centralizers to avoid any damage while deploying it into the well. The fiber is connected on the surface to an interrogator that converts the signal to temperature values and transmits the data to the monitoring platform in real time for surveillance purposes.

The equipment maintenance and calibration will be performed according to the manufacturer's manuals and will be the technology provider's responsibility. Technical specifications are available in the QASP.

5.1.2.4 Electromagnetic Casing Inspection Tool

Electromagnetic Pipe Xaminer® V (EPX™ V) (Halliburton technology) is an example of a proprietary electromagnetic tool. The operating principle of the tool is to induce a high-definition frequency (HDF) electromagnetic energy into the surrounding pipe, which propagates through the concentric well strings with no wellbore fluid influences. The interaction with the metal of the pipe returns a signal to the tool, yielding information on the metal loss present in the tubulars. The magnitude and location of corrosion-induced defects are identified using HDF variance algorithms of the returning electromagnetic waves. This information leads to a quick total thickness calculation determining the overall condition of the pipe structure. This technology enables examination of the whole well in one trip, for up to five concentric strings of pipe.

5.1.2.5 Temperature Log

Temperature logs are used to locate gas entries, detect casing leaks, and evaluate fluid movement behind casing. They are also used to detect lost-circulation zones and cement placement. Temperature logs are used as a basic diagnostic tool and are usually paired with other tools like acoustics or multi-arms calipers, if more in-depth analysis is required.

Temperature instruments used today are based on elements with resistances that vary with temperature. The variable resistance element is connected to bridge circuitry or a constant current circuit, so that a voltage response is proportional to temperature. The voltage signal from the temperature device is then usually converted to a frequency signal that is transmitted to the surface, where it is converted back to a voltage signal and recorded. The absolute accuracy of temperature logging instruments is not high (in the order of +- 5°F), but the resolution is good (0.05°F or better) although this accuracy can be compromised by present day digitalization of the signal on the

surface. The temperature instrument can usually be included in the string with other tools, such as radioactive tracer tools or spinners flowmeters. Temperature logs are run continuously, typically at cable speeds of 20 to 30 ft/min. (A. Daniel Hill 2021).

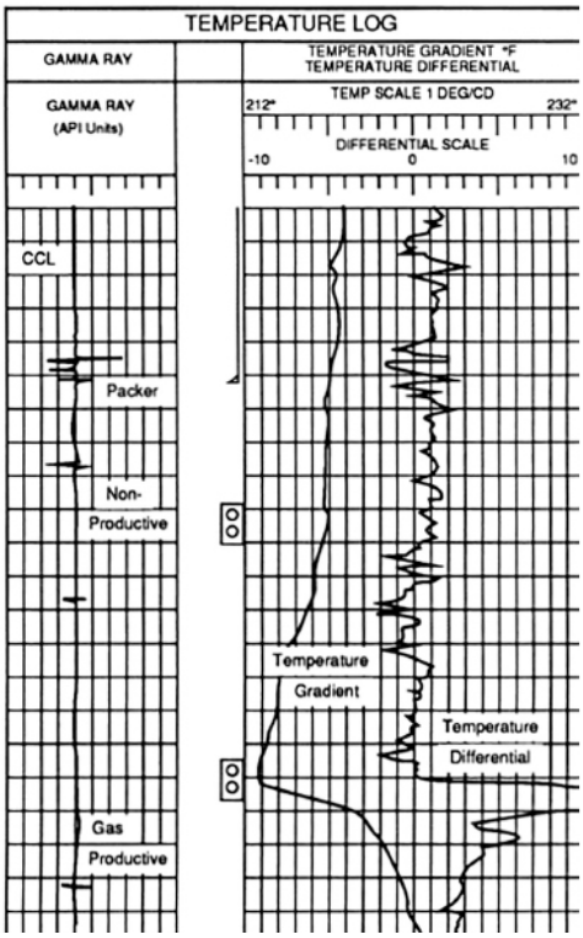


Figure TM-14: Example of temperature log output.

5.1.2.6 Pulse Neutron Log

Pulse neutron log (PNL) provides formation evaluation and reservoir monitoring in cased holes. The PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays. High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements. Each logging company has its own proprietary designs and improvements on the tool.

SLB's Pulsar multifunction spectroscopy service (PNX) pairs multiple detectors with a high-output pulsed neutron generator in a slim tool with an outer diameter (OD) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The tool's integration of the high neutron output and fast

detection of gamma rays, with proprietary pulse processing electronics, allows differentiation and quantification of gas-filled porosity from liquid-filled and tight zones. The tool can accurately determine saturation in any salinity of formation water, across a wide range of well conditions, mineralogy, lithology, and fluid contents profile at any inclination. Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity. Detailed measurement and mechanical specifications for the PNX tool are provided in the QASP document. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Halliburton's Reservoir Monitor Tool 3-Detector™ (RMT-3D) is a pulsed-neutron tool that solves for water, oil, and gas saturations within reservoirs using three independent measurements (Sigma, C/O, and SATG). This provides the ability to uniquely solve simple or complex saturation profiles in reservoirs, while eliminating phase-saturation interdependency. The RMT-3D provides gas phase analysis to identify natural gases, nitrogen, CO_2, steam, and air. The tool has 2.125 in. OD that allows it to be run through tubing.

5.1.3 Description and Technical Specifications of the Tools for External Mechanical Integrity Evaluation

Detailed information and technical references of these tools are provided in the QASP.

5.2 Internal Mechanical Integrity Testing

The Bluebonnet Sequestration Hub, LLC, will perform an annular pressure test in the CO_2 injection wells and in the in-zone monitoring wells to demonstrate internal mechanical integrity, according to 40 CFR 146.89(b).

Annular pressure testing is used to validate mechanical integrity. Tests will be performed according to the frequency presented in Table TM-15.

Table TM-15: Annular pressure testing frequency.

Tool	Location	Pre-Injection	Injection
Annular Pressure Test	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	After long-string installation before completion	After every well maintenance operation
Annular Pressure Test	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01 Bluebonnet IZM M1	After long-string installation before completion	Annually

If the additional monitoring systems indicate a potential mechanical integrity issue, the Bluebonnet Sequestration Hub, LLC, will perform troubleshooting and perform an annular pressure test as part of the protocol, if needed.

An example overview of the procedure is as follows (actual procedures may vary based upon operating conditions at the well and other safety or technical considerations):

1. First, shut in the well to stabilize the pressures in the injectors and validate static conditions in the monitoring wells.

2. Connect the testing equipment to the annular valves and test surface lines to 1,500 psi above the testing pressure.

3. Verify that there are no surface leaks from the pumping unit to the wellhead valve. Bleed off any air in the system. If needed, fill the annular space with packer fluid and corrosion inhibitor (if needed, it should require only a minimal amount). Record the initial tubing and casing pressure.

4. Test the well to 1,000 psi in the annular space for the CO_2 injection wells and 500 psi in the annular for in-zone monitoring wells. The pressure should not decrease more than 10% in 30 minutes.

5. Continuously monitor the tubing and casing pressures. Record the final tubing and casing pressure. If the pressure decreases more than 10%, bleed the pressure completely, test the surface connection, and repeat the test.

6. If there is an indication of mechanical failure, the operator will prepare a plan to repair the well and discuss it with the Director.

7. Document and store the test results in the centralized database of the project for reporting and documentation.

Note: Surface gauges should be calibrated according to manufacturer recommendations. There should be a pressure range that will allow the test pressure to be near the gauge's mid-range. Additionally, the gauge must be of sufficient accuracy and scale to allow an accurate reading of 5% change to be read.

6.0 Groundwater Quality and Geochemical Monitoring

The Bluebonnet Sequestration Hub, LLC, will monitor water quality and geochemical changes within the Miocene Composite Confining Zone and in the base of the USDW during the operation period to meet the requirements of 40 CFR 146.90(d).

The monitoring locations were selected based on the original screening of the AoR for existing legacy wells, results of the numerical simulation for CO_2 plume and pressure front, and risk assessment performed by the project. The location, techniques, and frequency were optimized, taking into consideration the complementary techniques proposed in this monitoring plan for direct and indirect measurements, such as 2D seismic surveys, 3D time lapse VSP, pulse-activated neutron logs, soil gas analysis, and others that are explained in additional sections of this document.

The Bluebonnet Sequestration Hub, LLC, selected 23 potential legacy shallow water wells distributed around the AoR to sample and test the freshwater aquifer in the area. These wells targeted the Chicot Aquifer to provide water for domestic, public, stock, and irrigation uses. Some of these wells could be replaced or eliminated after the project performs a mechanical integrity assessment on the wells.

Additionally, the project team drilled Bluebonnet USDW 1 in May 2024 and Bluebonnet USDW 8 in May 2025 to characterize the different zones between surface and base of the USDW. The Bluebonnet USDW 1 well was completed in the first permeable zone below the base of the USDW and will serve to monitor geochemical and pressure changes in the sands underlying the base of USDW while Bluebonnet USDW 8 was complete on the sand above the base of USDW.

The project team plans to drill one additional USDW monitoring well, Bluebonnet USDW 2, that will be completed in the base of the USDW to track pressure and temperature changes as well as geochemical changes in the aquifers across the AoR. Figure TM-2 shows the proposed well network for USDW and confining zone monitoring wells.

6.1 Freshwater Shallow Aquifer Water Sampling and Testing

Groundwater production for drinking and municipal use in Chambers, Liberty, and Jefferson Counties, Texas, is primarily sourced from shallow wells completed in the Chicot Aquifer. Therefore, proposed locations for sampling and testing the shallow freshwater (< 1,000 mg/l TDS) aquifer utilize existing wells completed in the Chicot Aquifer (Table TM-16).

Candidate wells for sampling and testing were meticulously selected to encompass a broad area within and surrounding the defined Area of Review (AoR). These candidate wells were evaluated using publicly available data, considering factors such as installation age, usage, depth, and their relative location to the AoR and other monitoring wells. In August 2025, field evaluations were conducted for each proposed candidate well to assess their mechanical integrity and accessibility. It was noted that some of the wells proposed in the previous submission were either inactive, defective, or misreported. Consequently, the list of legacy wells has been updated and is now presented in Table TM-16.

Shallow freshwater aquifer sampling and characterization is planned to commence a minimum of one year prior to the start of injection (Table TM-17). Detailed analytical suite for water samples is shown in Table TM-20, which includes characterization of physical and chemical compositions as well as analysis of dissolved gases and major isotope systems.

6.1.1 Monitoring Location and Frequency

Table TM-16 shows the proposed locations for sampling the freshwater shallow aquifer and Table TM-17 shows the frequencies proposed (40 CFR §146.90(d)(1) and 40 CFR §146.90 (d)(2)).

Table TM-16: Location of the freshwater shallow water wells selected for sampling in the AoR.

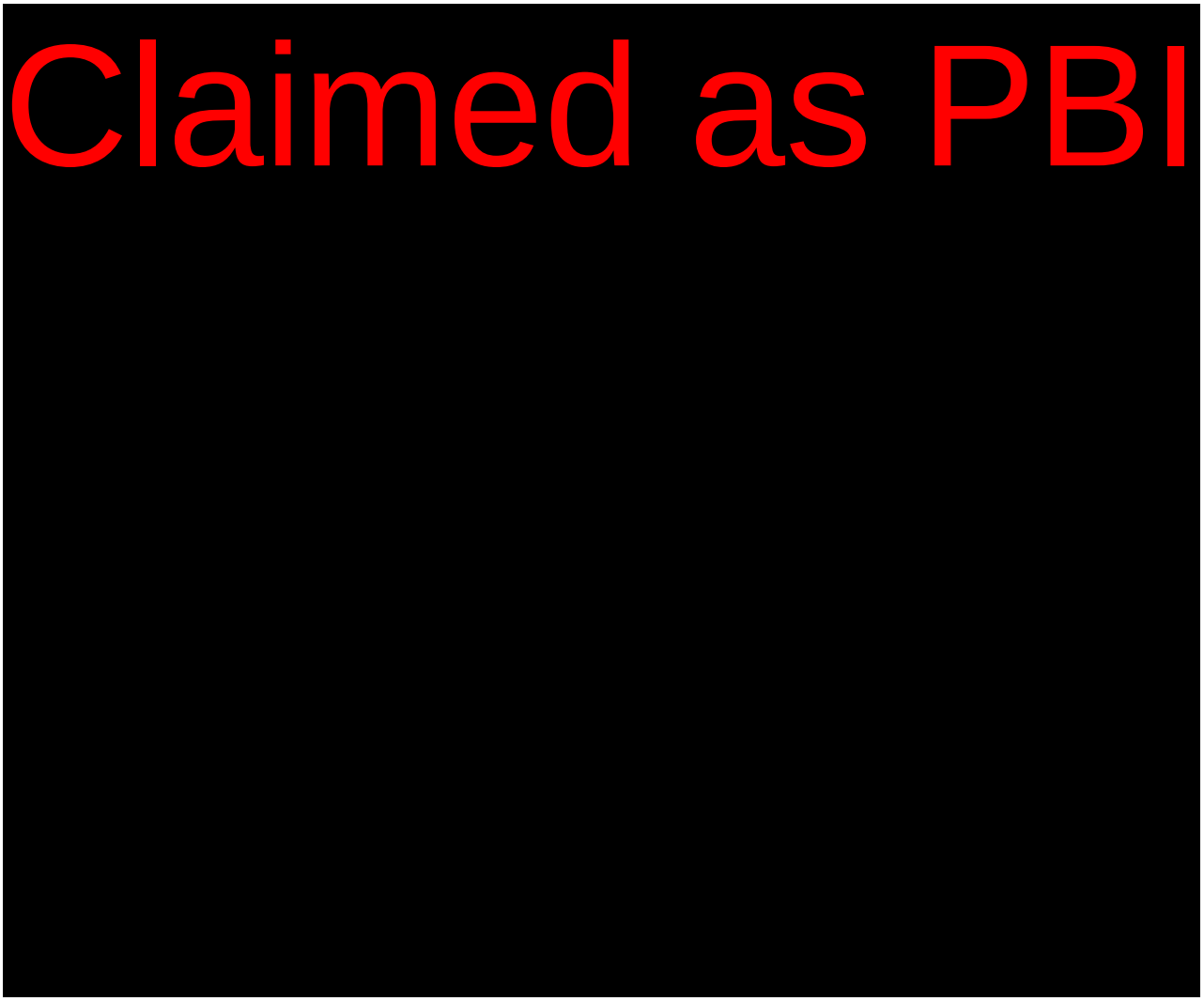


Table TM-17: Sampling frequency for existing shallow freshwater wells (40 CFR §146.90(d)(1) and 40 CFR §146.90(d)(2)).

Monitoring Location(s)	Monitoring Activity	Target Formation	Pre-Injection	Injection Period
10-23 shallow water wells distributed in the AoR.	Fresh water sampling and analysis.	Upper Chicot Aquifer	1 year before injection, 4 samples a year, 1 sample every quarter.	The first samples are 3 months after start of injection and quarterly after that for years 1 and 2.

6.2 Miocene Composite Confining Zone and ACZ/USDW Wells Water Sampling and Testing

Recent field investigations conducted onsite supported publicly available data that showed base USDW (<10,000 mg/l TDS) is in the lower Chicot Aquifer, at depths ranging from 1,100 to

1,700 ft MD within the AoR. Bluebonnet USDW 01 and Bluebonnet USDW 8 were recently drilled and completed, and one additional USDW monitoring well is planned. Bluebonnet plans to drilled three well to collect sample within the Miocene Composite Confining Zone, Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3.The detailed analytical suite is shown in Table TM-20 and is identical to the analytical suite used for the existing shallow freshwater wells.

Table TM-18: Planned and drilled Miocene Composite Confining Zone and USDW wells for water sampling and testing.

Well Name	Latitude	Longitude	Elevation (ft)	Status	Target monitoring Depth TVD (ft)	Target Formation
Bluebonnet USDW 1	Claimed as PBI			Drilled 2024	1,370-1,420	Lower Chicot
Bluebonnet USDW 2				To be Drilled	1,400-1,500	Lower Chicot
Bluebonnet USDW 8				Drilled 2025	927-1,017	Lower Chicot
Bluebonnet IZM M1				To be Drilled	2,700-2,800	Upper Miocene
Bluebonnet IZM M2				To be Drilled	1,880-1,980	Upper Miocene
Bluebonnet IZM M3				To be Drilled	1,740-1,840	Upper Miocene

Table TM-19: Location and frequency of the water sampling and testing in the USDW wells.

Monitoring Location(s)	Monitoring Activity	Target Formation	Pre-Injection	Injection Period
Bluebonnet USDW 1 Bluebonnet USDW 8	Water Sampling	Lower Chicot	Baseline. Quarterly min 1 year before injection.	Quarterly first 2 years of injection. Semi-annually from year 3 to end of injection.
Bluebonnet USDW 2	Water Sampling	Lower Chicot	Baseline. Data acquired during installation of the wells.	Quarterly first 2 years of injection. Semi-annually from year 3 to end of injection.
Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	Water Sampling	Upper Miocene	Baseline. Data acquired during installation of the wells.	Quarterly first 2 years of injection. Semi-annually from year 3 to end of injection.

6.3 Analytical Parameters for Water Testing in Miocene Composite Confining Zone and ACZ/USDW monitoring wells.

The Bluebonnet Sequestration Hub, LLC, has proposed an extensive water quality characterization program using natural tracers and unique fluid chemical characteristics to define reservoirs within the storage complex The sampling and analysis protocol will be used to establish baseline geochemical characteristics and differentiate changes in water quality between natural and anthropogenic influences.

The pre-injection baseline analytical suite will include detailed characterization of the chemical composition and major isotope systems. Following baseline characterization, a reduced analytical suite will be developed from baseline characterization results to focus on primary indicators of potential leakage. Isotopic compositions will likely not be routinely conducted during injection unless required for source attribution. Proposed changes to the analytical suite will be discussed with the UIC Director after the baseline data is collected and the routine testing protocol is finalized. Table TM-20 outlines the analytical suite for water analysis.

Field sampling methods and chain of custody procedures for water quality sampling are described in the QASP. All field and laboratory analytical tests will be performed by third-party certified laboratories and will follow applicable EPA or industry standard methods.

Table TM-20: Measured parameters and analytical methods summary for existing shallow freshwater wells and Confining Zone / USDW monitoring wells.

Parameter	Analytical Method
Cations: Al, Ba, B, Cd, Ca, Cu, Cr, Fe, Pb, Li, Mg, Mn, Ni, P, K, Si, Na Sr, Zn	ICP-OES, EPA Method 6010d, ICP-MS Method 200.8 or equivalent
Other Metals: As, U, Co, Se, Pb, Mo, V	ICP-MS Method 200.8 or equivalent
Mercury	EPA 245.7 CVAA, or equivalent
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-, $NO2^-$	Ion Chromatography, EPA Method 300.1 or similar
Carbonate, bicarbonate and hydroxide	Titration, ASTM D3875.
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C, ASTM D5907 or equivalent
Water Density	ASTM D5057, ASTM D4052 or equivalent
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of DIC in Water	Gas Bench and CF-IRMS for $^{13/12}C$
Radiocarbon 14C of DIC in Water	AMS for ^{14}C
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, ASTM 1945D, RSK 175 or equivalent
pH	ASTM D1293, EPA 150.23 or equivalent
Temperature	ASTM 2550
Conductivity	ASTMD1125

Parameter	Analytical Method
Conductivity (field)	EPA 120.1
ICP-OES = inductively coupled plasma optic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; GC/MS = gas chromatography–mass spectrometry; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: Cold Vapor Atomic Absorption;	

6.4 Sampling Methods for Water Characterization

Water sampling will be performed by personnel of a certified laboratory, following the specific methods approved by the EPA or other standards. Operators might audit the procedures and results of the selected laboratory with a third party to improve quality control.

Sampling procedures and technical specification of the tools are provided in the QASP.

6.5 Laboratory to be Used/Chain of Custody Procedures

The samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Sampling methods and chain of custody procedures are described in the QASP.

7.0 CO_2 Plume and Pressure-Front Tracking

7.1 Summary of Direct and Indirect Methods to Monitor CO_2 Plume and Pressure Front Development

Table TM-21 presents methods that Bluebonnet Sequestration Hub, LLC, will use to monitor the position of the CO_2 plume and development of the pressure front, including the activities, locations, and frequencies for the Bluebonnet Hub to comply with 40 CFR 146.90(g).

Table TM-21: Summary of methods for monitoring of CO_2 plume extension and pressure front.

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
AoR	2D Time-lapsed surface seismic survey	Reservoir, seal, and overburden	Baseline acquisition before injection	Every 5 years
AoR	3D Surface seismic survey	Reservoir, seal, and overburden	Baseline acquisition before injection	n/a

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 6 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1	3D VSP time lapsed survey	Reservoir, seal, and overburden	Baseline once the wells are drilled	Annually in CO2 injectors until plume extend beyond detection. Event triggered based on other monitoring techniques.
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	Pulse Neutron Log	Reservoir, seal, and overburden	Baseline will be acquired once the wells are drilled	Annually
Bluebonnet IZM FM 1 Bluebonnet IZM FM2 Encanto 01	Pulse Neutron Log	Reservoir, seal, and overburden	Baseline will be acquired once the wells are drilled	Event triggered in monitoring well based on other monitoring techniques.
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	Downhole gauges; pressure and temperature.	Reservoir	Baseline line will be acquired during completion of the wells	Continuously

7.2 Pressure and Temperature Measurement in the Reservoir

The use of pressure and temperature gauges and transducers for monitoring the CO_2 injectors and monitoring wells was explained in Sections 3 and 4 of this document.

Table TM-22: Summary of the sampling frequency for downhole pressure measurements in CO_2 injectors and in-zone monitoring well.

Location	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	Pressure and temperature gauges	Downhole deployment on tubing	1 sec	15 sec
Bluebonnet IZM FM 1 Bluebonnet IZM FM2 Encanto 01	Pressure and temperature gauges	Downhole deployment on tubing	15 sec	30 min

7.3 Pulse Neutron/Saturation Log for CO_2 Plume Tracking

The implementation of PNL was described in Section 3 as well as in Section 5 of this document.

Table TM-23: Location and frequency of pulse neutron or saturation log implementation for CO_2 plume monitoring in CO_2 injector wells and in-zone monitoring wells.

Tool	Location	Pre-Injection	Injection
Pulse Neutron	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	After completion installation or before injection to set baseline.	Once a year
Pulse Neutron	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	After completion installation or before injection to set baseline.	Event triggered in monitoring well based on other monitoring techniques.

7.4 Geophysical Methods for CO_2 Plume Extension Monitoring Details

A multi-scale approach will be employed for plume migration, CO_2 saturation monitoring, and potential leak detection with multiple seismic methods.

A baseline acquisition program consisting of surface 2D seismic, surface 3D seismic, and 3D VSP will be acquired prior to injection and is designed to calibrate the in-situ seismic response across multiple scales of investigation and model the predicted seismic response resulting from injection.

During the injection period, 3D VSP timelapse surveys will be acquired and analyzed annually, to provide high quality imaging and temporal resolution of plume movement proximal to injection wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, and Bluebonnet CCS 6, and monitoring wells Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Bluebonnet IZM M1. Injection wells Bluebonnet CCS 5 and Bluebonnet CCS 7 are not planned for 3D VSP since they

share well pads with Bluebonnet CCS 1 and Bluebonnet CCS 3, respectively. Monitoring well Encanto 01 will not encounter a modeled plume during injection period and is not included in the VSP program. Modeling indicates that the plume extents will be detectable from the injection well VSPs from the start of injection but will move beyond the radius of investigation by as early as year 5 of injection in the respective injection zone. Modeled plumes and VSP radius of investigation may be seen in Figure TM-15 for the Frio injection, Figure TM-16 for the Hackberry injection, and Figure TM-17 for the Miocene injection.

A 2D timelapse surface seismic will be acquired and analyzed every five years during injection to monitor plume movement and saturation on an AoR-wide scale. The 2D timelapse monitoring will be repeated at the end of injection period and before site closure to demonstrate non-endangerment to USDW. If any aspect of the monitoring system indicates unfavorable plume movement at any point during the injection and post-injection periods, the project team will evaluate the need for additional geophysical surveys. The proposed 2D program is conceptual and will be refined as needed to suit monitoring needs.

The combined 3D VSP and 2D seismic program is designed to leverage the high-resolution of 3D VSP (particularly at the injection well) to understand the early plume development in detail, with the broader scope of the timelapse 2D to monitor for long-term movement.



Figure TM-15: Proposed geophysical monitoring program for the Frio injection.

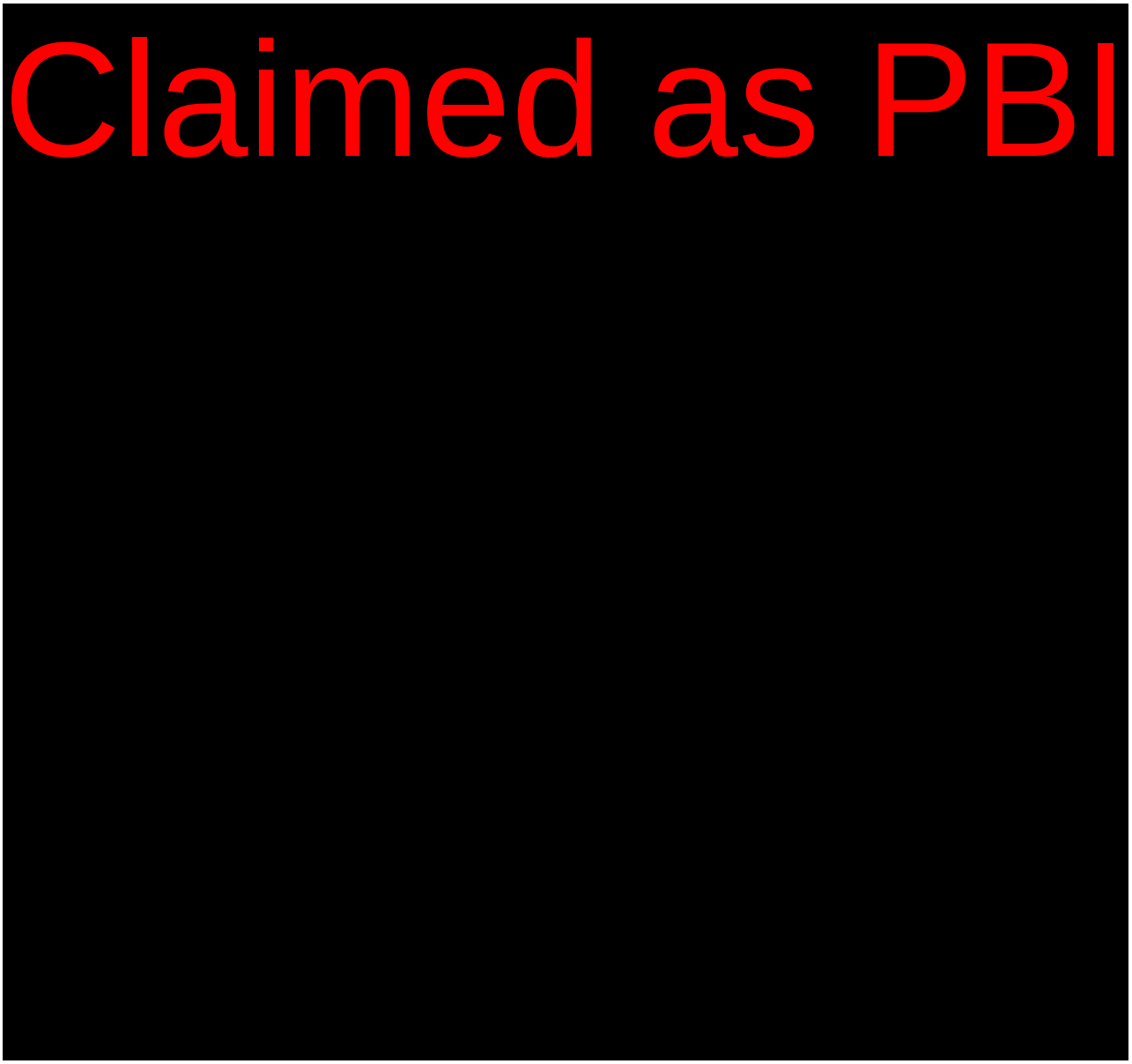


Figure TM-16: Proposed geophysical monitoring program for the Hackberry Injection.



7.3.1 3D Surface Seismic Baseline Survey

A 3D surface seismic baseline was acquired in 2025 covering the AoR prior to injection. Acquisition parameters for the survey were specifically designed to provide full-fold coverage of the storage complex and strata above. The 3D baseline was acquired with Vibroseis. The survey utilized a high density of sources and receivers designed to increase the definition of shallow horizons above the confining zone. The 3D baseline has a large surface footprint encompassing the AoR and is designed to image from surface to basement on a broad frequency band. The outline of planned 3D is seen in Figure TM-18. The processing sequence includes state-of-the-art onshore preprocessing and depth imaging (pre-stack depth migration and velocity model building),

followed by complete post-migration processing. Survey results will be used to update the structure, faulting (if any), and stratigraphy for input into an updated static model prior to injection.

Survey results will also be integrated with rock-physics studies to determine the expected timelapse 2D surface seismic response given predicted CO_2 saturation values.

Figure TM-19 and Figure TM-20 show examples of a modeled seismic response to CO_2 saturation performed using the Encanto 01 well. The model included the AoR document tested CO_2 saturations of Claimed as PBI within the Frio injection zone. No discernable seismic response was seen with Claimed as PBI turations resulted in detectable acoustic impedance signal deflection. Similarly, the Miocene injection zone was modeled and a similar detectable alteration to seismic response is expected within the CO_2 plumes. This modeling indicates that acoustic monitoring techniques, such as the planned 2D seismic and 3D VSPs, are valid for the Bluebonnet Project.

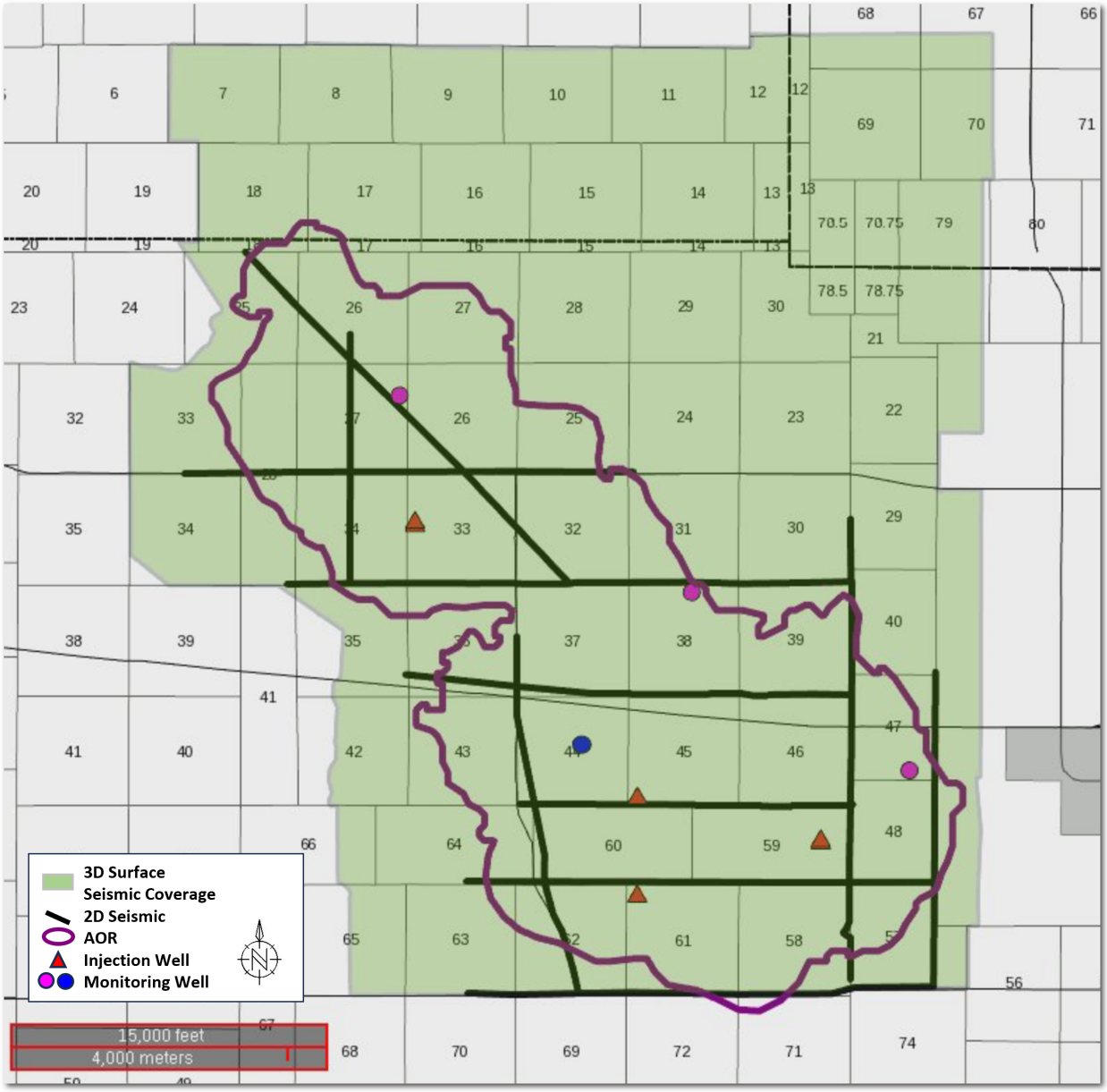


Figure TM-18: Baseline 3D seismic acquisition covering ~57.2 sq. miles of the Bluebonnet Project area.



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Claimed as PBI

7.3.2 2D Surface Seismic Base Line and Timelapse Surveys

Approximately 48 statute miles of 2D surface seismic was acquired in 2025 to establish a baseline The 2D layout covered the extent of the AoR and beyond, with 2D lines positioned along low-traffic roads as much as possible to minimize disruption and allow for frequent and cost-effective repeat surveys. The 2D baseline design was based upon the modeled plume and AoR, and may change according to subsequent model refinements and future re-evaluations.

The 2D baseline was acquired primarily with Vibroseis. The survey used a high density of sources and receivers designed to increase the definition of shallow horizons above the confining zone. The baseline 2D data will be processed with state-of-the-art 2D preprocessing and pre-stack migration, followed by complete post-migration processing. Survey results will be integrated with rock-physics studies to determine the expected timelapse 2D surface seismic response, given predicted CO_2 saturation values.

Repeat 2D timelapse surveys will be acquired (using the same acquisition parameters as the 2D baseline) every five years during injection. The 2D timelapse monitoring will be repeated at the end of the injection period, and before site closure to demonstrate non-endangerment to the USDW. The 2D timelapse data will be processed with state-of-the-art joint parallel 2D timelapse preprocessing of the baseline, current, and previous monitor surveys, followed by pre-stack time migration and complete post-migration processing. Seismic amplitude changes observed between the current and previous surveys will be evaluated against the rock-physics model to determine changes in CO_2 saturations. These results will be checked against and integrated into the predictive models.

7.3.3 3D VSP baseline and timelapse surveys

The 3D baseline vertical seismic profile (VSP) surveys will be acquired at the injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, and Bluebonnet CCS 6, and monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Bluebonnet IZM M1, using permanent DAS fiber optic cables installed in the wellbores with Vibroseis surface sources. The VSP survey will use state-of-the-art VSP preprocessing and depth imaging (pre-stack depth migration), followed by post-migration processing. The imaging radius for the 3D VSP survey is assumed to be 0.5 mile (see Figures TM-15, Figure TM-16, and Figure TM-17). Within this radius, high-resolution seismic imaging (exceeding that of surface seismic) is expected, along with accurate time-depth control. Structure and stratigraphy from the 3D baseline VSP surveys will be evaluated and integrated into the geomodel. Survey results will be integrated with rock-physics studies to determine the expected timelapse VSP seismic response given predicted CO_2 saturation values.

Repeat timelapse VSP surveys will be acquired on an annual basis (using the same acquisition parameters as the VSP baseline surveys) until a time when the plume is determined to have moved beyond the imaging radius for a particular location. The timing of plume movement into or out of the 3D VSP radius of influence varies according to the injection or monitoring well location and timing of injection into respective storage zones and may be seen in Figure TM-15, Figure TM-16, and Figure-17. The timelapse surveys will be processed using state-of-the-art joint parallel VSP timelapse preprocessing of baseline, current, and previous monitor surveys, followed by pre-

stack depth migration and complete post migration processing. Seismic amplitude changes observed between the current and previous surveys will be evaluated against the rock-physics model to infer changes in CO_2 saturations. The high-resolution imaging and frequent (annual) acquisition of repeat VSP surveys are intended to provide detailed information on the early evolution of the CO_2 plume, including (but not limited to) the response to heterogeneity within the injection reservoir, the integrity of the confining zones, the rate of CO_2 movement, and the fidelity of the subsurface geomodel and resulting simulation.

8.0 Surface and Near Surface Monitoring

8.1 Soil Gas Monitoring and Isotopic Fingerprinting

The Bluebonnet Sequestration Hub, LLC, installed 20 soil gas sample stations with the objective of collecting soil gas samples. The project plans to characterize the soil gas samples using a methodology developed by Dr. Katherine Romanak from the Gulf Coast Carbon Center (GCCC) 40 CFR §146.90 (h).

The samples will be analyzed by a certified commercial laboratory to determine gas composition and isotopic signatures of carbon and hydrogen elements. This data will be used to inform process-based soil gas monitoring (Romanak 2012) to monitor for ecological stress and distinguish a leakage signal from natural vadose-zone CO_2, providing for attribution at the site. Modeling and additional geochemical data from the subsurface overburden will be used to define diagnostic parameters for attribution in soil gas.

Soil gas assessment will consist of characterization of soil gas CO_2, CH_4, O_2, and N_2 ratios within a process-based framework and, if thresholds are ever exceeded, collection of additional isotopic parameters for further assessment.

For a minimum of one year prior to injection, soil gas will be analyzed quarterly for CO_2, O_2, N_2, CH_4, C1-C5 hydrocarbons, δ13C and 14C of CO_2, and CH_4 and δD of CH_4 (Table TM-25). At the end of characterization period, protocols for detection of leakage signal will be tailored to site base data.

As part of the process for designing the soil gas stations and selecting locations, an airborne electromagnetic survey was conducted over the AoR. The aerial electromagnetic (EM) data will be used to identify and map the extent of near-surface and surface salinization. This environmental determination will inform additional parameters for groundwater monitoring to complement soil gas as part of the near-surface monitoring strategy.

8.1.1 Sampling Location and Frequency for Soil Gas

Field activities at the Bluebonnet Site began on May 27, 2025. A total of twenty permanent soil gas monitoring wells were installed. Nineteen wells were installed using a Geoprobe® dual-tube sampling system; one well (SG-05) was installed using a hand auger due to limited rig access at that location. Boreholes were generally advanced to depths of 4 to 10 feet below ground surface (ft bgs), with specific wells installed deeper based on site conditions: SG-6 was installed to 13 ft,

SG-2 was installed to 12 ft and SG-15 was installed to 8 ft with a flush-mount surface completion due to potential for agricultural traffic nearby.

Each boring was continuously logged for soil lithology in accordance with the Unified Soil Classification System (USCS). Soil cuttings were collected for subsequent laboratory analysis. Soil cores were screened for volatile organic compounds (VOCs) using a photoionization detector (PID), and results were recorded on soil boring logs.

Wells were constructed using 6-inch stainless steel wire mesh screens and 0.25-inch flexible Teflon tubing risers extending to the surface. Clean #10 silica sand was used as the sand pack surrounding the screen. Above the sand pack, granular bentonite was placed in one- to two-foot lifts and hydrated to form a seal. The remaining annular space was filled with neat-cement grout to the surface. Each well was completed at the surface with a concrete pad and either a protective steel cover with a locking cap or a flush-mount completion. Teflon tubing risers were sealed from ambient air using stainless-steel caps. Figure TM-21 shows the schematic of the installation for SG-1 as an example.

Figure TM-22 shows the location for the soil gas probes installation relative to the AoR and CO_2 injectors.

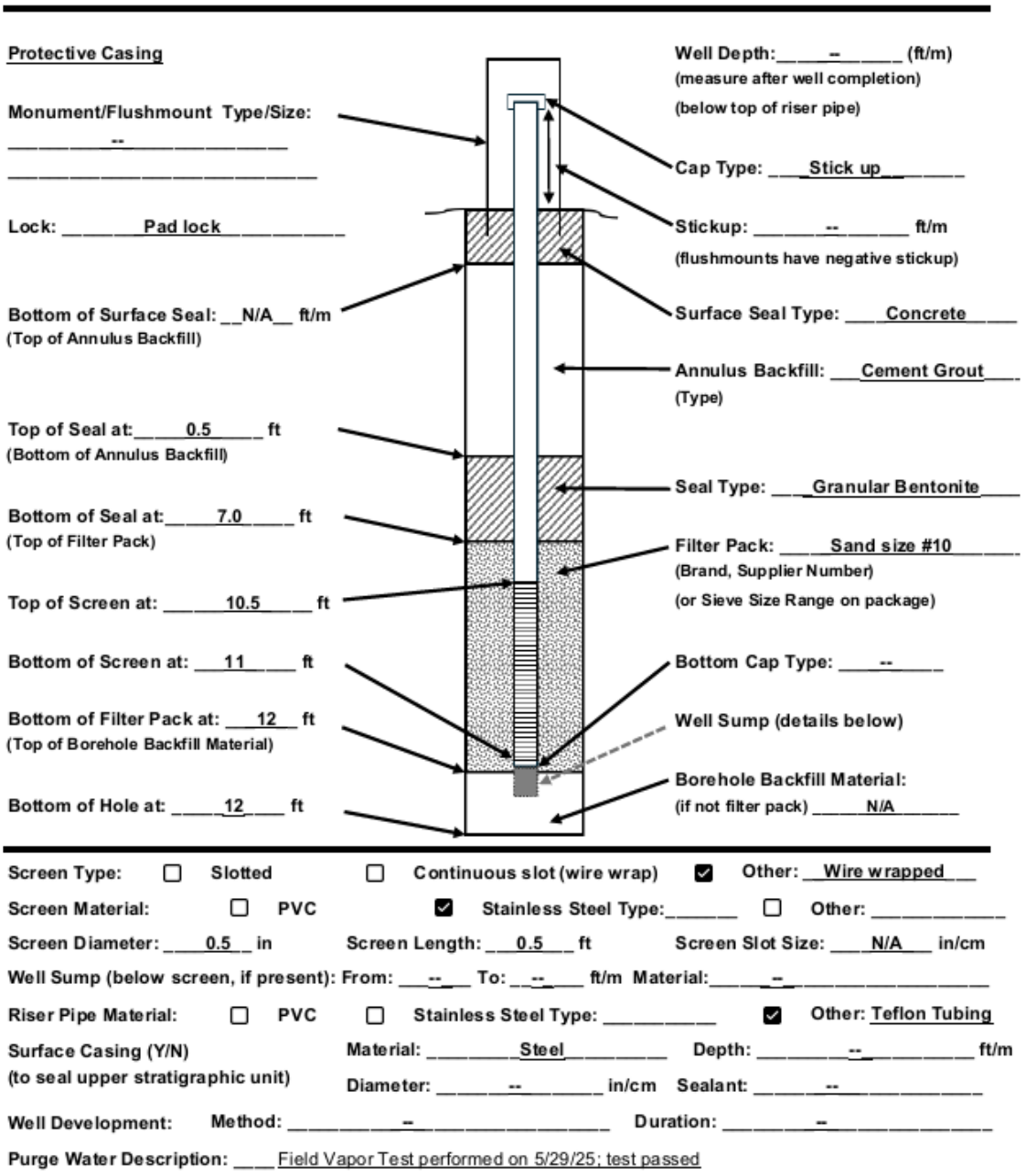


Figure TM-21: Schematic of soil gas sampling station installed (SG-1).

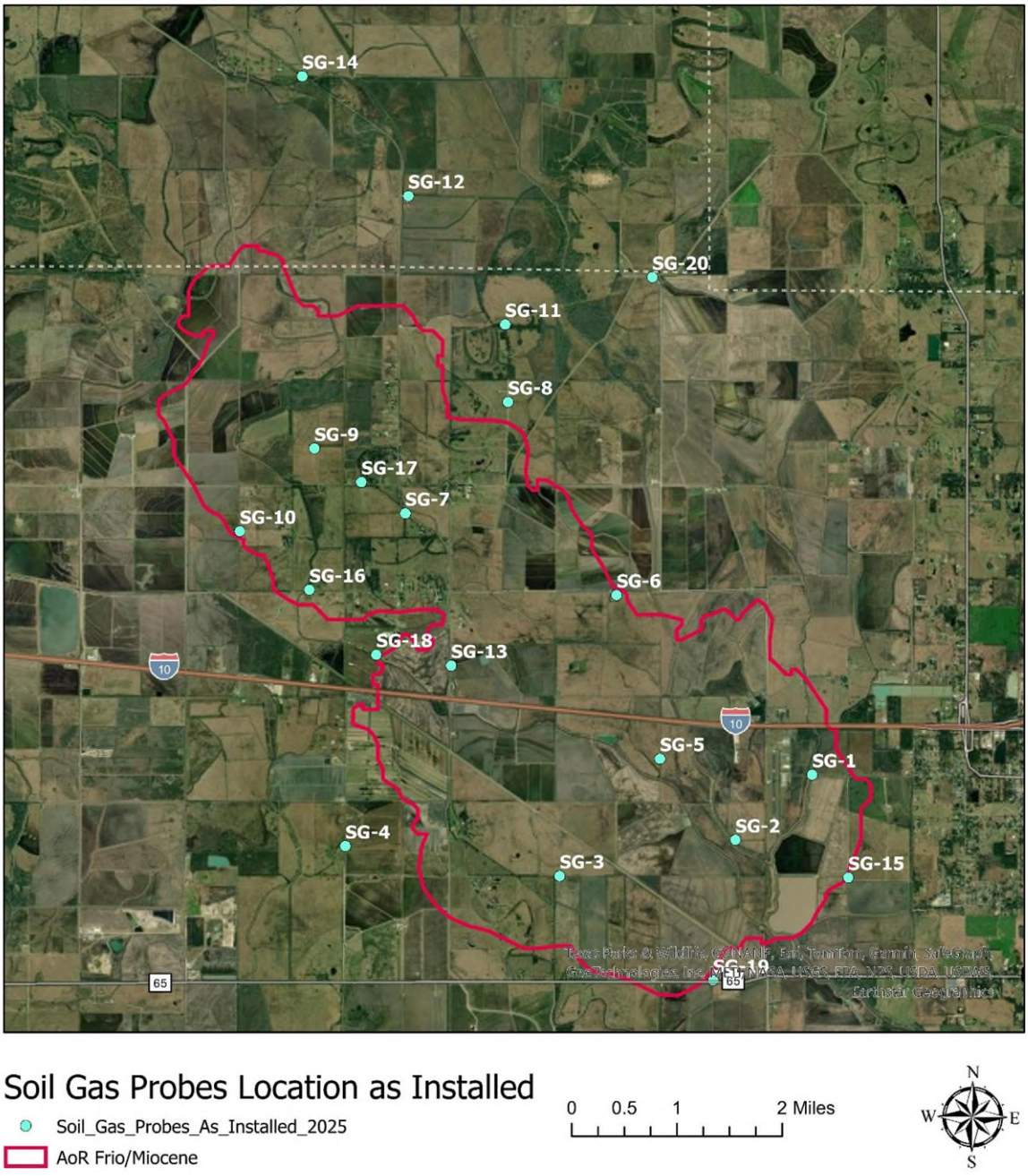


Figure TM-22: Location of the Soil Gas Probes as Installed in 2025.

Table TM-24 shows the frequency proposed for soil gas sampling and testing.

Table TM-24: Soil gas sampling locations and frequencies.

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
Soil gas stations	Soil gas sampling and basic gas analysis	Vadose zone	1-2 years of characterization, 1-2 sample per station per quarter	Quarterly starting 3 months after injection is approved, 1-2 sample per station
Soil gas stations	Isotopes analysis of CH_4 and CO_2	Vadose zone	1-2 years of characterization, 1-2 sample per station per quarter	As required
AoR	Electromagnetic airborne survey	Surface	1-2 years before injection	As required based on other monitoring techniques responses

8.1.2 Parameters for Soil Gas Analysis

Table TM-25: Soil Gas Analysis Parameters.

Soil Gas Parameter	Analysis method
CO_2, N_2, O_2,	Gas Chromatography (GC)
CH_4, C_2-C_4	Gas Chromatography (GC)
C_5-C_6	Gas Chromatography (GC)
$\delta^{13}C$ of CO_2	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)
$\delta^{13}C$ of CH_4	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)
δD of CH_4	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
^{14}C of CO_2	Accelerated mass spectrometry (AMS).
^{14}C CH_4	Accelerated mass spectrometry (AMS).

8.1.3 Sampling Soil Gas Analysis

Trained or specialized personnel will perform the sampling and the field operator will be trained in the process for taking samples and monitoring gas compositions with handheld devices as a routine operation. The samples are taken in specialized bags to collect the gas and will be sent to a third-party laboratory. Calibration of the field equipment will be performed per manufacturer protocol.

8.1.4 Laboratory to be Used/Chain of Custody and Analysis Procedures.

The samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Analytic methods and chain of custody procedures will follow the laboratory protocol.

8.2 CO_2 Sensors in Surface - Wellheads

The Bluebonnet Sequestration Hub, LLC, will install infrared gas detectors close to the wellheads of the injector, monitoring, and water production wells. These sensors will interface with the surveillance system to set alarms and identify potential leaks at the surface. The final selection of the technology will consider the integration of all the sensors and transducers in a unique surveillance system. Calibration and maintenance protocols will be based on the manufacturer specifications and performed by specialized professionals. Technical specifications for the CO_2 leak detector are provided in the QASP Plan.

Table TM-26: Atmospheric CO_2 sensor in wellhead.

Tool	Pre-Injection	Injection
Atmospheric CO_2 sensor in wellhead – CO_2 injector well	n/a	Continuously
Atmospheric CO_2 sensor in wellhead – In-zone monitoring wells	n/a	Continuously

8.3 Airborne Electromagnetic Survey

As part of the Class VI application's testing and monitoring plan, a baseline time-lapse airborne time-domain electromagnetic (AEM) survey was conducted from July 7th to July 23rd 2025 to characterize and map the near-surface electrical resistivity distribution. This effort aims to detect fluctuations in the water table and groundwater salinity, providing a robust reference for ongoing environmental monitoring. The electromagnetic data will be integrated with soil gas and water sample analyses to enhance the reliability of site characterization and long-term monitoring.

The survey utilized a helicopter-mounted Versatile Time-Domain Electromagnetic (VTEM™ ET) system from Geotech Ltd., employing full-waveform processing. Measurements included the vertical (Z) component of the electromagnetic field and total magnetic field. A total of 1,493 line-kilometers of geophysical data were acquired.

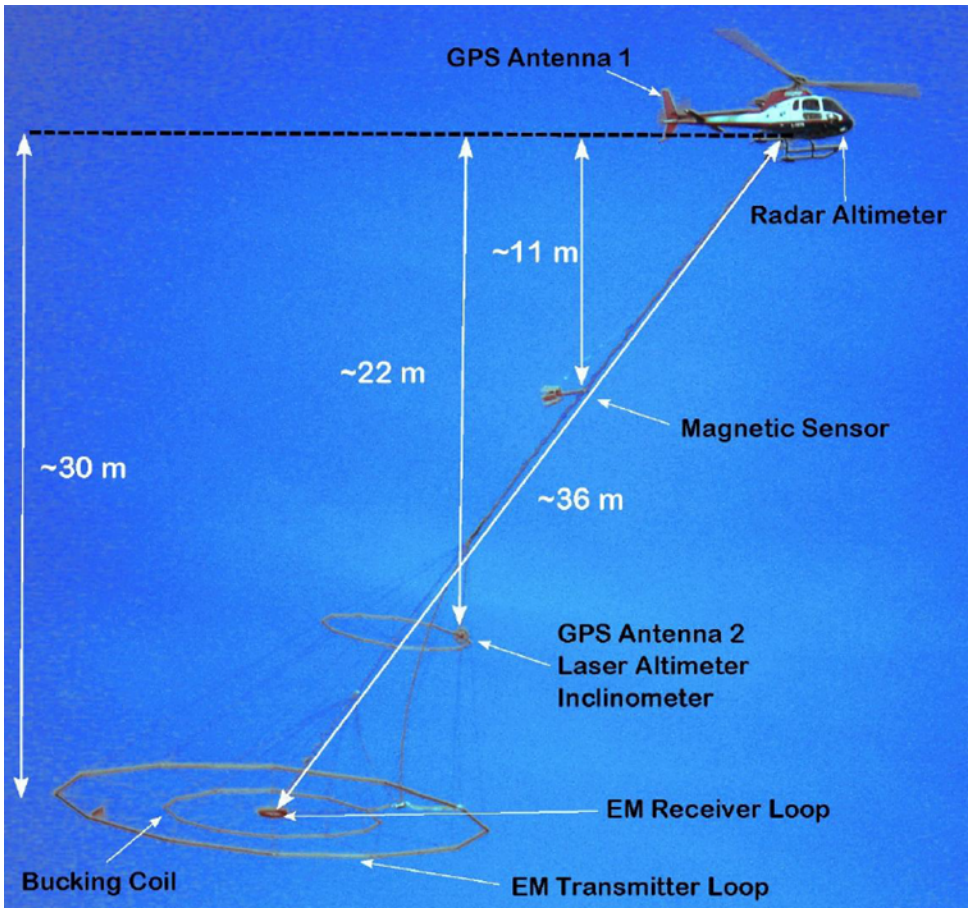


Figure TM-23: VTEM™ System Configuration, courtesy of Geotech Ltd.

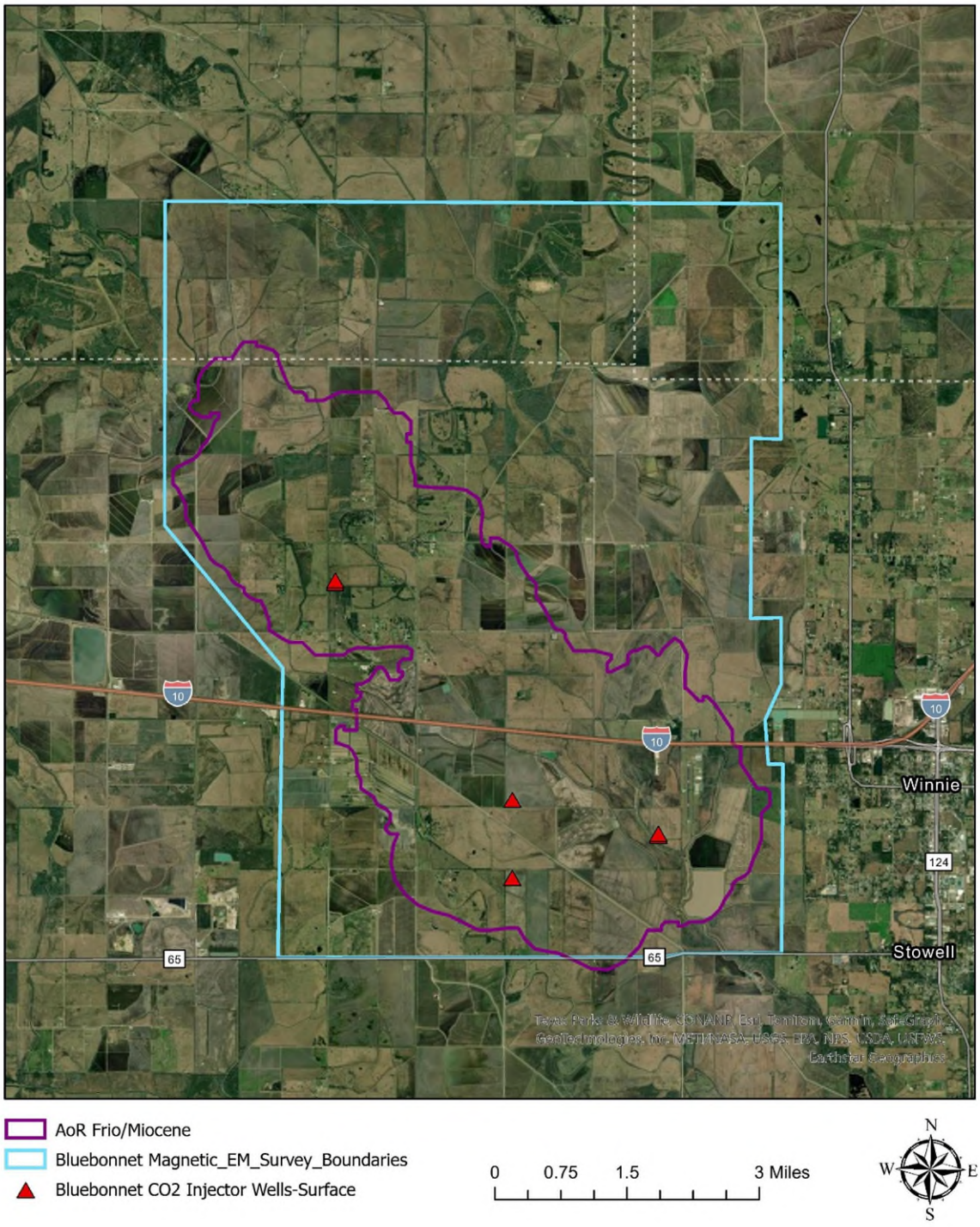


Figure TM-25: Location and the outline of the time-domain electromagnetic survey.

Note: Imagery courtesy of ESA contains modified Copernicus Sentinel data processed by Sentinel Hub.

To interpret the near-surface resistivity, a 1D inversion of the VTEM data was performed using the Geoscience Australia airborne electromagnetic 1D layered Earth inversion code (Brodie, 2016). Both raw data and inversion results were delivered in digital format for further analysis and for comparison with future measurements.

Table TM-27: Airborne electromagnetic survey.

Tool	Pre-Injection	Injection
Airborne Electromagnetic Survey	1 or 2 years prior the injection	As needed based on other monitoring techniques

8.4 Airborne Magnetic Survey

The Bluebonnet heliborne magnetic survey (Figure 1) was conducted in March 2025 by Xcalibur Inc. for Bluebonnet Sequestration Hub LLC. The survey aimed to enhance the understanding of the location of legacy wells and the other magnetic infrastructure in the Bluebonnet area. The data acquisition was followed up by in-house integrated interpretation.

8.4.1 Methodology to Acquire and Process Airborne Magnetic Survey.

Based on experience with in-house airborne magnetic surveys, the Bluebonnet Sequestration Hub, LLC, determined that magnetic anomalies resulting from steel-cased wells and wellheads would be detectable and resolvable by an airborne acquisition system, if the magnetometer height is 20 – 40 m above ground level and with line spacing not larger than 20 m. The Bluebonnet Sequestration Hub, LLC, engaged a third party to conduct the survey using a heliborne magnetic data acquisition system. In such a system, a magnetometer or an ensemble of magnetometers is attached or towed beneath a helicopter (Figure TM-26).

Data acquisition systems can have various configurations depending on the provider. However, regardless of the magnetic system configuration and provider, all types of heliborne magnetic data acquisition systems are equipped with GPS navigation system and laser and radar altimeters to ensure accurate positioning of the data. The data acquisition systems are also equipped with video recording capabilities, which was used in data interpretation for a real-time visual aid in detecting magnetic anomaly sources.

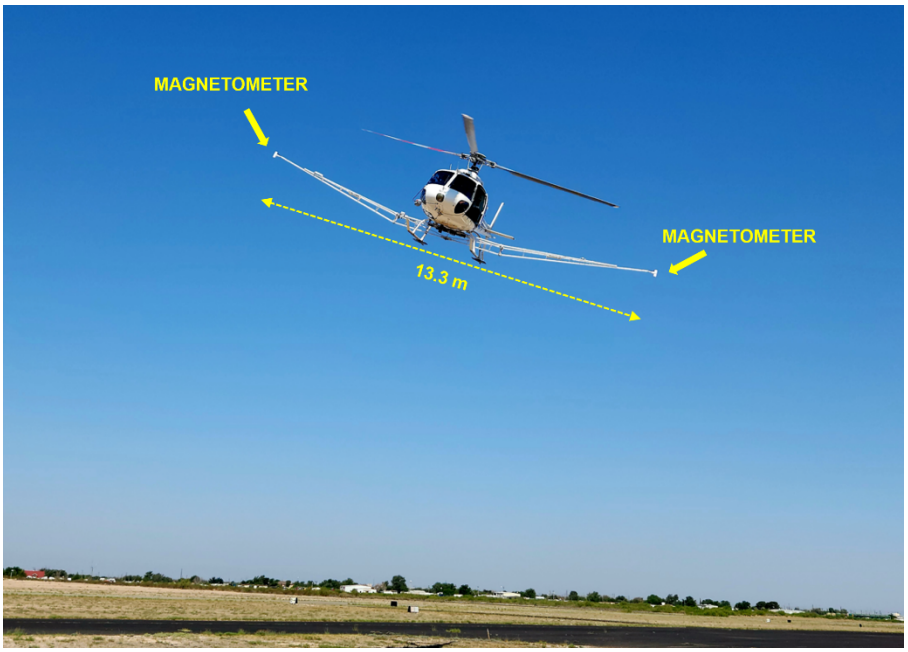


Figure TM-26: An example of heliborne magnetic data acquisition system (MIDAS by Xcalibur Inc.) used in a previous Oxy magnetic survey.

The Bluebonnet Sequestration Hub, LLC, magnetic survey was located at the intersection of Chambers, Liberty, and Jefferson counties in Texas. The data acquisition parameters were as follows: N-S 25 m flight line spacing resulting in 12-13 m data line spacing, E-W 250 m tie-line spacing, with an average flight altitude of 25 m above ground. The parameters were chosen to reduce the long wavelength aliasing (Reid, 1980), sample the anomalous field in direction of the Earth's filed declination for a proper recovery of induced anomalies (Reevs, 2025) and to detect signals due to legacy wells with weaker magnetic amplitudes.

Data processing was performed for eight weeks following the data acquisition by a vendor, while the data post-processing and interpretation was conducted in-house.

8.4.2 Methodology to Interpret Airborne Magnetic Survey.

The Bluebonnet Sequestration Hub, LLC, performed advanced data processing in house that includes transformations of the anomalous magnetic field to reduce the effects of inclination, declination, and remanent magnetization. Examples of such transformations are reduction to pole, magnetic magnitude (or magnetic amplitude), and their derivatives such as total gradient of the magnetic anomaly and normalized source signal. All transformations are intended to focus the magnetic signal close to the location of a source, independent of magnetization orientation.

The processed magnetic data was used to interpret locations of magnetic anomalies associated with surface and near-surface expression of steel-cased wells. This data was combined with helicopter-acquired video and high-resolution imagery to interpret sources of magnetic anomalies.

In addition to the surface locations of steel-cased wellbores, the Bluebonnet Sequestration Hub, LLC, was able to identify magnetic responses resulting from pipelines, electric power lines, and industrial activity. These features are located at the surface or near-surface and do not present a leakage hazard.

Table TM-28: Airborne magnetic survey.

Tool	Pre-Injection	Injection
Airborne Magnetic Survey	1 or 2 years prior to injection	n/a

9.0 Induced Seismicity Monitoring

The Bluebonnet Sequestration Hub, LLC, deployed a seismometer monitoring network to determine the locations, magnitudes, and focal mechanisms of the injection-induced seismic events when observed. This information will be used to address public concerns and identify features that may help to evaluate the plume and pressure front behavior.

9.1 Monitoring Location and Frequency for Induced Seismicity Measurement

The seismometer monitoring network contains 14 sensors strategically placed throughout the Bluebonnet Project area. The network is designed to provide a magnitude threshold equivalent to 0.0 on the Richter scale around the injection wells as well as along faults outside the AoR that are more likely to respond to reservoir pressure increases. Geomechanical modeling indicates that injection pressures will remain significantly below the threshold needed to initiate seismic movement along area faults, but those faults are still included in the seismometer monitoring network. The modeled seismometer network and modeled magnitude threshold in relation to the AoR is shown in Figure TM-27, and the coordinates of the seismometers are available in Table TM-30. Bluebonnet will connect at least one of its seismic monitoring stations to the State of Texas public seismic monitoring network, currently operated by TexNet.

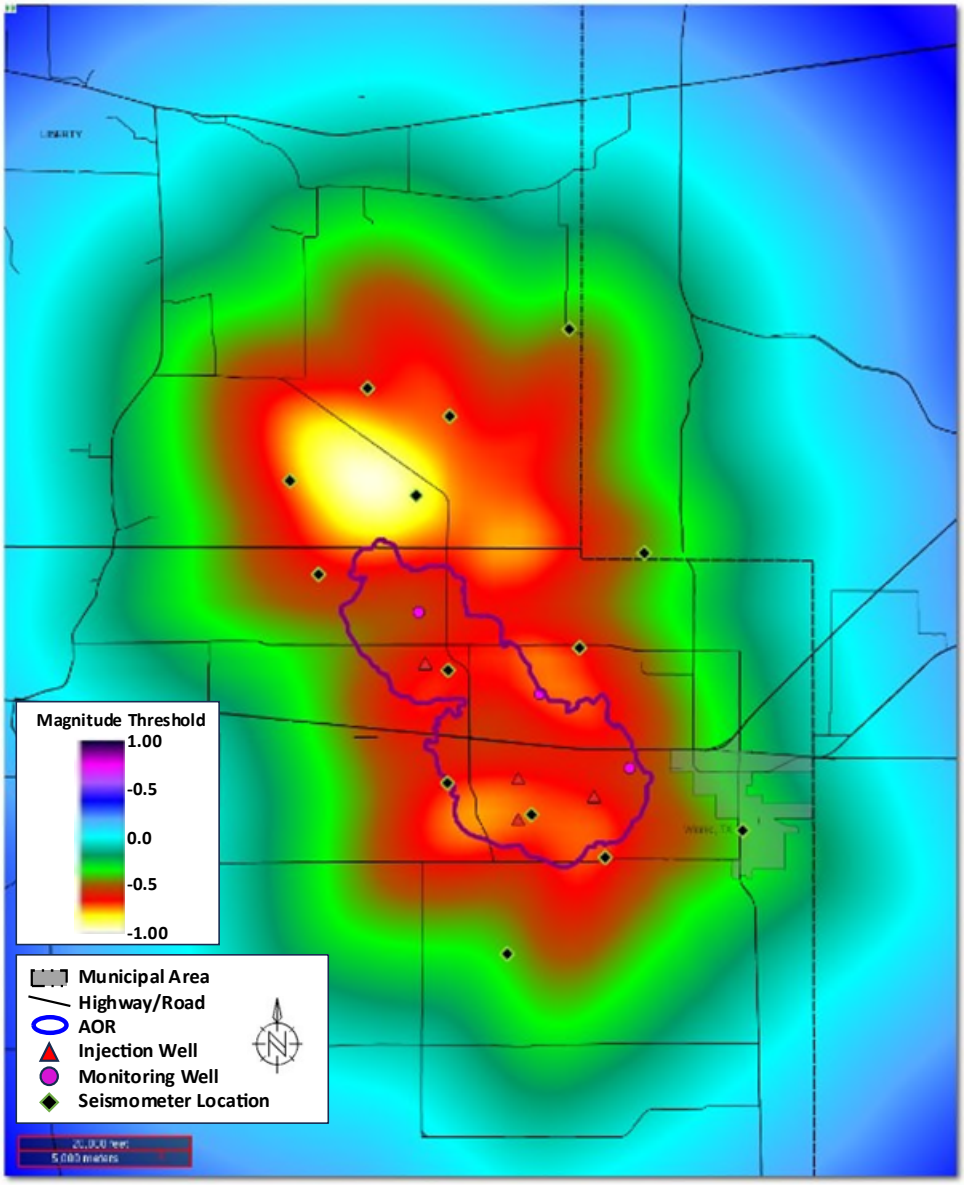


Figure TM-27: Seismometer monitoring network with 14 sensors placed in relation to the CO_2 injector wells and the AoR.

Table TM-29: Seismicity monitoring tools and frequency.

Tool	Pre-Injection	Injection
Seismometer network in surface to measure potential induced seismicity events.	Baseline 1-2 years before injection	Continuously

Table TM-30: Location of the seismometer**s. (WGS-84)**



9.2 Traffic Light System Protocol

The Richter Magnitude (or Local Magnitude) defines the local magnitude (ML) of an earthquake observed at a station to be ML = log A - log Ao (Δ), where A is the maximum amplitude in millimeters recorded on the Wood Anderson seismograph for an earthquake at epicentral distance of Δ km and Ao (Δ) is the maximum amplitude at Δ km for a standard earthquake; seismometers are calibrated so that consistent magnitudes are recorded from different seismographs. The local magnitude is thus a number characteristic of the earthquake, and is independent of the location of the recording station.

While the historical seismicity of the project area indicates no measured earthquakes in the area, the project intends to maintain a surface array for the duration of the project to ensure the safe operation of both the storage facility and adjacent infrastructure in the area. This seismic monitoring will be conducted with a surface array deployed to ensure detection of events above ML 2.0 with epicentral locations within 5.6 miles of any injection well covering an area of 100 square miles.

This areal coverage was determined by referencing the Texas Railroad Commission's historic designation of Seismic Response Areas (SRA). SRAs are areas determined by RRC seismologists for which consistent identification and seismic response approach will be implemented after the occurrence of seismic events with a magnitude of 3.5 or greater (TRRC, January 2022). For example, after a magnitude 5.4 earthquake occurred on December 19, 2022, the RRC designated the SRA with a radial area of 100 square miles (TRRC December 2022). Out of an abundance of caution, the seismic monitoring area for this project is designed to preemptively cover an area equivalent to the RRC's post-event SRA coverage.

If an event is recorded by either the local private array or public national array to have occurred within 5.6 miles of the injection well, the operator will implement its response plan, subject to detected earthquake magnitude limits defined below to eliminate or reduce the magnitude and/or frequency of seismic events.

- For events above ML 2.0 within 5.6 miles of the injection well, the project team will closely monitor seismic activity and may pause operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity.

- For events above ML 3.5 within 5.6 miles of the injection well, the project team will reduce the injection rate by at least 50%. A detailed analysis will be conducted to determine if a causal relationship exists. Should a causal relationship be determined, a revised injection plan will be developed to reduce or eliminate operationally related seismicity. Such plans will be dependent on the pressures and seismicity observed and may include, but not be limited to:

    1. Pausing operations until reservoir pressures fall below a critical limit,
    2. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

- For events above ML 4.5 within 5.6 miles of the injection well, the Bluebonnet Hub operations team will stop injection as soon as safely practical. The project team will inspect surface infrastructure for damage that may have resulted from the earthquake. The project team will then immediately inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis.

    A detailed analysis will be conducted to determine if a causal relationship exists between injection operations and observed seismic activity. Should a causal relationship be determined, a revised injection plan will be developed to reduce or eliminate operationally related seismicity before resuming injection operations and will be discussed with the UIC Director. Such plans will be dependent on the pressures and seismicity observed, and may include, but not be limited to:

    1. Pausing operations until reservoir pressures fall below a critical limit,
    2. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

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G. WELL(S) PLUGGING PLAN

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

	Surface Coordinates	
Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant 40 CFR §146.92, this Injection Well Plugging Plan describes the actions the Bluebonnet Sequestration Hub, LLC, will take to plug and abandon the CO_2 injector wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7. This plan also describes the proposed abandonment of the monitoring wells, water production wells, and water disposal wells in Appendix A.

After 15 years of injection, the project will plug and abandon Bluebonnet CCS 2, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7. The injection will continue for five additional years in Bluebonnet CCS 1 and Bluebonnet CCS 3 as described in the Area of Review (AoR) delineation and Corrective Action document of this application. When the injection period is completed in Bluebonnet CCS 1 and Bluebonnet CCS 3, the project will proceed to plug and abandon both of those wells.

The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO_2) with water mixtures, and protect any underground sources of drinking water (USDWs).

Bluebonnet Sequestration Hub, LLC, will notify the Underground Injection Control (UIC) Program Director in writing at least 60 days before plugging operations start. If there are changes required to the plugging plan, the project team will provide a revised program to the UIC Director for review and approval, per 40 CFR §146.92(c).

The project will submit a plugging report to the UIC Director within 60 days after plugging each well and will comply with the requirements in 40 CFR §146.92(d).

2.0 General Tests and Measures Before Plugging and Abandoning CO_2 Injector Wells

Pursuant to 40 CFR §146.92(a), the project will perform the following activities prior to plugging each well.

1. Bottomhole pressure (BHP) measurements will be taken using the installed downhole gauges. In case the gauges are not functioning properly, the Bluebonnet Hub will run downhole pressure gauges during the plug and abandon (P&A) process of the well.
2. After injection has ceased, the well will be flushed with a kill/buffer fluid. A minimum of three tubing volumes will be injected without exceeding the fracture pressure.
3. An annular pressure test will be performed to assess internal mechanical integrity before the tubing and packer are removed from the well.
4. The project will evaluate the external mechanical integrity and condition of the casing using one of the methods described in Section 3.
5. If a loss of mechanical integrity is discovered, the well will be repaired before proceeding further with the plugging operations.
6. All casing in this well will have been cemented to the surface at the time of construction and will not be retrievable at abandonment.
7. A cement retainer will be used to squeeze and isolate the perforated section to prevent flowback of formation fluids that could contaminate the plug. The balanced-plug placement method will be used for the additional cement plugs planned.
8. Heavy gel mud (9.5-10.5 ppg) will be left between cement plugs.
9. All casing strings will be cut off at least 5 ft below the surface and plow line.
10. A blanking plate with the required permit information will be welded on top of the cutoff casing.

3.0 Planned External Mechanical Integrity Test(s)

The Bluebonnet Sequestration Hub, LLC, will conduct at least one of the tests listed below to verify external mechanical integrity prior to plugging each injection well as required by 40 CFR §146.92(a):

a. Pulse neutron log
b. Noise log
c. DTS (Distributed Temperature Sensing)/DAS (Distributed Acoustic Sensing) survey
d. Temperature log.

4.0 Information on Plugs

The Bluebonnet Sequestration Hub, LLC, will use the materials and methods noted in Table PLG-1, Table PLG-2, and Table PLG-3 to plug the CO_2 injector wells. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the CO_2

stream. The cement formulation and required certification documents will be submitted to the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director as well as Texas regulators with the well plugging plan. Bluebonnet Sequestration Hub, LLC, will report the wet density and retain duplicate samples of the cement used for each plug.

An example of CO_2-resistant cement formulation is provided in Appendix B.

4.1 Bluebonnet CCS 1 Plug and Abandonment Details

Table PLG-1: Bluebonnet CCS 1 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze & Spot On Top CICR	7867	8980	CO2 Resistant	14.8-15.5	1.06	150%	8.535	617
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2450	3500	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 4	Balanced Plug	1400	2450	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

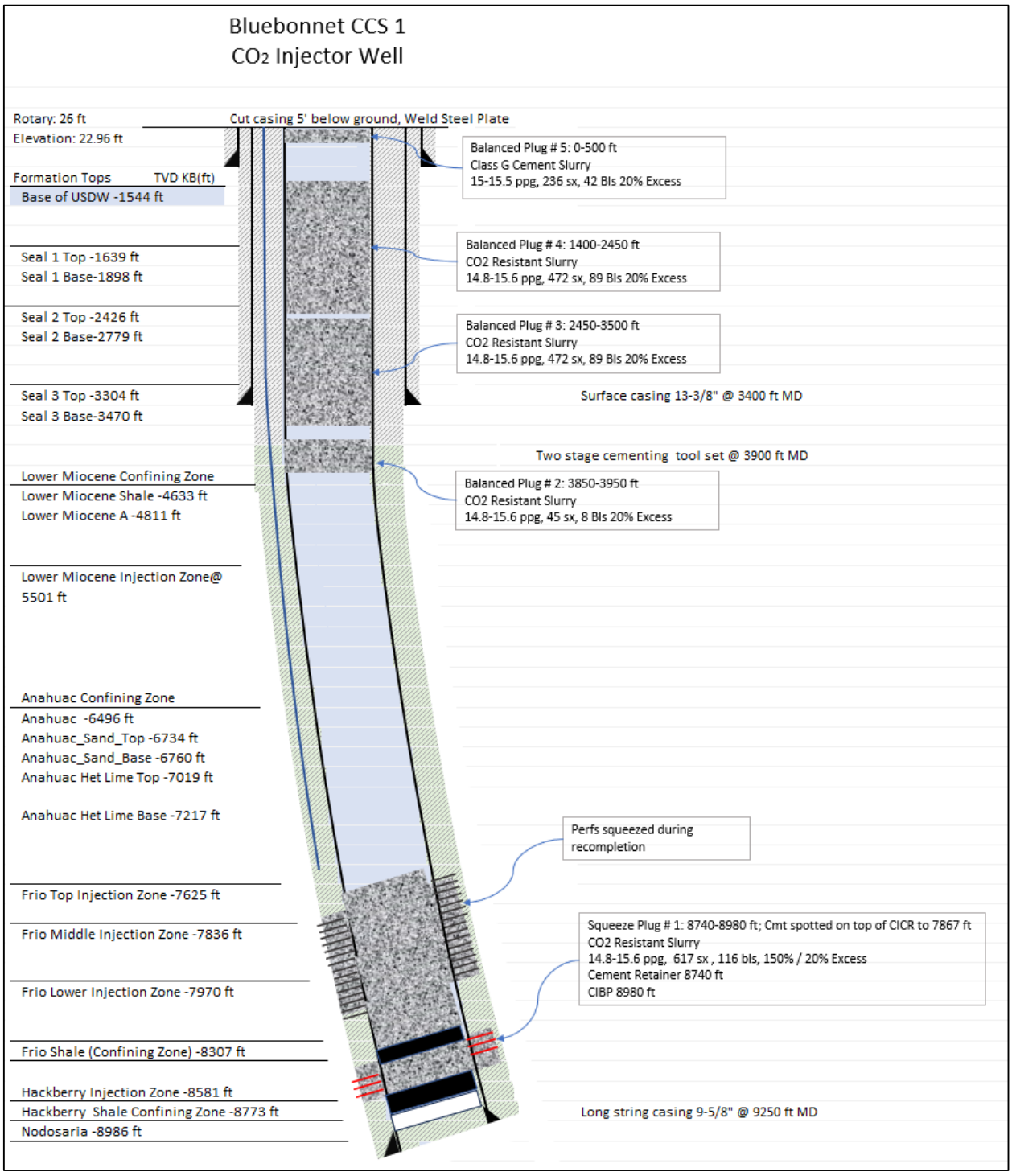


Figure PLG-1: Bluebonnet CCS 1 injection well plug schematic.

4.2 Bluebonnet CCS 2 Plug and Abandonment Details

Table PLG-2: Bluebonnet CCS 2 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	7980	8545	CO2 Resistant	14.8-15.5	1.06	150%	8.535	529
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2450	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	427
Plug # 4	Balanced Plug	1500	2450	CO2 Resistant	14.8-15.5	1.06	20%	8.535	427
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

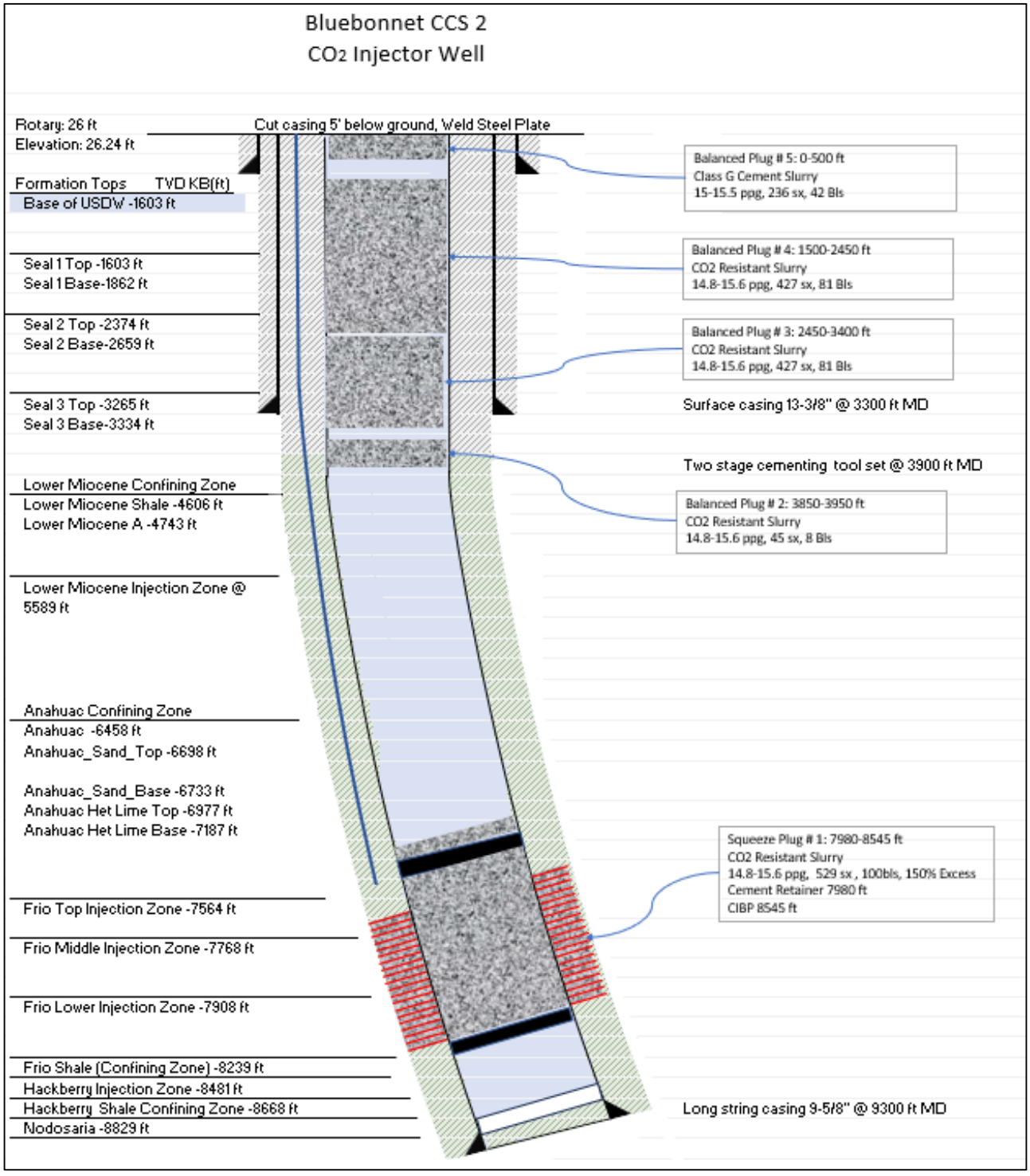


Figure PLG-2: Bluebonnet CCS 2 injection well plug schematic.

4.3 Bluebonnet CCS 3 Plug and Abandonment Details

Table PLG-3: Bluebonnet CCS 3 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	7630	8250	CO2 Resistant	14.8-15.5	1.06	150%	8.535	581
Plug # 2	Squeeze & Spot On Top CICR	7550	8785	CO2 Resistant	14.8-15.5	1.06	20%	8.535	929
Plug # 3	Balanced Plug	3550	3650	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 4	Balanced Plug	2345	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	474
Plug # 5	Balanced Plug	1290	2345	CO2 Resistant	14.8-15.5	1.06	20%	8.535	474
Plug # 6	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

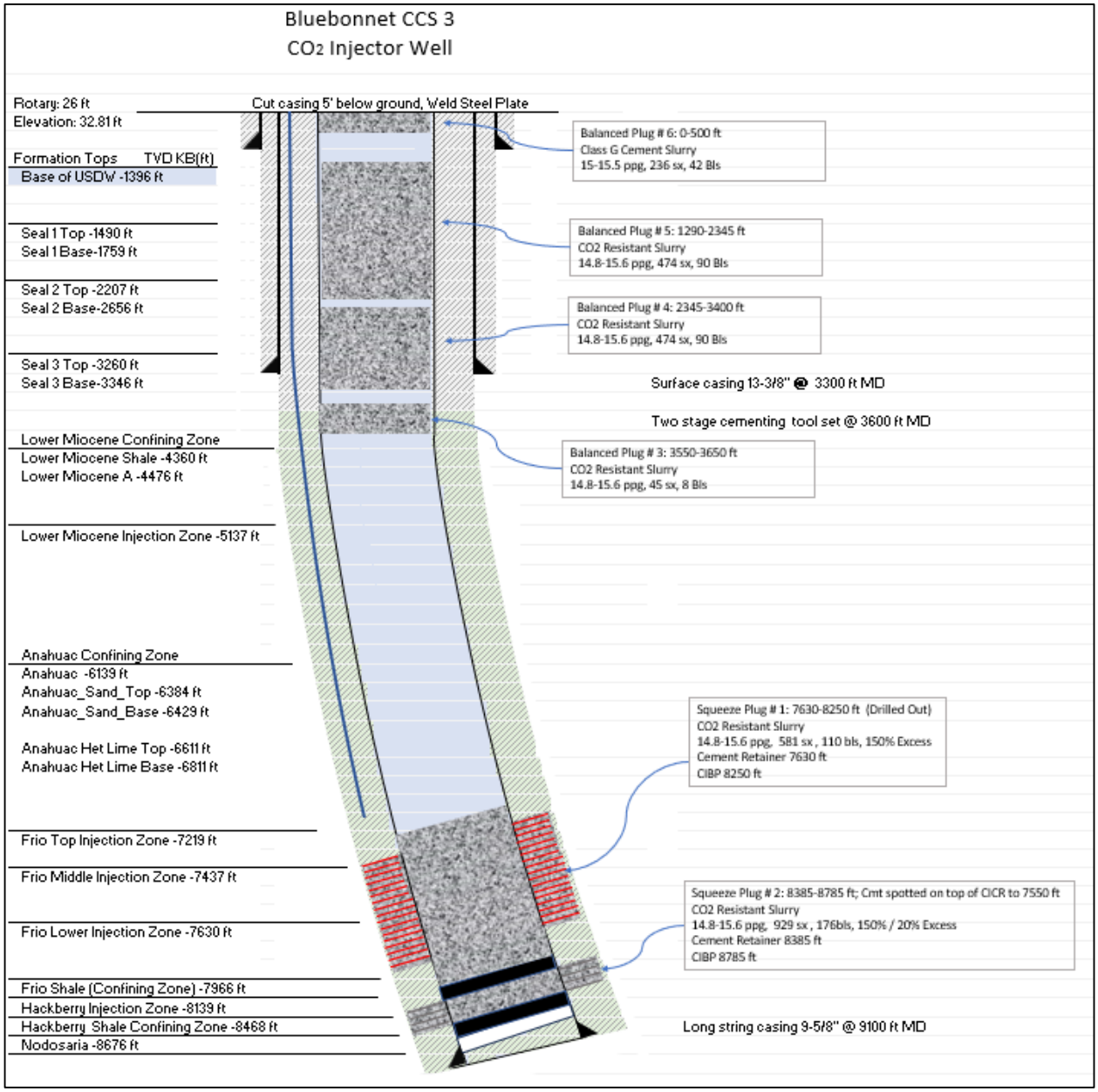


Figure PLG-3: Bluebonnet CCS 3 injection well plug schematic.

4.4 Bluebonnet CCS 5 Plug and Abandonment Details

Table PLG-4: Bluebonnet CCS 5 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	5450	6500	CO2 Resistant	14.8-15.5	1.06	150%	8.535	983
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2450	3500	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 4	Balanced Plug	1400	2450	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

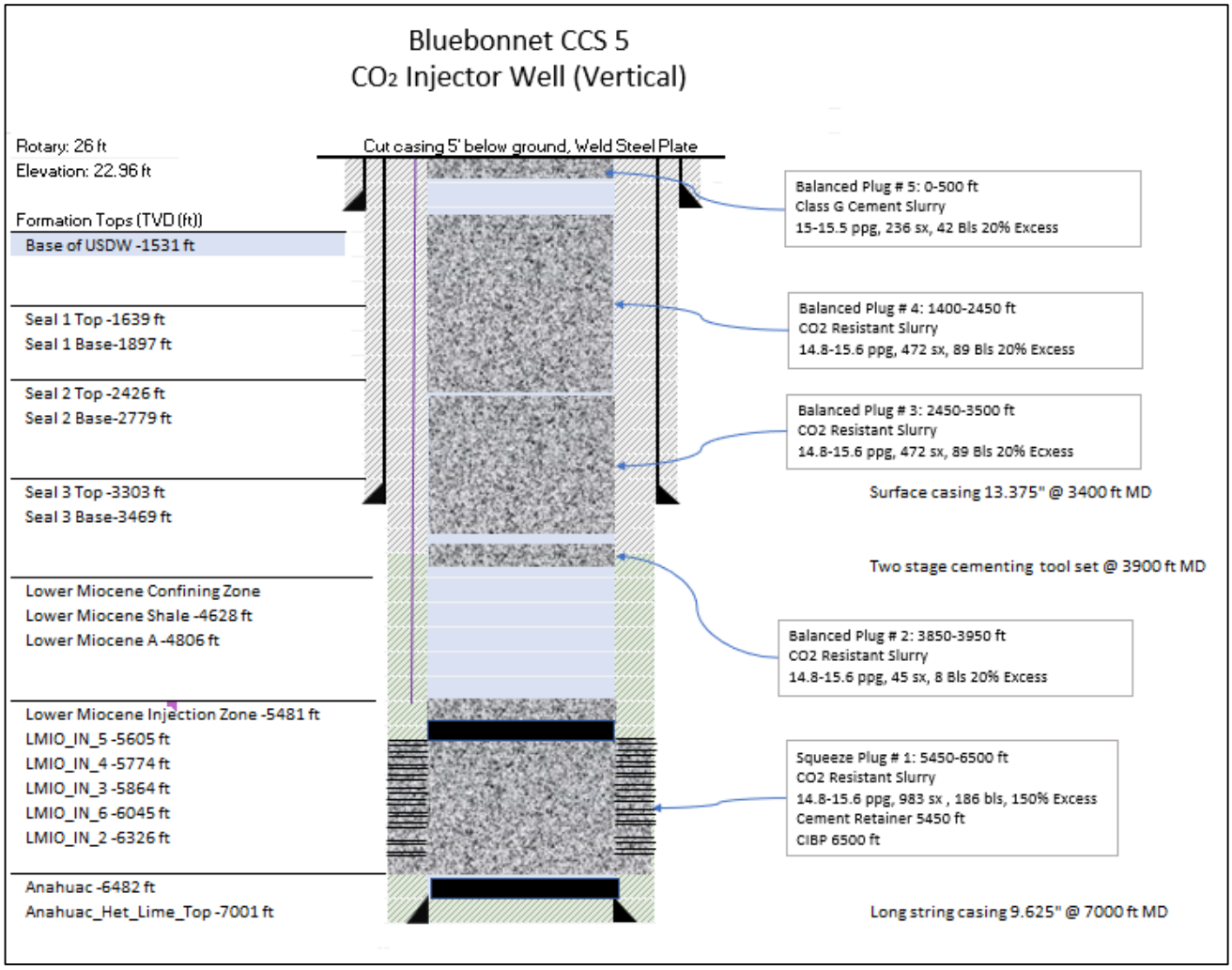


Figure PLG-4: Bluebonnet CCS 5 injection well plug schematic.

4.5 Bluebonnet CCS 6 Plug and Abandonment Details

Table PLG-5: Bluebonnet CCS 6 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	5500	6375	CO2 Resistant	14.8-15.5	1.06	150%	8.535	819
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2400	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	449
Plug # 4	Balanced Plug	1400	2400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	449
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

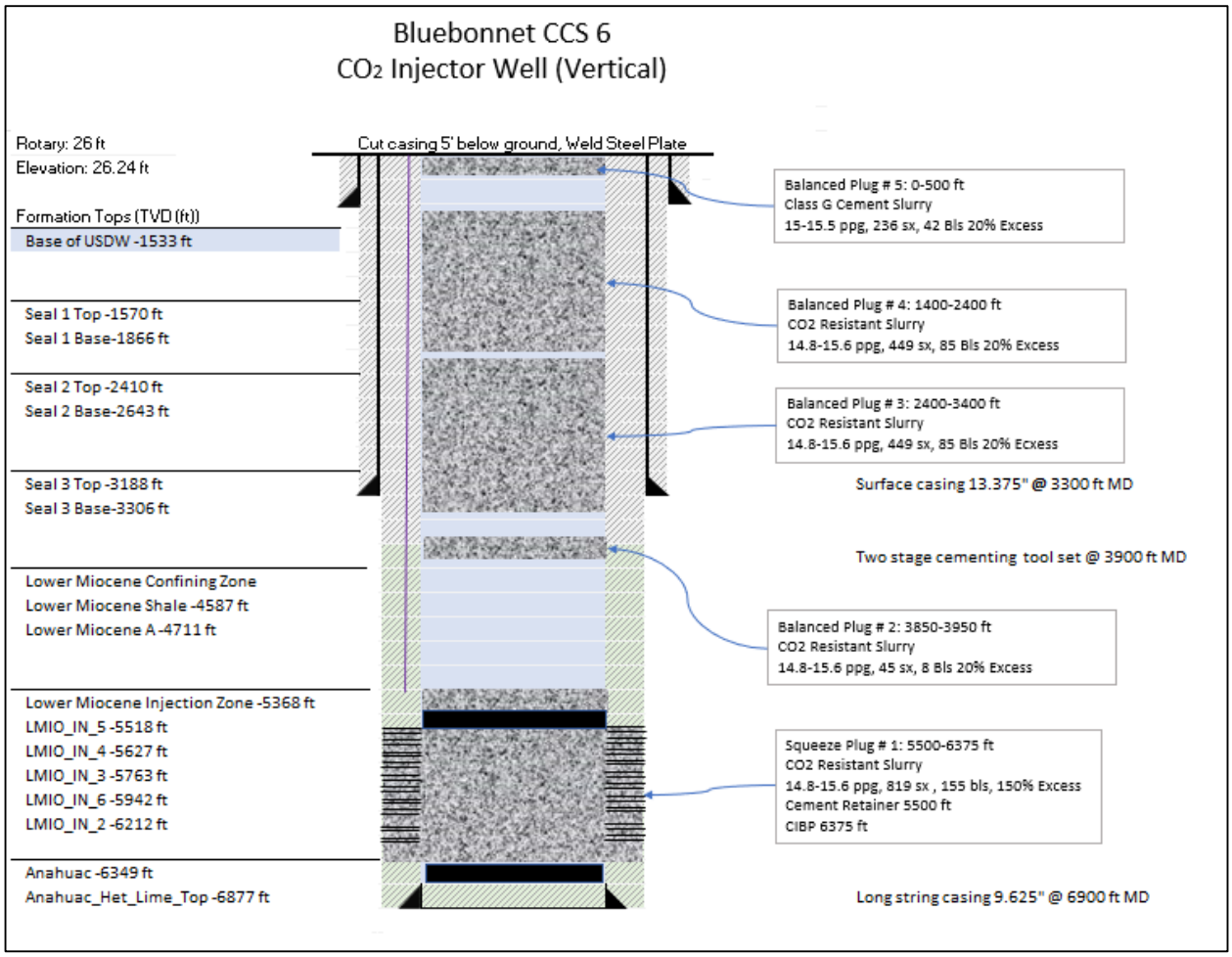


Figure PLG-5: Bluebonnet CCS 6 injection well plug schematic.

4.6 Bluebonnet CCS 7 Plug and Abandonment Details

Table PLG-6: Bluebonnet CCS 7 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	5150	6150	CO2 Resistant	14.8-15.5	1.06	150%	8.535	936
Plug # 2	Balanced Plug	3550	3650	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2325	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	483
Plug # 4	Balanced Plug	1250	2325	CO2 Resistant	14.8-15.5	1.06	20%	8.535	483
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

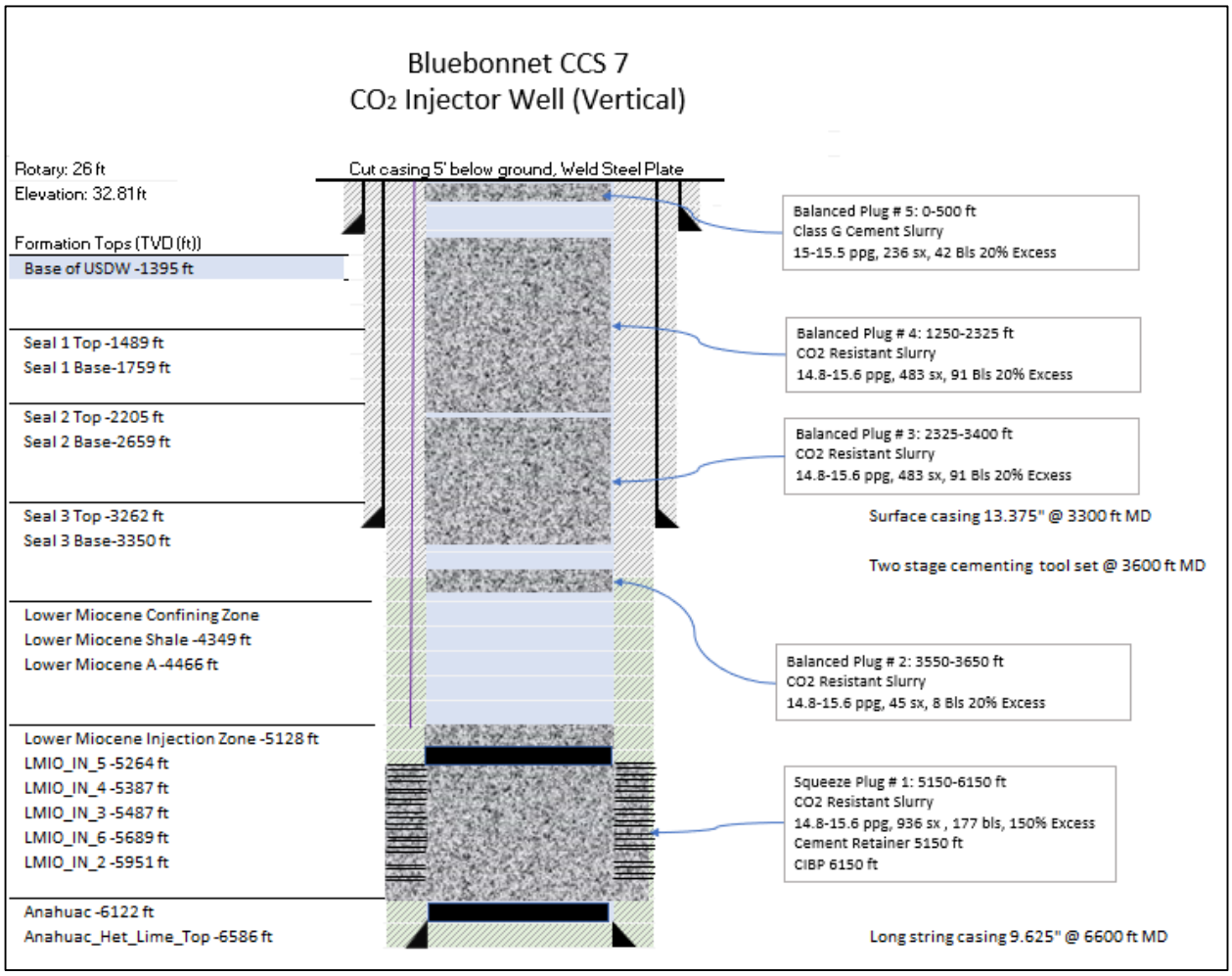


Figure PLG-6: Bluebonnet CCS 7 injection well plug schematic.

5.0 Narrative Description of Plugging Procedures for CO_2 Injector Wells

5.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), the Bluebonnet Sequestration Hub, LLC, will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

5.2 Bluebonnet CCS 1 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 1 site and rig up (RU). All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

Rig down the logging unit.

10. Set a cast iron bridge plug (CIBP) at 8,980 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 8,740 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the Hackberry formations from 8,740-8,980 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from the top of the cement retainer to 7,867 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pull up out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,450-3,500 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,400-2,450 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.3 Bluebonnet CCS 2 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 2 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP

measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.

5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.

6. If both the casing and tubing are controlled, then nipple up the BOPs.

7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.

8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS / DAS temperature survey (no need for logging unit)

   Rig down the logging unit.

10. Set a CIBP at 8545 ft.

11. Trip in hole with the work string and cement retainer to the top of plug #1 at 7,980 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.

12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Frio formation from 7,980-8,545 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.

13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.

14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,450-3,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.

15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,500-2,450 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.4 Bluebonnet CCS 3 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 3 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

    a. Pulse neutron log
    b. Noise log
    c. Temperature log
    d. Fiber optic DTS

    Rig down the logging unit.

10. Set a CIBP at 8,250 ft.

11. Trip in hole with the work string with a cast iron cement retainer to the top of plug #1 at 7,630 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.

12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Frio formation from 7,630-8,250 ft. Disconnect from the retainer and check the flow. Pull out of the hole.

13. Pick up the bit and trip in hole to the cast iron cement retainer (CICR) at 7,630 ft. Wait for the cement from plug #1 to develop 1,000 psi compressive strength according to the laboratory test and drill out the CICR and cement down to the CIBP at 8,250 ft. Test the casing to 500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. If the casing fails the pressure test, re-squeeze plug #1.

14. Continue cleaning the well down to 8,785 ft. Circulate the well clean. Pull out of the hole and lay down the bit.

15. Set a CIBP at 8,785 ft.

16. Trip in hole with the work string and cement retainer to the top of plug #2 at 8,385 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.

17. Plug #2: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Hackberry formation from 8,385-8,785 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from top of the cement retainer to 7,550 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pull out of the hole.

18. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,550-3,650 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.

19. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,345-3,400 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.

20. Plug #5: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,290-2,345 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
21. Plug #6: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
22. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.5 Bluebonnet CCS 5 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 5 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
    a. Pulse neutron log
    b. Noise log
    c. Temperature log
    d. DTS / DAS temperature survey (no need for logging unit)

    Rig down the logging unit.
10. Set a CIBP at 6,500 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 5,450 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Miocene formation from 5,450-6,500 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,450-3,500 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,400-2,450 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.6 Bluebonnet CCS 6 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 6 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.

3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS / DAS temperature survey (no need for logging unit)

   Rig down the logging unit.
10. Set a CIBP at 6,375 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 5,500 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Miocene formation from 5,500-6,375 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to

develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.

14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,400-3,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,400-2,400 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.7 Bluebonnet CCS 7 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 7 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.

8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
    a. Pulse neutron log
    b. Noise log
    c. Temperature log
    d. DTS / DAS temperature survey (no need for logging unit)

    Rig down the logging unit.
10. Set a CIBP at 6,150 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 5,150 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Miocene formation from 5,150-6,150 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,550-3,650 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,325-3,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,250-2,325 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

The proposed plugging and abandonment procedures and schematics for Bluebonnet IZM M1, Bluebonnet IZM M2, Bluebonnet IZM M3, Encanto 01, Bluebonnet PRDW F1, Bluebonnet PRDW F2, Bluebonnet DSW M2, Bluebonnet IZM FM1, Bluebonnet IZM FM2, Bluebonnet USDW 1, Bluebonnet USDW 2 and Bluebonnet USDW 8 are included in Appendix A.

All the monitoring wells that do not penetrate the base of usable quality water will be plugged according to the plan presented in Appendix A. (Certification added 04.07.25 to comply with Statewide Rule §5.203(k)(6))

H. EMERGENCY AND REMEDIAL RESPONSE PLAN

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.82(a)(19) and 40 CFR §146.94, this Emergency and Remedial Response Plan (ERRP) describes the actions that Bluebonnet Sequestration Hub, LLC, shall take to address movement of the injection or formation fluid in a manner that may endanger an Underground Source of Drinking Water (USDW) during the construction, operation, or post-injection site care periods of the Bluebonnet Sequestration Hub (the Project).

If the Bluebonnet Sequestration Hub, LLC, obtains evidence that the injected CO_2 stream and/or associated pressure front may endanger the USDW, the project must perform the following actions as required in 40 CFR §146.94(b):

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 Underground Injection Control (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 Bluebonnet Sequestration Hub, LLC, will immediately cease injection as quickly, technically, and safely possible. However, in some circumstances, Bluebonnet Sequestration Hub, LLC, in consultation with the UIC Program Director, will determine whether gradual cessation of injection is appropriate.

If the project demonstrates that the injection operation will not endanger USDWs, the UIC Director may allow the Bluebonnet Hub to resume injection prior to remediation 40 CFR §146.94(c).

2.0 Local Resources and Infrastructure

Resources in the vicinity of the Bluebonnet Sequestration Hub that may be affected due to an emergency event at the project site include groundwater (USDWs), surface riverine, freshwater ponds, lakes, estuarine, freshwater emergent wetlands, and palustrine farmed wetlands.

USDWs in the Gulf Coast includes the Chicot, Evangeline, and Jasper aquifers. In the Bluebonnet Hub site, the USDW has been identified within the Chicot aquifer, which is the main source of drinking water in the area. Site-specific base USDW (< 10,000 mg/l TDS) in the Bluebonnet Sequestration Hub proposed Area of Review (AoR) averages –1,356 TVDSS (true vertical depth subsea).

The physical geography of the AoR has the open water of the Rush Ditch, Spindletop Bayou, other unnamed ditches/riverine, and seasonally flooded rice or crawfish farming operations.

Figure ERR-1 shows the surface water features within the project AoR. The surface water features include palustrine, farmed wetlands, and riverine with limited freshwater ponds. The “Area of Review and Corrective Action Plan” document included in this permit application provides further details on the USDWs within the project area.



Infrastructure in the vicinity of the Bluebonnet Hub that may be affected due to an emergency at the project site includes domestic residences, water wells, local farming operations, Winnie Stowell Airport (a small-craft airport in Chambers County), and a major roadway, Interstate-10.

The towns of Winnie and Stowell, Texas are approximately two miles from the injection site. As of the 2020 census, the population of Winnie was 3,162 while the population of Stowell was 1,743.


Claimed as PBI

3.0 Potential Risk Scenarios

The events related to the Bluebonnet Sequestration Hub operations that could potentially result in an emergency response have been identified in a risk assessment workshop and are included in Table ERR-1. This table lists the types of potential adverse incidents that could trigger response actions to protect USDWs and when they might occur (i.e., during the construction, injection, or post-injection site care periods). In addition, the risk assessment workshop identified the emergency or remedial actions that the Bluebonnet Sequestration Hub, LLC, will undertake in response to these incidents. The worst-case consequences of various scenarios have been developed to ensure that response plans are in place for all eventualities.

Table ERR-1: Potential adverse incidents.

Construction/Pre-Injection Period
• Well control event during drilling, completion, or workovers with loss of containment. • Contamination of the USDW with formation brine or drilling fluids during drilling operations. • Unauthorized access or activities to the site.
Injection Period
• Loss of mechanical well integrity in injection wells due to tubing or packer leak. • Loss of mechanical well integrity in monitoring, water production, and water disposal wells due to tubing or packer leak. • Loss of mechanical well integrity in injection wells due to casing leak. • Loss of mechanical well integrity in monitoring, water production, and water disposal wells due to casing leak. • Well monitoring equipment failure or malfunction. • Loss of mechanical integrity in the pipeline. • Vertical migration of CO_2 and brines due to loss of external mechanical integrity in CO_2 injection wells. • Vertical migration of CO_2 and brines due to loss of external mechanical integrity in monitoring, water production, and water disposal wells. • Migration of CO_2 from the injection zone through documented legacy wells or undocumented artificial penetrations within the defined AoR. • Migration of CO_2 from the injection zone through faults and fractures or failure of the confining zone. • Rapid and/or unexpected movement of CO_2 outside the defined AoR. • External impact to the surface infrastructure (pipeline and wells). • Induced seismic event. • A natural disaster. • Unauthorized access or activities to the site.
Post-Injection Site Care Period
• Loss of mechanical well integrity in monitoring wells due to tubing or packer leak. • Loss of mechanical well integrity in monitoring wells due to casing leak.

- Monitoring equipment failure or malfunction.
- Vertical migration of CO_2 and brines due to loss of external mechanical integrity in monitoring wells.
- Migration of CO_2 from the injection zone through documented legacy wells or undocumented artificial penetrations within the defined AoR.
- Migration of CO_2 from the injection zone through faults and fractures or failure of the confining zone.
- Rapid and/or unexpected movement of CO_2 outside the defined AoR.
- External impact to the surface infrastructure (pipeline and wells).
- Induced seismic event.
- A natural disaster.
- Unauthorized access or activities to the site.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table ERR-2.

Table ERR-2: Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Known release or indication of a potential incident that poses an immediate (acute) risk to human health, resources, or infrastructure. Response actions involving local authorities (evacuation, isolation of areas, or restrictions on water usage) should be initiated.
Serious emergency	Incidents/releases posing potential (chronic) risk to human health, resources, or infrastructure, if conditions worsen or no mitigative or remedial actions are taken.
Minor emergency	Incident poses a challenge to the confinement barrier, but it does not result in the immediate release of CO_2 or brine posing a risk to human health, resources, or infrastructure.

4.0 Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, controls and mitigations in place, and severity of the event. The avoidance measures and potential actions set forth below are for information purposes. In an emergency, response actions will be based on operational, technical, and safety conditions at the time of the emergency. Additionally, avoidance measures may change over time based on technical and operational advancement. Depending on the severity of the event, the Bluebonnet Sequestration Hub, LLC, will activate its corporate emergency response organization as appropriate. The potential risk scenarios listed in Table ERR-1 are detailed below.

4.1 Well Control Event During Drilling, Completion, or Workovers with Loss of Containment

A well control event could occur during drilling, completions, and workover operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well. A well control event could also occur due to encountering unexpected overpressure zones while drilling.

Severity: Minor

Timing of event: Construction/Pre-Injection/Injection

Avoidance measures: Blowout prevention (BOP) equipment, BOP testing protocol, kill fluid, well control training, kick drill, lubricators for wireline operations, and legacy well analysis.

Detection methods: flow sensor, pressure sensor, tank level indicator, tripping displacement practices, and mud weight control.

Potential response actions:

- During drilling:
  - Stop operations.
  - Close the BOP.
  - Clear the floor and secure the area.
  - Execute the well control procedure.

  - Evaluate drilling parameters and identify root cause.
  - Continue operations.

- During completion/workovers:
  - Stop operations.
  - Close the BOP.
  - Clear the floor and secure the area.
  - Execute the well control procedure.
  - Continue operations.

Response personnel: Rig crew, rig manager, field superintendent, and project manager

4.2 Contamination of the USDW with Formation Brine or Drilling Fluids During Drilling Operations

Movement of brine between formations during drilling operations could occur if there is a cross flow with losses to the USDW. Contamination with drilling mud could occur during lost circulation events if the formation is not able to support the column of fluids, during a packoff event, or due to swab surge events.

Severity: Minor

Timing of event: Construction/Pre-Injection

Avoidance measures: USDW covered with surface casing, surface section drilled with fresh water and gel, casing test after cementing surface casing to check integrity, and formation integrity test (FIT) test to verify shoe integrity.

Detection methods: tank level sensor, mud lab test, pressure sensors, flow tensors, and tripping sheets.

Potential response actions:

- Stop drilling.
- Check the well level to detect lost circulation or influx.
- In case of loss, treat the well with lost circulation material and evaluate mud weight and drilling parameters.
- In case of influx, control the well without compromising shoe integrity.
- In case the shoe is identified as leaking, squeeze to regain integrity.
- In case the surface casing is identified as leaking, squeeze or casing patch are options.

Response personnel: Rig crew, rig manager, and field superintendent.

4.3 Loss of Mechanical Integrity in CO_2 Injector due to Tubing or Packer Leak

Loss of mechanical integrity due to a tubing or packer leak in the CO_2 injector wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause communication of the formation fluids with the annulus between the casing and tubing and sustained casing pressure. There is no loss of containment in this scenario.

Severity: Minor

Timing of event: Injection

Avoidance measures: Coated tubing, inhibited packer fluid in annulus, corrosion monitoring plan, dry CO_2 injected, nickel-plated packers, HH trim on tubing hanger for CO_2 injector wellheads and tree, and CR or Inconel carrier for the sensors.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, annular pressure test, distributed temperature sensing (DTS) fiber optic capabilities, and CO_2 leak sensor on the wellhead.

Potential response actions:

- Follow protocol to close the well, stop operations, and vent or divert CO_2.
- Troubleshoot the well.
- If a tubing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, and rig crew

4.4 Loss of Mechanical Integrity in Monitoring Wells, Water Production Wells, and Water Disposal Wells Due to Tubing or Packer Leak

Loss of mechanical integrity due to a tubing or packer leak in the monitoring, water production, and water disposal wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause communication of the formation fluids with the annulus between the casing and tubing and sustained casing pressure. There is no loss of containment in this scenario.

Severity: Minor

Timing of event: Injection/Post Injection

Avoidance measures: Inhibited packer fluid in annulus, corrosion monitoring plan, nickel-plated packers, and CR or Inconel carrier for the sensors.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, annular pressure test, CO_2 leak sensor on the wellhead, DTS fiber installed alongside casing, pulse-activated neutron log, and electromagnetic inspection log.

Potential response actions:

- Troubleshoot the well.
- If a tubing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, and rig crew.

4.5 Loss of Mechanical Integrity in CO_2 Injection Wells Due to Casing Leak

Loss of mechanical integrity due to a casing leak in the CO_2 injection wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause a migration of CO_2 and brines through the casing, the cement sheet, and into a different formation in the injection target or USDW.

Severity: Minor

Timing of event: Injection

Avoidance measures: CO_2-resistant cement and metallurgy across injection zone, injection through tubing and packer, nickel-plated packers, CR or Inconel carrier sensors, inhibited packer fluid in the annulus, cement to surface, corrosion monitoring plan, Cement Bond Log (CBL) or Ultrasonic Image Tool (USIT) after installation, robust mechanical integrity plan, and USDW cover with surface casing cemented to surface.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, CO_2 leak sensor on the wellhead, real-time DTS fiber alongside of casing, flow rate monitoring, soil gas probes, neutron-activated logs, and USDW water monitoring.

Potential response actions:

- Follow protocol to stop operations and vent or divert CO_2.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to the USDW.
- If the USDW is affected, discuss remediation with the regulating authority.
- If a casing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.6 Loss of Mechanical Integrity in Monitoring Wells, Water Production Wells, and Water Disposal Wells Due to Casing Leak

Loss of mechanical integrity due to a casing leak in the monitoring, water production, and disposal wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause a migration of CO_2 and brines through the casing, the cement sheet, and into a different formation in the injection target or USDW.

Severity: Minor

Timing of event: Injection/Post Injection

Avoidance measures: CO_2-resistant cement across injection zone, nickel-plated packers, CR or Inconel carrier sensors, inhibited packer fluid in the annulus, cement to surface, corrosion monitoring plan, CBL/USIT after installation, and USDW cover with surface casing cemented to surface.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, annular pressure test, DST capabilities, CO_2 leak sensor on the wellhead, soil gas probes, neutron-activated logs, and USDW water monitoring.

Potential response actions:

- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to the USDW.
- If the USDW is affected, discuss remediation with the regulating authority.
- If a casing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.7 Well Monitoring Equipment Failure or Malfunction During Injection

A failure of the monitoring system or associated alarm devices may cause over pressurization of the system or reservoir beyond the design limits, which could cause reservoir fracture, leaks, failure of equipment and tubulars, and facilities damage.

Severity: Minor

Timing of event: Injection

Avoidance measures: Preventative maintenance program and periodic inspections

Detection methods: Real-time monitoring systems, redundancy, and field inspections.

Potential response actions:

- If a single surface-monitoring device (e.g., surface pressure transmitter) that has a redundant device (i.e., second pressure transmitter) still in operation fails, the operational response required is to repair the device. No change to operations will be immediately planned.
- If a downhole monitoring equipment fails, the project manager will assess the impact and prepare an action plan to be discussed with the UIC Director.

4.8 Vertical Migration of CO_2 and Brines Due to Loss of External Mechanical Integrity in CO_2 Injection Wells Due to Cement Failure

During the life of the injector wells, there are induced stresses and chemical reactions on the cement exposed to the CO_2 pressure and plume. These mechanics could lead to cracks, channels, or permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines or CO_2 potentially affecting the USDW.

Severity: Minor

Timing of event: Injection

Avoidance measures: CO_2-resistant cement and metallurgy across the injection zone, injection through tubing and packer, cement to surface, CBL/USIT after installation, and USDW covered as a section barrier with surface casing and surface cement sheet.

The injection zones in the Hackberry, Frio, and the Lower Miocene Formations are separated from the base of the USDW by more than 3,000 ft of shales and sand layers. The described base of the Hackberry, intraformational Frio, primary Anahuac, and secondary Lower Miocene Confining Zones as well as the additional Composite Confining Zones (five confining zones altogether) are in place to protect and dissipate any fluid migration outside the permitted Hackberry, Frio, and Lower Miocene Injection Zones to protect the USDW.

The injector wells will be plugged and abandoned at the end of the injection period in accordance with the Injection Well Plugging Plan included with this permit application.

Detection methods: CO_2 leak sensors on the wellhead, real-time DTS fiber alongside the casing, soil gas probes, USDW water monitoring, neutron-activated logs to be run for external MI, pressure gauges at the surface, and flow rate monitoring.

Potential response actions:

- Follow protocol to stop operations and vent or deviate CO_2.
- Troubleshoot the well.
- Evaluate if there is any movement of CO_2 or brine to the USDW.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary.
- Discuss plans to repair the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.9 Vertical Migration f CO_2 and Brines Due to Loss of External Mechanical Integrity in Monitoring Wells, Water Production Wells, and Water Disposal Wells Due to Cement Failure

During the life of the monitoring wells, water production wells, and water disposal wells, there are induced stresses and chemical reactions on the cement exposed to brines, the pressure plume, and CO_2. These mechanics could lead to cracks, cement deterioration, and/or channels or permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines or CO_2.

Severity: Minor

Timing of event: Injection and Post-Injection

Avoidance measures: CO_2-resistant cement across the injection zone, cement to surface, CBL/USIT after installation, and USDW is covered the surface casing and surface cement sheet as primary barrier. The water disposal wells and the above-confining-zone/USWD wells do not penetrate the CO_2 injection target.

Detection methods: CO_2 leak sensors on the wellhead, soil gas probes, USDW water monitoring, neutron-activated logs to be run for external MI, and pressure gauges at the surface. DST fiber installed alongside the casing in water production wells and in-zone monitoring wells.

Potential response actions:

- Troubleshoot the well.
- Evaluate if there is any movement of CO_2 or brine to the USDW.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary.
- Discuss plans to repair the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.10 Migration of CO_2 From the Injection Zone through Documented Legacy Wells or Undocumented Artificial Penetrations within the Defined AoR

This event occurs if formation brines and CO_2 migrate through poor cement bonding, cement degradation, open hole abandonments, or cracking in the cement in existing legacy wells.

Severity: Serious

Timing of event: Injection and Post-Injection

Avoidance measures: Twenty-Five legacy wells were identified in the proposed AoR. The wells are or will be properly abandoned based on the leak assessment evaluation. CO_2-resistant cement will be used on wells that require a P&A program. An airborne magnetic survey will be conducted over the AoR before injection to identify potential undocumented wells.

Detection methods: Soil gas probes across the AoR, real-time pressure and temperature indication on monitoring wells, 2D surface seismic surveying, 3D VSP (vertical seismic profile) surveys, time-lapse pulse-neutron electromagnetic log, groundwater monitoring, and in-zone monitoring dedicated to measuring reservoir pressure to calibrate the model.

Potential response actions:

- Evaluate if there is any movement of CO_2 or brine to the USDW due to a leak in a legacy or plugged and abandoned well.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary
- Discuss plans to repair the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors.

4.11 Migration of CO_2 from the Injection Zone Through Faults and Fractures or Failure of the Confining Zone

Migration of brine or CO_2 during injection could occur if the pressure of the injection zone exceeds the sealing capacity of the caprock or seal above or if fault or fracture features are reactivated. Brine or CO_2 could migrate to a shallower formation, including the USDW.

Severity: Minor

Timing of event: Injection/Post Injection

Avoidance measures: Seismic survey of the area shows no faults crossing the storage formation or the seal, injection is limited to 90% of the fracture gradient, and extensive characterization of the geology shows good sealing capacity. The injection zones in the Hackberry, Frio and the Lower Miocene Formations are separated from the base of the USDW by more than 3,000 ft of shales and sand layers. The described base of the Hackberry, intraformational Frio, primary Anahuac, and secondary Lower Miocene Confining Zones as well as the additional Composite Confining Zones (five confining zones altogether) are in place to protect and dissipate any fluid migration outside the permitted Hackberry, Frio, and Lower Miocene Injection Zones to protect the USDW.

Detection methods: Above-confining-zone/USDW water sampling and pressure monitoring, 2D surface seismic, 3D VSP surveys, neutron-activated logs in monitoring wells, soil gas monitoring, and reservoir pressure and temperature real-time monitoring with in-zone monitoring wells.

Potential response actions:

- Follow protocol to stop injection.
- Assess the root cause by reviewing monitoring data.
- If required, conduct a geophysical survey to delineate potential leak path.
- Evaluate if there is any movement of CO_2 or brine to the USDW due to a failure of confining rock, faults, or fractures.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary
- Take appropriate actions to restore injection, depending on the nature of the leak path and extension.

Response personnel: Monitoring staff, geologist, reservoir engineer, project manager, and remediation contractors

4.12 Rapid and/or Unexpected Movement of CO_2 Outside the Defined AoR

Lateral migration of CO_2 outside the defined AoR could occur during injection or post-injection if the plume moves faster or in an unexpected pattern and expands beyond the secure pore space and AoR for the project.

Severity: Serious

Timing of event: Injection/Post-Injection

Avoidance measures: Detailed geologic model with the stratigraphic well as a calibration, seismic survey integrated in the model, extensive characterization of the rocks and formation, AoR review and calibration at least every 5 years, and monitoring of the plume until stabilization.

Detection methods: 2D surface seismic, 3D VSP surveys, neutron-activated logs in monitoring wells, soil gas monitoring, and reservoir pressure and temperature real-time monitoring with in-zone monitoring wells.

Potential response actions:

- Injection

  - Review monitoring data and trends compared with simulation.
  - Discuss findings with the regulating authority and request to maintain injection during AoR evaluation if data shows no endangerment of USDWs.
  - Perform logging in monitoring wells.
  - Conduct geophysical survey as required to evaluate the AoR.
  - Recalibrate the model and simulate the new AoR.
  - Assess if additional corrective actions and additional pore space are needed.
  - Assess if remediation is needed: prepare an action plan and review with the regulating authority.
  - Present the AoR review to the regulating authority for approval and adjust the monitoring plan.
- Post-Injection
  - Review monitoring data and trends compared with simulation.
  - Discuss findings with the regulating authority.
  - Conduct a geophysical survey as required to evaluate the AoR.
  - Recalibrate model and simulate the new AoR.
  - Assess if additional corrective actions and pore space are needed.

Response personnel: Monitoring staff, geologist, reservoir engineer, and project manager

4.13 External Impact to the Infrastructure (Pipeline, Wells)

Surface impact may cause loss of containment during the follow scenarios:

- External impact to the wellhead of the CO_2 Injection wells.
- External impact to the wellhead of the monitoring wells, water production wells, and water disposal wells.
- External impact to the surface piping or buried pipelines

4.13.1 Loss of Containment; External Impact to the Wellhead of the CO_2 Injection Wells

This event could occur if the wellhead is hit by a massive object (such as a vehicle or other heavy equipment) while in operation. In this scenario, the object causes major damage to the equipment that results in the well separating from the pipeline and shut-off system and leads to a loss of containment of CO_2 and brine.

Severity: Major

Timing of event: Injection

Avoidance measures: Fenced location and bollards installed and signage. A dispersion analysis was performed for this potential release event and did not identify any major public impact. This event is very unlikely to happen.

Detection methods: Real-time pressure and temperature at the wellhead and surface facilities, field inspections, and OGI (optical gas imaging) cameras.

Potential response actions:

- Automated shutdown will initiate; however, follow protocol to shutdown CO_2 delivery if the automated shutdown devices are not functional.
- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Contact the well control special team to execute blowout emergency plan that may include capping the well, drilling a relief well to kill the injector, repair the well, and/or abandon the well; discuss plan with the regulating authority.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system, as needed.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, remediation contractors, and well control specialist

4.13.2 Loss of Containment; External Impact to the Wellhead of The Monitoring Wells, Water Production Wells and Water Disposal Wells

This event would occur if the wellhead of the deep monitoring well or water production well is hit by a massive object and causes major damage leading to a loss of containment. Since the well is open to the formation pressure at the CO_2 injection zone, formation fluids have the potential to flow and spill on the location and around the area.

Severity: Serious

Timing of event: Injection and Post-Injection

Avoidance measures: Fenced location and bollards installed, signage, and reduced pressure in the monitoring well compared with the injection well.

Detection methods: Field inspections and real-time pressure and temperature at the wellhead and surface facilities.

Potential response actions:

- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Contact the well control special team to execute blowout emergency plan that may include capping the well, drilling a relief well to kill the injector, repair the well, and/or abandon the well; discuss plan with the regulating authority.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system, as needed.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, remediation contractors, and well control specialist

4.13.3 Loss of Containment; External Impact to the Surface Piping or Buried Pipeline

External impact to the surface piping or buried pipeline due to heavy trucks or equipment could cause loss of containment of brine or CO_2, if the pipe is ruptured.

Severity: Major

Timing of event: Injection

Avoidance measures: Fenced location and bollards installed to protect surface piping, field pipeline buried, pipeline Right-of-Way identified with signage, and One Call 811 Program. A dispersion analysis was performed for this potential release event and did not identify any public impact.

Detection methods: Real-time pressure, temperature, and flow measurements and field inspections.

Potential response actions:

- Automated shutdown will initiate; however, follow protocol to shutdown CO_2 delivery if the automated shutdown devices are not functional.
- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, and well control specialist

4.14 Earthquake

A major seismic event may disturb surface and/or subsurface facilities. Bluebonnet will develop and implement a site-based earthquake response plan. The purpose of the earthquake response plan is to identify the actions that will be taken to inspect for damage, mitigate and/or manage risk by modifying operations, and establish thresholds for suspension of injection activity.

- The earthquake response plan shall be filed with the Commission before injection activities begin.
- The operator will monitor TexNet and USGS earthquake catalogs.
- The earthquake response plan is triggered when a 3.5 M event is detected with a reported hypocenter within the 9.08 (5.6 miles) km AoR.
- The earthquake response plan shall identify the actions the operator will take when a 3.5 M event is detected with a reported hypocenter within the 9.08 (5.6 miles) km AoR.
- The operator shall notify the Commission within 24 hours of an earthquake that triggers the response plan.
- Within 30 days of an earthquake trigger, the operator shall file a report with the Commission documenting the event, response actions taken, and findings

Timing of event: Injection and Post-Injection

Avoidance measures: Shutoff valves are present to shutoff injection into the wells when abnormal operating parameters, particularly high or low pressures, are present in the pipeline delivering CO_2 to the injection site.

Detection methods: A geophone array located on the surface to monitor seismicity will detect naturally occurring major seismic events during the injection period, in addition to pipeline and wellhead real-time monitoring of pressures and flows.

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, and emergency teams

4.15 Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise from a natural disaster affecting the normal operation of the injection wells. If a natural disaster occurs that affects normal operation of an injection well, perform the following:

Severity: Dependent on severity of event, potentially Major

Timing of event: Injection and Post-Injection

Avoidance measures: Shutoff valves are present to shutoff injection into the wells when abnormal operating parameters, particularly high or low pressures, are present in the pipeline delivering CO_2 to the injection site.

Detection methods: The site will be equipped with real-time monitoring devices for pipeline and well operations. Daily surveillance of the site will allow forecasting natural events and start securing the site ahead of the event.

Potential response actions:

- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Follow protocol to stop injection in the event the site was not secured previously.
- Assess the mechanical integrity of the system and propose repair actions based on findings.
- If assessment allows for resuming injection safely, increase surveillance to validate effectiveness of actions.

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, and emergency teams

4.16 Induced Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a 5.6-mile radius of an injection well and follow the actions described in the section 4.14.

A geophone array has been installed on the surface to monitor the area for seismicity.

Severity: Minor

Timing of event: Injection and Post Injection

Avoidance measures: Seismic survey of the storage complex shows no faults that could be reactivated, detailed geomechanical model created to evaluate the storage complex, and region is seismically stable. Shutoff valves are present to shutoff injection into the well.

Detection methods: Geophone array on surface

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, and emergency teams

4.17 Unauthorized access or activities on the Site. (Statewide Rule §5.203(I)(3)(B))

The Bluebonnet Hub primarily encompasses surface locations related to the CO_2 injection and monitoring wells, as well as the buster pads for the water and CO_2 pumps. Additionally, it is important to note that the majority of the CO_2 and water pipelines will be buried underground to ensure safety and efficiency.

Severity: Serious

Timing of event: Construction, Injection and Post Injection

Avoidance measures: During the construction phase, the locations and equipment will be under continuous surveillance by security guards stationed on the rigs and by construction crews. Once the equipment is installed, the locations will be fenced, and bollards will be set up to safeguard surface piping and the wellhead. During operation, a field supervisor will conduct regular visual inspections, and a 24/7 surveillance system will monitor operating parameters in real-time. The site is equipped with automatic shut-off devices to handle emergencies. Additionally, the field pipeline will be buried, the pipeline Right-of-Way will be marked with signage, and the One Call 811 Program will be implemented.

Detection methods: Real-time pressure, temperature, and flow measurements and field inspections.

Potential response actions:

- Automated shutdown will initiate; however, follow protocol to shutdown CO_2 delivery if the automated shutdown devices are not functional.
- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, and well control specialist

5.0 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement the ERRP. Monitoring, control, and routine maintenance of the injection operations will be the responsibility of the Injection Operations Staff. Site personnel must include, at minimum, the positions listed below in Table ERR-3.

If an adverse event is discovered, the Operations Manager and Emergency Coordinator on duty will be notified immediately. The Emergency Coordinator will be responsible for notifying offsite emergency agencies and resources. The Operations Manager or their delegate will contact outside emergency response organizations, if the Emergency Coordinator is not available. The EPA (Environmental Protection Agency) Region 6 UIC Program Director will be notified within 24 hours, per 40 CFR §146.91(c) and 40 CFR §146.94(b)(3).

Table ERR-3: Operations staff descriptions.

Position	Function	Qualifications
Emergency Coordinator	Responsible for notification of offsite support agencies in accordance with written procedures. Responsible for coordination and overseeing contact with the media.	Trained in the Communications Plan and Emergency Notification Procedures requirements as contained in the ERRP.
Operations Manager	Serves as the Emergency Response Manager responsible for the overall management of the Incident Response Team. Manages facility operations and personnel during an emergency and is responsible for implementation of appropriate emergency procedures and their follow-up activities.	Trained in the requirements of the ERRP and facility operations.
Project Manager	Serves as the Emergency Response Coordinator responsible for the overall communication between Incident Response Team members. Directs facility operations during an emergency and is responsible for communication between on-site personnel and professional services. Implements emergency procedures and ensures documentation of follow-up activities.	Trained in the requirements of the ERRP and facility operations.
Senior Reservoir Engineer	Responsible for injection operation and monitoring. Lead incident response manager regarding injection and storage zone operation at the facility.	Experienced professional in reservoir dynamics and relevant monitoring interpretation.
Geologist/ Geophysicist	Professional serving to assist in operations, maintenance, and monitoring of the injection process. Conducts routine data management and interpretation. Assists in implementing response actions regarding injection zone integrity.	Experienced professional in geophysics or geology.
Operations Engineer	Oversees mechanical and fluid management operation of the injection wells, annulus pressure control system, and wellhead piping systems. Maintains and repairs injection-related equipment, including valves, instruments, and piping. Assists in mechanical and electronic control of the injection process.	Experienced professional in field operations, maintenance, monitoring systems. Trained in the requirements of the ERRP and facility operations.

A site-specific emergency contact list will be developed and maintained during the project's life. The Bluebonnet Sequestration Hub, LLC, will provide the current site-specific emergency contact list to the UIC Program Director.

A list of contacts for state agencies having jurisdiction within the AoR and key local emergency agencies is presented below in Table ERR-4.

There are no federally recognized Native American Tribes located within the AoR. If a federally recognized Native American Tribes were to exist in the AoR at the time of a site emergency, then that tribe(s) will be notified of the site emergency at that time.

Table ERR-4: Contact information for key local, state, and other authorities.

Agency/Service	Location	Phone
Chambers County – Emergency Mgt Office	Anahuac, TX	(409) 267-2445
Liberty County – Emergency Mgt Office	Liberty, TX	(936) 334-3219
Jefferson County – Emergency Mgt Office	Beaumont, TX	(409) 835-8757
Chambers County Sheriff — Main	Anahuac, TX	(409) 267-2500
Chambers County Sheriff (Office)	Anahuac, TX	(409) 267-3220
Winnie-Stowell Fire Dept. (District 1)	Winnie, TX	(409) 296-4133
Winnie-Stowell Volunteer EMS	Winnie, TX	(409) 296-9627
Jefferson County ESD No. 4	Beaumont, TX	(409) 796-1704
Riceland Hospital	Winnie, TX	(409) 730-8054
St. Elizabeth Hospital	Beaumont, TX	(409) 892-7171
Baptist Hospital	Beaumont, TX	(409) 212-5000
Medical Center Hospital	Beaumont, TX	(409) 724-7389
Texas Highway Patrol — Beaumont	Winnie/Beaumont, TX	(409) 924-5466
Texas Highway Patrol — Houston	Houston, TX	(281) 517-1220
US Geological Survey of Texas	Austin, TX	(512) 927-3500
Texas Railroad Commission (District 03)	Houston, TX	(713) 869-5001
Texas Railroad Commission (24-Hr Line)	Austin, TX	(844) 773-0305 or (512) 463-6788
TCEQ Region 12 — Houston	Houston, TX	(713) 767-3500
EPA Region 6	Dallas, TX	(214) 665-2294

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

6.0 Emergency Communications Plan

Bluebonnet Sequestration Hub, LLC, will communicate to the public about any event that requires an emergency response. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether there is any risk to human health or the environment or any impacts to drinking water, any impacts to the surrounding community, and current understanding of the event.

As may be required by any government agency with jurisdiction over the project, the Bluebonnet Sequestration Hub, LLC, will, to the extent known, communicate with appropriate stakeholders

what happened, current or potential impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long term (e.g., ongoing cleanups), the Bluebonnet Sequestration Hub, LLC, will provide appropriate periodic updates to the UIC Program Director on the progress of the response action(s).

The Bluebonnet Sequestration Hub, LLC, will also communicate with entities who need to be informed about or act in response to the event, including local water system operators, CO_2 source(s), pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

If a seismic event occurs, the Bluebonnet Sequestration Hub, LLC, will, to the extent it can be reasonably determined, provide information to the UIC Program Director about whether the event was naturally occurring or induced by the injection, whether any damage to the well or other structures in the area occurred, the investigative process, and what responses, if any, were taken by the Bluebonnet Sequestration Hub, LLC, or others.

7.0 Emergency and Remedial Response Plan Review

The project team will review the ERRP periodically and will comply with 40 CFR §146.94(d), including:

- At least once every five years following its approval by the permitting agency.
- Within one year of an AoR reevaluation.
- Within a prescribed period (to be determined by the permitting agency) following any significant changes to the injection process or injection facility or an emergency event
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, the project team will provide the permitting agency with the documentation supporting the “no amendment necessary” determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within six months following an event that initiates the ERRP review procedure.

8.0 Staff Training and Exercise Procedures

All operations employees will receive training related to health and safety, operational procedures, and emergency responses according to the roles and responsibilities of their work assignments. Initial training will be conducted by, or under, the operations manager or a designated representative's supervision. Trainers will be thoroughly familiar with the Operations Plan and ERRP.

Facility personnel will participate in annual training that teaches how to perform their duties in ways that prevent CO_2 discharge. The training will include familiarization with operating

procedures and equipment configurations appropriate to the job assignment and emergency response procedures, equipment, and instrumentation. New personnel will be instructed before beginning work.

Refresher training will be conducted at least annually for all operations personnel. Monthly briefings will be provided to operations personnel according to their respective responsibilities and highlighted with recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.

Only personnel who have been properly trained will participate in drilling, construction, operations, and equipment repair at the storage site. A record including the person's name, date of training, and instructor's signature will be maintained.

I. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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Plan revision number: 4
Plan revision date: 09/25/2025

1.0 Facility Information

Facility name: Bluebonnet CO_2 Sequestration Hub
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7 Wells.

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.93 this Post-Injection Site Care and Site Closure (PISC) Plan describes the activities that the Bluebonnet Sequestration Hub, LLC will take after injection ceases in the site until closure. The Bluebonnet Sequestration Hub, LLC will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years post injection. The Bluebonnet Sequestration Hub, LLC, may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the Underground Injection Control (UIC) Program Director. Following approval for site closure, the Bluebonnet Sequestration Hub, LLC, will plug all monitoring wells still active, restore the site in accordance with applicable law and good industry practice, and submit a site closure report and associated documentation.

2.0 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

2.1 Lower Miocene, Frio and Hackberry Pre- and Post-Injection Pressure Differential.

Based on the modeling of the pressure front as part of the AoR delineation, the magnitude and area of elevated pressure rapidly decreases over time after the end of injection reaching values close to original reservoir pressure in the first five years of the post-injection period.

The highest pressures are observed in the immediate vicinity of each CO_2 injector well. Table PISC-1 demonstrates the pressure differential at reference depth for Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3.

Table PISC-2 demonstrates the pressure differential at reference depth for Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7.

Table PISC-3 demonstrates the pressure differential at reference depth for each in zone monitoring well.

Figure PISC-1 and Figure PISC-2 show the bottomhole pressure versus time at reference depth for the CO_2 injector wells, Bluebonnet CCS 1, Bluebonnet CCS 2 , Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 and the in zone monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2 and Encanto 01well in the Area of Review (AoR).

Table PISC-1: Pressure differential to pre-injection conditions at the CO_2 injector wells Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3.

Year From Injection	Pressure Differential (psi)		
	Bluebonnet CCS 1F	Bluebonnet CCS 2F	Bluebonnet CCS 3F
0	0	0	0
1	186 (Stage 1, measured at Frio Low)	241 (Stage 1, measured at Frio Low)	187 (Stage 1, measured at Hackberry)
2	183	227	194
3	184	223	199
4	186	224	203
5	189	225	206
6	192	227	210
7	195	231	213
8	199	234	216
9	211 (Stage 2, measured at Frio Mid)	220 (Stage 2, measured at Frio Mid)	227 (Stage 2, measured at Frio Low)
10	217	226	224
11	222	232	225
12	228	238	229
13	234	244	233
14	240	250	237
15	245	256	242
16	795 (Stage 3, measured at Hackberry)	124 (Shut in, measured at Frio Mid)	224 (Stage 3, measured at Frio Mid)
17	714	114	212
18	664	111	206
19	634	109	203
20	610	108	201
25	38	89	88
30	40	81	81
35	44	76	76
40	48	72	73
45	50	69	70
50	52	67	68
55	54	65	66
60	55	64	65
65	55	63	64
70	56	62	63

Table PISC-2: Pressure differential to pre-injection conditions at the CO_2 injector wells Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7

Year From Injection	Pressure Differential (psi)		
	Bluebonnet CCS 5	Bluebonnet CCS 6	Bluebonnet CCS 7
	(Ref 6,405 ft)	(Ref 6,289 ft)	(Ref 6,054 ft)
1	165.5	162.8	132.1
2	166.0	162.4	131.8
3	169.5	166.1	136.6
4	168.0	169.7	134.1
5	143.8	163.7	93.4
6	143.4	162.5	89.6
7	143.4	155.3	91.3
8	115.9	90.6	90.1
9	111.4	87.1	63.5
10	111.4	88.0	63.0
11	108.5	90.4	65.2
12	63.0	84.7	66.1
13	60.3	82.6	49.5
14	52.1	81.3	50.7
15	52.9	67.2	52.4
End of Injection			
16	31.8	34.9	41.4
17	25.5	28.4	35.8
18	22.9	25.7	33.7
19	21.3	24.1	32.9
20	20.4	23.1	32.6
25	18.2	21.1	32.1
30	16.2	20.7	31.7
35	15.4	21.1	31.5
40	16.0	21.5	31.5
45	16.6	21.8	31.5
50	17.1	22.0	31.5
55	17.4	22.2	31.5
60	17.7	22.3	31.5
65	17.8	22.4	31.5
70	18.0	22.5	31.5

Table PISC-3: Pressure differential to pre-injection conditions at the in zone monitoring well locations Bluebonnet IZM FM1, Bluebonnet IZM FM2 and Encanto 01.

Reference, ft, TVDSS	7,417	7,185	7,770	6,059*
Year From Injection	Pressure Differential (psi)			
	Encanto 01 (Frio)	Bluebonnet IZM FM 1	Bluebonnet IZM FM2	Encanto (Lower Miocene)
0	0	0	0	36
1	13	9	18	72
2	23	19	29	82
3	31	27	36	89
4	38	34	44	90
5	45	40	50	87
6	51	46	56	89
7	57	52	62	86
8	63	58	68	93
9	77	70	92	93
10	90	82	107	96
11	100	91	117	95
12	108	99	126	94
13	116	107	134	95
14	123	114	141	94
15 (End Injection Lower Miocene)	130	121	148	94
16	123	123	116	62
17	118	119	109	57
18	116	117	106	55
19	115	116	105	54
20 (End of Injection Hackberry/Frio)	114	116	104	53
25	89	88	88	50
30	82	81	80	49
35	77	76	76	49
40	74	73	72	48
45	71	70	70	48
50	69	68	68	48
55	67	67	66	48
60	66	65	65	47
65	65	64	64	47
70	64	63	63	47

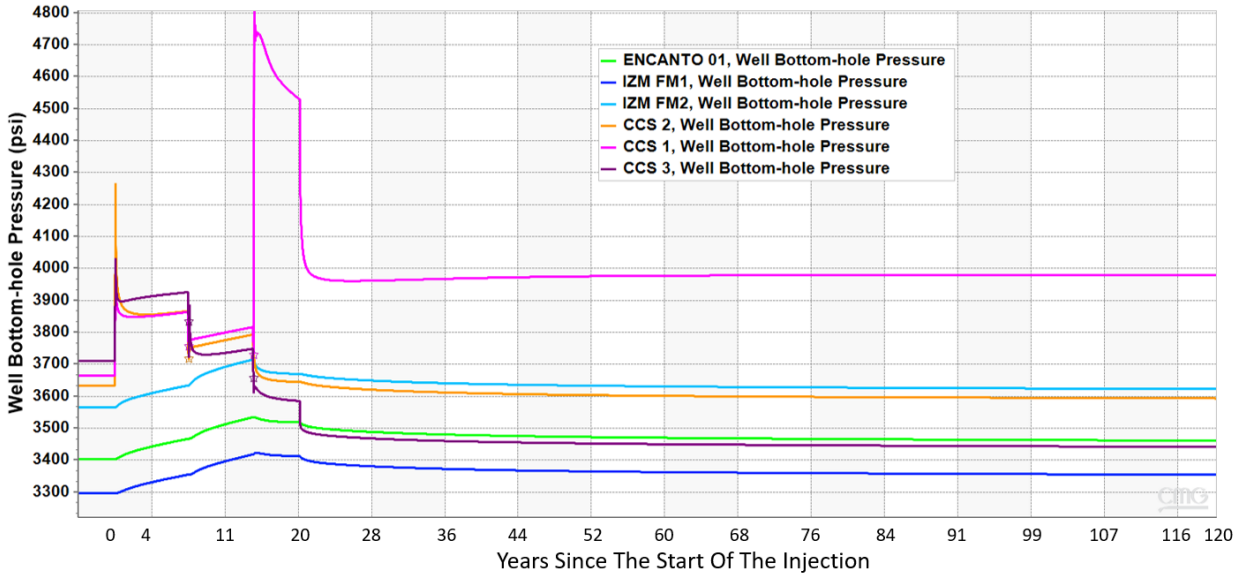


Figure PISC-1: Simulated pressure vs. time at reference depth in the Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 injection and in the in zone monitoring wells Bluebonnet IZM FM1, Bluebonnet IZM FM2 and Encanto 01 wells*.

* Even though Encanto 01 will be completed as Lower Miocene monitoring well, the projected pressure differential in Frio is presented in figure PISC-1

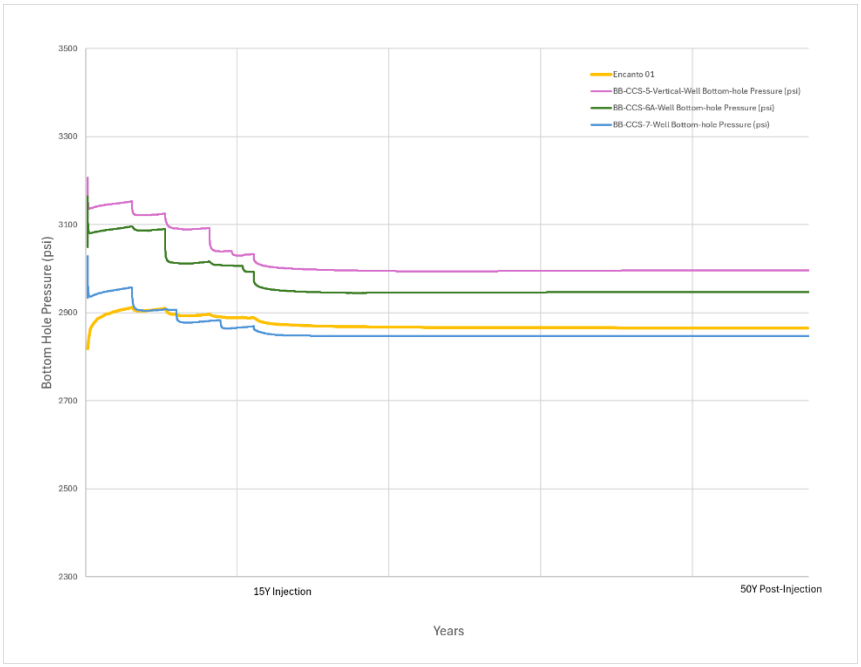


Figure PISC-2: Simulated pressure vs. time at reference depth in the Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 injection and Encanto 01 well at reference depth.

Figure PISC-3, Figure PISC-4, and Figure PISC-5 show the simulated pressure differentials from the baseline at the reference point of the Lower Miocene, Frio Injection Zone, and the Hackberry Injection Zone at the highest pressure increase point respectively.

Figure PISC-6 shows the pressure differential 50 years post injection in the Lower Miocene Injection Zone. Figure PISC-7 shows the pressure differential 50 years post injection in the Frio Injection Zone. Figure PISC-8 shows the pressure differential 50 years post injection in the Hackberry Injection Zone. The pressure will have dissipated below the critical pressure in all areas of the site in the first 5 years of the post-injection period.

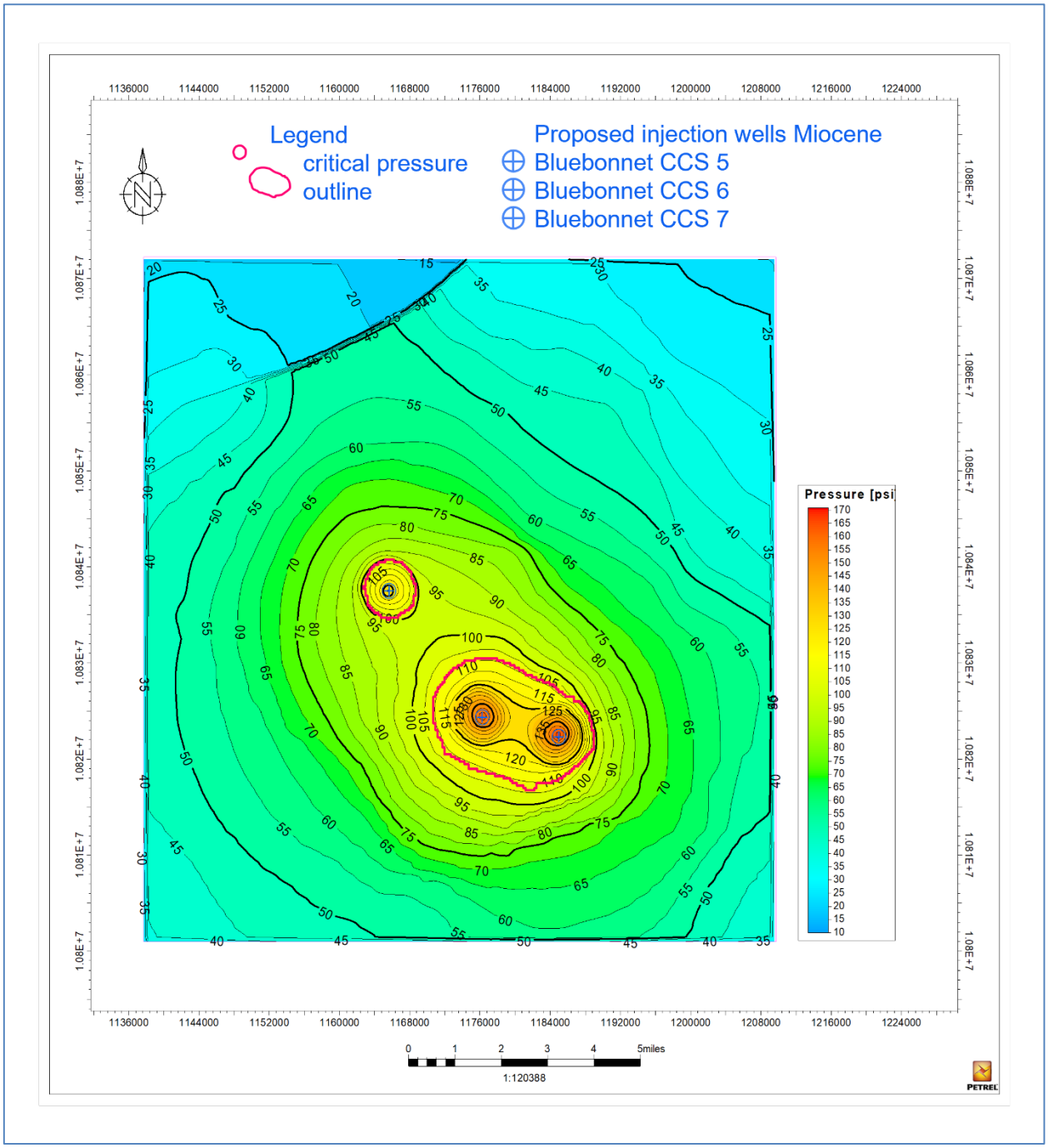


Figure PISC-3: Averaged aqueous pressure differentials from the baseline condition in the Lower Miocene Injection Zone (highest pressure increase point).

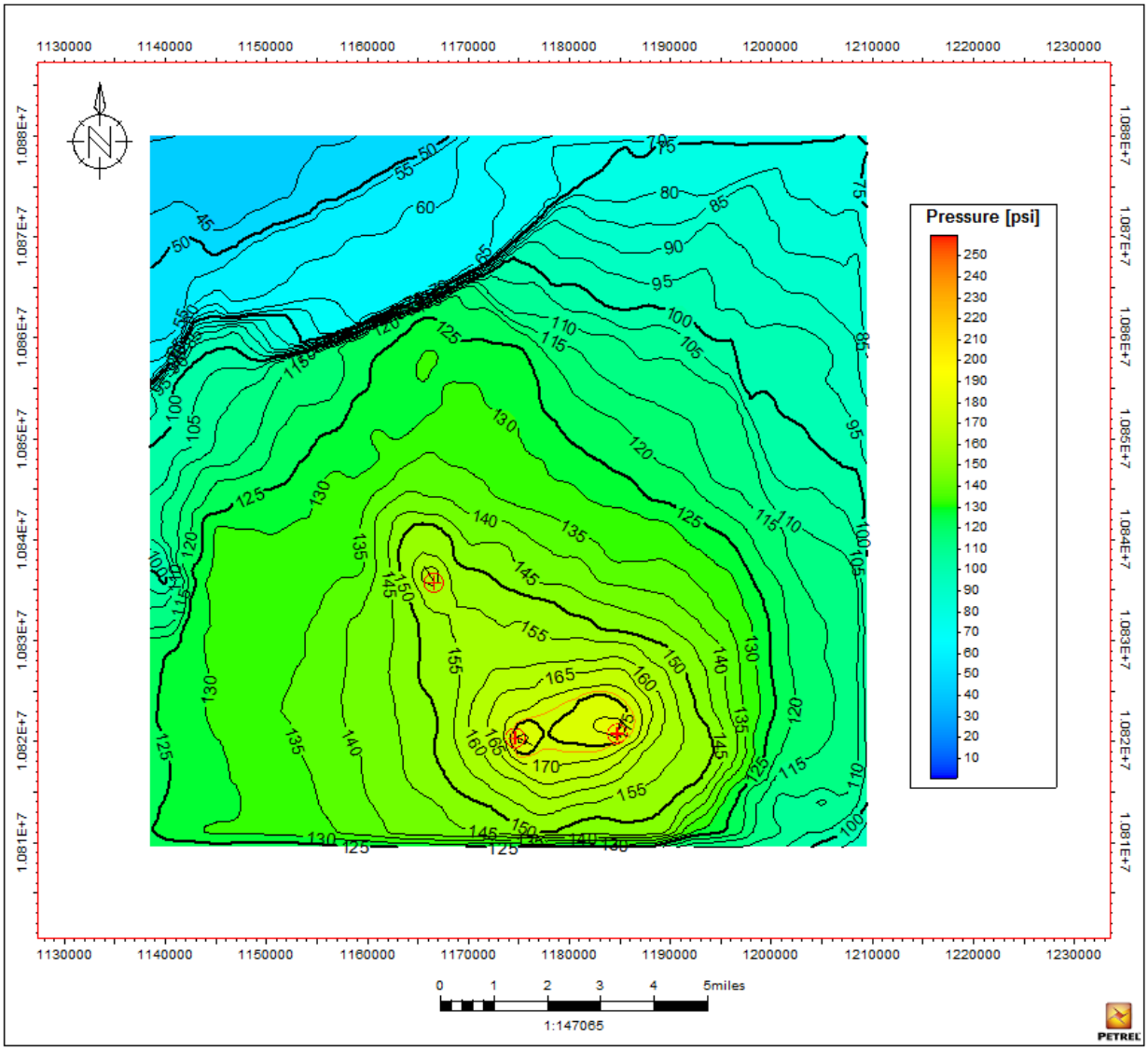


Figure PISC-4: Averaged aqueous pressure differentials from the baseline condition in the Frio Injection Zone (highest pressure increase point).

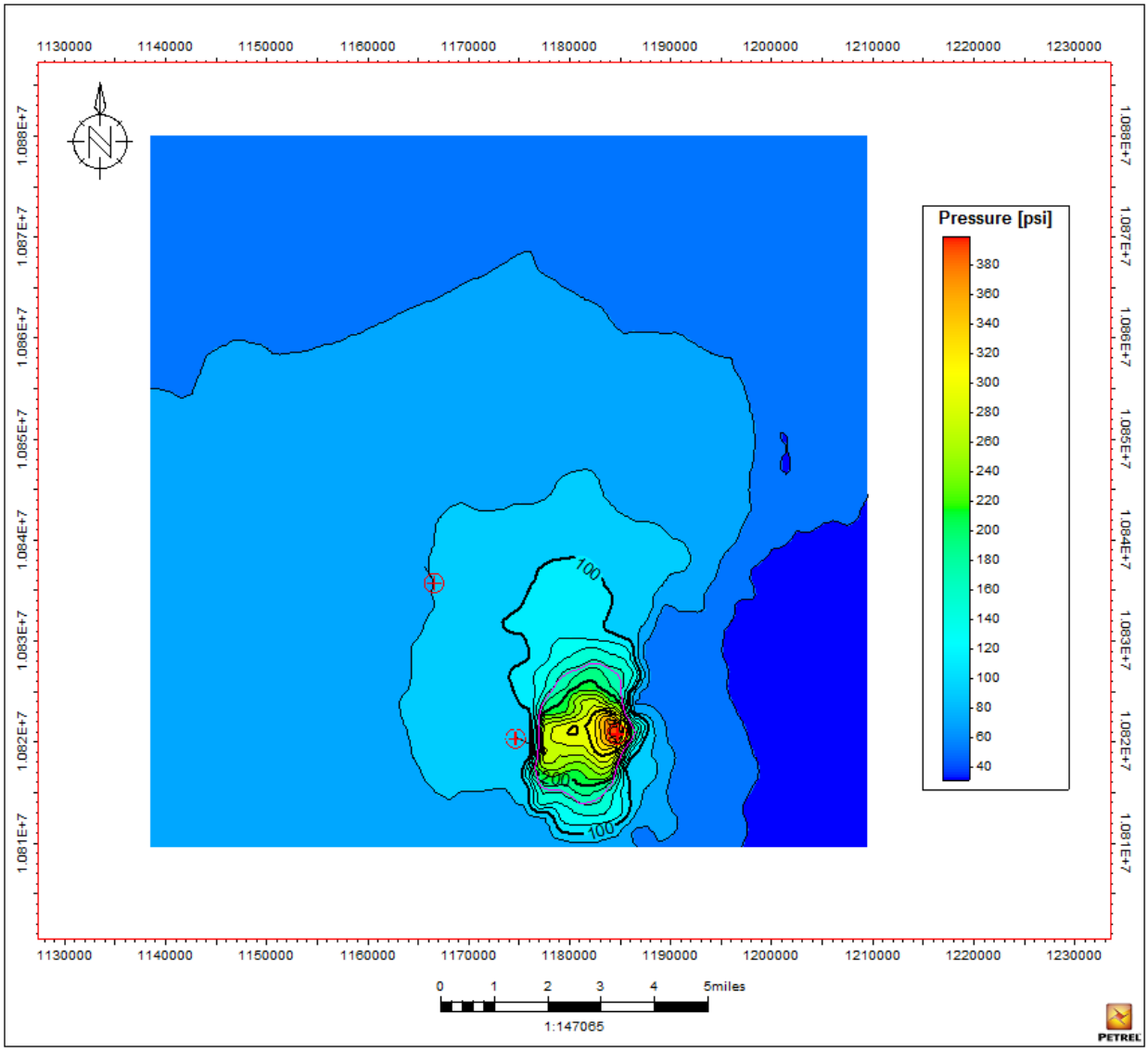


Figure PISC-5: Averaged aqueous pressure differentials from the baseline condition in the Hackberry Injection Zone (higher pressure increase point).

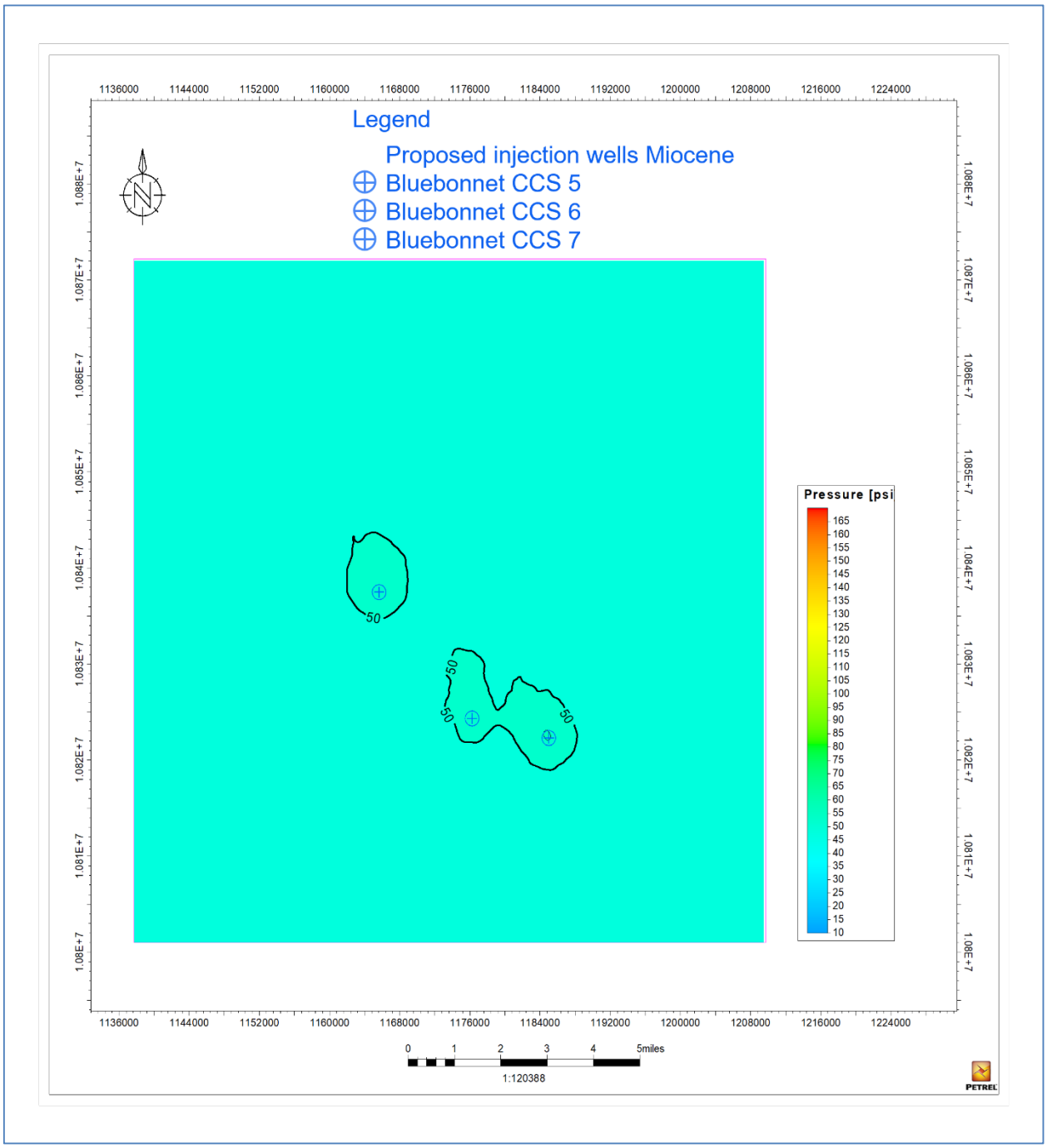


Figure PISC-6: Averaged aqueous pressure differentials from the baseline condition after 50 years post injection in the Lower Miocene Injection Zone

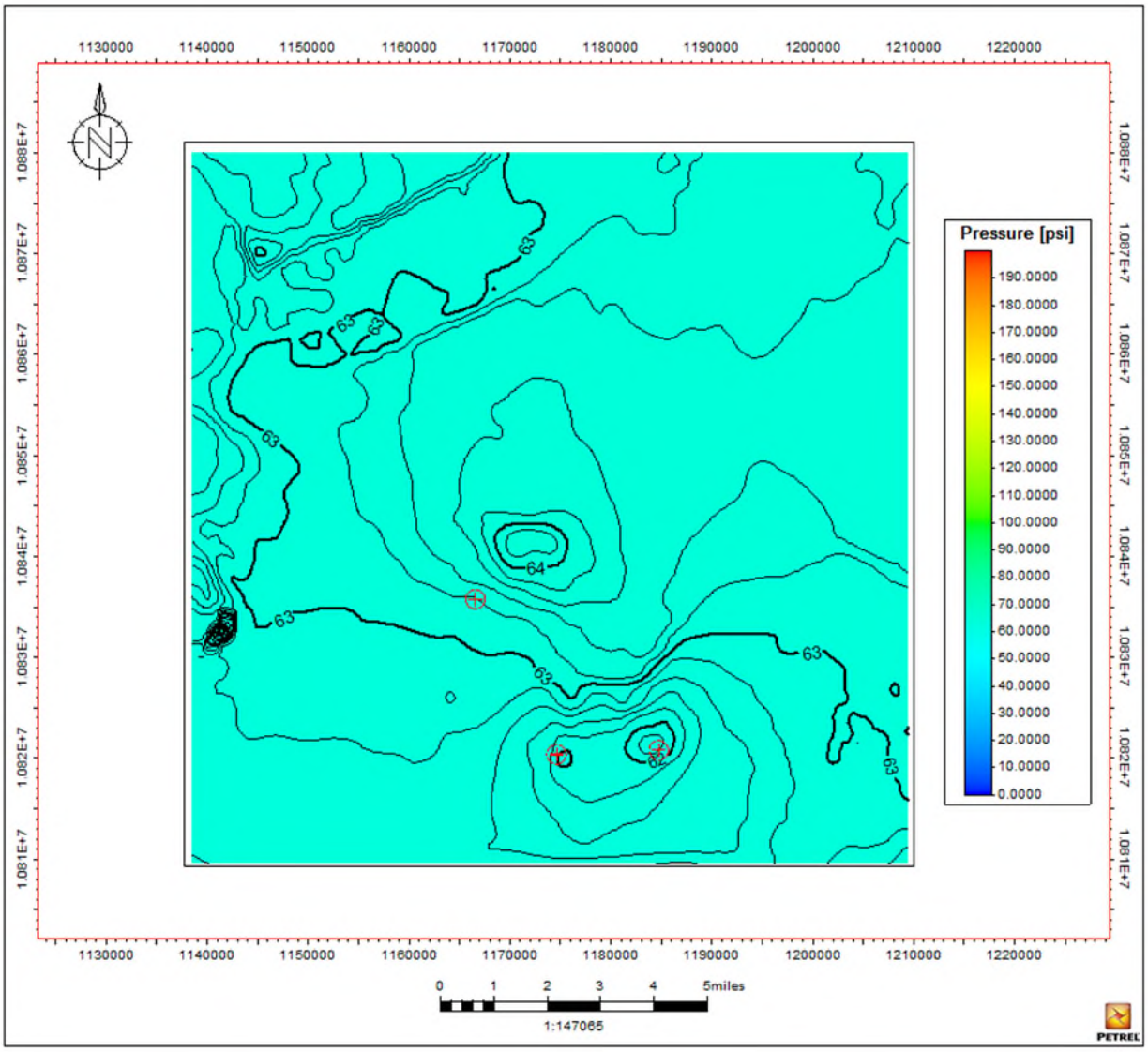


Figure PISC-7: Averaged aqueous pressure differentials from the baseline condition after 50 years post injection in the Frio Injection Zone.

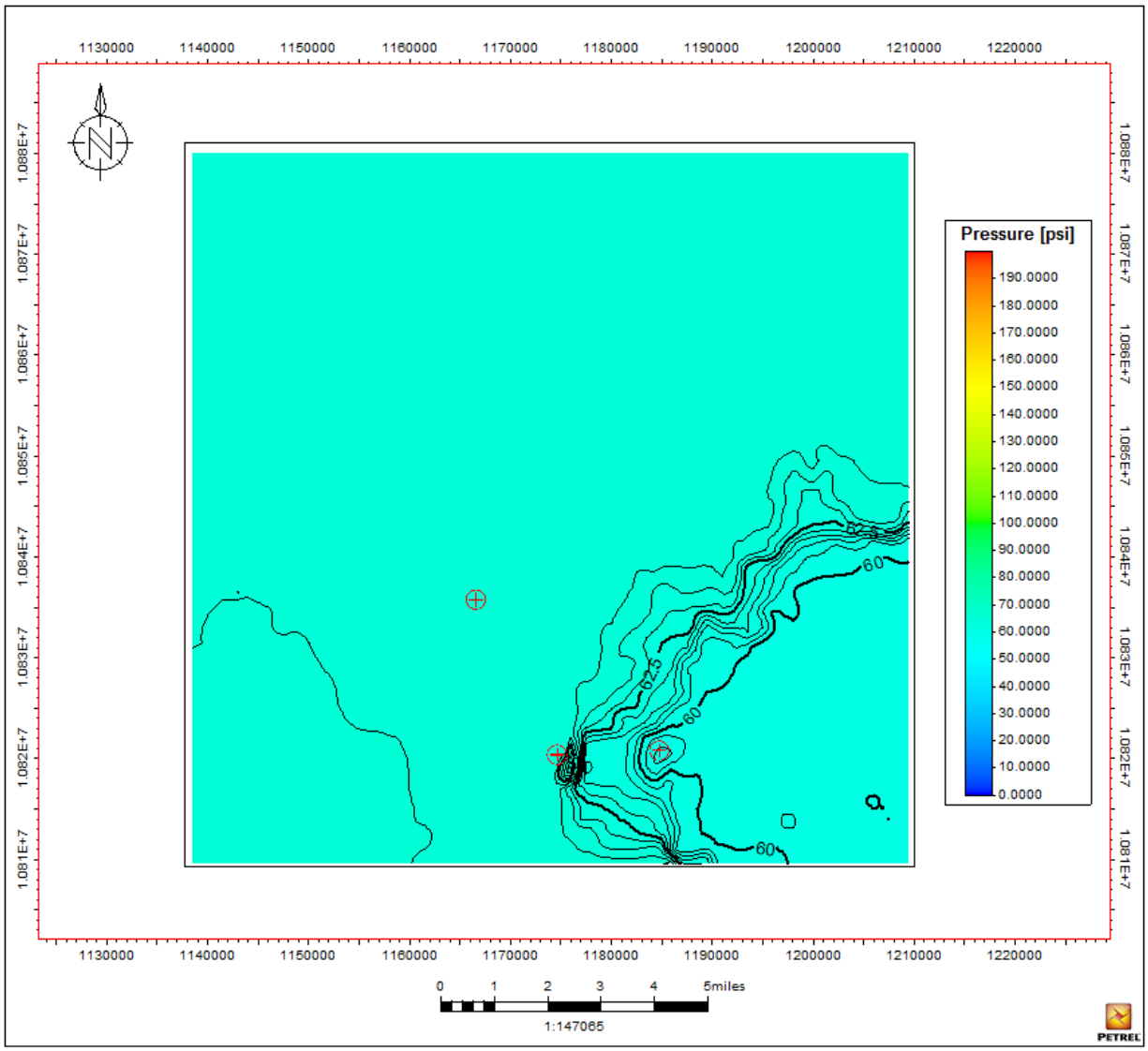


Figure PISC-8: Averaged aqueous pressure differentials from the baseline condition after 50 years post injection in the Hackberry Injection Zone.

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

3.1 Predicted Position of the CO_2 Plume and Pressure Front at Site Closure in Lower Miocene, Frio and Hackberry Injection Zones.

The reservoir simulation for Lower Miocene, Frio and Hackberry reservoirs indicates that, after injection ceases, the CO_2 plume remains within the Lower Miocene, Frio and Hackberry formations but continues to expand northward in the updip direction of the reservoir with time. The pressure front dissipated in the first years post injection as explain in the previous section. To be conservative, the sub AoR for Lower Miocene, Frio and Hackberry was defined by the combination of the pressure front at the end of injection and the plume shape and size after 100 years post-injection show in Figure PISC-9 (Lower Miocene Injection Zone), Figure PISC-10 (Frio Injection Zone), and Figure PISC-11 (Hackberry Injection Zone).

The colored area in Figure PISC-10 shows the CO_2 plume extent in year 70 (i.e., 50 years post-injection) and year 120 (100 years post injection) in the Frio Injection Zone. Figure PISC-11 shows CO_2 plume extent in year 70 (i.e., 50 years post-injection) and year 120 (100 years post injection) in the Hackberry Injection Zones.

Figure PISC-12 demonstrates the simulated plume in different years for the Lower Miocene Injection Zone. Figure PISC-13 demonstrates the simulated plume in different years for the Frio Injection Zone. Figure PISC-14 demonstrates the simulated plume at different years for the Hackberry Injection Zone.

The differences between the 50-year post-injection vertical extent and the 100-year post-injection vertical extent are almost negligible. The calculated plume size difference between year 70 and year 120 year is about 0.07 $mile^2$ in the Frio and 0.02 $mile^2$ in the Hackberry. This continued migration of the plume is due to buoyancy of the mobile supercritical phase CO_2, which moves along the strata in the updip direction.

Figure PISC-15, Figure PISC-16, Figure PISC-17, Figure PISC-18, Figure PISC-19, and Figure PISC-20 show a north-south cross section through wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7.

In addition, as previously shown in Figure PISC-6, Figure PISC-7, and Figure PISC-8, all pressures have been reduced to levels below the level of endangerment to USDWs in the first 5 years post injection for each well. Therefore, 50 years post injection is considered as the site closure date.

The maps are based on the final AoR delineation modeling results submitted, pursuant to 40 CFR §146.84.

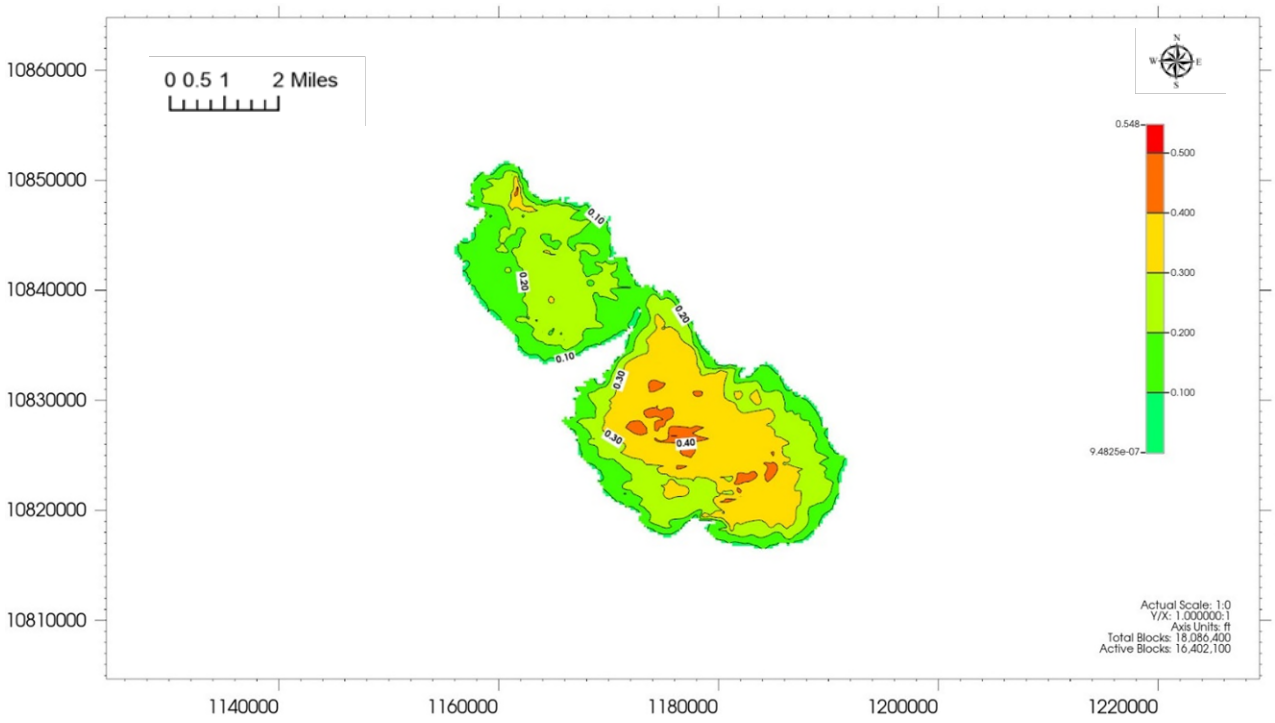


Figure PISC-9: Areal extent of the CO_2 plume after 100 years post injection in the Lower Miocene formation

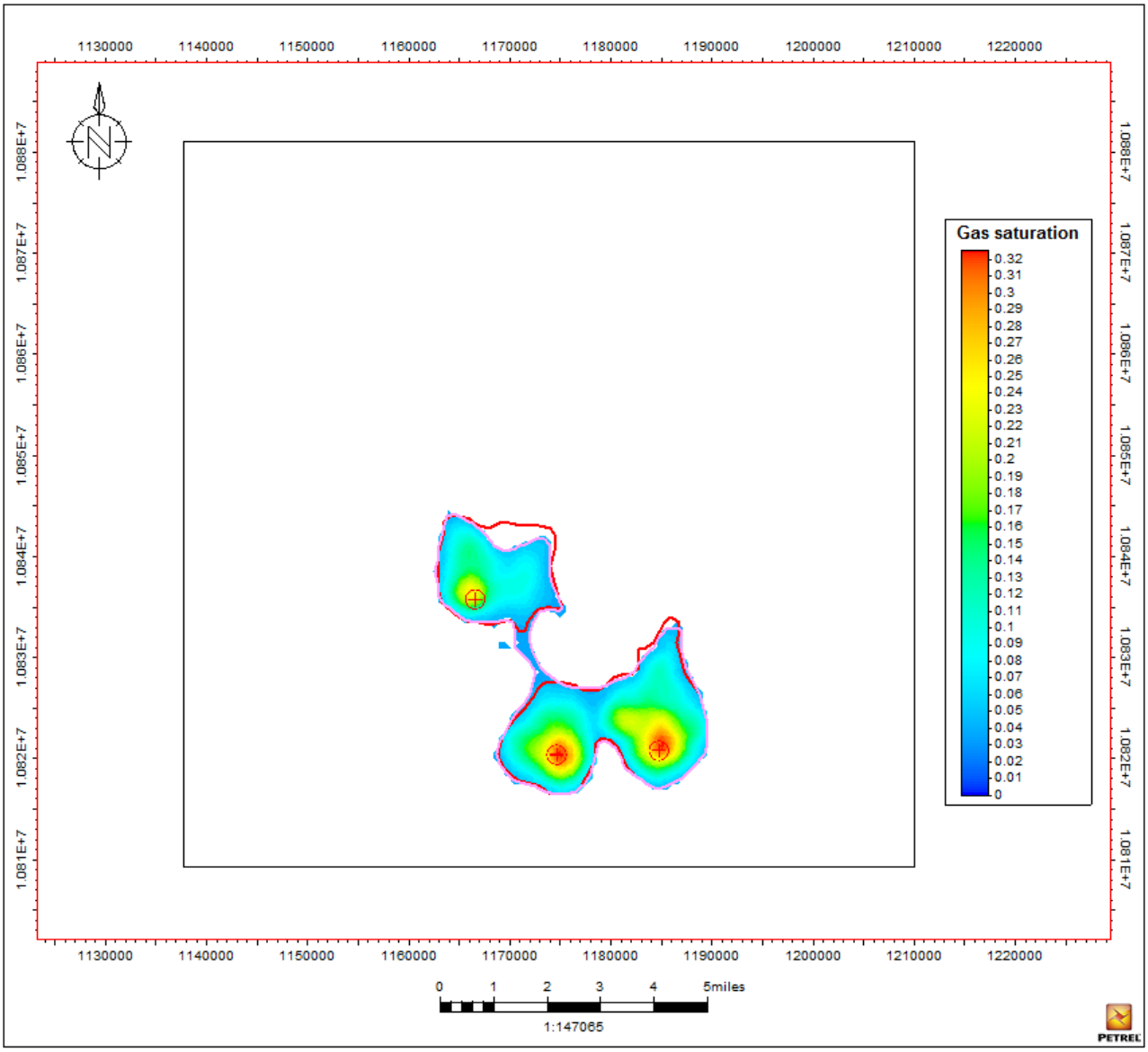


Figure PISC-10: Areal extent of the CO_2 plume at site closure 50 years post injection. The red outline represents the simulated CO_2 plume after 100 years post injection in the Frio formation.

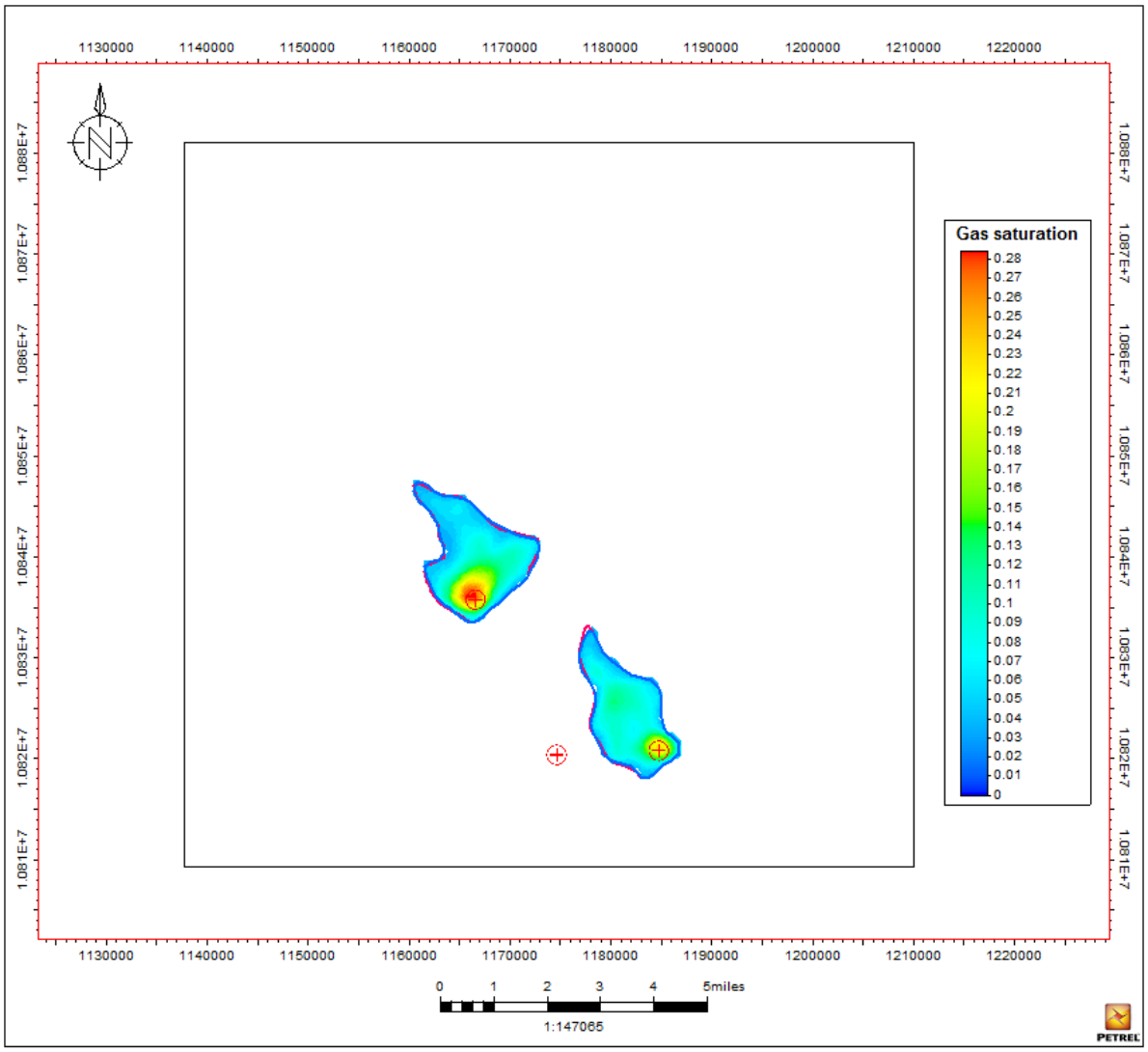
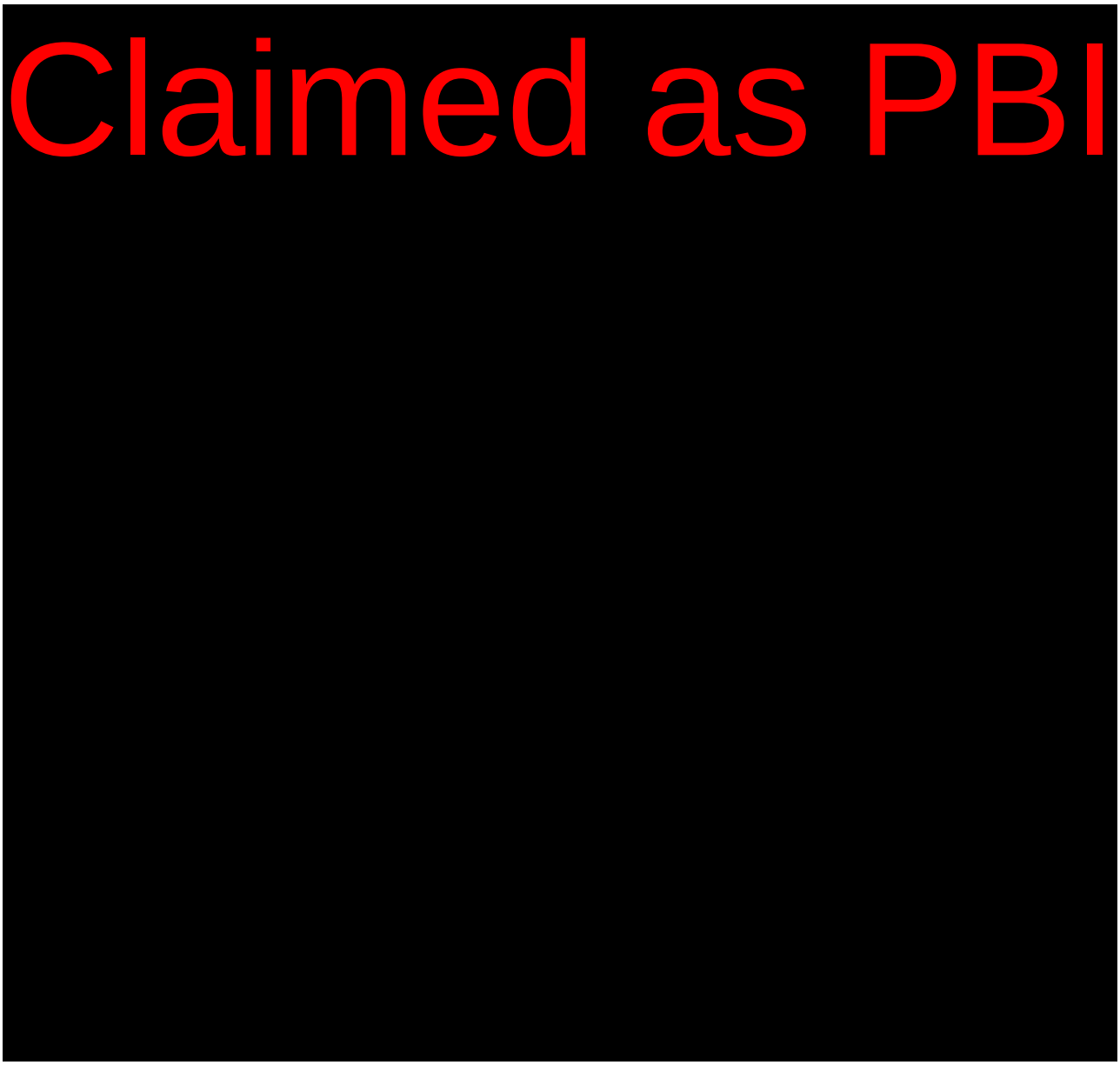
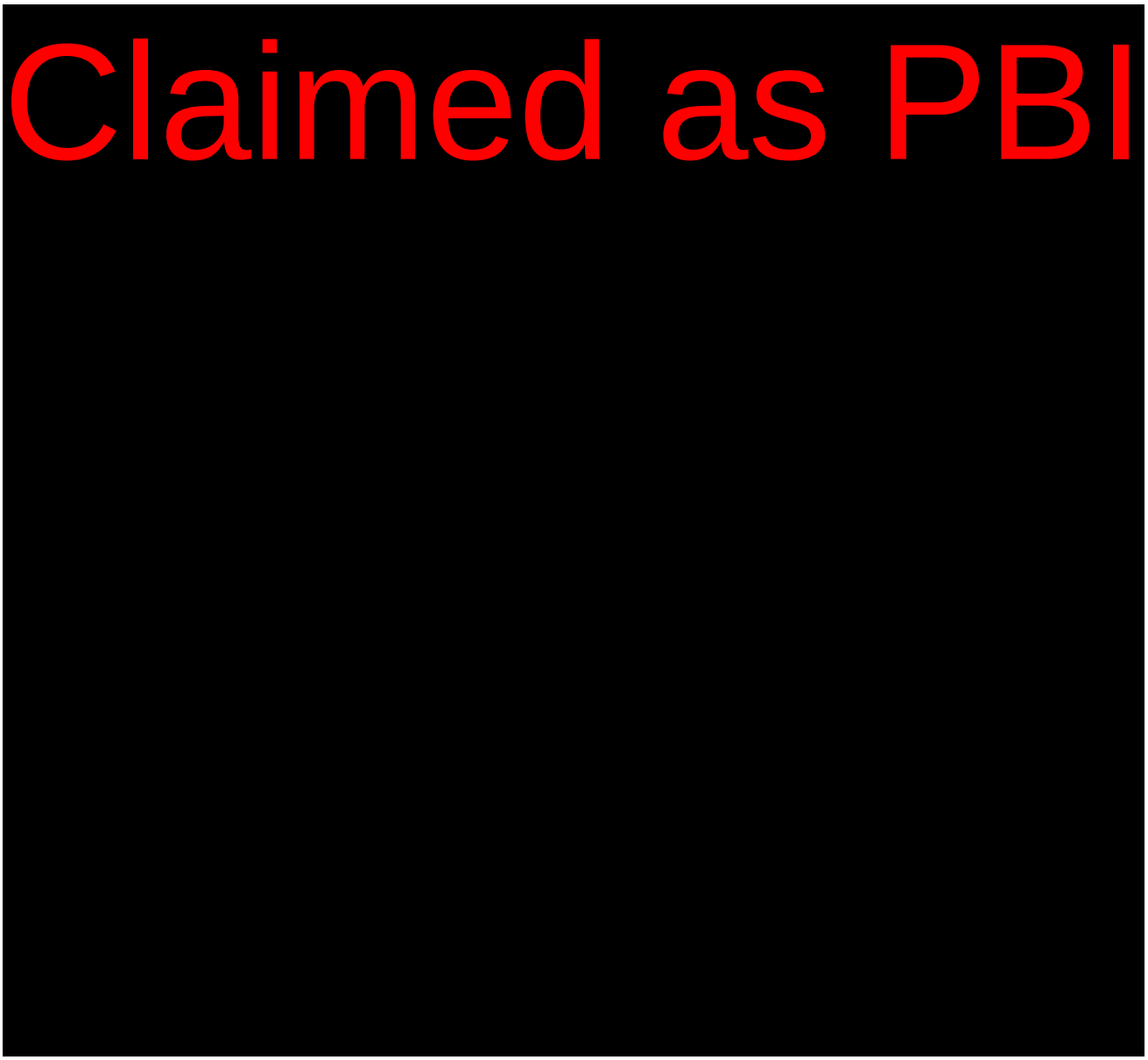


Figure PISC-11: Areal extent of the CO_2 plume at site closure 50 years post injection. The red outline represents the simulated CO_2 plume at 100 years post injection in the Hackberry formation.


Claimed as PBI


Claimed as PBI


Claimed as PBI

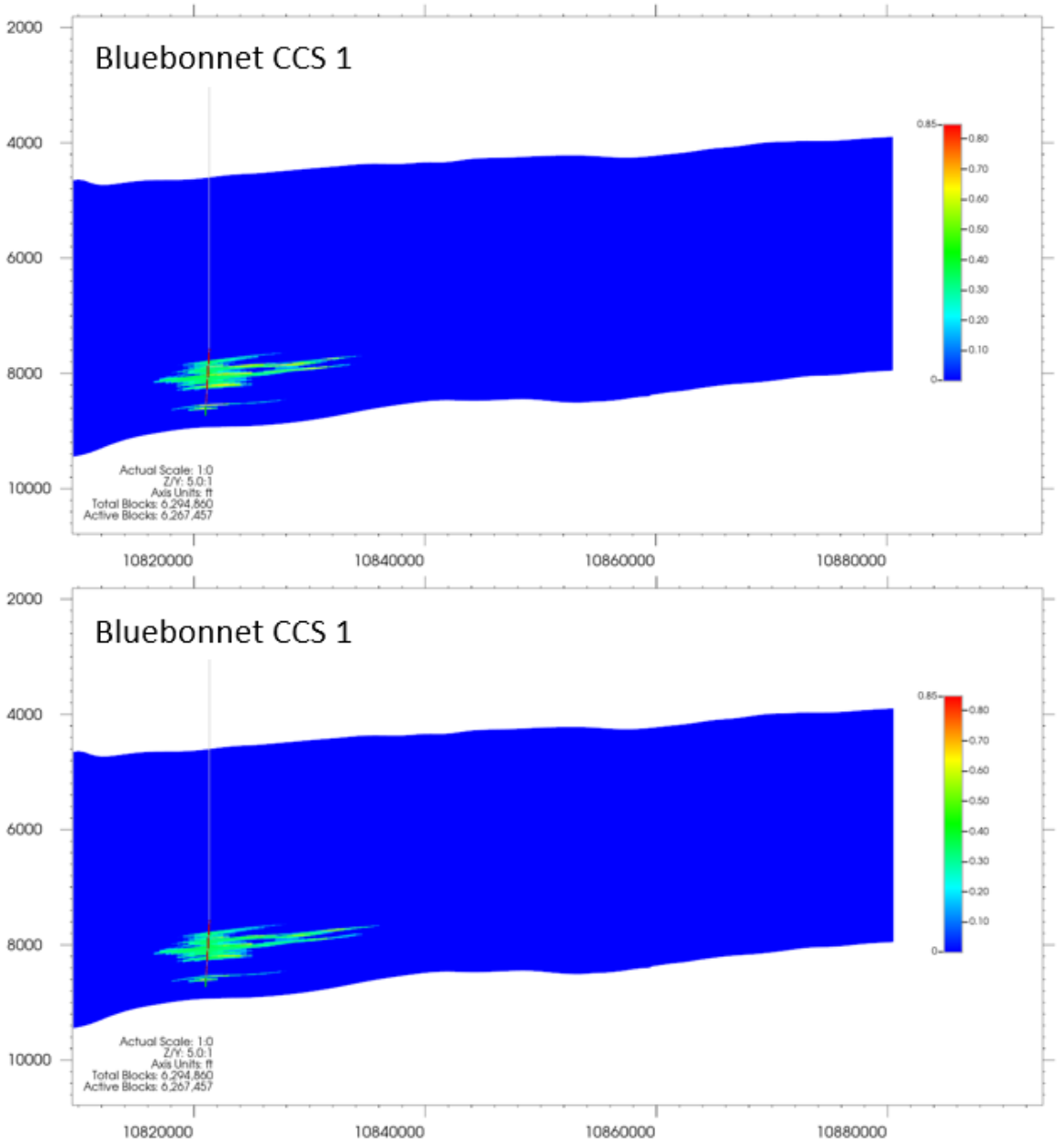


Figure PISC-15: North–south cross-section through well Bluebonnet CCS 1 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

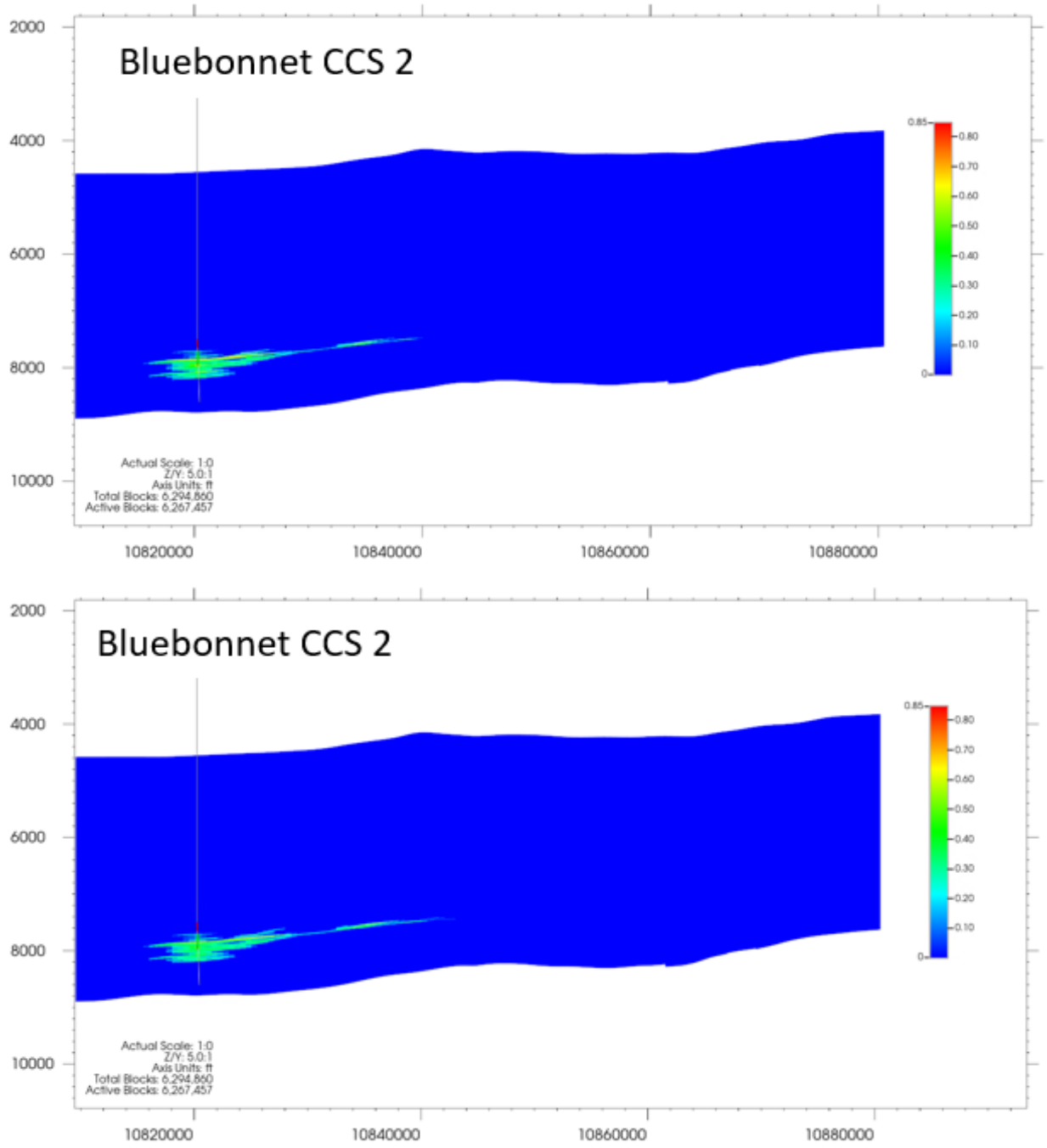


Figure PISC-16: North–south cross-section through well Bluebonnet CCS 2 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

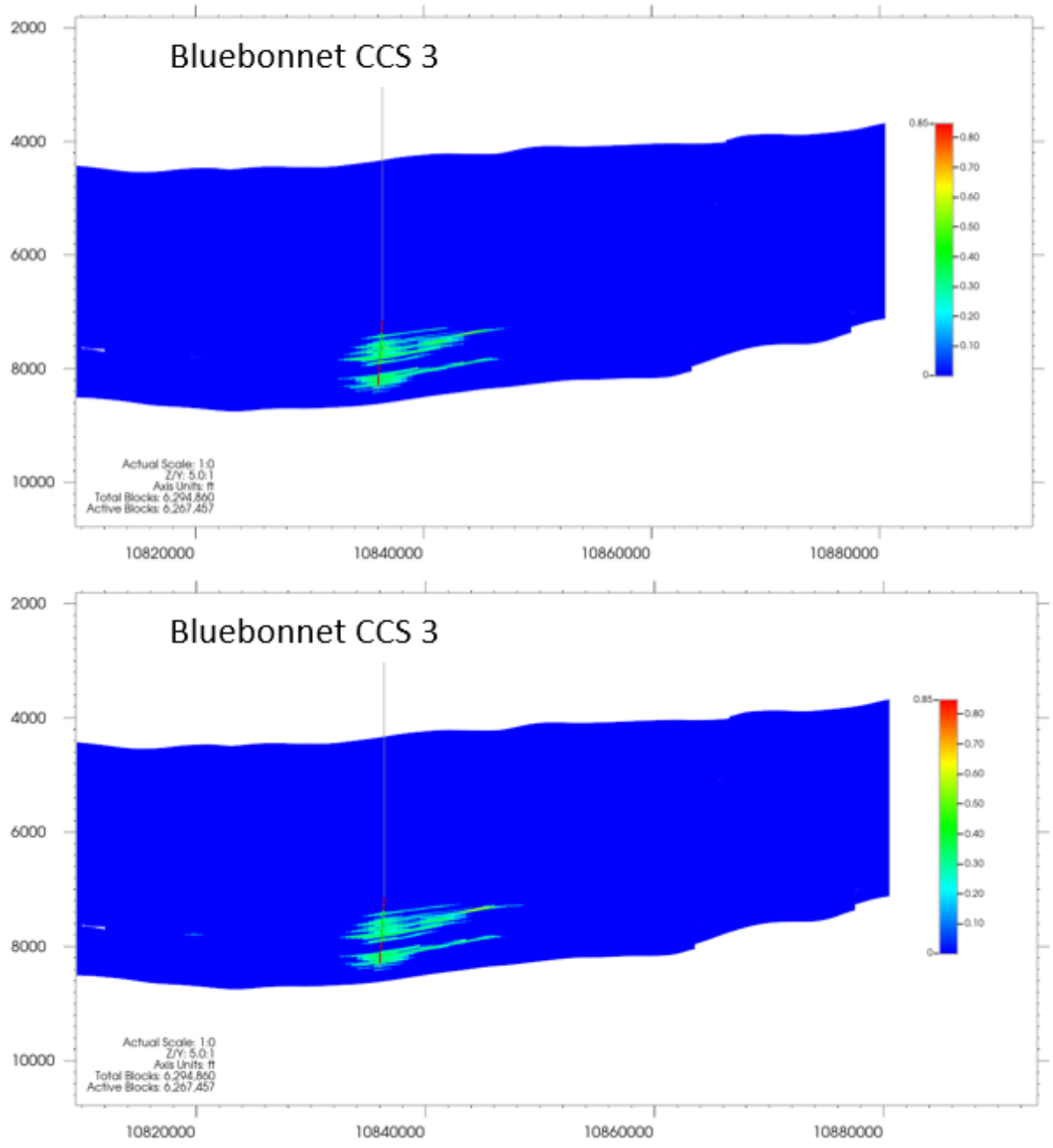


Figure PISC-17: North–south cross-section through well Bluebonnet CCS 3 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

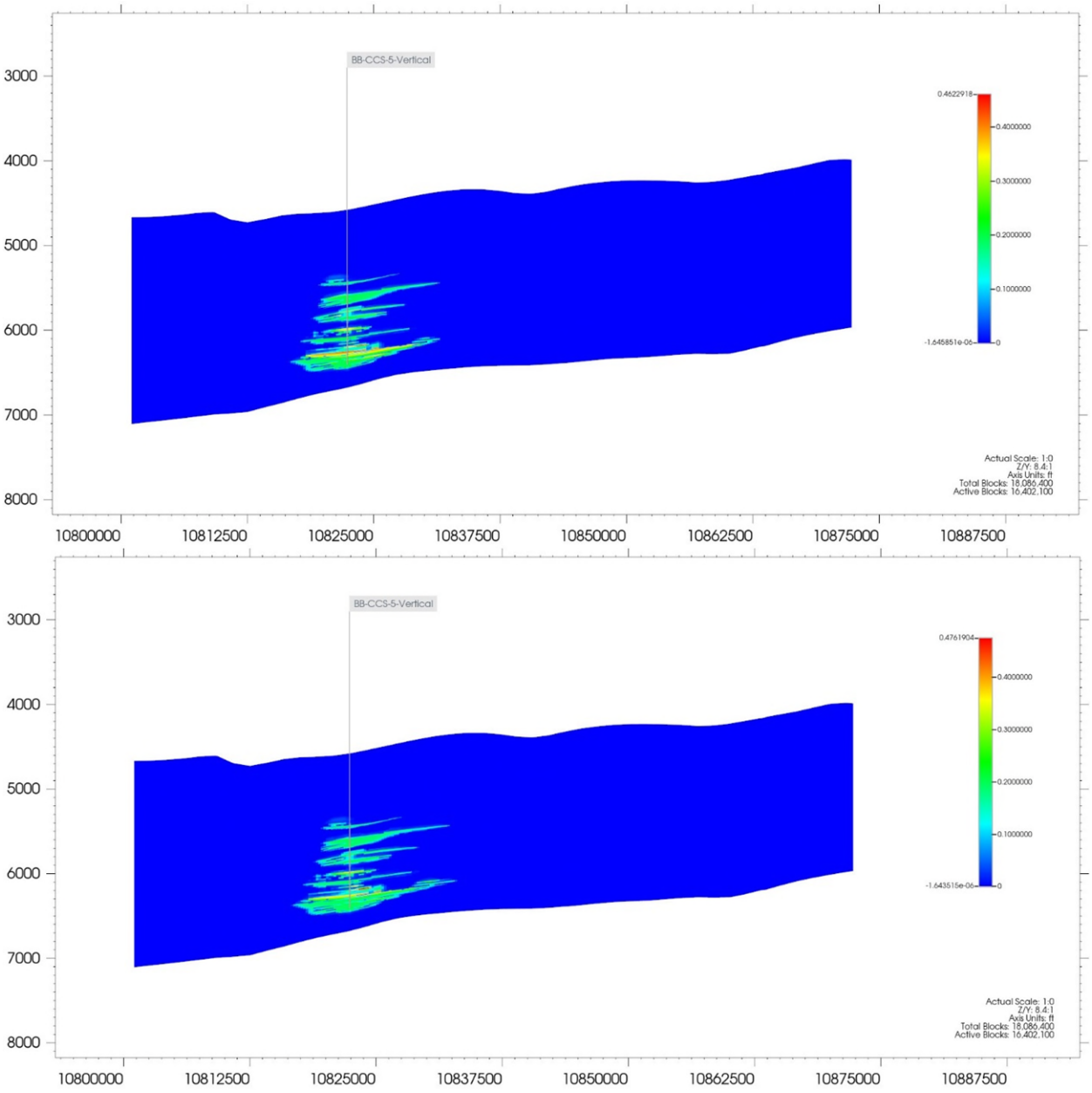


Figure PISC-18: North–south cross-section through well Bluebonnet CCS 5 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

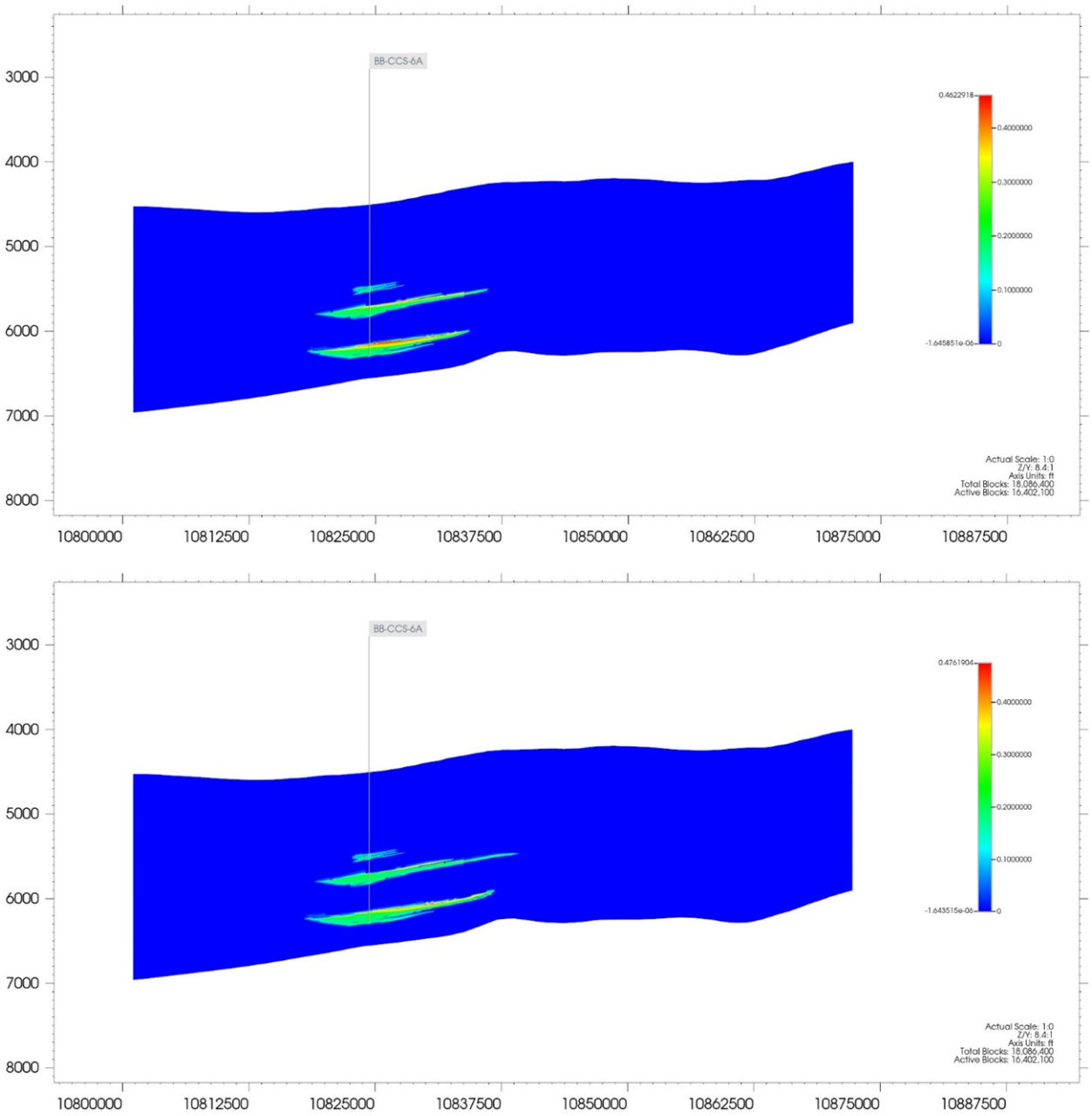


Figure PISC-19: North–south cross-section through well Bluebonnet CCS 6 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

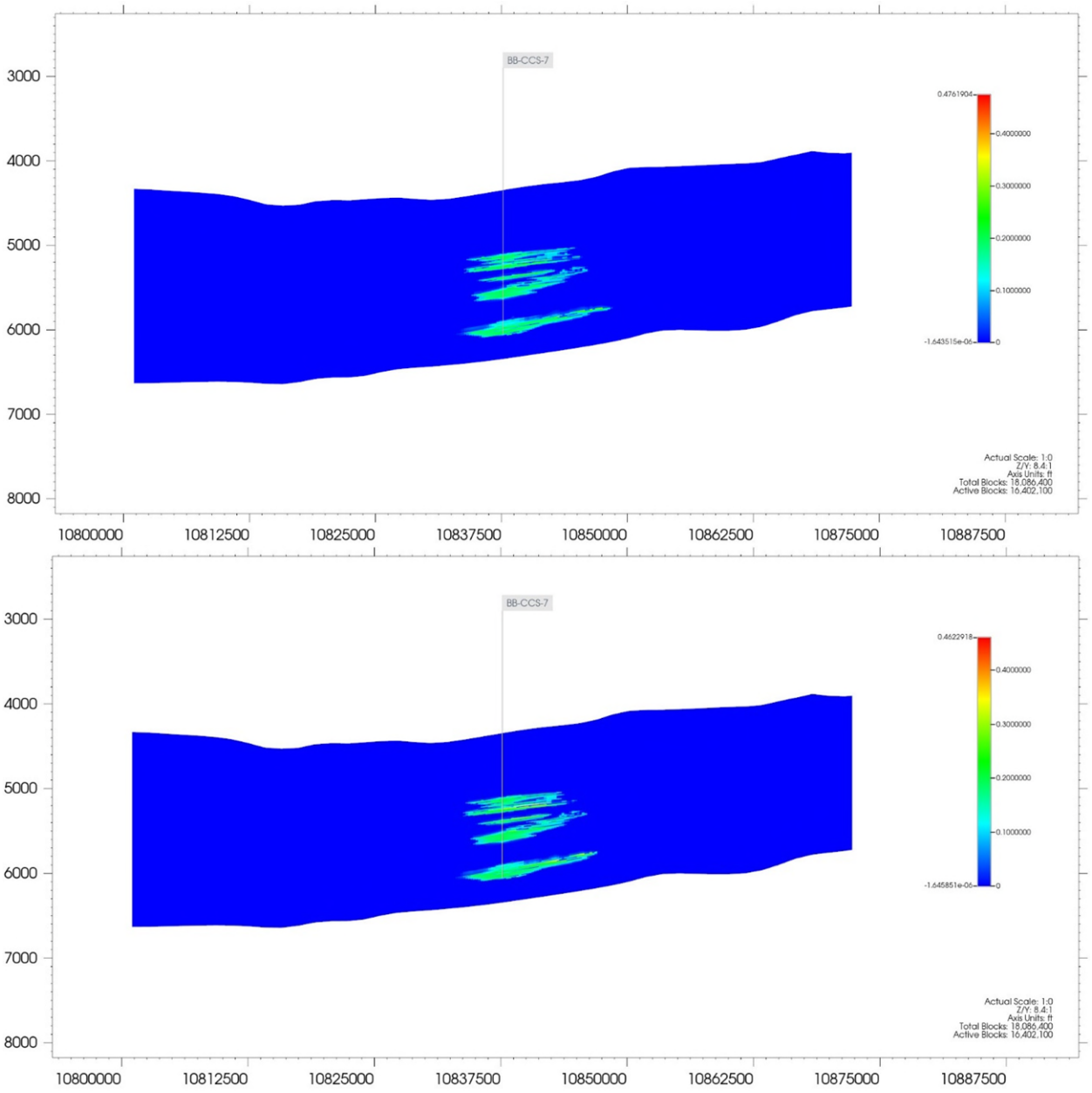


Figure PISC-20: North–south cross-section through well Bluebonnet CCS 7 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

4.0 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(a)(2)(iii). The results of all post-injection phase testing and monitoring will be submitted annually, within 60 days of the anniversary of the date that injection ceases, as described under Section 4.3 Schedule for Submitting Post-Injection Monitoring Results.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided as a separate document of this permit.

After the injection ceases, the project will plug and abandon all the CO_2 injector wells according to the plugging procedure proposed in the Injection Well Plugging Plan of this permit.

The project will abandon the water production wells, Bluebonnet PRDW F1 and Bluebonnet PRDW F2 during the operative life of the project at year 15 of injection, or when the last recompletion in Frio formation is performed in the Bluebonnet CCS 3 well.

After injection ceases, the Project will keep operative Bluebonnet IZM FM1, Bluebonnet IZM FM2 Encanto 01, Bluebonnet IZM M1, Bluebonnet IZM M2, Bluebonnet IZM M3, Bluebonnet USDW 1, Bluebonnet USDW 2, Bluebonnet USDW 8 and Bluebonnet DSW during the post-injection period.

After injection cease the Project will repeat a 2D surface seismic survey to map the extension of the CO_2 plume. This survey will be repeated at year 5 and 10 post injection and before the site closure as a proof of non-endangerment to USDW.

During the post-injection period, the model predicts that, 10 years after the injection ceases, the pressure variation every 5 years will be less than 5%, as shown in Table PISC-4, while the CO_2 plume will continue to slightly migrate but in stable rate.

Table PISC-4: Modeled bottomhole pressure variation with time at the in-zone monitoring locations.

Reference, ft, TVDSS	7,417	7,185	7,770	6,059
Year From Injection	Differential Bottomhole Pressure Changes (psi)			
	Encanto 01 (Frio)	Bluebonnet IZM FM 1	Bluebonnet IZM FM2	Encanto 001 (Lower Miocene)
20 (End of Injection Frio/Hackberry)				
25	-22%	-24%	-15%	-44%
30	-8%	-8%	-9%	-1%
35	-6%	-6%	-5%	-1%
40	-4%	-4%	-5%	-1%
45	-4%	-4%	-3%	-1%
50	-3%	-3%	-3%	-1%
55	-3%	-1%	-3%	-1%
60	-1%	-3%	-2%	-1%
65	-2%	-2%	-2%	0
70	-2%	-2%	-2%	0

For the first 10 years of the post-injection period, the monitoring program will focus on demonstrating stabilization of the pressure and CO_2 plume migration and demonstration of non-endangerment to USDW.

After 10 years of the post-injection period, the Project will plug Bluebonnet IZM FM1, Bluebonnet IZM FM2, Bluebonnet IZM M1, Encanto 01 and Bluebonnet DSW M2 and will continue monitoring USWD groundwater and the Miocene Composite Confining Zone with Bluebonnet USDW 1, Bluebonnet USDW 2, Bluebonnet USDW 8, Bluebonnet IZM M2 and Bluebonnet IZM M3, in combination visual inspections, and soil gas monitoring, until the closure of the site.

Table PISC-5 describes the methods and techniques to be used while monitoring the site during the post-injection period. Locations and frequency for each method or technique are also presented in Table PISC-5.

Table PISC-5: Monitoring Plan for post-injection site care.

Description	Method	Location	Post-Injection period
Operations	Surface pressure and temperature measurements in tubing - gauges	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01 Bluebonnet DSW M2	Monthly until the wells are plugged.
	Visual inspections and handheld monitors (LEL, H_2S, CO_2)	General facilities	Quarterly until facilities are closed.
Mechanical Integrity	Pulse neutron, Temperature log, or Electromagnetic log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01	As required for plume monitoring, no minimum than every 5 years.
	Annular pressure test	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01 Bluebonnet DSW M2	Every 5 years until the wells are plugged.
Groundwater quality and geochemical monitoring	Water sampling and testing of USWD well.	Bluebonnet USWD 1 Bluebonnet USWD 2 Bluebonnet USWD 8 Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	Annually first 10 years of post-injection period, biannually from year 10 to site closure. Bluebonnet IZM M1 will be closed at year 10 of PISC.
CO_2 plume and pressure front tracking	Pulse Neutron Log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01	Biannually first 10 years of post-injection period
	In-reservoir pressure and temperature measurement - downhole gauges	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01	Monthly until the wells are plugged.

Description	Method	Location	Post-Injection period
	2D time lapsed surface seismic	AoR	At 5 years post injection, at 10 years post injection, and at site closure.
Near-Surface Monitoring	Process-based soil gas approach	AoR	Annually until site closure.

Specifics of the methods, techniques, and analytics to be tested as part of the proposed monitoring plan are described in detailed in the Testing and Monitoring Plan and in the QASP document.

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

During the PISC period, the monitoring reports will be prepared annually and submitted to the EPA Region 6 UIC Branch Office. These reports will summarize methods and results of groundwater quality monitoring, CO_2 storage zone pressure tracking, and indirect geophysical monitoring for CO_2 plume tracking.

The PISC and Site Closure Plan will be reviewed every 5 years during the PISC period. Results of the plan review will be included in the PISC monitoring reports. The operational and monitoring results will be reviewed for adequacy in relation to the objectives of the PISC. The monitoring locations, methods, and schedule will be analyzed in relation to the size of the CO_2 storage zone, pressure front, and protection of USDWs. In case of changes to the PISC plan, a modified plan will be submitted to the EPA Region 6 UIC Branch Office at least 30 days before the planned initiation of the changes.

6.0 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, the Bluebonnet Sequestration Hub, LLC, will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(1), (2) and (3).

The Bluebonnet Sequestration Hub LLC, will issue a report to the UIC Program Director that will demonstrate that the project poses no danger to the USDWs, 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.

6.1 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.

6.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan document 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)].

6.3 Summary of Computational Modeling History

The computational modeling results used for the AoR delineation will be compared to monitoring data collected during the operational and PISC periods. Monitoring data will also be compared with data collected during site characterization, as per 40 CFR 146.82(a)(6) and 146.87(d)(3). The data will be used to update the computational model and monitor the site, and will include both direct (e.g., measurements of pressure, temperature, groundwater quality) and indirect (e.g., 2D seismic, pulse neutron logging) geophysical methods.

Data generated during the PISC period will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. The Bluebonnet Sequestration Hub, LLC, will demonstrate this degree of accuracy by comparing the monitoring data obtained during the operational and PISC period with the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to represent the storage site accurately. The validation of the computational model with the large quantity of measured data will be a significant element to support the non-endangerment demonstration.

6.4 Evaluation of Reservoir Pressure

The Bluebonnet Sequestration Hub, LLC, will demonstrate non-endangerment to USDWs by showing that, during the PISC period, the pressure within the Lower Miocene, Frio, and Hackberry reservoir will have rapidly decreased to levels near its pre-injection static reservoir pressure. Because increased pressure is the primary driving force for fluid movement, which might endanger a USDW, the decay in the pressure differential provides strong justification that the injectant will no longer pose a risk to any USDWs.

The Bluebonnet Sequestration Hub, LLC, will monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared with the pressure predicted by the computational model, which was previously shown in Figure PISC-1, Figure PISC-2, Figure PISC-3, and Figure PISC-4. Agreement between the actual and predicted values will validate the accuracy of the model and further demonstrate non-endangerment.

6.5 Evaluation of CO_2 Plume

The Bluebonnet Sequestration Hub, LLC, will use a combination of monitoring data, logs, geophysical surveys, and seismic methods to locate and track the movement of the CO_2 plume. The data produced by these activities will be compared with the modeled predictions (previously shown in Figure PISC-6 and Figure PISC-7) using statistical methods to validate the model's ability to represent the storage site accurately. The PISC monitoring data will show the stabilization of the separate-phase CO_2 plume as the reservoir pressure returns to its near pre-injection state.

6.6 Evaluation of Emergencies or Other Events

In addition to the CO_2 plume, mobilized fluids may also pose an ongoing risk to USDWs, as the reservoir fluids include brines high in total dissolved solids (TDS) and other drinking water contaminants. The geochemical data collected from USDW/above-confining-zone monitoring wells will be used to demonstrate that no mobilized fluids have moved above the confining formation, and therefore would not pose a risk to USDWs after the PISC period.

To demonstrate non-endangerment, the Bluebonnet Sequestration Hub, LLC, will compare the operational and PISC period samples of the lowermost USDW/above confining zone with the pre-injection characterization of the aquifers. This evaluation will demonstrate that no mobilized formation fluids have moved through the confining formation. In addition, this validation of confining zone integrity will demonstrate that the injectant and/or mobilized fluids will not represent an endangerment to any USDWs.

Other than the project and monitoring wells, other potential conduits for fluid movement or leakage pathways within the AoR will be adequately plugged and abandoned. Based on this information, the potential for fluid movement through artificial penetrations of the confining formation does not present a risk of endangerment to any USDWs.

7.0 Site Closure Plan

Pursuant 40 CFR §146.93(d), the Bluebonnet Sequestration Hub, LLC, will notify the UIC Program Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original Post-Injection Site Care and Site Closure Plan, Bluebonnet Hub will provide the revised plan to the Program Director for approval.

The Bluebonnet Sequestration Hub, LLC, will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. Once the UIC Program Director has approved closure of the site, the Bluebonnet Sequestration Hub, LLC, will plug the remaining

monitoring wells in a manner that will not allow movement of injection or formation fluids that would endanger a USDW.

Bluebonnet Sequestration Hub, LLC, will submit a site closure report to UIC Program Director within 90 days of site closure [40 CFR 146.93(f)].

In addition to the EPA, the Texas Railroad Commission, Chambers County, the City of Winnie, and any other agencies governing the project at the time of site closure will be notified prior to the scheduled site closure. Currently, there are no federally recognized Native American Tribes located within the AoR; however, if a federally recognized Native American Tribe becomes known within the AoR at the time of site closure, that tribe (or tribes) will be notified of the site closure.

7.1 Plugging Monitoring Wells

Upon conclusion of the 50-year post-injection site care period, any remaining monitoring well will be plugged and capped below grade in accordance with the approved plugging and abandonment plans, which is included as Appendix A in the Injection Well Plugging Plan.

After completion of the plugging activities, a plugging report will be submitted to the UIC Program Director describing the methods used and tests performed on the well during plugging. This report will be submitted to the UIC Program Director within 60 days of completing the plugging activities.

7.2 Planned Remedial and Site Restoration Activities

At the end of the PISC phase, Bluebonnet Sequestration Hub, LLC, will ensure the site is reclaimed and returned to predevelopment condition.

Surface equipment decommissioning will occur in two phases: the first phase will occur after the active injection phase and the second phase will occur at the end of the PISC phase.

At the end of the active injection period, plume monitoring will continue, but there will be no further need for the pumping and control equipment. The process control building at the surface pumping facility will remain. This building will serve as a hub for control and monitoring of the well network, so it will remain operational. The pumping system and aboveground pipe, valves, and fittings at the surface pumping facility will be removed.

The injection wells will be plugged per the Injection Well Plugging Plan document of this permit. The process control building at the pumping facility site will act as the collection node for data from the plume-monitoring equipment. This building will contain the equipment required to receive real-time data from the monitoring wells and other monitoring stations and send the data via an internet connection to be analyzed offsite during post-injection monitoring period.

Surface facilities will be removed at the end of the PISC phase. The site will be reclaimed and returned to predevelopment condition except any facilities still in operation to serve other active projects (e.g., electrical supply serving other power users and roadways used or needed by surface landowners). Buried pipelines are expected to be idled and abandoned in place.

The soil will be backfilled around the monitoring and geophysical wells to bring the area around the wells back to the preinstallation grade. Any remaining surface facilities associated with the monitoring wells will be reclaimed and the area will be returned to the predevelopment condition. Gravel well pads will be removed, and the land will be reclaimed for preconstruction uses.

7.3 Site Closure Report [40 CFR 146.93(f)]

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of all injection and monitoring wells.
- Location of each well on a plat survey submitted to the local zoning authority.
- Notifications to State, local and Tribal authorities.
- Records regarding the nature, composition, and volume of CO_2 injected.
- Pre-injection, injection, and post-injection monitoring records.
- Certifications that all injection and storage activities have been completed.

Bluebonnet Sequestration Hub, LLC, will record a notation to the property's deed on which the CO_2 injection wells were located that will indicate the following:

- That the property was used for CO_2 sequestration.
- The name of the State agency, local authority and/or Tribe 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.
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by Bluebonnet Sequestration Hub, LLC, for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years, after which these records will be delivered to the UIC Program Director.

J. FINANCIAL ASSURANCE DEMONSTRATION

Bluebonnet Sequestration Hub

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub, LLC (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

The matter of financial assurance demonstration is relevant to the requirements of 16 TAC 5.205 and the Environmental Protection Agency (EPA) document 40 CFR Subpart H - Criteria and Standards applicable to Class VI Wells. The main topics covered in this attachment are activities

requiring financial assurance, instruments to meet financial responsibility, and the plan to be implemented by the Bluebonnet Sequestration Hub, LLC for the Bluebonnet Sequestration Project.

2.0 Activities Requiring Financial Assurance

Pursuant to TAC 5.205 and 40 CFR 146.85, the Bluebonnet Sequestration Hub, LLC is required to demonstrate financial ability to successfully complete all the tasks associated with performing well corrective action, injection well plugging, post-injection site care, site closure, and implementation of an emergency remedial response plan as specified in Table FA-1.

Table FA-1: List of project activities that require financial assurance.

Activity	Period of Performance
Performing corrective action	As needed
Plugging CO_2 injector wells	One time
Post-injection site care	Throughout the post-injection phase
Site closure	At closure
Emergency/remedial response	As needed

3.0 Instruments to Meet Financial Responsibility

Bluebonnet has reviewed the requirements of 16 TAC 5.205 and the extensive guidance, research, and analysis documents published by the EPA and proposes to utilize a letter of credit to demonstrate financial responsibility for all activities requiring financial assurance. The letter of credit will be issued by Claimed as PBI that has (a) assets of at least Ten Billion Dollars ($10,000,000,000) and (b) has a Long-Term Credit Rating of at least “A-” by S&P and at least “A3” by Moody’s The letter of credit will be irrevocable, require the issuing institution to provide notice if it does not plan to reissue the letter of credit and will include a provision for automatic renewal. Claimed as PBI N.A maintains a "Certificate of Account Status," previously called "Certificates of Good Standing," with the Texas Comptroller of Public Accounts evidencing the status of its right to conduct financial transactions in Texas (which may be confirmed by entering Claimed as PBI at this link maintained by the Texas Comptroller: Taxable Entity (https://comptroller.texas.gov/taxes/franchise/account-status/search).Bluebonnet Sequestration Hub, LLC shall deposit funds as instructed by the Texas Railroad Commission. Bluebonnet Sequestration Hub, LLC may change the instrument(s) used to demonstrate financial assurance in accordance with 16 TAC 5.205 or 40 CFR 146.85.

4.0 Cost Estimate for Activities Covered by Financial Responsibility

The Bluebonnet Sequestration Hub, LLC will provide financial assurance sufficient to cover the costs identified in Table FA-2. Costs are to be in 2026 U.S. dollars. A detailed cost estimate is included in Appendix A.

The cost estimation provided in Appendix A is based on hiring a third party to perform the required activities (Statewide Rule §5.205(c)(2)(C)(i)).

In Accordance with 16 TAC §5.205(c)(2)(C)(ii), the preparation of the highest likely cost necessary to close the geologic storage facility have been supervised and reviewed by a qualified professional engineer licensed by the state of Texas.

Table FA-2: Cost estimate for activities covered by financial assurance.

Activity	Total Cost
Performing Corrective Action on Wells in AOR	Claimed as PBI
Plugging Injector Wells	
Post-injection Site Care	
Site Closure (Facilities and Monitoring Wells)	
Emergency and Remedial Response Actions	
Regulatory fee	
Total $	

4.1 Corrective Action

Twenty-five wells within the Area of Review (AoR) were determined to require corrective actions. Bluebonnet Hub will conduct corrective action as per schedule presented in the AoR attachment.

4.2 Plugging Injection Wells

Details of the well plugging plan are found in the Plugging Plan document of this permit. CO_2 injection wells will be plugged and abandoned when injection cease in the site.

4.3 Post-Injection Site Care

Details of the post-injection site and site closure plan are found in the Post Injection Site Care and Site Closure Plan document of this permit. The Post-Injection Site care costs were estimated from cessation of injection to site closure and account for activities included in the Post-Injection Site Care Plan.

4.4 Site Closure

Details of the site closure plan are found in the Post Injection Site Care and Site Closure Plan document of this permit. Monitoring wells and water extraction wells will be covered by the blank bond under Bluebonnet Sequestration Hub LLC P5. The water disposal well (Class I) will be covered through separate financial assurance document provided to the Texas Commission on Environmental Quality (TCEQ).

4.5 Emergency and Remedial Response

Details of the emergency and remedial response plan are found in the Emergency and Remedial Response plan document of this permit application.

The instrument values included in this document are based upon cost estimates by the Bluebonnet Sequestration Hub, LLC project team with input cost data from representative projects and service providers. Cost estimates provided during the permit process can be expected to change during the application approval process. The Bluebonnet Sequestration Hub, LLC will adjust the value of the financial instruments prior to securing them.

The Bluebonnet Project used a Carbon capture and Storage stochastic Monte Carlo model that has been tailored to reflect site-specific factors for emergency and remedial repose actions. This estimation approach is consistent with the U.S. EPA's Underground Injection Control (UIC) Program's Class VI regulatory requirements and is intended to inform the face value of financial assurance for the Bluebonnet Project. Details of this study are included in Appendix B.