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ExxonMobil Low Carbon Solutions
22777 Springwoods Village **Parkway**
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ExxonMobil

Mr. Rob Castillo
Railroad Commission of Texas
Underground Injection Control - Special Injection Permits
1701 North Congress Avenue
Austin, Texas 78701

Certification of Class VI Permit Application Submittal
Sunflower CCS Project (Permit No. 58608)

ExxonMobil Low Carbon Solutions Onshore LLC (ExxonMobil) is submitting this Underground Injection Control (UIC) Class VI Permit Application to support the development of the Sunflower Carbon Capture and Storage (CCS) Project in Jefferson and Liberty Counties, Texas (Project). The Project will sequester carbon dioxide (CO_2) from ExxonMobil's Gulf Coast CO_2 pipeline via three injection wells.

This Application has been developed to meet the requirements of Texas Water Code, Chapter 27, the Texas Natural Resources Chapter 91, and Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5. The information and evaluations performed for the Application demonstrate that the Project is protective of the underground sources of drinking water, has an injection zone sufficient to store large volumes of CO_2, and has confining zones suitable for containment and permanent sequestration of the injected CO_2.

Pursuant to 16 TAC 5.203(a)(1)(C), I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Additionally, pursuant to 16 TAC §5.201(j), I certify that the Sunflower CCS facility and all associated pipelines will operate in compliance with 16 TAC Chapter 8 Pipeline Safety Regulations as well as all other applicable Commission rules and orders. Similarly, pursuant to 16 TAC §8.1 (b)(2), I certify that the Sunflower CCS facility will operate in compliance with 49 U.S.C. §§60101, et seq.; and 49 CFR Part 195.

DocuSigned by:
Brian P McGowan
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Brian McGowan
Vice President

ExxonMobil Low Carbon Solutions
22777 Springwoods Village Parkway
Spring, TX 77389

ExxonMobil

Mr. Rob Castillo
Railroad Commission of Texas
Underground Injection Control - Special Injection Permits
1701 North Congress Avenue
Austin, Texas 78701

Re: Confidential Business Information in Application for a Permit Pursuant to Texas Administrative Code (TAC), Title 16, Part 1, Chapter 5, Subchapter B, relating to Geologic Storage and Associated Injection of Anthropogenic Carbon Dioxide (CO_2)

Applicant:	ExxonMobil Low C Sol On Stor LLC (P5 # 101256)
Facility Name:	Sunflower Carbon Capture and Storage Project
Injection Wells:	Sunflower INJ No. 01
	Sunflower INJ No. 02
	Sunflower INJ No. 03
County:	Jefferson and Liberty
RRC District:	03-Houston

Dear Mr. Castillo,

ExxonMobil asserts confidentiality pursuant to Government Code Ch. 552 for those portions marked "Confidential Business Information" and denoted with a redaction box. ExxonMobil asserts confidentiality for those marked portions of the Application pursuant to Texas Government Code Sections 552.101, 552.110, 552.113, and 552.1101.

Please let me know if I can provide you with any additional information or answer any questions. Thank you very much for your attention to this matter.

Respectfully submitted,

Cody Todd, P.E.
Underground Injection Control Lead

16 TAC Chapter 5	TAC Category	Description	Confirmation
§5.201 (f)	Applicability and compliance	Injection depth waiver. An operator may seek a waiver from the Class VI injection depth requirements for geologic storage to allow injection into non-USDW formations while ensuring that USDWs above and below the injection zone are protected from endangerment. An operator seeking a waiver of the requirement to inject below the lowermost USDW shall submit, concurrent with the permit application, a supplemental report that complies with 40 21 CFR §146.95. The Commission adopts 40 CFR §146.95 by reference, effective July 1, 2022.	N/A
§5.202 (c)(2)	Applicability and compliance	Evidence of financial responsibility. The operator acquiring the permit must provide the director with evidence of financial responsibility satisfactory to the director in accordance with §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	Section 9
§5.203 (a)(1)(A)	General	Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. **On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality.**	Submitting the Permit
§5.203 (a)(1)(B)	General	Signatories to permit applications. An applicant must ensure that the application is executed by a party having knowledge of the facts entered on the form and included in the required attachments. All permit applications shall be signed as specified in this subparagraph:	Ceritification Document
§5.203 (a)(1)(B)(i)	General	For a corporation, the permit application shall be signed by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision making functions for the corporation, or the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.	Ceritification Document
§5.203 (a)(1)(B)(ii)	General	For a partnership or sole proprietorship, the permit application shall be signed by a general partner or the proprietor, respectively.	na
§5.203 (a)(1)(B)(iii)	General	For a municipality, State, Federal, or other public agency, the permit application shall be signed by either a principal executive officer or ranking elected official.	na
§5.203 (a)(1)(C)	General	Certification. Any person signing a permit application or permit amendment application shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."	Ceritification Document
§5.203 (a)(2)	General	General	Various
§5.203 (a)(2)(A)		On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.	Section 0
§5.203 (a)(2)(B)		When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.	na
§5.203 (a)(2)(C)		The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Section 0
§5.203 (a)(2)(D)	General	A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued.	Will be submitted
§5.203 (a)(3)	General	Application completeness. The Commission shall [may] not issue a permit before receiving a complete application. A permit application is complete when the director determines that the application contains information addressing each application requirement of the regulatory program and all information necessary to initiate the final review by the director.	Application Review
§5.203 (a)(4)	General	Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.	5.2, QASP
§5.203 (a)(5)	General	If otherwise required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, a licensed professional engineer or geoscientist must conduct the geologic and hydrologic evaluations required under this subchapter and must affix the appropriate seal on the resulting reports of such evaluations.	Section 0
§5.203 (b)	Surface Map Information	Surface map and information. Only information of public record is required to be included on this map.	Appendix G, C, Section 1, Section 3, Section 8
§5.203 (b)(1)	Surface Map Information	The applicant must file with the director a surface map delineating the proposed location of any injection wells and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR.	**1.3, Appendix c**
§5.203 (b)(2)	Surface Map Information	The applicant must show within the AOR on the map the number or name and the location of:	
§5.203 (b)(2)(A)	Surface Map Information	all known artificial penetrations through the confining zone, including injection wells, producing wells, inactive wells, plugged wells, or dry holes;	Table 3-3

16 TAC Chapter 5	TAC Category	Description	Confirmation
§5.203 (b)(2)(B)	Surface Map Information	the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and	Appendix C Figure 1-50,
§5.203 (b)(2)(C)	Surface Map Information	other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.	Appendix C Figure 1-50, Appendix G
§5.203 (b)(3)	Surface Map Information	The applicant must identify on the map any known or suspected faults expressed at the surface.	1.5.2, 1.10.2
§5.203 (c)(1)	Geologic, geochemical, and hydrologic information	The applicant must submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations.	Section 1
§5.203 (c)(2)	Geologic, geochemical, and hydrologic information	The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including the following information:	Section 1
§5.203 (c)(2)(A)	Geologic, geochemical, and hydrologic information	geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	Appendix B
§5.203 (c)(2)(B)	Geologic, geochemical, and hydrologic information	The depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	**1.3, 1.4, 1.5, 1.7**
§5.203 (c)(2)(C)	Geologic, geochemical, and hydrologic information	the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment;	1.5.2, 1.10.3
§5.203 (c)(2)(D)	Geologic, geochemical, and hydrologic information	the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;	1.10
§5.203 (c)(2)(E)	Geologic, geochemical, and hydrologic information	geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;	1.6
§5.203 (c)(2)(F)	Geologic, geochemical, and hydrologic information	a description of the formation testing program used and the analytical results used to determine the chemical and physical characteristics of the injection zone and the confining zone; and	4.8.4, 1.3
§5.203 (c)(2)(G)	Geologic, geochemical, and hydrologic information	Baseline geochemical data on subsurface formations, including all formations containing USDWs in the AOR;	1.7
§5.203 (d)	AOR and corrective action	Area of Review and Corrective Action. This subsection describes the standards for the information regarding the delineation of the AOR, the identification of penetrations, and corrective action that an applicant must include in an application.	Section 3
§5.203 (d)(1)	AOR and corrective action	Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3
§5.203 (d)(1)(A)(i)	AOR and corrective action	Using computational modeling that considers the volumes and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods:	Section 2, Section 3
§5.203 (d)(1)(A)(i)(I)	AOR and corrective action	five years after initiation of injection;	2.7.2
§5.203 (d)(1)(A)(i)(II)	AOR and corrective action	from initiation of injection to the end of the injection period proposed by the applicant; and	2.7.2
§5.203 (d)(1)(A)(i)(III)	AOR and corrective action	from initiation of injection until the plume movement ceases, for a minimum of [to] 10 years after the end of the injection period proposed by the applicant.	2.7.2
§5.203 (d)(1)(A)(ii)	AOR and corrective action	The applicant must use a computational model that:	2.5, 2.6
§5.203 (d)(1)(A)(ii)(I)	AOR and corrective action	Is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone	2.6.3-2.6.5
§5.203 (d)(1)(A)(ii)(II)	AOR and corrective action	is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	2.1,2.6.6
§5.203 (d)(1)(A)(ii)(III)	AOR and corrective action	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	2.5.8
§5.203 (d)(1)(A)(ii)(IV)	AOR and corrective action	considers the physical and chemical properties of injected and formation fluids; and	2.6.5
§5.203 (d)(1)(A)(ii)(V)	AOR and corrective action	Considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.	2.5.2, 2.6.2, 2.7.4
§5.203 (d)(1)(A)(iii)	AOR and corrective action	The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.	2.3
§5.203 (d)(1)(B)	AOR and corrective action	Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR [area of review] that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled, location, depth, record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.	Table 3-3
§5.203 (d)(1)(C)	AOR and corrective action	Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO2 stream. Corrective action may be phased.	Table 3-3

16 TAC Chapter 5	TAC Category	Description	Confirmation
§5.203 (d)(2)	AOR and corrective action	Area of review and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information:	3.3, 3.5
§5.203 (d)(2)(A)	AOR and corrective action	The method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	2.3.1, 2.6
§5.203 (d)(2)(B)	AOR and corrective action	For AOR, a description of:	
§5.203 (d)(2)(B)(i)	AOR and corrective action	the minimum frequency subject to the annual certification pursuant to §5.206(f) of this title (relating to Permit Standards) at which the applicant proposes to re-evaluate the AOR during the life of the geologic storage facility;	3.6.1
§5.203 (d)(2)(B)(ii)	AOR and corrective action	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	3.6.3
§5.203 (d)(2)(B)(iii)	AOR and corrective action	the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and	3.6.3
§5.203 (d)(2)(C)	AOR and corrective action	a corrective action plan that describes:	Section 3
§5.203 (d)(2)(C)(i)	AOR and corrective action	how the corrective action will be conducted;	3.5.3, 3.5.4
§5.203 (d)(2)(C)(ii)	AOR and corrective action	how corrective action will be adjusted if there are changes in the AOR;	3.5.3
§5.203 (d)(2)(C)(iii)	AOR and corrective action	if a phased corrective action is planned, how the phasing will be determined; and	3.5.2.1
§5.203 (d)(2)(C)(iv)	AOR and corrective action	how site access will be secured for future corrective action.	3.5.5
§5.203 (e)	Injection well construction	Injection well construction	Section 4
§5.203 (e)(1)	Injection well construction	Criteria for construction of anthropogenic CO2 injection wells. This paragraph establishes the criteria for the information about the construction and casing and cementing of, and special equipment for, anthropogenic CO2 injection wells that an applicant must include in an application.	Section 4
§5.203 (e)(1)(A)	Injection well construction	General. The operator of a geologic storage facility must ensure that all anthropogenic CO2 injection wells are constructed and completed in a manner that will:	Section 4
§5.203 (e)(1)(A)(i)	Injection well construction	Prevent the movement of injected CO2 or displaced fromation fluids into any unauthorized zones or into any areas where they could endanger USDWs;	4.1
§5.203 (e)(1)(A)(ii)	Injection well construction	Allow the use of appropriate testing devices and workover tools; and	4.1
§5.203 (e)(1)(A)(iii)	Injection well construction	Allow continuous monitoring of the annulus space between the injection tubing and long string casing.	4.1
§5.203 (e)(1)(B)	Injection well construction	Casing and Cementing of anthropogenic CO2 injection wells	Section 4
§5.203 (e)(1)(B)(i)	Injection well construction	The operator must ensure that injection wells are cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), in addition to the requirements of this section.	4.5
§5.203 (e)(1)(B)(ii)	Injection well construction	Casing and cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards approved by the Director.	4.4.3, 4.5
§5.203 (e)(1)(B)(iii)	Injection well construction	Surface casing must extend through the base of the lowermost USDW above the injection zone and be cemented to the surface	4.5.2
§5.203 (e)(1)(B)(iv)	Injection well construction	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	NA
§5.203 (e)(1)(B)(v)	Injection well construction	At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The long string casing must isolate the injection zone and other intervals as necessary for the protection of USDWs and to ensure confinement of the injected and formation fluids to the permitted injection zone using cement and/or other isolation techniques. If the long string casing does not extend through the injection zone, another well string or liner must be cemented through the injection zone (for example, a chrome liner).	4.5.3
§5.203 (e)(1)(B)(vi)	Injection well construction	The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered.	4.8.2
§5.203 (e)(1)(B)(vii)		The director may exempt existing Class II wells that have been associated with injection of CO2 for the purpose of enhanced recovery, Class V experimental technology wells, and stratigraphic test wells from provisions of these casing and cementing requirements if the applicant demonstrates that the well construction meets the general performance criteria in subparagraph (A) of this paragraph. A converted well must meet all other requirements under this section. The demonstration must include the following:	NA
§5.203 (e)(1)(B)(vii)(I)		as-built schematics and construction procedures to demonstrate that repermitting is appropriate;	NA
§5.203 (e)(1)(B)(vii)(II)		recent or newly conducted well-log information and mechanical integrity test results;	NA
§5.203 (e)(1)(B)(vii)(III)		a demonstration that any needed remedial actions have been performed;	NA
§5.203 (e)(1)(B)(vii)(IV)		a demonstration that the well was engineered and constructed to meet the requirements of subparagraph (A) of this paragraph and ensure protection of USDWs;	NA
§5.203 (e)(1)(B)(vii)(V)		a demonstration that cement placement and materials are appropriate for CO2 injection for geologic storage;	NA
§5.203 (e)(1)(B)(vii)(VI)		a demonstration that the well has, and is able to maintain, internal and external mechanical integrity over the life of the project; and	NA
§5.203 (e)(1)(B)(vii)(VII)		the results of any additional testing of the well to support a demonstration of suitability for geologic storage.	NA
§5.203 (e)(1)(C)	Injection well construction	Special equipment.	Section 4, Appendix D
§5.203 (e)(1)(C)(i)	Injection well construction	Tubing and packer. All injection wells must inject fluids through tubing set on a mechanical packer. Packers must be set no higher than 100 feet above the top of the permitted injection interval or at a location approved by the director.	4.6
§5.203 (e)(1)(C)(ii)	Injection well construction	Pressure observation valve. The wellhead of each injection well must be equipped with a pressure observation valve on the tubing and each annulus of the well.	4.6.4
§5.203 (e)(2)	Injection well construction	Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:	Section 4

16 TAC Chapter 5	TAC Category	Description	Confirmation
§5.203 (e)(2)(A)	Injection well construction	Depth to the injection zone(s);	section 4.9.1. Appendix D
§5.203 (e)(2)(B)	Injection well construction	Hole size	4.5
§5.203 (e)(2)(C)	Injection well construction	size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths);	4.5
§5.203 (e)(2)(D)	Injection well construction	proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, and maximum proposed volume and/or mass of the CO2 stream to be injected;	2.7.1, 4.9.2
§5.203 (e)(2)(E)	Injection well construction	type of packer and packer setting depth	4.6.3, Appendix ?
§5.203 (e)(2)(F)	Injection well construction	a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids;	4.4
§5.203 (e)(2)(G)	Injection well construction	Down-hole temperatures and pressures	4.6.2
§5.203 (e)(2)(H)	Injection well construction	Lithology of injection and confining zone(s)	4.8
§5.203 (e)(2)(I)	Injection well construction	Type or grade of cement and cement additives; and	4.5, Appendix ?
§5.203 (e)(2)(J)	Injection well construction	Quantity, chemical composition, and temperature of the carbon dioxide stream.	2.1, Table 4-1, 2.1, 4.9.2
§5.203 (e)(2)(K)	Injection well construction	Schematic drawings of the surface and subsurface construction details.	Appendix D
§5.203 (e)(3)	Injection well construction	Well construction plan. The applicant must submit an injection well construction plan that meets the criteria in paragraph (1) of this subsection.	4.7, Appendix ?
§5.203 (e)(4)	Injection well construction	Well stimulation plan. The applicant must submit, as applicable, a description of the proposed well stimulation program and a determination that stimulation will not compromise containment	4.9.3
§5.203 (f)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The applicant must submit a plan for logging, sampling, and testing of each injection well after permitting but prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.	4.8
§5.203 (f)(1)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Logs and surveys of newly drilled and completed injection wells.	4.8.2
§5.203 (f)(1)(A)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	During the drilling of any hole that is constructed by drilling a pilot hole which is enlarged by reaming or another method, the operator must perform deviation checks at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.	N/A
§5.203 (f)(1)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	4.8.2
§5.203 (f)(1)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.8.2
§5.203 (f)(1)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.8.2
§5.203 (f)(1)(D)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Before long string casing is installed, the operator must run logs appropriate to the 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.	Table 4-18
§5.203 (f)(2)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Testing and determination of hydrogeologic characteristics of injection and confining zone.	Section 1, 4
§5.203 (f)(2)(A)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	4.8.5
§5.203 (f)(2)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must perform an initial pressure fall-off or 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.	4.8.5
§5.203 (f)(2)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone	1.6.3,2.6.6.1, 4.9.2
§5.203 (f)(3)(A)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must record the formation fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone.	4.8.3
§5.203 (f)(3)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must submit analyses of whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well.	4.8.1, 4.8.3
§5.203 (g)	Compatibility determination	Compatibility determination. Based on the results of the formation testing program required by subsection (f) of this section, the applicant must submit a determination of the compatibility of the CO2 stream with:	Section 1, 2, 4
§5.203 (g)(1)	Compatibility determination	the materials to be used to construct the well;	4.4
§5.203 (g)(2)	Compatibility determination	fluids in the injection zone; and	4.4, 1.7
§5.203 (g)(3)	Compatibility determination	minerals in both the injection and the confining zone.	2.4.4, 1.7
§5.203 (h)	Mechanical integrity testing	Mechanical integrity testing.	Section 5

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§5.203 (h)(1)	Mechanical integrity testing	Criteria. This paragraph establishes the criteria for the mechanical integrity testing plan for anthropogenic CO2 injection wells that an applicant must include in an application.	5.4.2
§5.203 (h)(1)(A)	Mechanical integrity testing	Other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.	4.2
§5.203 (h)(1)(B)	Mechanical integrity testing	Before beginning injection operations and at least once every five years thereafter, the operator must demonstrate internal mechanical integrity for each injection well by pressure testing the tubing-casing annulus.	5.4.2.1
§5.203 (h)(1)(C)	Mechanical integrity testing	Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, injected volumes and pressure on the annulus between tubing and long-string casing to confrim that the injected fluids are confined to the injection zone.	5.5.1.1, 5.5.1.2
§5.203 (h)(1)(D)	Mechanical integrity testing	At least once per year until the injection well is plugged the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).	5.4.2.2
§5.203 (h)(1)(E)	Mechanical integrity testing	The operator must test injection wells after any workover that disturbs the seal between the tubing, packer, and casing in a manner that verifies internal mechanical integrity of the tubing and long string casing.	5.4.2.1
§5.203 (h)(1)(F)	Mechanical integrity testing	An operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	8.4.1
§5.203 (h)(2)	Mechanical integrity testing	Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. [The plan must include a schedule for the performance of a series of tests at a minimum frequency of five years.] The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:	5.4.2
§5.203 (h)(2)(A)	Mechanical integrity testing	A pressure test with liquid or gas;	5.4.2
§5.203 (h)(2)(B)	Mechanical integrity testing	A tracer survey such as oxygen-activation logging;	5.4.2
§5.203 (h)(2)(C)	Mechanical integrity testing	A temperature or noise log;	NA
§5.203 (h)(2)(D)	Mechanical integrity testing	A casing inspection log; and	5.5.2.1
§5.203 (h)(2)(E)	Mechanical integrity testing	Any alternative methods approved by the director, and if necessary by the Administrator of EPA under 40 CFR §146.89(e), that provides equivalent or better information approved by the director.	Director
§5.203 (i)(1)	Operating Information	Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) [§5.206(c)] of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:	4.9
§5.203 (i)(1)(A)	Operating Information	The average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	2.7.1, 4.9.2
§5.203 (i)(1)(B)	Operating Information	The average and maximum surface injection pressure;	4.9.2
§5.203 (i)(1)(C)	Operating Information	The sources of the carbon dioxide stream and the volume of carbon dioxide from each source; and	
§5.203 (i)(1)(D)	Operating Information	An analysis of the chemical and physical characteristics of the carbon dioxide stream prior to injection.	4.3
§5.203 (i)(2)	Operating Information	Maximum injection pressure. The director will approve a maximum injection pressure limit that:	
§5.203 (i)(2)(A)	Operating Information	Considers the risks of tensile failure and, where appropriate, geomechanical or other studies that assess the risk of tensile failure and shear failure;	4.9.2
§5.203 (i)(2)(B)	Operating Information	With a reasonable degree of certainty will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive; and	4.9.2
§5.203 (i)(2)(C)	Operating Information	in no case may cause the movement of injection fluids or formation fluids in a manner that endangers USDWs.	4.1, 4.2
§5.203 (j)	Plan for monitoring, sampling, and testing after initiation of operation	Plan for monitoring, sampling, and testing after initiation of operation.	Section 5
§5.203 (j)(1)	Plan for monitoring, sampling, and testing after initiation of operation	The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.	Section 5
§5.203 (j)(2)	Plan for monitoring, sampling, and testing after initiation of operation	The plan must include the following:	Section 5
§5.203 (j)(2)(A)	Plan for monitoring, sampling, and testing after initiation of operation	The analysis of the carbon dioxide stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;	Table 5-2
§5.203 (j)(2)(B)	Plan for monitoring, sampling, and testing after initiation of operation	The installation and use of continuous recording devices to monitor injection pressure, rate, and volume and the pressure on the annulus between the tubing and the long string casing, except during workovers	5.5.1
§5.203 (j)(2)(C)	Plan for monitoring, sampling, and testing after initiation of operation	After initiation of injection, the performance on a semi-annual basis of corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in subsection (e)(1)(A) of this section. The operator must report the results of such monitoring annually. Corrosion monitoring may be accomplished by:	5.5.2
§5.203 (j)(2)(C)(i)	Plan for monitoring, sampling, and testing after initiation of operation	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	5.5.2.1
§5.203 (j)(2)(C)(ii)	Plan for monitoring, sampling, and testing after initiation of operation	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	5.5.2.1
§5.203 (j)(2)(C)(iii)	Plan for monitoring, sampling, and testing after initiation of operation	using an alternative method, materials, or time period approved by the director;	Director
§5.203 (j)(2)(D)(i)	Plan for monitoring, sampling, and testing after initiation of operation	Periodic sampling of the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone and monitoring for pressure changes, and for changes in geochemistry, in a permeable and porous formation near to and above the top confining zone;	Table 5-8,

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§5.203 (j)(2)(D)(ii)	Plan for monitoring, sampling, and testing after initiation of operation	periodic monitoring of the quality and geochemistry of a USDW within the AOR and the formation fluid in a permeable and porous formation near to and above the top confining zone to detect any movement of the injected CO_2 through the confining zone into that monitored formation;	Table 5-8,
§5.203 (j)(2)(D)(iii)	Plan for monitoring, sampling, and testing after initiation of operation	The location and number of monitoring wells justified on the basis of AOR, injection rate and volume, geology, the presence of artificial penetrations and other factors specific to the geologic storage facility; and	5.4.1
§5.203 (j)(2)(D)(iv)	Plan for monitoring, sampling, and testing after initiation of operation	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under subsection (c)(2) of this section and any modeling results in the AOR evaluation;	5.3, 5.4.1
§5.203 (j)(2)(D)	Plan for monitoring, sampling, and testing after initiation of operation	Monitoring of geochemical and geophysical changes, including:	Section 5
§5.203 (j)(2)(E)	Plan for monitoring, sampling, and testing after initiation of operation	tracking the extent of the CO2 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 CO2 detection tools;	Table 5-2, 5.4
§5.203 (j)(2)(F)		a demonstration of external mechanical integrity pursuant to subsection (h)(2) of this section at least once per year until the injection well is plugged, and, if required by the director, a casing inspection log pursuant to requirements in subsection (h)(2) of this section at a frequency established in the testing and monitoring plan;	5.4.2.2
§5.203 (j)(2)(G)	Plan for monitoring, sampling, and testing after initiation of operation	A pressure fall-off test at least once every five years unless more frequent testing is required by the director based on site-specific information; and	5.4.3
§5.203 (j)(2)(H)	Plan for monitoring, sampling, and testing after initiation of operation	Additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.	Director
§5.203 (k)(1)	Well Plugging Plan	A proposal for plugging all monitoring wells that penetrate the base of usable quality water and all injection wells upon abandonment in accordance with §3.14 of this title (relating to Plugging), in addition to the requirements of this section. The proposal must include:	Section 6
§5.203 (k)(1)(A)	Well Plugging Plan	The type and number of plugs to be used;	6.4.2
§5.203 (k)(1)(B)	Well Plugging Plan	The placement of each plug, including the elevation of the top and bottom of each plug;	6.4.2
§5.203 (k)(1)(C)	Well Plugging Plan	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	6.4.2
§5.203 (k)(1)(D)	Well Plugging Plan	The method of placement of the plugs.	6.4.2
§5.203 (k)(2)(A)	Well Plugging Plan	flush each injection well with a buffer fluid;	6.3.1
§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.3.3
§5.203 (k)(2)(C)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.3.4
§5.203 (k)(2)(D)	Well Plugging Plan	ensuring that the material to be used in plugging must be compatible with the CO2 stream and the formation fluids;	6.3.5
§5.203 (k)(3)(A)	Well Plugging Plan	the operator notifies the director at least 60 days before plugging a well. At this time, if any changes have been made to the original well plugging plan, the operator must also provide a revised well plugging plan. At the discretion of the director, an operator may be allowed to proceed with well plugging on a shorter notice period; and	6.4.2.1
§5.203 (k)(3)(B)	Well Plugging Plan	the operator will file a notice of intention to plug and abandon (Form W-3A) a well with the appropriate Commission district office and the division in Austin at least five days prior to the beginning of plugging operations;	6.4.2.1
§5.203 (k)(4)	Well Plugging Plan	plugging report for monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that within 30 days after plugging the operator will file a complete well plugging record (Form W-3) in duplicate with the appropriate district office. The operator and the person who performed the plugging operation (if other than the operator) must certify the report as accurate;	6.4.2.1
§5.203 (k)(6)	Well Plugging Plan	A plan for certifying that all monitoring wells that do not penetrate the base of usable quality water will be plugged in accordance with 16 TAC Chapter 76.	7.7.2, 6.6
§5.203 (k)	Well Plugging Plan	Injection well plugging	Section 6
§5.203 (k)	Well Plugging Plan	Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that penetrate the base of usable quality water that includes the following:	Section 6
§5.203 (l)	Emergency and remedial response plan	Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:	Section 8
§5.203 (l)(1)	Emergency and remedial response plan	accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	8.1
§5.203 (l)(2)	Emergency and remedial response plan	describes actions to be taken to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to USDWs during construction, operation, closure, and post-closure periods;	8.4
§5.203 (l)(3)	Emergency and remedial response plan	Includes a safety plan that includes:	8.4
§5.203 (l)(3)(A)	Emergency and remedial response plan	emergency response procedures;	8.4
§5.203 (l)(3)(B)	Emergency and remedial response plan	provisions to provide security against unauthorized activity;	8.1
§5.203 (l)(3)(C)	Emergency and remedial response plan	CO2 release detection and prevention measures;	8.4.3, 8.4.4
§5.203 (l)(3)(D)	Emergency and remedial response plan	instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency;	8.6
§5.203 (l)(3)(E)	Emergency and remedial response plan	procedures for requesting assistance and for follow-up action to remove the public from an area of exposure;	8.6
§5.203 (l)(3)(F)	Emergency and remedial response plan	provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO2,	8.8
§5.203 (l)(3)(G)	Emergency and remedial response plan	the manner in which the public will be notified of an emergency and steps to be taken in case of an emergency; and	8.6,8.8
§5.203 (l)(3)(H)	Emergency and remedial response plan	if necessary, proposed actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring; and	8.4.5

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§5.203 (l)(4)	Emergency and remedial response plan	includes a description of the training and testing that will be provided to each employee at the storage facility on operational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility. The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. Emergency measures specific to the contractor's work must be explained in the contractor safety meeting. Training schedules, training dates, and course outlines must be provided to Commission personnel upon request for the purpose of Commission review to determine compliance with this paragraph.	8.8
§5.203 (m)	Post-injection storage facility care and closure plan	The applicant must submit a post-injection storage facility care and closure plan.	Section 7
§5.203 (m)(1)	Post-injection storage facility care and closure plan	a demonstration containing substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the post-injection storage facility care timeframe. The demonstration must be based on significant, site-specific data and information, including all data and information collected pursuant subsections (b)-(d) of this section and §5.206(b)(5) of this title;	7.6
§5.203 (m)(2)	Post-injection storage facility care and closure plan	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	Table 7-1
§5.203 (m)(3)	Post-injection storage facility care and closure plan	the predicted position of the CO2 plume and associated pressure front at closure as demonstrated in the AOR evaluation required under subsection (d) of this section;	7.4
§5.203 (m)(4)	Post-injection storage facility care and closure plan	A description of post-injection monitoring location, methods, and proposed frequency;	7.5
§5.203 (m)(5)	Post-injection storage facility care and closure plan	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	7.5.4
§5.203 (m)(6)	Post-injection storage facility care and closure plan	the estimated cost of proposed post-injection storage facility care and closure; and	9.7.2
§5.203 (m)(7)	Post-injection storage facility care and closure plan	consideration and documentation of:	
§5.203 (m)(7)(A)	Post-injection storage facility care and closure plan	the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;	7.6.3, 2.7
§5.203 (m)(7)(B)	Post-injection storage facility care and closure plan	the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre-injection pressures;	7.6.4, 2.7.3
§5.203 (m)(7)(C)	Post-injection storage facility care and closure plan	the predicted rate of CO2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO2 plume and associated pressure front;	7.6.5, 2.7.2
§5.203 (m)(7)(D)	Post-injection storage facility care and closure plan	a description of the site-specific processes that will result in CO2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	2.4
§5.203 (m)(7)(E)	Post-injection storage facility care and closure plan	the predicted rate of CO2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	2.4.5
§5.203 (m)(7)(F)	Post-injection storage facility care and closure plan	the results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in subparagraphs (D) and (E) of this paragraph;	Section 2
§5.203 (m)(7)(G)	Post-injection storage facility care and closure plan	a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., CO2, formation fluids) movement;	1.3.2, 1.3.3
§5.203 (m)(7)(H)	Post-injection storage facility care and closure plan	the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO2 plume and area of elevated pressure;	7.2
§5.203 (m)(7)(I)	Post-injection storage facility care and closure plan	a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;	Section 4, Section 6, Section 7
§5.203 (m)(7)(J)	Post-injection storage facility care and closure plan	the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	Section 6, Appendix F
§5.203 (m)(7)(K)	Post-injection storage facility care and closure plan	any additional site-specific factors required by the director; and	Director
§5.203 (m)(8)	Post-injection storage facility care and closure plan	information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:	
§5.203 (m)(8)(A)	Post-injection storage facility care and closure plan	all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	7.1
§5.203 (m)(8)(B)	Post-injection storage facility care and closure plan	estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	7.4
§5.203 (m)(8)(C)	Post-injection storage facility care and closure plan	predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project;	7.4
§5.203 (m)(8)(D)	Post-injection storage facility care and closure plan	predictive models must be calibrated using existing information where sufficient data are available;	7.4
§5.203 (m)(8)(E)	Post-injection storage facility care and closure plan	reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	7.4
§5.203 (m)(8)(F)	Post-injection storage facility care and closure plan	an analysis must be performed to identify and assess aspects of the alternative PISC timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;	NA
§5.203 (m)(8)(G)	Post-injection storage facility care and closure plan	an approved quality assurance and quality control plan must address all aspects of the demonstration; and	QASP
§5.203 (m)(8)(H)	Post-injection storage facility care and closure plan	any additional criteria required by the director.	Director
§5.203 (n)	Fees, financial responsibility, and financial assurance	Fees, financial responsibility, and financial assurance. The applicant must pay the fees, demonstrate that it has met the financial responsibility requirements, and provide the Commission with financial assurance as required under §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	Section 9
§5.203 (n)(1)		The applicant must demonstrate financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided to the operator a written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.3

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§5.203 (n)(2)		In determining whether the applicant is financially responsible, the director must rely on the following:	Appendix H
§5.203 (n)(2)(A)		the person's most recent audited annual report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)). The date of the audit may not be more than one year before the date of submission of the application to the division; and	Appendix H-1
§5.203 (n)(2)(B)		the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or	Appendix H-2
§5.203 (n)(2)(C)		if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the division.	NA
§5.203 (o)		Letter from the Groundwater Advisory Unit of the Oil and Gas Division. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with Texas Water Code, §27.046.	1.8.3
§5.203 (p)		Other information. The applicant must submit any other information requested by the director as necessary to discharge the Commission's duties under Texas Water Code, Chapter 27, Subchapter B-1, or deemed necessary by the director to clarify, explain, and support the required attachments.	Director
§5.205 (b)	Fees, financial responsibility, and financial assurance	Financial Responsibility	Section 9
§5.205 (b)(1)	Fees, financial responsibility, and financial assurance	A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The operator must demonstrate and maintain financial responsibility and resources for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.3
§5.205 (b)(2)	Fees, financial responsibility, and financial assurance	In determining whether the person is financially responsible, the director must rely on:	Appendix H
§5.205 (b)(2)(A)	Fees, financial responsibility, and financial assurance	the person's most recent audited annual report 1 filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); and	Appendix H-1
§5.205 (b)(2)(B)	Fees, financial responsibility, and financial assurance	the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or	Appendix H-2
§5.205 (b)(2)(C)	Fees, financial responsibility, and financial assurance	if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the director.	NA
§5.205 (b)(3)	Fees, financial responsibility, and financial assurance	The applicant's demonstration of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	8.3, 9.4
§5.205 (b)(3)	Fees, financial responsibility, and financial assurance	The applicant's demonstratio of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.3
§5.205 (c)	Financial assurance	Financial assurance.	Section 9
§5.205 (c)(1)	Fees, financial responsibility, and financial assurance	Injection and monitoring wells. The operator must comply with the requirements of §3.78 of this title for all monitoring wells that penetrate the base of usable quality water and this subsection for all injection wells.	9.4
§5.205 (c)(2)	Fees, financial responsibility, and financial assurance	Geologic storage facility.	Various
§5.205 (c)(2)(A)	Fees, financial responsibility, and financial assurance	The applicant must include in an application for a geologic storage facility permit:	
§5.205 (c)(2)(A)(i)	Fees, financial responsibility, and financial assurance	a written estimate of the highest likely dollar amount necessary to perform post-injection monitoring and closure of the facility that shows all assumptions and calculations used to develop the estimate;	9.7
§5.205 (c)(2)(A)(ii)	Fees, financial responsibility, and financial assurance	a copy of the form of the bond or letter of credit that will be filed with the Commission; and	Appendix H-3,
§5.205 (c)(2)(A)(iii)	Fees, financial responsibility, and financial assurance	information concerning the issuer of the bond or letter of credit including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.	Appendix H-4
§5.205 (c)(2)(B)	Fees, financial responsibility, and financial assurance	A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.	Director
§5.205 (c)(2)(C)	Fees, financial responsibility, and financial assurance	The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:	Section 9
§5.205 (c)(2)(C)(i)	Fees, financial responsibility, and financial assurance	The director must approve the dollar amount of the financial assurance. The amount of financial assurance required to be filed under this subsection must be equal to or greater than the maximum amount necessary to perform corrective action, emergency response, and remedial action, post-injection monitoring and site care, and closure of the geologic storage facility at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit;	9.4
§5.205 (c)(2)(C)(ii)	Fees, financial responsibility, and financial assurance	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 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; and	Appendix H-5
§5.205 (c)(2)(C)(iii)	Fees, financial responsibility, and financial assurance	The Commission may use the proceeds of financial assurance filed under this subsection to pay the costs of plugging any well or wells at the facility if the financial assurance for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.	NA
§5.205 (c)(2)(D)	Financial assurance	Bonds and letters of credit filed in satisfaction of the financial assurance requirements for a geologic storage facility must comply with the following standards as to issuer and form.	Section 9, Appendix H-3,H-4
§5.205 (c)(2)(D)(i)	Financial assurance	The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection must be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection must provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.	Appendix H-4

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§5.205 (c)(2)(D)(ii)	Financial assurance	Any letter of credit filed in satisfaction of the requirements of this subsection must be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit must be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101 - 5.118. The letter of credit must provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the director.	NA
§5.205 (c)(2)(D)(iii)	Financial assurance	The qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	9.3
§5.205 (c)(2)(D)(iii)(I)	Financial assurance	Cancellation. An owner or operator must provide that its financial instrument may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the director. The cancellation must not be final until at least 120 days after the Commission receives the cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.	9.3
§5.205 (c)(2)(D)(iii)(II)	Financial assurance	Renewal. If a financial instrument expires, the owner or operator must renew the financial instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	9.3
§5.205 (c)(2)(D)(iii)(III)	Financial assurance	Financial instrument to remain in effect. Cancellation, termination, or failure to renew shall not occur and the financial instrument shall remain in full force and effect if on or before the date of expiration:	9.3
§5.205 (c)(2)(D)(iii)(III)(-a-)		the director deems the facility abandoned;	9.3
§5.205 (c)(2)(D)(iii)(III)(-b-)		the permit is terminated or revoked or a new permit is denied;	9.3
§5.205 (c)(2)(D)(iii)(III)(-c-)		closure is ordered by the director or a United States district court or other court of competent jurisdiction;	9.3
§5.205 (c)(2)(D)(iii)(III)(-d-)		the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or	9.3
§5.205 (c)(2)(D)(iii)(III)(-e-)		the amount due is paid.	9.3
§5.205 (c)(2)(E)	Fees, financial responsibility, and financial assurance	The operator of a geologic storage facility must provide to the director annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The operator must provide to the director upon request an adjustment of the cost estimate if the director has reason to believe that the original demonstration is no longer adequate to cover the cost of injection well plugging and post-injection storage facility care and closure.	9.4
§5.205 (c)(2)(F)	Fees, financial responsibility, and financial assurance	The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	9.4, ?
§5.205 (c)(2)(G)	Fees, financial responsibility, and financial assurance	Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the operator has received written approval from the director.	9.4
§5.205 (c)(2)(H)	Fees, financial responsibility, and financial assurance	The requirement to maintain adequate financial responsibility is directly enforceable regardless of whether the requirement is a condition of the permit.	9.3
§5.205 (c)(2)(H)(i)	Fees, financial responsibility, and financial assurance	The owner or operator must maintain financial responsibility until:	9.3
§5.205 (c)(2)(H)(i)(I)	Fees, financial responsibility, and financial assurance	the director receives and approves the completed post-injection storage facility care and closure plan; and	9.3
§5.205 (c)(2)(H)(i)(II)	Fees, financial responsibility, and financial assurance	the director issues the certificate of closure.	9.3
§5.205 (c)(2)(H)(ii)	Fees, financial responsibility, and financial assurance	The owner or operator may be released from a financial instrument in the following circumstances:	Operations
§5.205 (c)(2)(H)(ii)(I)	Fees, financial responsibility, and financial assurance	The owner or operator has completed the phase of the geologic storage project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the director, including obtaining financial responsibility for the next phase of the geologic storage project, if required; or	Operations

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§5.205 (c)(2)(H)(ii)(II)	Fees, financial responsibility, and financial assurance	The owner or operator has submitted a replacement financial instrument and received written approval from the director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.	Operations
§5.205 (c)(3)	Fees, financial responsibility, and financial assurance	The director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors.	Director
§5.205 (c)(4)	Fees, financial responsibility, and financial assurance	The director may approve a reduction in the amount of financial assurance required for post-injection monitoring and/or corrective action based on project-specific monitoring results.	Director
§5.205 (c)(5)		The owner or operator must maintain the required financial responsibility regardless of the status of the director's review of the financial responsibility demonstration.	9.3
§5.205 (D)	Fees, financial responsibility, and financial assurance	Notice of adverse financial conditions	9.3
§5.205 (D)(1)	Fees, financial responsibility, and financial assurance	The operator must notify the Commission of adverse financial conditions that may affect the operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An operator must file any notice of bankruptcy in accordance with §3.1(f) of this title (relating to Organization Report; Retention of Records; Notice Requirements). The operator must give such notice by certified mail.	9.3
§5.205 (D)(2)	Fees, financial responsibility, and financial assurance	The 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 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.	Appendix H-4
§5.205 (D)(3)	Fees, financial responsibility, and financial assurance	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 operator to be without bond coverage. The Commission must issue a notice to any operator who is without bond coverage and must specify a reasonable period to replace bond coverage, not to exceed 60 days.	NA
§5.206 (a)	Permit Standards	Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	Condition
§5.206 (a)(1)		Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	Condition
§5.206 (a)(2)		The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.	Condition
§5.206 (b)	Permit Standards	General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that:	Director
§5.206 (b)(1)	Permit Standards	the injection and geologic storage of anthropogenic CO2 will not endanger or injure any existing or prospective oil, gas, geothermal, or other mineral resource, or cause waste as defined by Texas Natural Resources Code, §85.046(11);	Section 0 - App Narr
§5.206 (b)(2)	Permit Standards	with proper safeguards, both USDWs and surface water can be adequately protected from CO2 migration or displaced formation fluids;	Section 4
§5.206 (b)(3)	Permit Standards	the injection of anthropogenic CO2 will not endanger or injure human health and safety;	Section 0 - App Narr
§5.206 (b)(4)		the construction, operation, maintenance, conversion, plugging, abandonment, or any other injection activity does not allow the movement of fluid containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons;	Condition
§5.206 (b)(5)	Permit Standards	the reservoir into which the anthropogenic CO2 is injected is suitable for or capable of being made suitable for protecting against the escape or migration of anthropogenic CO2 from the storage reservoir;	Condition
§5.206 (b)(6)	General Criteria	the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include:	Section 1
§5.206 (b)(6)(A)	General Criteria	an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO2 stream; and	1.3.1, 1.11
§5.206 (b)(6)(B)	General Criteria	a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs;	1.3.2, 1.11
§5.206 (b)(7)	Permit Standards	the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit;	
§5.206 (b)(8)	Permit Standards	the applicant has provided a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with §5.203(o) of this title (relating to Application Requirements);	1.8.3
§5.206 (b)(9)	Permit Standards	the applicant has provided a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ;	In progress
§5.206 (b)(10)	Permit Standards	the applicant has provided a signed statement that the applicant has a good faith claim to the necessary and sufficient property rights for construction and operation of the geologic storage facility for at least the first five years after initiation of injection in accordance with §5.203(d)(1)(A) of this title;	Sectio 0 - Application Narrative
§5.206 (b)(11)	Permit Standards	the applicant has paid the fees required in §5.205(a) of this title (relating to Fees, Financial Responsibility, and Financial Assurance);	Fee
§5.206 (b)(12)	Permit Standards	the director has determined that the applicant has sufficiently demonstrated financial responsibility as required in §5.205(b) of this title; and	Section 9
§5.206 (b)(13)	Permit Standards	the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.	Section 9
§5.206 (c)(1)	Permit Standards	Construction of anthropogenic CO 2 injection wells must meet the criteria in §5.203(e) of this title.	Section 4

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§5.206 (c)(2)	Permit Standards	Within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on the appropriate form showing the current completion.	4.7.1
§5.206 (c)(3)	Permit Standards	Except in the case of an emergency repair, the operator of a geologic storage facility must notify the director in writing at least 30 days prior to conducting any well workover that involves running tubing and setting packers, beginning any workover or remedial operation, or conducting any required pressure tests or surveys. Such activities shall not commence before the end of the 30 days unless authorized by the director. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical.	5.2
§5.206 (d)	Permit Standards	Operating a geologic storage facility.	Various
§5.206 (d)(1)(A)	Permit Standards	Operating plan. The operator must maintain and comply with the approved operating plan.	Operations
§5.206 (d)(1)(B)		Prior to approval for the operation of a Class VI injection well, the operator shall submit, and the director shall consider, the following information:	Director
§5.206 (d)(1)(B)(i)		the final AOR based on modeling, using data obtained during logging and testing of the well and the formation as required by clauses (ii), (iii), (iv), (vi), (vii), and (x) of this subparagraph;	Section 2,3
§5.206 (d)(1)(B)(ii)		any relevant updates, based on data obtained during logging and testing of the well and the formation as required by clauses (iii), (iv), (vi), (vii), and (x) of this subparagraph to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of §5.203(c)(2) and (3) of this title;	Section 2, 3, 4
§5.206 (d)(1)(B)(iii)		information on the compatibility of the CO2 stream with fluids in the injection zones and minerals in both the injection and the confining zones, based on the results of the formation testing program, and with the materials used to construct the well;	2.4.4, 1.7
§5.206 (d)(1)(B)(iv)		the results of the formation testing program required by §5.203(f) of this title;	Operations
§5.206 (d)(1)(B)(v)		final injection well construction procedures that meet the requirements of §5.203(e) of this title;	Appendix D
§5.206 (d)(1)(B)(vi)		the status of corrective action on wells in the AOR;	Operations
§5.206 (d)(1)(B)(vii)		all available logging and testing program data on the well required by §5.203(f) of this title;	Operations
§5.206 (d)(1)(B)(viii)		a demonstration of mechanical integrity pursuant to §5.203(h) of this title;	Operations
§5.206 (d)(1)(B)(ix)		any updates to the proposed AOR and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection storage facility care and closure plan, or the emergency and remedial response plan submitted under §5.203(m) of this subchapter, which are necessary to address new information collected during logging and testing of the well and the formation as required by this section, and any updates to the alternative post-injection storage facility care timeframe demonstration submitted under §5.203(m) of this title, which are necessary to address new information collected during the logging and testing of the well and the formation as required by this section; and	Operations
§5.206 (d)(1)(B)(x)		any other information requested by the director.	Director
§5.206 (d)(2)	Permit Standards	Operating criteria.	Various
§5.206 (d)(2)(A)	Operating a geologic storage facility	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	4.2
§5.206 (d)(2)(B)	Permit Standards	The total volume of CO2 injected into the storage facility must be metered through a master meter or a series of master meters. The volume and/or mass of CO2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.	5.5.1.1, table 5-2, 5.3
§5.206 (d)(2)(C)	Permit Standards	The operator must comply with a maximum surface injection pressure limit approved by the director and specified in the permit. In approving a maximum surface injection pressure limit, the director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults or fractures transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection fluids or formation fluids in a manner that endangers USDWs. The Commission shall include in any permit it might issue a limit of 90 percent of the fracture pressure to ensure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. The director may approve a plan for controlled artificial fracturing of the injection zone.	4.9.2
§5.206 (d)(2)(D)	Operating a geologic storage facility	The owner or operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	4.6.3, 4.1, 4.2, 4.7.1, 4.9.2
§5.206 (d)(2)(E)	Permit Standards	The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO2 stream. The operator must monitor the pressure on the annulus between the tubing and the long string casing. The operator must continuously record, continuously monitor, or control by a preset high-low pressure sensor switch the wellhead pressure of each injection well.	5.5.1
§5.206 (d)(2)(F)	Operating a geologic storage facility	The operator must comply with the following requirements for alarms and automatic shut-off systems.	Section 4, 8, 5
§5.206 (d)(2)(F)(i)	Operating a geologic storage facility	The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	5.5.1
§5.206 (d)(2)(F)(ii)	Operating a geologic storage facility	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must	4.10, 8.4.1
§5.206 (d)(2)(F)(ii)(I)	Operating a geologic storage facility	Immediately cease injection;	4.10, 8.4.1

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§5.206 (d)(2)(F)(ii)(II)	Operating a geologic storage facility	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone	4.10, 8.4.1
§5.206 (d)(2)(F)(ii)(III)	Operating a geologic storage facility	Notify the Director within 24 hours	8.4.1
§5.206 (d)(2)(F)(ii)(IV)	Operating a geologic storage facility	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	8.4.1
§5.206 (d)(2)(F)(ii)(V)	Operating a geologic storage facility	Notify the Director when injection can be expected to resume	8.4.1
§5.206 (e)	Permit Standards	Monitoring, sampling, and testing requirements.	Section 5
§5.206 (e)(1)	Permit Standards	The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.	Section 5
§5.206 (e)(2)	Permit Standards	All permits shall include the following requirements:	
§5.206 (e)(2)(A)	Permit Standards	the proper use, maintenance, and installation of monitoring equipment or methods;	Appendix E.4
§5.206 (e)(2)(B)	Permit Standards	monitoring including type, intervals, and frequency sufficient to yield data that are representative of the monitored activity including, when required, continuous monitoring;	Table 5-2, Table 5-3, Table 5-4, Table 5-5, Table 5-8,
§5.206 (e)(2)(C)	Permit Standards	reporting no less frequently than as specified in §5.207 of this title (relating to Reporting and Record-Keeping).	Table 5-2, Table 5-3, Table 5-4, Table 5-5, Table 5-8,
§5.206 (e)(3)	Monitoring, sampling, and testing requirements	The director may require additional monitoring as necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirement that the injection activity not allow movement of fluid that would endanger USDWs	Director
§5.206 (e)(4)	Permit Standards	The director may require measures and actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring.	Director
§5.206 (e)(5)		The operator shall comply with the following monitoring and record retention requirements.	Section 5
§5.206 (e)(5)(A)		Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.	Section 5
§5.206 (e)(5)(B)		The permittee shall retain records of all monitoring information, including the following:	5.2
§5.206 (e)(5)(B)(i)		calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for a period of at least ten years from the date of the sample, measurement, report, or application. This period may be extended by the director at any time; and	5.2
§5.206 (e)(5)(B)(ii)		the nature and composition of all injected fluids until ten years after the completion of any plugging and abandonment procedures specified in §5.203(k)(2) of this title for the injection wells. The director may require the operator to submit the records to the director at the conclusion of the retention period. This period may be extended by the director at any time.	5.2
§5.206 (e)(5)(C)		Records of monitoring information shall include:	5.2
§5.206 (e)(5)(C)(i)		the date, exact place, and time of sampling or measurements;	5.2
§5.206 (e)(5)(C)(ii)		the individuals who performed the sampling or measurements;	5.2
§5.206 (e)(5)(C)(iii)		the dates analyses were performed;	5.2
§5.206 (e)(5)(C)(iv)		the individuals who performed the analyses;	5.2
§5.206 (e)(5)(C)(v)		the analytical techniques or methods used; and	5.2
§5.206 (e)(5)(C)(vi)		the results of such analyses.	5.2
§5.206 (e)(5)(D)		Operators of Class VI wells shall retain records as specified in this subchapter.	5.2
§5.206 (f)	Mechanical integrity	Mechanical Integrity	
§5.206 (f)(1)	Permit Standards	The operator must maintain and comply with the approved mechanical integrity testing plan submitted in accordance with §5.203(j) of this title.	Section 5
§5.206 (f)(2)	Mechanical integrity	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	4.2
§5.206 (f)(3)	Permit Standards	The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	8.4.1
§5.206 (f)(4)	Mechanical integrity	The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	Director
§5.206 (f)(5)	Permit Standards	The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	Director
§5.206 (g)	AOR and corrective action	Permit conditions for AOR and corrective action. At the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must:	3.6.1,3.6.2
§5.206 (g)(1)	AOR and corrective action	perform a re-evaluation of the AOR by performing all of the actions specified in §5.203(d)(1)(A) - (C) of this title to delineate the AOR;	3.6.1
§5.206 (g)(2)	AOR and corrective action	Identify all wells in the reevaluated area of review that require corrective action;	3.6.2
§5.206 (g)(3)	AOR and corrective action	perform corrective action on wells requiring corrective action in the re-evaluated AOR in the same manner specified in §5.203(d)(1)(C) of this title;	3.6.2
§5.206 (g)(4)	AOR and corrective action	submit an amended AOR and corrective action plan or demonstrate to the director through monitoring data and modeling results that no change to the AOR and corrective action plan is needed. Any amendments to the AOR and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at §5.202 of this title (relating to Permit Required, and Draft Permit and Fact Sheet), as applicable; and	Operations
§5.206 (g)(5)	AOR and corrective action	retain all modeling inputs and data used to support AOR reevaluations for at least 10 years.	2.2
§5.206 (h)	Emergency, mitigation, and remedial response	Emergency mitigation, and remedial response	Section 8

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§5.206 (h)(1)	Permit Standards	The operator must maintain and comply with the approved emergency and remedial response plan required by §5.203(l) of this title. The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title (relating to Reporting and Record-Keeping). The operator must make copies of the plan available at the storage facility and at the company headquarters.	Section 8
§5.206 (h)(2)(A)	Permit Standards	The operator must prepare and implement a plan to train and test each employee at the storage facility on occupational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must make copies of the plan available at the geological storage facility. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility.	8.8
§5.206 (h)(2)(B)	Permit Standards	The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. The operator must explain emergency measures specific to the contractor's work in the contractor safety meeting.	4.1
§5.206 (h)(2)(C)	Permit Standards	The operator must provide training schedules, training dates, and course outlines to Commission personnel annually and upon request for the purpose of Commission review to determine compliance with this paragraph.	4.1
§5.206 (h)(3)(A)	Emergency and remedial response plan	If an operator obtains evidence that the injected CO2 stream and associated pressure front may cause an endangerment to USDWs, the operator must:	8.4.3
§5.206 (h)(3)(A)(i)	Emergency and remedial response plan	immediately cease injection;	8.4.3
§5.206 (h)(3)(A)(ii)	Emergency and remedial response plan	take all steps reasonably necessary to identify and characterize any release;	8.4.3
§5.206 (h)(3)(A)(iii)	Emergency and remedial response plan	notify the director as soon as practicable but within at least 24 hours; and	8.4.3
§5.206 (h)(3)(A)(iv)	Emergency and remedial response plan	implement the approved emergency and remedial response plan.	8.4.3
§5.206 (h)(3)(B)		If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, except as authorized by an aquifer exemption, the director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting, including plugging of the injection well, as are necessary to prevent such movement.	8.4.3
§5.206 (h)(4)	Permit Standards	Resumption of injection. The Director may allow the operator to resume injection prior to remediation if the operator demonstrates that the injection operation will not endanger USDWs.	8.4.3
§5.206 (i)	Permit Standards	Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	Table 5-1
§5.206 (j)	Permit Standards	Well plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by §5.203(k) of this title.	Section 6
§5.206 (k)(1)	Permit Standards	Post-injection storage facility care and closure plan.	Section 7
§5.206 (k)(1)(A)	Permit Standards	The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan.	Section 7
§5.206 (k)(1)(B)	Post-injection storage facility care and closure	The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post-injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements in §5.202 of this title (relating to Permit Required), as appropriate.	7.5.1
§5.206 (k)(1)(C)	Permit Standards	Upon cessation of injection, the operator of a geologic storage facility must either submit an amended plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed.	7.1
§5.206 (k)(2)	Post-injection storage facility care and closure	Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	7.1
§5.206 (k)(3)	Post-injection storage facility care and closure	Prior to closure. Prior to authorization for storage facility closure, the operator must demonstrate to the Director based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs. The operator must demonstrate, based on the current understanding of the site, including monitoring data and/or modeling, all of the following:	7.6
§5.206 (k)(3)(A)	Permit Standards	the estimated magnitude and extent of the facility footprint (the CO2 plume and the area of elevated pressure);	Operations
§5.206 (k)(3)(B)	Permit Standards	that there is no leakage of either CO2 or displaced formation fluids that will endanger USDWs;	Operations
§5.206 (k)(3)(C)	Permit Standards	that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into USDWs;	Operations
§5.206 (k)(3)(D)	Permit Standards	that the injection wells at the site completed into or through the injection zone or confining zone will be plugged and abandoned in accordance with these requirements; and	Operations
§5.206 (k)(3)(E)	Permit Standards	any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.	Operations
§5.206 (k)(4)	Post-injection storage facility care and closure	Notice of intent for site closure. The owner or operator must notify the 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, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	7.7.1
§5.206 (k)(5)	Post-injection storage facility care and closure	Authorization for storage facility closure. No operator may initiate storage facility closure until the director has approved closure of the storage facility in writing. After the Director has authorized site closure, the operator must plug all monitoring wells in accordance with the approved plan required by §5.203(k) of this title.	7.7.1

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§5.206 (k)(6)	Post-injection storage facility care and closure	Storage facility closure report. Once the director has authorized storage facility closure, The operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	7.7.4
§5.206 (k)(6)(A)	Post-injection storage facility care and closure	Documentation of appropriate injection and monitoring well plugging. The operator must provide a copy of a survey plat which has been submitted to the Regional Administrator of Region 6 of the United States Environmental Protection Agency. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks.	7.7.4
§5.206 (k)(6)(B)	Post-injection storage facility care and closure	Documentation of appropriate notification and information to such State and local authorities that have authority over drilling activities to enable such State and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	Operations
§5.206 (k)(6)(C)	Post-injection storage facility care and closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	7.7.4
§5.206 (k)(7)		Certificate of closure. Upon completion of the requirements in paragraphs (3) - (6) of this subsection, the director will issue a certificate of closure. At that time, the operator is released from the requirement in §5.205(c) of this title to maintain financial assurance.	Operations
§5.206 (l)	Deed notation	Deed notation. The operator of a geologic storage facility must record a notation on the deed to the facility property; on any other document that is normally examined during title search; or on any other document that is acceptable to the county clerk for filing in the official public records of the county that will in perpetuity provide any potential purchaser of the property the following information:	7.7.4
§5.206 (l)(1)	Permit Standards	a complete legal description of the affected property;	7.7.4
§5.206 (l)(2)	Deed notation	The fact that land has been used to sequester carbon dioxide;	7.7.4
§5.206 (l)(3)	Deed notation	that the survey plat has been filed with the Commission;	7.7.4
§5.206 (l)(4)	Deed notation	the address of the office of the United States Environmental Protection Agency, Region 6, to which the operator sent a copy of the survey plat; and	7.7.4
§5.206 (l)(5)	Deed notation	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	7.7.4
§5.206 (m)		Permit conditions for retention of records. The permittee shall retain records as follows.	Various
§5.206 (m)(1)		All modeling inputs and data used to support area of review reevaluations under subsection (e) of this section shall be retained for 10 years.	3.2
§5.206 (m)(2)		The permittee shall retain records as follows:	Various
§5.206 (m)(2)(A)		All data collected under §5.203 of this title for Class VI permit applications shall be retained throughout the life of the geologic storage project and for 10 years following site closure.	7.7.4
§5.206 (m)(2)(B)		Data on the nature and composition of all injected fluids collected pursuant to §5.203(i)(1)(D) of this title shall be retained until 10 years following site closure. The director may require the operator to submit the records to the director at the conclusion of the retention period.	7.7.4
§5.206 (m)(2)(C)		Monitoring data collected pursuant to §5.203(j)(2) of this title shall be retained for 10 years after it is collected.	7.7.4
§5.206 (m)(2)(D)		Well plugging reports, post-injection site care data, including data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements of subsection (k)(6) of this section and paragraph (4) of this subsection shall be retained for 10 years following site closure.	7.7.4
§5.206 (m)(2)(E)		The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years following site closure.	Director
§5.206 (m)(3)		Within 60 days after plugging, the operator must submit, pursuant to §5.207(b)(2) of this title, a plugging report to the director. The report must be certified as accurate by the operator and by the person who performed the plugging operation (if other than the operator.) The operator shall retain the well plugging report for 10 years following site closure.	6.4.2.1
§5.206 (m)(4)		The operator must submit a site closure report to the director within 90 days of site closure, which must thereafter be retained at a location designated by the director for 10 years following site closure. The report must include:	7.7.4
§5.206 (m)(4)(A)		documentation of appropriate injection and monitoring well plugging as specified in §5.203(k) of this title. The operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; and	7.7.4
§5.206 (m)(4)(B)		documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	Operations
§5.206 (m)(5)		Records reflecting the nature, composition, and volume of the CO2 plume shall be retained for 10 years following site closure.	7.7.4
§5.206 (m)(6)	Retention of Records	The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	7.7.4
§5.206 (n)	Permit Standards	Signs. The operator must identify each location at which geologic storage activities take place, including each injection well, by a sign that meets the requirements specified in §3.3(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign must include a telephone number where the operator or a representative of the operator can be reached 24 hours a day, seven days a week in the event of an emergency.	4.1
§5.206 (o)	Permit Standards	Other permit terms and conditions.	Operations
§5.206 (o)(1)	Permit Standards	Protection of USDWs. In any permit for a geologic storage facility, the director must impose terms and conditions reasonably necessary to protect USDWs. Permits issued under this subchapter continue in effect until revoked, modified, or terminated by the Commission. The operator must comply with each requirement set forth in this subchapter as a condition of the permit unless modified by the terms of the permit.	Director

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§5.206 (o)(2)	Permit Standards	Other conditions. The following conditions shall also be included in any permit issued under this subchapter.	Operations
§5.206 (o)(2)(A)	Permit Standards	Duty to comply. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. However, the permittee need not comply with the provisions of the permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR §144.34.	NA
§5.206 (o)(2)(B)	Permit Standards	Need to halt or reduce activity not a defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.	NA
§5.206 (o)(2)(C)	Permit Standards	Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.	NA
§5.206 (o)(2)(D)	Permit Standards	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 includes 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 the permit.	E.3 in QASP
§5.206 (o)(2)(E)	Permit Standards	Property rights not conveyed. The issuance of a permit does not convey property rights of any sort, or any exclusive privilege.	NA
§5.206 (o)(2)(F)		Activities not authorized. The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulations.	NA
§5.206 (o)(2)(G)	Permit Standards	Coordination with exploration. The permittee of a geologic storage well shall coordinate with any operator planning to drill through the AOR to explore for oil and gas or geothermal resources and take all reasonable steps necessary to minimize any adverse impact on the operator's ability to drill for and produce oil and gas or geothermal resources from above or below the geologic storage facility.	Section 0 - App Narr
§5.206 (o)(2)(H)	Permit Standards	Duty to provide information. The operator shall furnish to the Commission, within a time specified by the Commission, any information that the Commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The operator shall also furnish to the Commission, upon request, copies of records required to be kept under the conditions of the permit.	Director
§5.206 (o)(2)(I)	Permit Standards	Inspection and entry. The operator shall allow any member or employee of the Commission, on proper identification, to:	Operations
§5.206 (o)(2)(I)(i)	Permit Standards	enter upon the premises where a regulated activity is conducted or where records are kept under the conditions of the permit;	Operations
§5.206 (o)(2)(I)(ii)	Permit Standards	have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit;	Operations
§5.206 (o)(2)(I)(iii)	Permit Standards	inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and	Operations
§5.206 (o)(2)(I)(iv)	Permit Standards	sample or monitor any substance or parameter for the purpose of assuring compliance with the permit or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012.	Operations
§5.206 (o)(2)(J)	Permit Standards	Schedule of compliance: The permit shall, when appropriate, specify a schedule of compliance leading to compliance with all provisions of this subchapter and Chapter 3 of this title. If the time necessary for completion of any interim requirement is more than one year and is not readily divisible into stages for completion, the permit shall specify interim dates for the submission of reports of progress toward completion of the interim requirements and indicate a projected completion date.	Operations
§5.206 (o)(2)(J)(i)	Permit Standards	Any schedule of compliance shall require compliance as soon as possible, and in no case later than three years after the effective date of the permit.	Operations
§5.206 (o)(2)(J)(ii)	Permit Standards	If the schedule of compliance is for a duration of more than one year from the date of permit issuance, then interim requirements and completion dates (not to exceed one year) must be incorporated into the compliance schedule and permit.	Operations
§5.206 (o)(2)(J)(iii)	Permit Standards	Progress reports must be submitted no later than 30 days following each interim date and the final date of compliance.	Operations
§5.206 (o)(2)(K)	Permit Standards	Modification, revocation and reissuance, or termination. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.	Operations
§5.206 (o)(2)(L)	Permit Standards	Signatory requirement. All applications, reports, or information shall be signed and certified.	Operations
§5.206 (o)(2)(M)	Permit Standards	Reporting requirements.	Various
§5.206 (o)(2)(M)(i)	Permit Standards	Planned changes. The permittee shall give notice to the director as soon as possible of any planned physical alterations or additions to the permitted facility.	5.1
§5.206 (o)(2)(M)(ii)	Permit Standards	Anticipated noncompliance. The permittee shall give advance notice to the director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.	5.1
§5.206 (o)(2)(M)(iii)	Permit Standards	Transfers. This permit is not transferable to any person except after notice to and approval by the director. The director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.	NA
§5.206 (o)(2)(M)(iv)	Permit Standards	Monitoring reports. Monitoring results shall be reported at the intervals specified elsewhere in this permit.	Section 5
§5.206 (o)(2)(M)(v)	Permit Standards	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 no later than 30 days following each schedule date.	Various

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§5.206 (o)(2)(M)(vi)	Permit Standards	Twenty-four hour reporting. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The permittee shall report any noncompliance which may endanger health or the environment including:	Section 8
§5.206 (o)(2)(M)(vi)(I)	Permit Standards	any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and	8.4.3
§5.206 (o)(2)(M)(vi)(II)	Permit Standards	any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.	8.4.3
§5.206 (o)(2)(N)	Permit Standards	Other information. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the director, it shall promptly submit such facts or information.	Operations
§5.206 (o)(2)(O)	Permit Standards	Other noncompliance. The permittee shall report all instances of noncompliance not reported under subsection (e) of this section, subparagraphs (J) and (M) of this paragraph, and §5.207(a)(2)(A) of this title at the time monitoring reports are submitted. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The reports required by this subparagraph shall contain the following information:	Section 8
§5.206 (o)(2)(O)(i)	Permit Standards	any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and	8.4.3
§5.206 (o)(2)(O)(ii)	Permit Standards	any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.	8.4.3
§5.206 (o)(2)(P)	Permit Standards	Incorporation of requirements in permits. New permits, and to the extent allowed under §5.202 of this title modified or revoked and reissued permits, shall incorporate each of the applicable requirements referenced in this section. An applicable requirement is a State statutory or regulatory requirement that takes effect prior to final administrative disposition of the permit. An applicable requirement is also any requirement that takes effect prior to the modification or revocation and reissuance of a permit, to the extent allowed in §5.202 of this title.	Operations
§5.206 (o)(2)(Q)	Permit Standards	Compliance with SWDA and related regulations. In addition to conditions required in all permits, the director shall establish conditions in permits as required on a case-by-case basis to provide for and assure compliance with all applicable requirements of the SWDA and 40 CFR Parts 144, 145, 146 and 124.	Operations
§5.207 (a)	Reporting and Record-Keeping	Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information:	5.2
§5.207 (a)(1)	Reporting and Record-Keeping	Test records. The operator must file a complete record of all tests in duplicate with the district office within 30 days after the testing. In conducting and evaluating the tests enumerated in this subchapter or others to be allowed by the director, the operator and the director must apply methods and standards generally accepted in the industry. When the operator reports the results of mechanical integrity tests to the director, the operator must include a description of any tests and methods used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.	5.2
§5.207 (a)(2)	Reporting and Record-Keeping	Operating reports. The operator also must include summary cumulative tables of the information required by the reports listed in this paragraph.	5.2
§5.207 (a)(2)(A)	Reporting and Record-Keeping	Report within 24 hours. The operator must report to the appropriate district office the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir. Such report must be made orally as soon as practicable, but within 24 hours, following the discovery of the leak, and must be confirmed in writing within five working days.	Table 5-1
§5.207 (a)(2)(A)(i)		the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir;	5.2
§5.207 (a)(2)(A)(ii)	Reporting and Record-Keeping	any evidence that the injected CO2 stream or associated pressure front may cause an endangerment to a USDW;	Table 5-1
§5.207 (a)(2)(A)(iii)	Reporting and Record-Keeping	any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	Table 5-1
§5.207 (a)(2)(A)(iv)	Reporting and Record-Keeping	any triggering of a shut-off system (i.e., down-hole or at the surface); and	Table 5-1
§5.207 (a)(2)(A)(v)	Reporting and Record-Keeping	any failure to maintain mechanical integrity.	Table 5-1
§5.207 (a)(2)(B)	Reporting and Record-Keeping	**Report, within 30 days, the results of:**	Table 5-1
§5.207 (a)(2)(B)(i)	Reporting and Record-Keeping	the results of periodic tests for mechanical integrity;	Table 5-1
§5.207 (a)(2)(B)(ii)	Reporting and Record-Keeping	the results of any other test of the injection well conducted by the operator if required by the director; and	Table 5-1
§5.207 (a)(2)(B)(iii)	Reporting and Record-Keeping	a description of any well workover.	Table 5-1
§5.207 (a)(2)(C)	Reporting and Record-Keeping	**Semi-annual reports containing:**	5.2
§5.207 (a)(2)(C)(i)	Reporting and Record-Keeping	a summary of well head pressure monitoring;	5.2
§5.207 (a)(2)(C)(ii)	Reporting and Record-Keeping	Any changes to the source as well as the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	5.2
§5.207 (a)(2)(C)(iii)	Reporting and Record-Keeping	monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;	5.2

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§5.207 (a)(2)(C)(iii)	Reporting and Record-Keeping	monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;	5.2
§5.207 (a)(2)(C)(iv)	Reporting and Record-Keeping	monthly annulus fluid volume added;	5.2
§5.207 (a)(2)(C)(v)	Reporting and Record-Keeping	description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;	5.2
§5.207 (a)(2)(C)(vi)	Reporting and Record-Keeping	a description of any event that triggers a shutdown device and the response taken; and	5.2
§5.207 (a)(2)(C)(vii)	Reporting and Record-Keeping	the results of monitoring prescribed under §5.206€ [§5.206(d)] of this title (relating to Permit Standards).	5.2, 5.3, 5.4
§5.207 (a)(2)(D)	Reporting and Record-Keeping	Annual reports. The operator must submit an annual report detailing:	5.2
§5.207 (a)(2)(D)(i)	Reporting and Record-Keeping	corrective action performed;	5.2
§5.207 (a)(2)(D)(ii)	Reporting and Record-Keeping	new wells installed and the type, location, number, and information required in §5.203(e) of this title (relating to Application Requirements);	5.2
§5.207 (a)(2)(D)(iii)	Reporting and Record-Keeping	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;	5.2
§5.207 (a)(2)(D)(iv)	Reporting and Record-Keeping	the updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;	5.2
§5.207 (a)(2)(D)(v)	Reporting and Record-Keeping	tons of CO2 injected; and	5.2
§5.207 (a)(2)(D)(vi)	Reporting and Record-Keeping	other information as required by the permit.	5.2
§5.207 (a)(2)(E)	Reporting and Record-Keeping	Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter.	5.2
§5.207 (a)(2)(E)(i)	Reporting and Record-Keeping	Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has:	5.2
§5.207 (a)(2)(E)(i)(I)	Reporting and Record-Keeping	reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title; and	5.2
§5.207 (a)(2)(E)(i)(II)	Reporting and Record-Keeping	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.	5.2
§5.207 (a)(2)(E)(ii)	Reporting and Record-Keeping	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.	5.2
§5.207 (a)(3)	Reporting and Record-Keeping	The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	8.7, 5.2, 5.3
§5.207 (b)(1)	Reporting and Record-Keeping	The operator must report the results of injection pressure and injection rate monitoring of each injection well on Form H-10, Annual Disposal/Injection Well Monitoring Report, and the results of internal mechanical integrity testing on Form H-5, Disposal/Injection Well Pressure Test Report. Operators must submit other reports in a format acceptable to the Commission. At the discretion of the director, other formats may be accepted.	5.2
§5.207 (b)(2)	Reporting and Record-Keeping	The operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by director.	5.2
§5.207 (c)	Reporting and Record-Keeping	Signatories to reports.	5.2
§5.207 (c)(1)	Reporting and Record-Keeping	Reports. All reports required by permits and other information requested by the director, shall be signed by a person described in §5.203(a)(1)(B) of this title, or by a duly authorized representative of that person. A person is a duly authorized representative only if:	5.2
§5.207 (c)(1)(A)	Reporting and Record-Keeping	the authorization is made in writing by a person described in §5.203(a)(1)(B) of this title;	5.2
§5.207 (c)(1)(B)	Reporting and Record-Keeping	the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility; and	5.2
§5.207 (c)(1)(C)	Reporting and Record-Keeping	the written authorization is submitted to the director.	5.2
§5.207 (c)(2)	Reporting and Record-Keeping	Changes to authorization. If an authorization under paragraph (1) of this subsection is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (1) of this subsection must be submitted to the director prior to or together with any reports, information, or applications to be signed by an authorized representative.	5.2
§5.207 (d)	Reporting and Record-Keeping	Certification. All reports required by permits and other information requested by the director under this subchapter, shall be certified as follows: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."	5.2
§5.207 (e)	Reporting and Record-Keeping	Record retention.	5.2
§5.207 (e)(1)	Reporting and Record-Keeping	The operator must retain all data collected under §5.203 of this title for Class VI permit applications throughout the life of the geologic sequestration project and for 10 years following storage facility closure.	5.2
§5.207 (e)(2)	Reporting and Record-Keeping	The operator must retain data on the nature and composition of all injected fluids collected pursuant to §5.203(j)(2)(A) of this title until 10 years after storage facility closure. The operator shall submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	5.2

16 TAC Chapter 5	TAC Category	Description	Confirmation
§5.207 (e)(3)	Reporting and Record-Keeping	The operator must retain all testing and monitoring data collected pursuant to the plans required under §5.203(j) of this title, including wellhead pressure records, metering records, and integrity test results, and modeling inputs and data used to support AOR calculations for at least 10 years after the data is collected.	5.2
§5.207 (e)(4)	Reporting and Record-Keeping	The operator must retain well plugging reports, post-injection storage facility care data, including data and information used to develop the demonstration of the alternative post-injection storage facility care timeframe, and the closure report collected pursuant to the requirements of §5.206(k)(6) and (m) of this title for 10 years following storage facility closure.	5.2
§5.207 (e)(5)	Reporting and Record-Keeping	The operator must retain all documentation of good faith claim to necessary and sufficient property rights to operate the geologic storage facility until the director issues the final certificate of closure in accordance with §5.206(k)(7) of this title.	5.2
§5.207 (e)(6)	Reporting and Record-Keeping	The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years after storage facility closure.	5.2
§5.207 (e)(7)	Reporting and Record-Keeping	The director may require the operator to submit the records to the director at the conclusion of the retention period.	5.2

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 0 – APPLICATION NARRATIVE

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 2: May 2026

SECTION 0 – INTRODUCTION

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General Application Information

Project Name: Sunflower Carbon Capture and Storage Project

Mailing Address: 22777 Springwoods Village Parkway
Spring, Texas 77389

Well Location(s): Jefferson and Liberty Counties, Texas
Sunflower INJ No. 01: 30.0204249 N, 94.4656525 W (NAD 83)
Sunflower INJ No. 02: 30.0485414 N, 94.4219994 W (NAD 83)
Sunflower INJ No. 03: 30.0487361 N, 94.4054694 W (NAD 83)

*NAD 83 – North American Datum of 1983

Project Contact: Name: Br[redacted]M[redacted]
[redacted] om
[redacted]

Project Owner: ExxonMobil Low Carbon Solutions Onshore Storage, LLC

Ownership Status: Limited Liability Company

Entity Status: Public

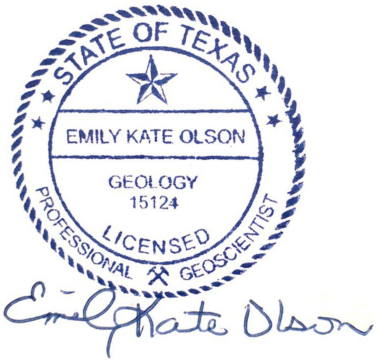
Standard Industrial Classification (SIC) Codes: 4953 – Refuse Systems (nonhazardous waste disposal sites)

This facility is not located on federal, Indian, or state lands.

CERTIFICATION OF PROFESSIONAL GEOLOGIST:

Sections of permit applications that represent geologic and hydrologic evaluations required under 16 TAC Chapter 5 shall be sealed, signed, and dated by a licensed professional geologist.

The geologic and hydrologic studies that are included in this application were all completed under the responsible charge or direct supervision of the licensee, who has reviewed this work and certifies that it is prepared according to the highest standards of Professional Geology.



Emily Kate Olson

Printed Name of Professional Geologist

P.G. Number 15124

12/18/2025

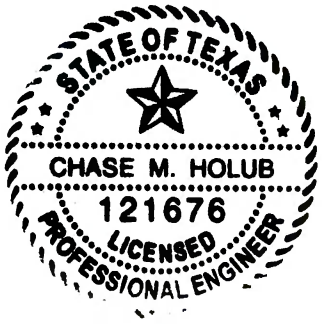
Signature of Professional Geologist

Date Signed

CERTIFICATION OF PROFESSIONAL ENGINEER

Sections of permit application that represent engineering work shall be sealed, signed, and dated by a licensed professional engineer.

Applicable Sections
Section 4 – Well Construction Plan and Operating Conditions
Appendix D – Well Construction Plan and Operating Conditions
Section 6 – Injection Well Plugging Plan
Appendix F – Injection Well Plugging Plan



Chase M Holub

Printed Name of Professional Engineer

P.E. Number (SEAL)

Signature of Professional Engineer

3 June 2026

Date Signed

1. Additional Permits

Table 1 – Additional Required Permits

Agency	Permit and Authorization	Permit Number	Filing Date	Anticipated Receipt Date	Status
TCEQ	Industrial Hazardous Waste Registration (Episodic Waste)	TBD	TBD	TBD	Not yet submitted
TCEQ	Texas Pollutant Discharge Elimination System Multi-Sector General Permit	TBD	TBD	TBD	Not yet submitted
TCEQ	Drilling Stormwater Pollution Prevention Plan	TBD	TBD	TBD	Not yet submitted
TRRC	Groundwater Determination Application (GW-2) – Well letters	401859 409988 409989		5/18/2026	Received
TRRC	Groundwater Protection Determination (GW- 2) – AOR letter	409697 409698		5/18/2026	Received
TRRC	Statewide Rule-13 Exception	TBD	TBD	TBD	Not yet submitted
TRRC	W-1 Drilling Permit	912899 912901 912902		2/11/26	Received
EPA	Spill Prevention Controls and Countermeasures Plan	TBD	TBD	TBD	Not yet submitted
TCEQ	Stormwater Notice of Termination	TBD	TBD	TBD	Not yet submitted
TRRC	W-2 Oil Well Potential Test, Completion or Recompletion Report, and Log	TBD	TBD	TBD	Not yet submitted

TCEQ = Texas Commission on Environmental Quality
TRRC = Railroad Commission of Texas

2. Project Background

This application has been developed to meet all of the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5.

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is submitting this permit application for the Sunflower Geologic Storage Facility to construct and operate three carbon sequestration wells in Jefferson and Liberty Counties in southeastern Texas. The geologic storage facility for the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project), as defined by 16 TAC **§5.102(29)**, is delineated on Figure 1 below. The geologic storage facility for the Sunflower Project includes the area of review (AOR), three proposed injection wells, three USDW monitoring wells, one Above-zone/In-zone monitoring well, two Above-zone monitoring wells, and a central pad and flowlines necessary for the geologic storage of carbon dioxide (CO_2). The central pad will include a metering station and will also be the terminus of the fiber-optic lines for subsurface monitoring that will be installed in each injection well.

The Sunflower Project targets two formations within a single injection zone: the Frio Formation and the Fleming Formation. Both the Frio and Fleming Formations are laterally extensive and exhibit internal pressure communication over the entire project area. However, there are two distinct AORs generated by the numerical model, which follow the definition of AOR found in 16 TAC **§5.102(5) -** the outermost extent of the overlay of the subsurface three-dimensional extent of the stabilized CO_2 plume and the associated pressure front. The associated pressure front will be referred to as critical pressure or the critical pressure front throughout this application. Although the model produces two separate AOR polygons, injection into either the Frio or Fleming Formation within one AOR results in a measurable pressure response in the other AOR, even though this response does not reach critical pressure levels between them. Accordingly, while the AORs are separate, they represent components of a single project and an integrated injection strategy that must be evaluated concurrently. The two AORs, together with the necessary rights and appurtenances for facility operation, form the geologic storage facility as defined by 16 TAC **§5.102(29)**.

The goal of the Sunflower Project is to permanently store anthropogenic CO_2 captured from industrial sources, thereby facilitating the United States' effort to reduce greenhouse gas emissions. The Sunflower Project will be a commercial-scale carbon capture system that is designed, constructed, and operated with the capability of storing CO_2 in deep geologic formations. The site was chosen based on the favorable geology—ideal for storage—and proximity to ExxonMobil's existing CO_2 pipeline. ExxonMobil's US Gulf Coast CO_2 pipeline will be the source of all CO_2 volumes injected through the three proposed injection wells . The CO_2 will be injected into the Frio and Fleming formations at a proposed rate of approximately 25.3 million metric tons (MMT) of CO_2 over an 11-year injection period.

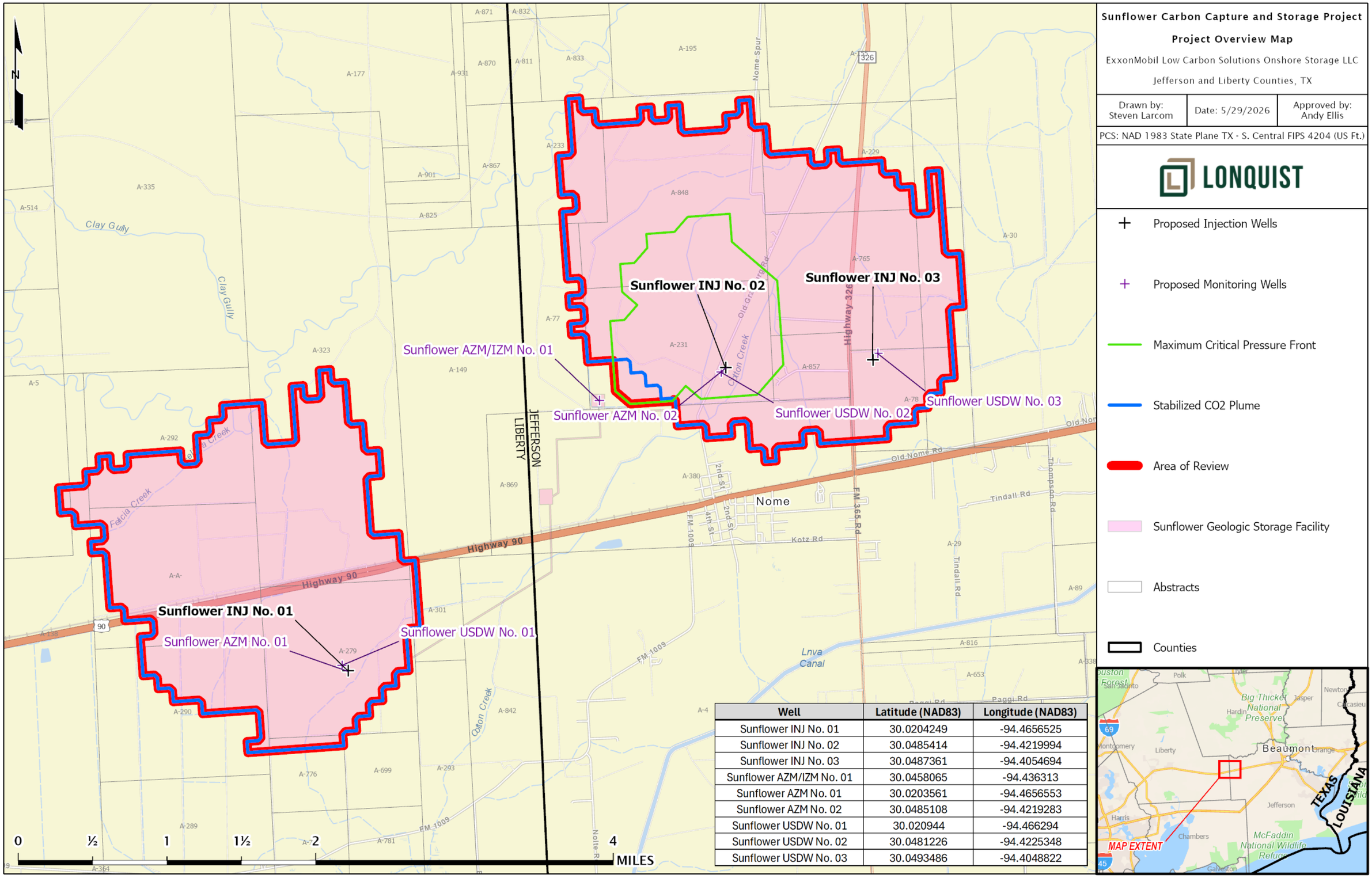
The Sunflower Project will be developed and operated in a manner that does not endanger human health and safety and nor endanger or injure any existing or prospective oil, gas, geothermal, or other mineral resource, or cause waste as defined by Texas Natural Resources

Code, §85.046(11) (16 TAC **§5.206 (b)(1)** and 16 TAC **§5.206 (b)(3)**). ExxonMobil will coordinate with any operators planning to drill through the AOR for mineral exploration and take reasonable steps to minimize any adverse impacts (16 TAC **§5.206 (o)(2)(D)**).

This permit application thoroughly describes and characterizes the geology of the planned well locations, evaluates the formations for the qualities required to permanently contain the sequestered CO_2, and outlines the engineering design and safety requirements of the constructed wells. The application also describes and details the planned monitoring system, which will be used to analyze movement of the actual injectate plume with that predicted by reservoir modeling and simulation.

ExxonMobil has obtained the required letter of determination from the TRRC Groundwater Advisory Unit pursuant to 16 TAC **§5.203(a)(2)(D)**. Additionally, pursuant to 16 TAC **§5.206 (b)(1)**, ExxonMobil has provided to the Director a good faith claim statement in a letter dated May 6, 2026 that ExxonMobil has the necessary and sufficient property rights for construction and operation for the Sunflower Project for at least five years after initiation of injection in accordance with §85.046(11).

Per 16 TAC **§5.203(a)(2)(D)**, ExxonMobil will submit the required letter of determination from the Texas Commission on Environmental Quality (TCEQ) to the Railroad Commission of Texas (TRRC) director as soon as it is received and prior to permit issuance.



Well	Latitude (NAD83)	Longitude (NAD83)
Sunflower INJ No. 01	30.0204249	-94.4656525
Sunflower INJ No. 02	30.0485414	-94.4219994
Sunflower INJ No. 03	30.0487361	-94.4054694
Sunflower AZM/IZM No. 01	30.0458065	-94.436313
Sunflower AZM No. 01	30.0203561	-94.4656553
Sunflower AZM No. 02	30.0485108	-94.4219283
Sunflower USDW No. 01	30.020944	-94.466294
Sunflower USDW No. 02	30.0481226	-94.4225348
Sunflower USDW No. 03	30.0493486	-94.4048822

Figure 1 – Sunflower Project

3. Site Characterization

A regional and local geologic evaluation was conducted (*Section 1 – Site Characterization*) for the Sunflower Project site using geologic, geophysical, petrophysical, hydrogeological, and well log analysis data obtained from published literature, commercial sources, proximal core data, and publicly available data sets. In 2023 and 2024, ExxonMobil drilled five stratigraphic test wells nearby (Bead Farm Co. No. 1, (API No. 4224532908), Labelle Properties LTD No. 1 (API 4224532913), Bead Farm Co. No. 2 (API 4224532911), Bead Farm No. 3 (API 4224532912), and Bead Farm Company No. 4 (API 42245632914)) that provided additional site-specific information on the geology, rock properties, hydrogeology, and geochemistry.

Detailed discussions of the geologic setting, seismic history, injection and confining zones, and the AOR site suitability are in *Section 1 – Site Characterization*, *Section 2 – Plume Model*, and *Section 3 – Area of Review and Corrective Action Plan*. Consistent with the requirements at 16 TAC **§5.206**, the information provided in these sections demonstrates the suitability of the Frio and Fleming formations at the Sunflower Project site for CO_2 injection and sequestration. The injection zone is composed of thick, porous, and permeable sandstones that will support the proposed injection operations, including an approximately 1,700-foot-thick Miocene (Fleming) and 2,200-foot-thick Oligocene (Frio) age rock consisting of stacked sand sequences with excellent permeability and porosity. The Fleming and Frio formations are separated by an approximately 300-foot-thick Anahuac Shale, a regionally extensive and well-defined sealing unit across the US Gulf Coast. The upper confining zone (UCZ) is characterized by low porosity and permeability and capable of preventing the upward migration of fluids.

4. Plume Model

A compositional model delineated the AOR for the Sunflower Project consistent with the requirements of 16 TAC **§5.203(d)(1)(A)**. Advanced modeling workflows within SLB's (formerly Schlumberger) industry-standard software were employed to construct geological and dynamic models. An extensive literature and public data search was conducted to help generate model inputs. Calibration of the model was further refined using stratigraphic and petrophysical data from the five nearby stratigraphic test wells ExxonMobil drilled and 3D seismic data. Additional site-specific data will be acquired during the drilling phase to enhance the model and validate storage capacity and containment integrity.

Intersect™ was chosen to build the dynamic model for its ability to handle large data sets and multiple grids, offering various tools for data management, visualization, and uncertainty analysis. This software is a widely recognized tool used for modeling both compositional and unconventional reservoirs. Intersect employs cutting-edge computational techniques and equation of state (EOS) algorithms to simulate compositional, chemical, and geochemical processes with high fidelity, making it well-suited for CCS applications. The dynamic model accounts for the various trapping mechanisms that may occur in the subsurface. Structural, residual gas, and solubility trapping are all included to predict the migration of CO_2 and delineate the AOR.

Reservoir modeling efforts forecast the storage of approximately 25.3 MMT of CO_2 over an 11-year injection period, distributed across three injection wells. The proposed injection strategy incorporates a bottom-up completion design, optimized for the safe and efficient operation of CCS activities. This completion approach leverages the stratigraphic characteristics of the Miocene and Oligocene sands to divide each well into multiple completion stages within the injection zone. By utilizing stages, the project aims to maximize storage capacity while preventing movement of fluid into and demonstrating non-endangerment of the USDW, as identified through legacy and newly acquired local data collected in nearby stratigraphic wells (e.g., well logs, fluid samples). After injection operations cease, the reservoir model shows that pressure will stabilize to near in situ conditions. *Section 2 – Plume Model* presents a complete discussion on the generation of the model.

5. Area of Review and Corrective Action

Section 3 – AOR and Corrective Action Plan details the methodology behind the determination of the AOR and subsequent assessment of all of the artificial penetrations in the AOR to satisfy the requirements of 16 TAC **§5.203(d)(1)(B)**. The final AOR is made of two distinct evaluations: (1) the determination of the CO_2 plume; and (2) the determination of the extent of the critical pressure front. *Section 3* outlines in detail how both of those were determined. From that evaluation it was determined that the UCZ has eleven artificial penetrations within the AOR, all of which will need corrective actions. A complete discussion on each well and the proposed schedule of corrective action are also presented in *Section 3.*

6. Injection Well Construction and Operations

As discussed in *Section 4 – Well Construction Plan and Operating Conditions*, ExxonMobil plans to construct three CO_2 injection wells, two in Jefferson County and one in Liberty County, Texas. The wells will be constructed in compliance with the Class VI Underground Injection Control (UIC) requirements of 16 TAC **§5.203**, on injection-well construction. The goal of the operating parameters and material selection is to guarantee the system's mechanical integrity—ensuring protection of the underground source of drinking water (USDW)—and to maximize the Sunflower Project's performance during the life of the project.

The casing and cementing, and tubing and packer materials to be used in the construction of the wells will be of sufficient strength and design to last the life of the geologic sequestration project and to be compatible with fluids with which those materials will be expected to come into contact. As required by 16 TAC **§5.203(e)(1)-(4)** information about those materials is included in *Section 4*. Wellbore schematics and a more in-depth discussion of the injection-well construction procedures are also presented in *Section 4.*

The proposed injection wells are designed to allow maximum injection volume while ensuring that bottomhole pressure does not exceed 90% of the formation fracture gradient. The well design maintains enough clearance for the continuous monitoring of bottomhole pressure and

temperature using a pressure/temperature (P/T) gauge deployed on the tubing. The high-concentration CO_2 stream will be sourced from ExxonMobil's US Gulf Coast CO_2 Pipeline.

7. Testing and Monitoring

Section 5 – Testing and Monitoring Plan describes how ExxonMobil will monitor the Sunflower Project pursuant to 16 TAC **§5.203** and **§5.206**. As detailed in that section, ExxonMobil has conducted or will conduct required testing and monitoring activities including analysis of the CO_2 stream, use of continuous recording devices, corrosion monitoring, groundwater quality monitoring, mechanical integrity, pressure falloff testing, and plume tracking. Details of each of these testing and monitoring activities are provided in *Section 5*. In addition to demonstrating that the well is operating as planned, the CO_2 plume and pressure front are moving as predicted, and there is no endangerment to the USDW, 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 and to support AOR reevaluations. Results of the testing and monitoring activities described in the Testing and Monitoring Plan may trigger action according to the Emergency and Remedial Response Plan (*Section 8*).

8. Injection Well Plugging

After the cessation of injection, ExxonMobil plans to plug and abandon the injection and monitoring wells pursuant to 16 TAC **§5.203(k)**. *Section 6 – Injection Well Plugging Plan* discusses in detail the procedures and plans for the plugging of the injection and monitoring wells of the Sunflower Project.

9. Post-Injection Site Care and Site Closure

Section 7 – Post-Injection Site Care and Site Closure Plan describes the activities that ExxonMobil will perform during those phases of the project pursuant to 16 TAC **§5.203** and **§5.206**. ExxonMobil will monitor groundwater quality and track the position of the CO_2 plume and pressure for 50 years—or less, if the plume reaching stabilization sooner can be demonstrated and approved by the UIC Program director (UIC Director). ExxonMobil may not cease post-injection monitoring until a demonstration of non-endangerment of the USDW has been approved by the UIC Director. Following approval for site closure, ExxonMobil will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

10. Emergency and Remedial Response

In the event of an emergency that could endanger public health and safety or any USDW during the construction, operation, or post-injection site care periods, *Section 8 – Emergency and Remedial Response Plan* describes the actions that ExxonMobil would perform if needed at the Sunflower Project pursuant to 16 TAC **§5.203, §5.206,** and **§5.207**. If verified evidence that the

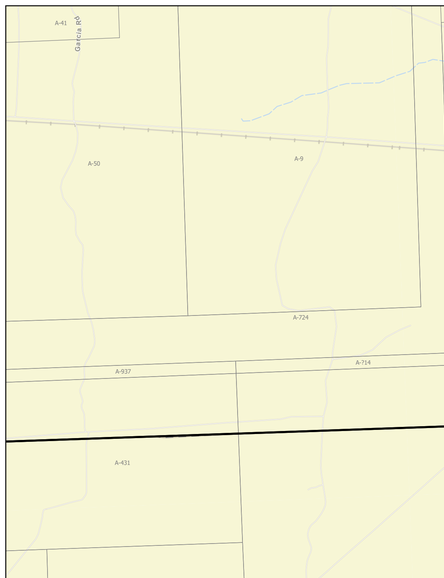
injected CO_2 stream and/or associated pressure front may cause endangerment to a USDW, ExxonMobil will initiate the shutdown plan for the injection well(s), take all steps reasonably necessary to identify and characterize the release, notify the permitting agency (UIC Director) of the emergency event within 24 hours, and implement the approved Emergency and Remedial Response Plan. Key contact information related to the project is outlined in *Section 8* (Table 8-4) for local, state, and federal agencies.

11. Financial Responsibility

Pursuant to 16 TAC **§5.203** and **§5.205**, ExxonMobil will maintain financial responsibility throughout all phases of the Sunflower Project, as detailed in *Section 9 – Financial Assurance*. ExxonMobil proposes a performance bond to satisfy the TRRC's financial assurance requirements. The instrument will be sufficient to cover the costs of corrective action, injection well plugging, post-injection site care, site closure, and emergency and remedial response. Adjustments to the cost estimates, including adjustments for inflation, cost estimate increases, or an event that may adversely affect financial conditions, will be provided in writing to the UIC Director.

Appendix A – Project Maps

Appendix A1 – Project Overview Map



Sunflower Carbon Capture and Storage Project

Project Overview

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Jefferson and Liberty Counties, Texas

Appendix A-1

Drawn by:	Date:	Approved by:
Steven Larcom	5/29/2026	Andy Ellis

PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)

LONQUIST

Texas Registration No. F-8952

- Proposed Injection Wells
- Proposed Monitoring Wells
- Area of Interest
- Maximum Critical Pressure Front
- Stabilized CO2 Plume
- Area of Review
- Sunflower Geologic Storage Facility
- Abstracts
- Counties

Sunflower INJ No. 02
30.0485414, -94.4219994

Sunflower INJ No. 03
30.0487361, -94.4054694

Sunflower AZM/LZM No. 01
30.0458065, -94.436313

Sunflower AZM No. 02
30.0485108, -94.4219283

Sunflower USDW No. 02
30.0481226, -94.4225348

Sunflower USDW No. 03
30.0493486, -94.4048822

Sunflower INJ No. 01
30.0204249, -94.4656525

Sunflower USDW No. 01
30.020944, -94.466294

Sunflower AZM No. 01
30.0203561, -94.4656553

HARDIN
LIBERTY

HARDIN
JEFFERSON

JEFFERSON
LIBERTY

Sour Lake
Grayburg
Nome
Felicia

Highway 326 S
Highway 90
FM 1009
FM 365 Rd

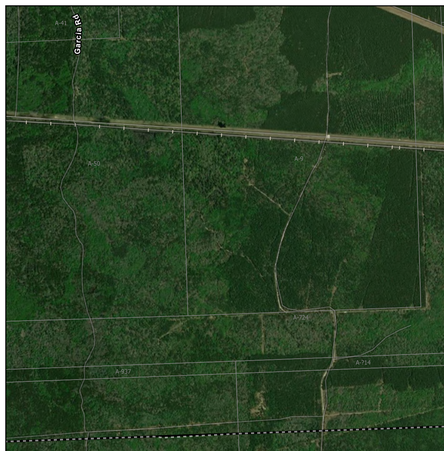
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0 ½ 1 1½ 2 4 Miles

0 1,000 2,000 3,000 4,000 5,000 10,000 Feet

N

Appendix A2 – Aerial Project Overview Map



Sunflower Carbon Capture and Storage Project

Project Overview (Aerial)

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Jefferson and Liberty Counties, Texas

Appendix A-2

Drawn by: Steven Larcom	Date: 5/29/2026	Approved by: Andy Ellis

PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)

LONQUIST

Texas Registration No. F-8952

- Proposed Injection Wells
- Proposed Monitoring Wells
- Area of Interest
- Maximum Critical Pressure Front
- Stabilized CO2 Plume
- Area of Review
- Sunflower Geologic Storage Facility
- Abstracts
- Counties

Sunflower USDW No. 02
30.0481226, -94.4225348

Sunflower USDW No. 03
30.0493486, -94.4048822

Sunflower AZM/IZM No. 01
30.0458065, -94.436313

Sunflower INJ No. 02
30.0485414, -94.4219994

Sunflower INJ No. 03
30.0487361, -94.4054694

Sunflower AZM No. 02
30.0485108, -94.4219283

Sunflower USDW No. 01
30.020944, -94.466294

Sunflower INJ No. 01
30.0204249, -94.4656525

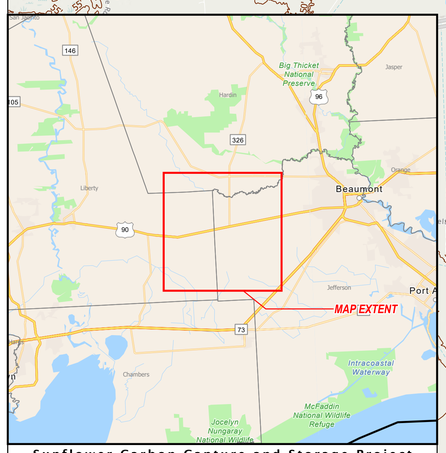
Sunflower AZM No. 01
30.0203561, -94.4656553

1:22,000

0 ½ 1 1½ 2 4 Miles

0 1,000 2,000 3,000 4,000 5,000 10,000 Feet

Appendix A3 – Topographic Project Overview Map



Sunflower Carbon Capture and Storage Project

Topographic Map

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Jefferson and Liberty Counties, Texas

Appendix A-3

Drawn by: Steven Larcom	Date: 5/29/2026	Approved by: Andy Ellis

PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)

LONQUIST

Texas Registration No. F-8952

- Proposed Injection Wells
- Proposed Monitoring Wells
- Bead Farm Co. #1
- Surface Elevation Contours (CI = 5')
- Area of Interest
- Maximum Critical Pressure Front
- Stabilized CO2 Plume
- Area of Review
- Sunflower Geologic Storage Facility
- Counties

Sunflower AZM/IZM No. 01
30.0458065, -94.4436313

Sunflower INJ No. 02
30.0485414, -94.4219994

Sunflower USDW No. 03
30.0493486, -94.4048822

Sunflower INJ No. 03
30.0487361, -94.4054694

Sunflower-AZM No.02
30.0485108, -94.4219283

Sunflower USDW No. 02
30.0481226, -94.4225348

Sunflower USDW No. 01
30.020944, -94.466294

Sunflower INJ No. 01
30.0204249, -94.4656525

Sunflower AZM No. 01
30.0203561, -94.4656553

BEAD FARM CO. #1

1:30,000

0 ½ 1 1½ 2 4 Miles

0 1,000 2,000 3,000 4,000 Feet 10,000

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 1 – Site Characterization

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 2: May 2026

SECTION 1 – SITE CHARACTERIZATION

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1.1 Overview

The site characterization for the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) was prepared to meet the requirements of Title 16, Texas Administrative Code (TAC), Part 1, Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the project in Jefferson and Liberty Counties, Texas, to sequester approximately 25.3 million metric tons (MMT) of CO_2 over the 11-year life of the project. The purpose of this site characterization is to identify the potential risks and demonstrate, to the satisfaction of the Underground Injection Control (UIC) Program director (UIC Director), that the project site is suitable for the sequestration project. The key aspects of this demonstration are that the geologic formations provide adequate storage capacity to store the intended volume of injected CO_2, and that a competent confining zone is present that will contain the injected CO_2 throughout the life of the project.

ExxonMobil has completed a thorough review of site characterization data and analyses from multiple data types including public, proprietary, and licensed data sets. A high degree of confidence has been gained during this process regarding the effectiveness of the storage and confining properties of the sequestration site, and the anticipated alignment with data that will become available in the future.

1.1.1 Objectives

The following objectives were developed to demonstrate compliance with the requirements of 16 TAC **§5.201**, **§5.203**, and **§5.206**:

- Provide maps and cross sections of the area of review (AOR) 16 TAC **§5.203(c)(2)(A)** and 16 TAC **§5.203(b)**.
- Summarize available data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes 16 TAC **§5.203(c)(2)(B)**.
- Provide geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area 16 TAC **§5.203(c)(2)(A)**.
- Identify the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AOR, along with an assessment that they will not interfere with containment 16 TAC **§5.203(c)(2)(C)**.
- Discuss the available geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) 16 TAC **§5.203(c)(2)(E)**.
- Present maps and stratigraphic cross sections indicating the general vertical and lateral limits of the underground sources of drinking water (USDWs) and water wells' completion details within the AOR, their positions relative to the injection zone, and the direction of water movement (where known) 16 TAC **§5.203(c)(2)(A)**.
- Summarize the available baseline geochemical data on subsurface formations, including the USDWs in the AOR 16 TAC **§5.203(c)(2)(G)**.

- Summarize the available information on the seismic history of the area, including the presence and depths of seismic sources, and an assessment of the potential for seismicity to interfere with containment 16 TAC **§5.203(c)(2)(D)**.

1.2 Regional Geology

Tectonostratigraphic and Paleoclimatic History – Northern Portion of the Gulf of Mexico Basin

The incipient Gulf of Mexico basin (Figure 1-1) formed via the extension of largely continental crust during the Late Triassic to Early Jurassic breakup of the Pangean supercontinent, specifically rifting between the North American and South American plates (Bird et al., 2005, and references therein; Galloway, 2008). Rifting and basin growth accelerated into the Late Jurassic and Early Cretaceous (Salvador, 1987; Jacques and Clegg, 2002; Galloway, 2008) and, as a result, areas immediately outside the basin consist of unmodified continental crust, while the basin itself is underlain by shallow (2–12 kilometers (km) deep), moderately thinned, transitional crust along the margin and progressively more extended, thinner, and deeper (up to 20 km) transitional crust to marine crust near the basin center (Galloway, 2008). Crustal extension prior to this accelerated growth phase ultimately resulted in a structural sag on the western side of the basin.

All figures here in *Section 1.2* are displayed in high resolution in *Appendix B-1***.**

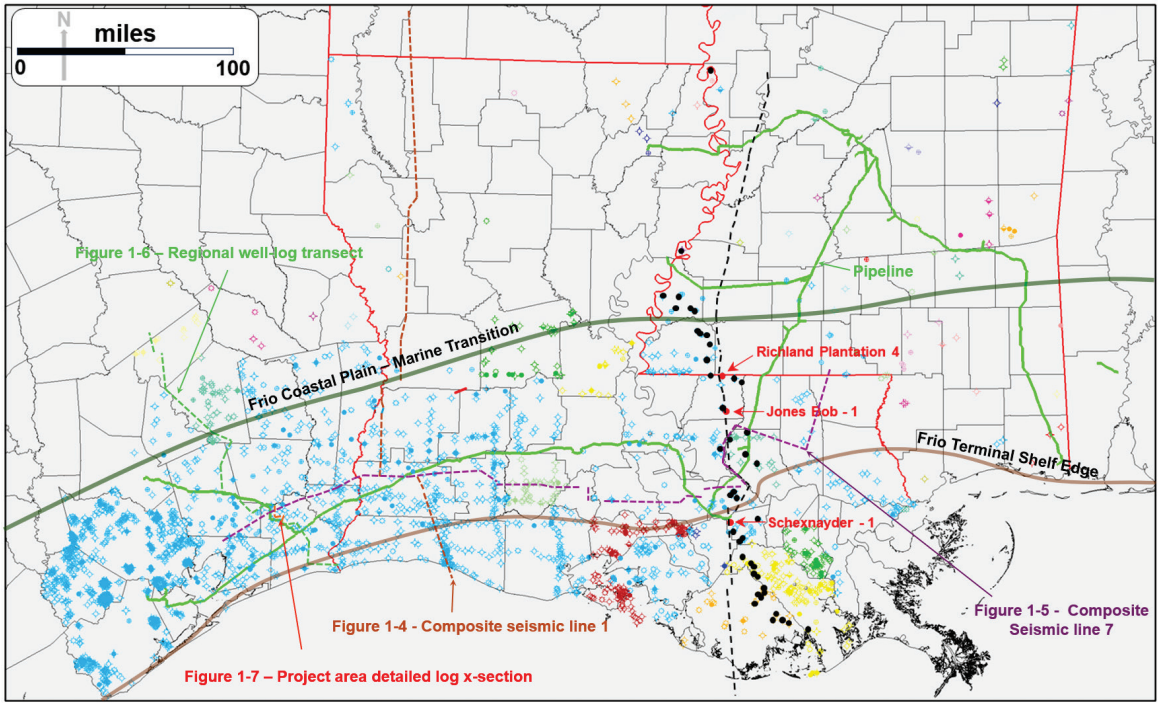


Figure 1-1 – Base map for the Gulf of Mexico. Wells used in the regional analysis are depicted as circles. Dashed lines represent seismic sections and well-log sections shown in Figures 1-4 through 1-7. (Figure 1-3 presents the basin margin and limits of the study area.) Initial coastal plain to marine transition zone and the terminal shelf edge boundary for the Frio Formation are shown (see Galloway et al., 2008).

This structural low allowed Pacific Ocean water to enter the basin—a connection that was fully established by the middle to late Callovian. Deposition within the basin switched from primarily terrestrial facies to a hypersaline, restricted-marine facies (Galloway, 2008). This switch is recorded by the widespread deposition of evaporitic deposits, collectively referred to as the Louann Salt. The abrupt transition from older, synrift continental deposits to more widespread, marine-influenced evaporitic deposits is commonly used to define the base of the Gulf of Mexico basin fill succession (Sawyer, 1991; Galloway, 2008).

Accelerated extension caused by Callovian-age crustal rupture, emplacement of basaltic crust, and increased seafloor spreading rates resulted in the termination of widespread evaporitic deposition in the basin. By the end of the Early Cretaceous, spreading centers had shifted east into the Atlantic and Caribbean basins. As a result, the crust underpinning the Gulf of Mexico basin began to cool and subside.

A series of basin-rimming Aptian-Albian carbonate platforms (i.e., Sligo Formation, James Limestone, Rodessa Formation, and Glen Rose Limestone, to name a few) developed on the more slowly subsiding basin margin (Winker and Buffler, 1988). Clastic sediments were largely constrained to an area inboard of the platform carbonates along the periphery of the basin. It was at that time that the Gulf of Mexico achieved its current morphologic form. These carbonate

platforms ultimately drowned in the Late Cretaceous due to high, load-driven subsidence rates. By the start of the Cenozoic, clastic depositional systems previously constrained to the basin margin begin to prograde and fill the basin—and this process continues through today (Figure 1-2).

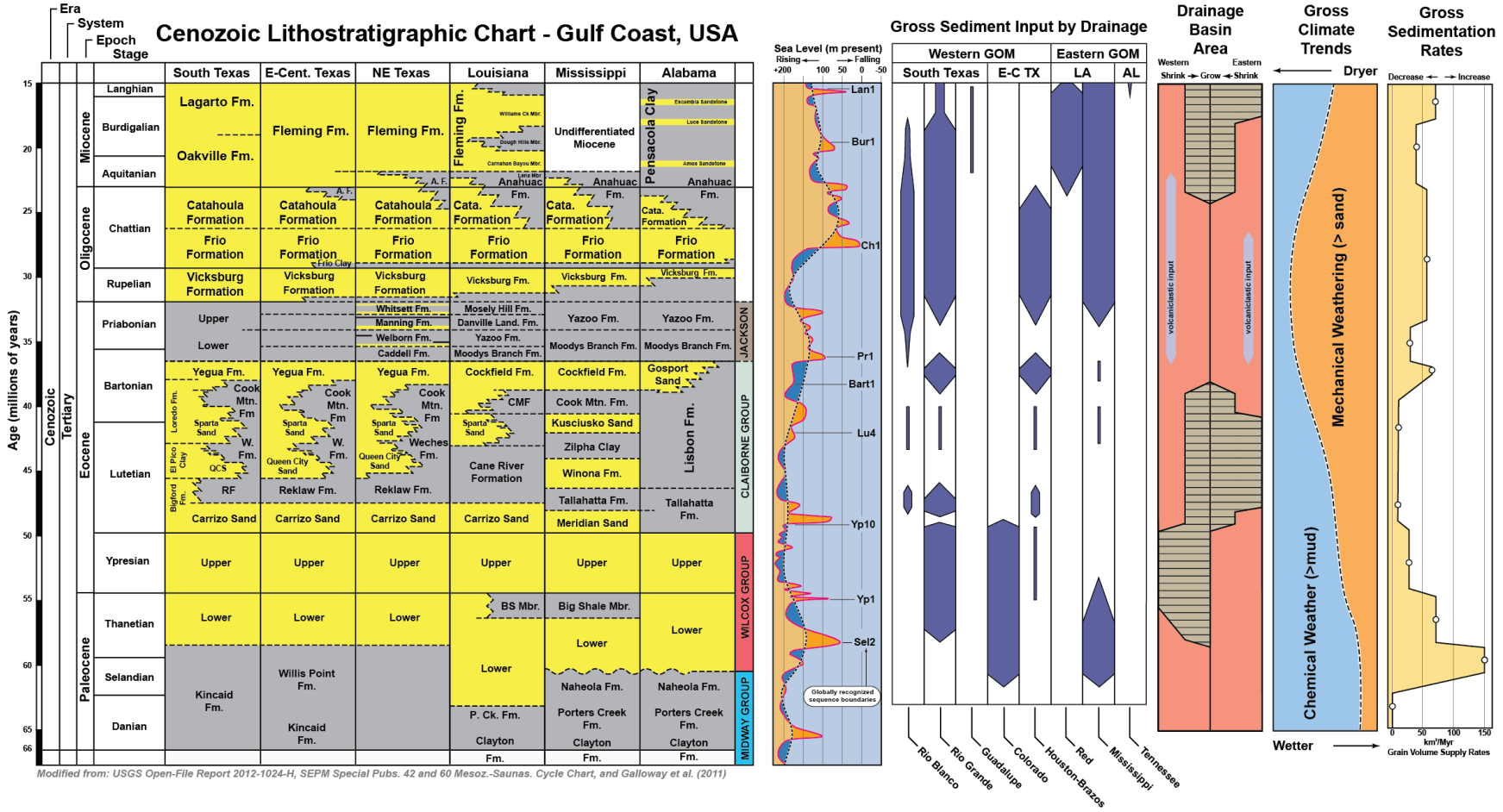


Figure 1-2 – Lithostratigraphic correlation chart for the northern portion of the Gulf of Mexico Basin (left). Yellow formations represent more sandy intervals and gray formations represent more muddy intervals. A comparison of stratigraphic forcing mechanisms, relative to the development of formations within the basin, is shown to the right.

Paleoclimates, Eustasy, and Fluvial Drainage Area Evolution – Greater Gulf of Mexico Region

The Cenozoic fill succession in the Gulf of Mexico basin records the climatically modulated delivery of sediment from the interior of the continental United States to the Gulf of Mexico basin. Although long-term climatic trends played an important role in the style, scale, and sediment flux of fluvial delivery systems to the Gulf of Mexico basin, far-field tectonic influences and modification of the paleo-landscape played an equally important role in the development and evolution of catchment areas and drainage-basin networks (Figure 1-3). Galloway et al. (2011) and Snedden and Galloway (2019) present a more detailed discussion of the development of the structural features.

As sediment was delivered to the basin margin, eustasy and relative sea level had a profound influence on the location and style of deposition, depositional body morphology, and stratal stacking patterns within the coastal to fully marine portions of the receiving basin. Galloway et al. (2011) provided a detailed description of Cenozoic forcing mechanisms, their variability through time across the continental interior and Gulf Coast regions of the United States, and maps of drainage basin evolution. Figure 1-4 summarizes observations from Galloway et al. (2011) concerning sediment supply to the major Gulf of Mexico depocenters through the Cenozoic. This figure also illustrates the timing and location of key sequence stratigraphic surfaces, long-term stratal stacking trends, and the development of reservoir-seal couplets in the basin.

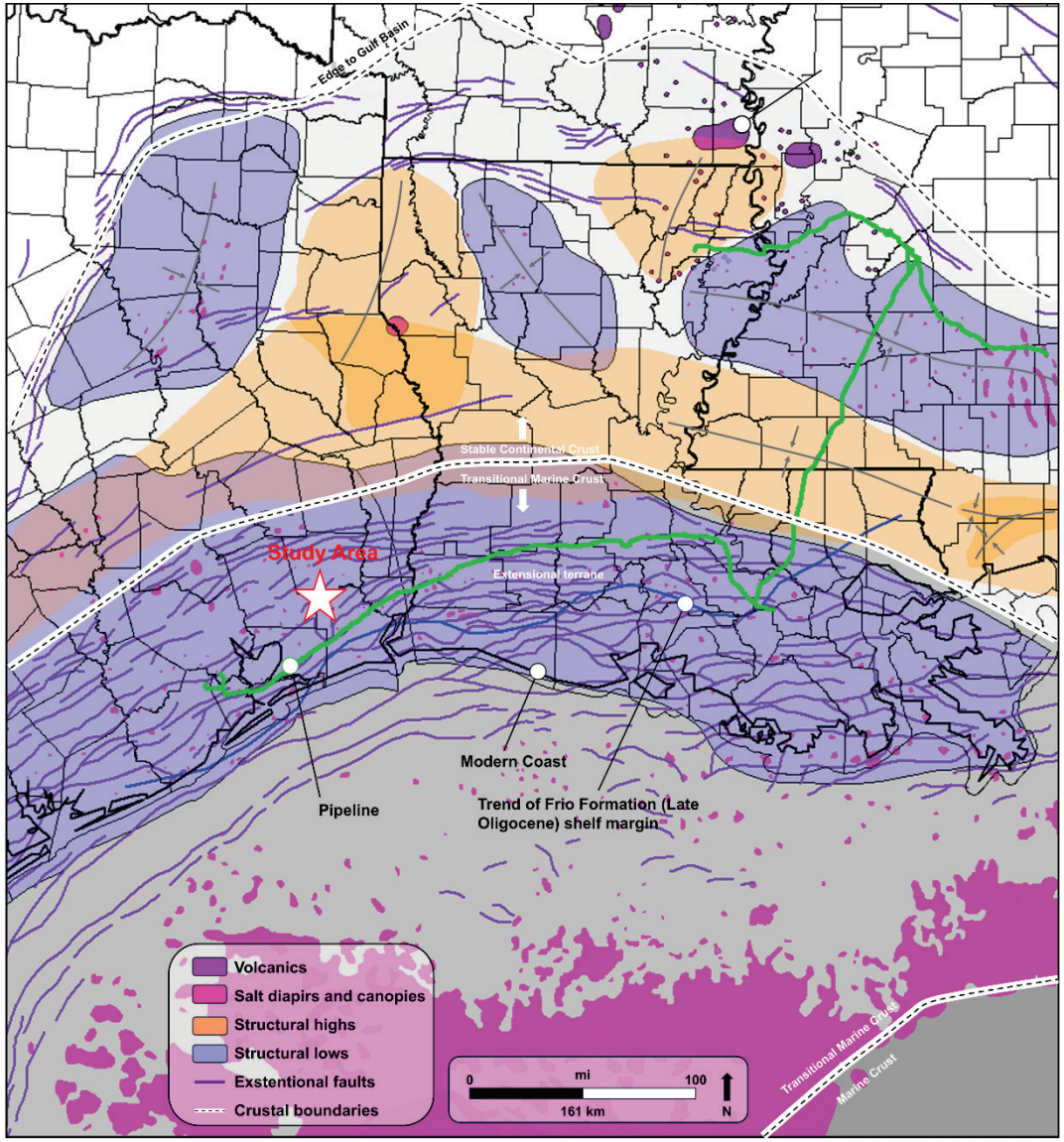


Figure 1-3 – Structural Elements of the Northern Gulf Basin.



Northern Gulf of Mexico Cenozoic Basin Fill Succession

The Cenozoic fill succession is characterized by a largely progradational stack of both ramp-style and passive margin-style continental shelves (Figures 1-4 through 1-6). The overall pattern of south-directed progradation reflects, in part, the load-driven generation of accommodation space due to the overall deepening of the basin. Loading also played a major role in the deformation of the northern Gulf of Mexico. Observed deformation can be separated into three different but interrelated styles: (1) extensional faulting and failure of the distal portions of coastal prisms and/or continental shelf edges along large, down-to-the-south, mostly listric faults (Figures 1-5 and 1-6); (2) Louann Salt migration associated with differential loading and development of salt diapirs, stocks, canopies, welds, and salt evacuation mini-basins; and (3) far-field tectonic effects associated with Laramide thrusting events in the western interior of the continental United States.



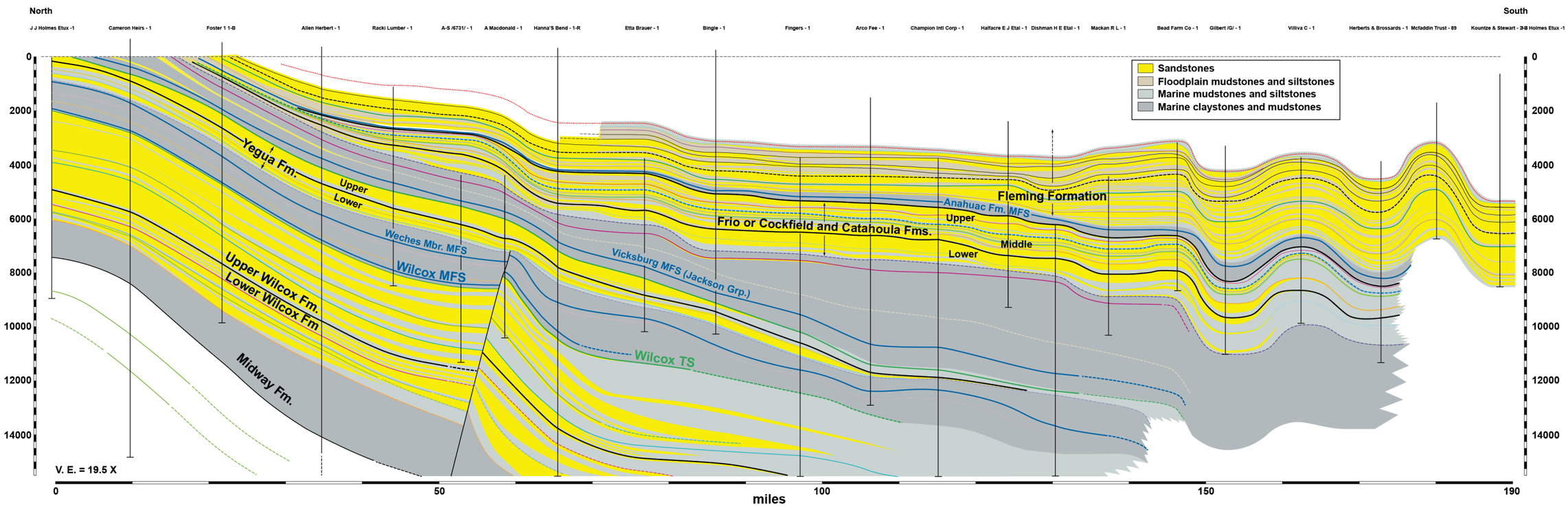
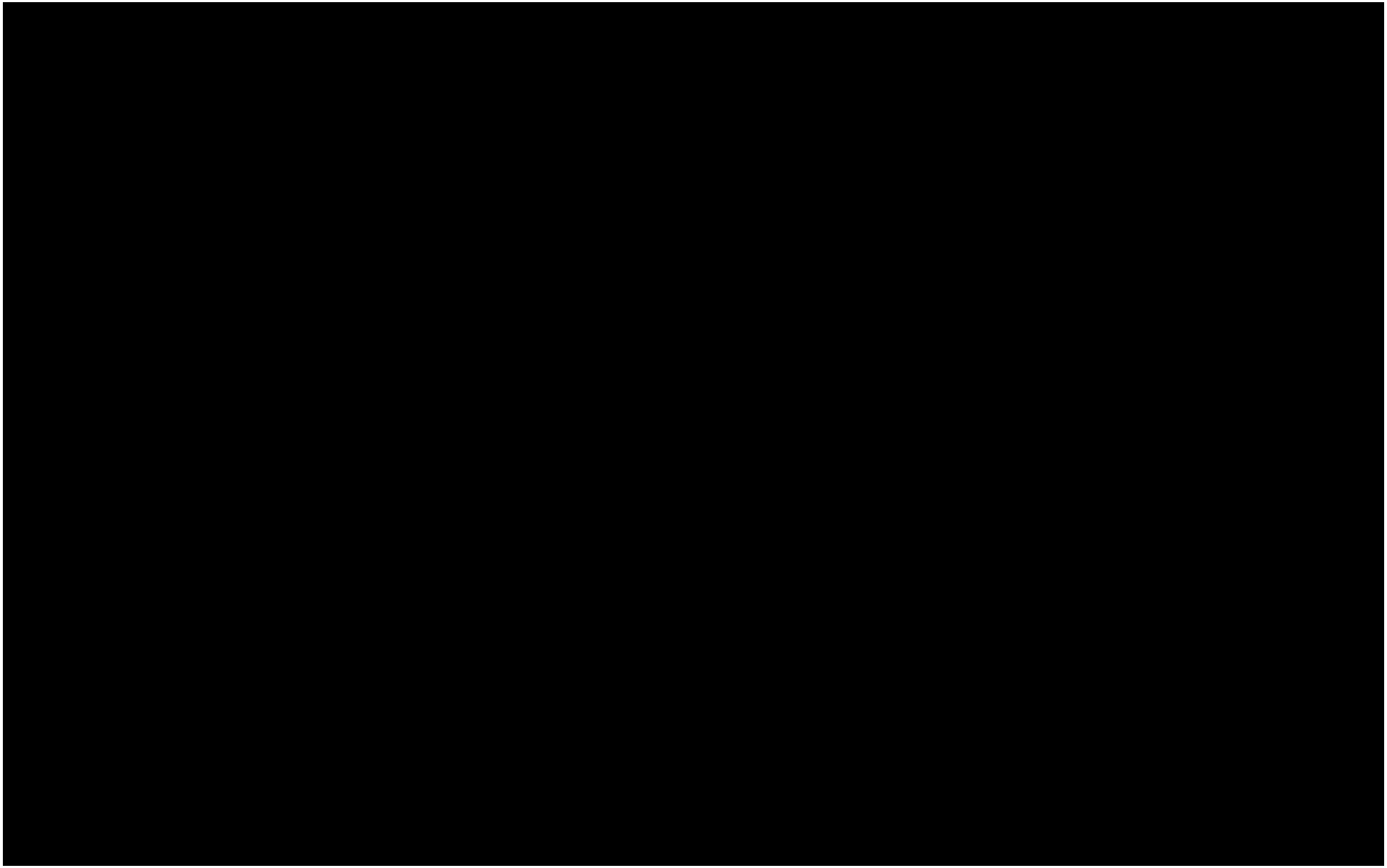


Figure 1-6 – Schematic, north-south or dip-oriented cross section through the greater Sunflower Project study area.
Note the fold axis or hinge line in the northern portion of this diagram, as well as the truncation of older stratigraphy over the hinge line location near the modern surface.

Figure 1-2 summarized many of the key forcing mechanisms that influenced the deposition of major reservoir and seal systems across much of the basin. With respect to this permit application, the focus will be on the Oligo-Miocene section—the primary injection interval in the Sunflower Project development area. The primary reservoirs in this area consist of fully marine to fluvial sandstones of the Chattian Frio–Catahoula formations and shallow-water coastal marine sandstone, to marine-influenced and non-marine, coastal plain fluvial sandstones of the Aquatanian to early Burdigalian Fleming Formation.

Figure 1-7 illustrates the distribution of the Frio and Catahoula (F-C) reservoirs within the preferential window or zone for potential CCS projects. The observed reservoir types, qualities, thicknesses, and connectivity change across the zone are strongly influenced by proximity to drainage basin outlets (depocenter); hinterland mineralogy and timing of sediment delivery to the coast; coastal marine processes at and between primary depocenters; local tectonics; and the position and direction of the sea-level fluctuations through the late Miocene and early Oligocene. The genetically related Frio and Catahoula formations form a southward prograding coastal prism consisting of fully marine, marine-influenced fluvial, fluvial, and coastal plain deposits. The form of this coastal prism was modified by extensional faulting and salt-related folding and by younger faulting, but reconstructions indicate that the F-C system had a typical, passive margin-type shape—and that the youngest shelf-slope break parallels the modern-day shoreline along the Texas sector of the Gulf Coast (Figure 1-1).

The primary F-C reservoirs in eastern Texas consist primarily of the clean, shallow marine deltaic and correlative wave-dominated shoreface deposits of the Frio Formation. Major depocenters at the mouth of the Houston-Brazos system in eastern Texas and the Mississippi system in central Louisiana were receiving significant volumes of sediment at this time (Galloway et al., 2011). In the Sunflower Project area, a large, river-dominated deltaic complex (referred to herein as the Houston delta) with attached wave-dominated strandplains formed (Figure 1-3).



Observed increase in sediment supply during the early Oligocene is partially in response to crustal uplift in the southwestern-to-western source areas of the drainages on the Texas sector of the Gulf of Mexico (Galloway et al., 2011), where Cretaceous through early Cenozoic foreland basin fill in the western interior of the United States was uplifted some 3 km (Gray et al., 2001). As a result, surface gradients during the Oligocene were relatively steep in the hinterland, and fluvial systems likely became more efficient at delivering sediment to the western margin of the Gulf of Mexico basin. Arid climatic conditions dominated the far western portion of the basin. Therefore, mechanical weathering outpaced chemical weathering in the hinterland, generating an overabundance of reservoir-grade sands that could be delivered to the Houston-Brazos Delta. The presence of a minor component of volcanoclastic sediments and their weathering derivatives within the Frio Formation is thought to be linked to the development of the Pioche-Marysville Igneous Belt of western Utah and eastern Nevada. Explosive volcanic events in this area occurred just prior to and during delivery of sediments to the Houston delta and development of the Frio Formation (Best and Grant, 1987).

Weathering products from rhyolitic and dacitic tuffs that characterize the Pioche-Marysville Igneous Belt, as well as other associated igneous deposits, led to an overall increase of observed volcanoclastic materials and their weathering derivatives being delivered to the western margin of the Gulf of Mexico basin during late Eocene and throughout the Oligocene. Records of global sea-level fluctuations (Figure 1-2) indicate that the position of sea level was significantly higher in the Eocene than during the ensuing Oligocene. This overall trend from relatively high to substantially lower sea-level positions in the Gulf of Mexico is reflected in the stratal stacking patterns and lithologic assemblages in the basin, indicating that eustatic effects played a major role in the spatial and temporal position of shorelines, key reservoirs, and the development of internal and ultimate sealing intervals within the Oligocene and into the early Miocene. Figure 1-2 illustrated the observed stratal architecture for the late Eocene through early Miocene sediments in the eastern Texas and western Louisiana sectors of the Gulf of Mexico basin, as well as the interplay of forcing mechanisms on the development of Oligo-Miocene reservoir-seal units.

The Cenozoic fill succession has a predictable stratigraphic stacking pattern that reflects the influence of sea-level fluctuations, basin subsidence associated with hydrodynamic- and sediment-driven loading, down to the basin extensional faulting associated with the failure of paleoshelf margins, and variations in sediment flux associated with the long-term growth or demise of coastal drainage systems. Overall, the stratal architecture of the Cenozoic can be characterized as a series of progradational, sand-prone wedges separated by a series of more muddy, transgressive marine intervals, each of which has a moderately well-developed maximum flooding surface (MFS), an interval of slow deposition that often has exceptional sealing characteristics (Figure 1-6). Although this stratal architecture has a predictable stacking pattern, the interpretation of the Cenozoic is in places problematic due to structural modification related to high subsidence rates away from the basin margin, which result in the southward bending and deepening of the Cenozoic and older stratigraphy south of a major hinge line. Furthermore, much of the northern portions of the various formations have been removed by late Cenozoic erosion centered on this hinge line area.

The Cenozoic fill is interpreted as a series of southward-directed, downward-stepping clastic wedges that form a highstand sequence set. Overall, lowstand deposits appear to be a secondary reservoir type in the basin, most likely due to high subsidence rates that reduced the depth and extent of fluvial erosion associated with the fall of sea level and extension of fluvial systems onto and across the exposed inner paleoshelf. The reservoir succession in the F-C interval is interpreted as a series of thick, down-stepping or offlapping, sandy highstand and falling-stage systems tracts, with a minor component of muddier lowstand systems tracts that are mostly south of this study area. The F-C interval is underlain by a major transgressive interval (referred to herein as the Clayborn interval and the Vicksburg MFS). The F-C intervals are in turn overlain by another mud-prone transgressive systems tract (TST) of the Anahuac Formation (Anahuac). In comparison to older, underlying TSTs, the Anahuac interval is thinner and of lesser extent. This likely reflects the more muted nature of Miocene sea-level transgressions.

Furthermore, the extent of sea-level falls through the Miocene increased in frequency and extent, as did the sediment yield to the basin. This resulted in the next major regressive phase of deposition and development of the Fleming Formation. During deposition of the formation, accommodation along the basin margin was somewhat limited. This resulted in a series of rapidly basinward-stepping shorelines and highly progradational and slightly down-stepping shelf margins. In the Sunflower Project study area, the marine portion of the Fleming Formation is constrained to the bottom, oldest reservoir intervals. For the most part, the Fleming consists of sandy fluvial channel belts and more muddy floodplain complexes in the project study area.

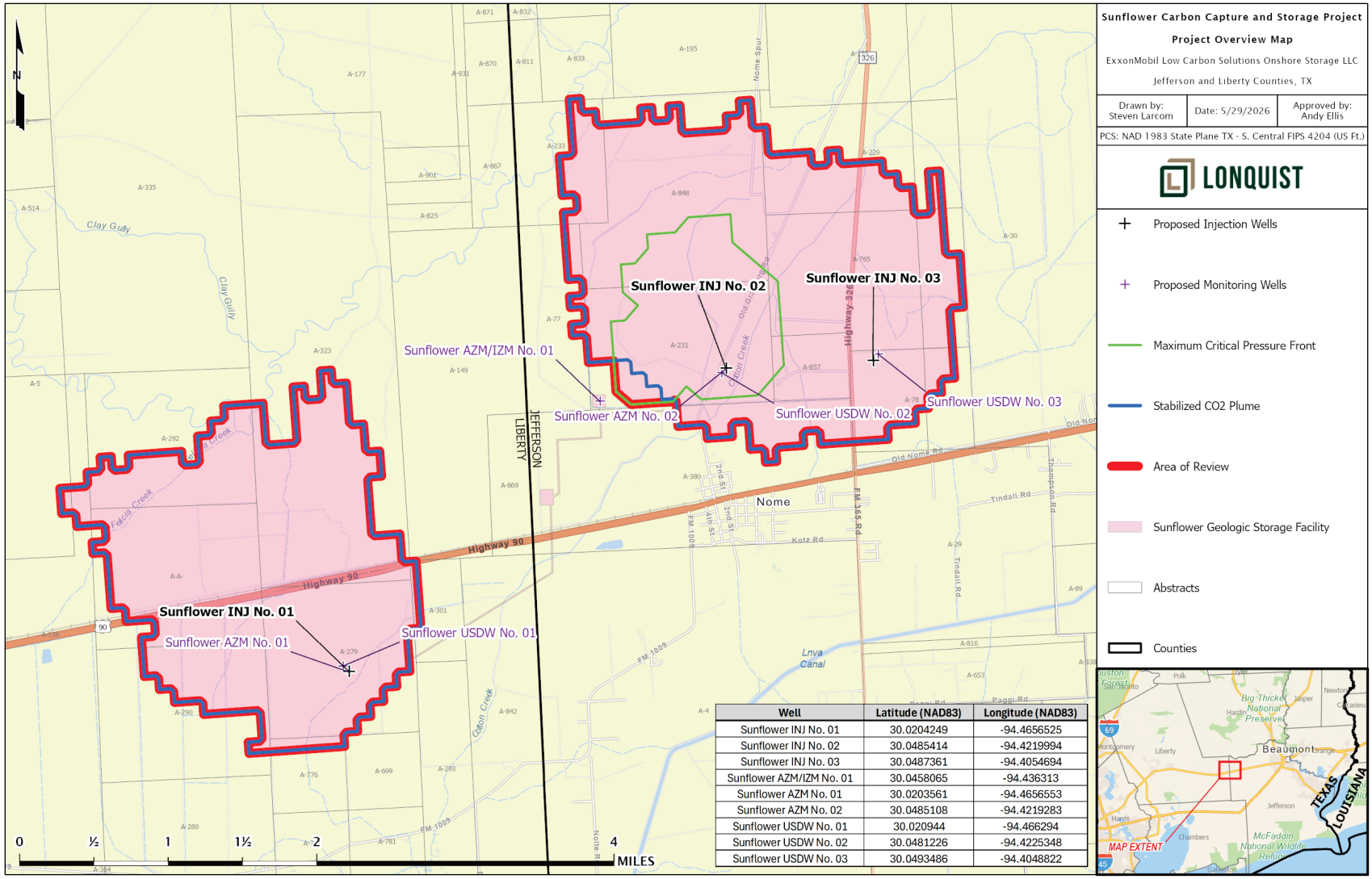
Figure 1-7 depicted the detailed stratigraphic interpretation of the Paleocene through middle Miocene section in the Sunflower Project study area. The attempt here was to define key stratigraphic surfaces, integrate core results, and interpret depositional facies across the study area. Based on the well-log character and core interpretations, the Hackberry through Frio formations are characterized as a largely marine succession of high-quality reservoirs deposited within a large deltaic complex. The overlying Catahoula Formation is characterized by lower net sand and is interpreted as the genetically linked deltaic plain to coastal plain associated with the Frio deltaic complex. The Anahuac Formation consists of middle- to outer-shelf marine mudstones and is interpreted as a major transgressive deposit with very good sealing properties across the entire project study area. The basal Fleming Formation is defined by the first widespread sandstone above the Anahuac mudstone. In this area, the lowermost sandstones of the Fleming Formation are interpreted as low-gradient, wave-dominated shoreface deposits.

The Fleming Formation becomes rapidly more terrestrial in nature and is dominated by a series of vertically aggrading fluvial, levee, and flood basin complexes, each of which is capped by a more mud-prone, possibly marine-influenced interval that is thought to have been deposited within interdistributary bays, swamps, and marshy flood basins by aggrading and retreating fluvial systems as the delta plain and outer coastal plain was drowned by rising sea-levels. These muddy intervals are locally to regionally mappable and are thought to have some ability to act as seals within the Fleming Formation. Where cored, they are interpreted as very fine-grained,

floodplain and interfluve soils that formed between coastal fluvial channel belts, at or near the seaward edge of the coastal plain.

1.3 Site Geology

The AOR, as defined by the maximum critical pressure front and stabilized CO_2 plume extent, is located in Jefferson and Liberty Counties, as shown in Figure 1-8. Reservoir characteristics and geological properties of the injection and confining zones within the AOR are drawn from proprietary, licensed, subscribed, and public data sources, including the Texas Bureau of Economic Geology, IHS LogNet, Enverus, Core Laboratories' Reservoirs Applied Petrophysical Integrated Data (RAPID) service, and published research. General geologic setting and lithological attributes are described regionally from publications, and heavily supported by 5 nearby stratigraphic test wells (completed by ExxonMobil, located approximately 7 - 8 miles southeast of Sunflower INJ No. 03 (Figure 1-8). Structure depth maps and isochores for key major intervals are contained in *Appendix B-2*. A seismic cross section through the proposed Sunflower INJ No. 01, No. 02, and No. 03 is shown in Figure 1-9.



Well	Latitude (NAD83)	Longitude (NAD83)
Sunflower INJ No. 01	30.0204249	-94.4656525
Sunflower INJ No. 02	30.0485414	-94.4219994
Sunflower INJ No. 03	30.0487361	-94.4054694
Sunflower AZM/IZM No. 01	30.0458065	-94.436313
Sunflower AZM No. 01	30.0203561	-94.4656553
Sunflower AZM No. 02	30.0485108	-94.4219283
Sunflower USDW No. 01	30.020944	-94.466294
Sunflower USDW No. 02	30.0481226	-94.4225348
Sunflower USDW No. 03	30.0493486	-94.4048822

Figure 1-8 – Overview Map of the Sunflower Project



The Carpenter – 1 (API No. 4224530290) is the offset wellbore (with full log coverage) closest to proposed Sunflower INJ No. 02 and No. 03. Several logs from Carpenter – 1, including spontaneous potential and resistivity, were recorded over the measured depths of approximately 1,376–7,815 feet in 1974. Depths and associated thicknesses of the upper confining, injection, and lower confining zones as encountered in this offset well are listed in Table 1-1. Figures 1-10 and 1-11 show well cross sections of Vshale, resistivity, formations, and depths as encountered in multiple wells within the project area of interest (AOI), including Carpenter – 1.

Table 1-1 – Injection and Confining Zones as Encountered in Carpenter – 1

Epoch	Group/Formation Name	Injection/Confining	Formation Top (ft MD)	Formation Base (ft MD)	Thickness (ft)
Miocene	Fleming	Upper Confining	3,370	3,527	157
Miocene	Fleming	Injection	3,527	5,221	1,695
Oligocene	Frio	Anahuac Seal – Confining	5,221	5,492	270
Oligocene	Frio	Injection	5,492	7,624	2,132
Oligocene	Frio	Lower Confining	7,624	7,815**	191+

*MD – measured depth ** End of Log





1.3.1 Injection Zone

The injection zone is composed of sediments deposited during the Oligocene and Miocene, representing the Frio and Fleming formations, respectively. These are separated by the Anahuac Shale confining zone, a regionally mappable unit representing a major transgression at the time of deposition. *Appendix B-2* illustrates these intervals—relating them to recognized biostratigraphic zones—and also presents depth structure maps of the confining and two injection intervals. Based on the detailed site characterization work, ExxonMobil is proposing an injection zone from the top of the Fleming 2 at approximately 3,572 ft – to the base of the Frio 3 at approximately 7,775 ft TVD but may slightly revise these depths based on the as-drilled conditions in the injection wells themselves. One example structure depth map (top of the injection zone (Fleming 2)) is depicted in Figure 1-12.

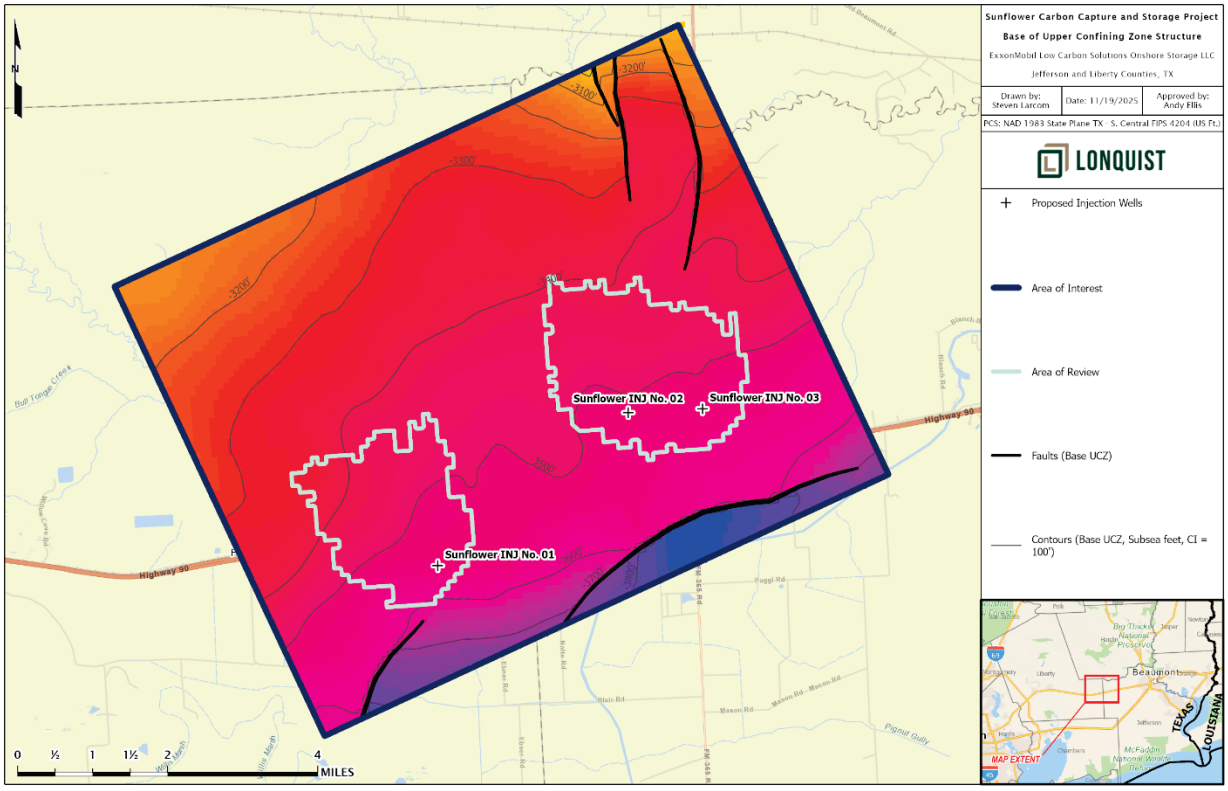


Figure 1-12 – Structure Depth Map of the Base of the UCZ – Top Injection Zone

Both the Miocene-age Fleming and Oligocene-age Frio sediments targeted for injection are composed of interbedded sandstones, siltstones, and shales sourced primarily from the paleo-Mississippi River system and deposited in a deltaic setting. However, the relative influence of deltaic and shoreline processes on reservoir quality and style varies relative to stratigraphic level and lateral position within the delta at the time of deposition. Both the Oligocene and Miocene intervals are fluvially dominated; the older Frio Formation represents a more distal location within the depositional system relative to the Miocene interval. Mineralogy and other

petrophysical characteristics of the injection intervals are based on data collected from Bead Farm Co. – 1.

1.3.1.1 Fleming Injection Interval

Figures 1-10 and 1-11 illustrated the alternating sands, siltstones, and shales of the Fleming Formation and the internal division of the Fleming into Fleming 2 and 3 (below the UCZ) as defined for the Sunflower Project. The Fleming sands have been divided based on the correlation of regionally mappable shale zones that act as internal baffles and barriers. The gross Fleming interval within the AOR ranges from approximately 900–1,100 feet for Fleming Sand 3 and 570–690 feet for Fleming Sand 2.

Based on the offset Bead Farm Co. – 1 stratigraphic test well, and supported by the four additional stratigraphic test wells, the Fleming injection interval is composed of generally unconsolidated, very fine to fine-grained arkosic to subarkosic sandstones. Thin sections available from the Fleming Formation (Fleming Sand 3) collected from Bead Farm Co. – 1 are presented in Figure 1-13. The analyzed samples demonstrate excellent reservoir quality, with good intergranular porosity and little-to-no diagenetic alteration of the sediments. The X-ray diffraction (XRD) data from the Fleming injection intervals from Bead Farm Co. – 1 show that stable quartz and K-feldspar minerals comprise the majority of the rock by weight percentage, a mineralogy that is highly compatible with CO_2 injection.



1.3.1.2 Frio Injection Interval

Figures 1-10 and 1-11 illustrated the alternating sands, siltstones, and shales of the Frio Formation and the internal division of the Frio into Frio 1, 2 and 3 as defined for the project. The Frio sands have been divided based on correlation of regionally mappable shale zones that act as internal baffles and barriers. The gross Frio interval within the AOR ranges from approximately 390–590 feet for Frio Sand 3, 580–710 feet for Frio Sand 2, and 730–1,000 feet for Frio Sand 1.

Based on the offset stratigraphic test wells, the Frio injection interval, much like the Fleming, is composed of generally unconsolidated, very fine to fine-grained type sandstones. Thin section images available from the Frio Formation (Frio Sand 1) collected from Bead Farm Co. – 1 are presented in Figure 1-14. The analyzed samples demonstrate excellent reservoir quality, with good intergranular porosity. Minor diagenetic alterations to the injection zone are present within this interval. These include the dissolution of labile Na-plagioclase grains and the precipitation of minor amounts of quartz cement (less than [redacted] by volume). The XRD data from the Frio injection intervals show that stable quartz minerals and K-feldspar comprise most of the rock by weight percentage, a mineralogy that is highly compatible with CO_2 injection.



1.3.2 Upper Confining Zone

The upper confining zone (UCZ) occurs immediately above the Fleming injection interval and is below a regional flooding event associated with the *Amphistegina B* shale, a regional sealing interval across the Texas Gulf Coast (based on biostratigraphic interpretation, *Appendix B-2*). The geological characteristics of the UCZ are consistent with the requirements of 16 TAC **§5.203(c)(2)(B)** for confining the CO_2 plume and acting to protect USDWs from endangerment. The gross UCZ interval ranges from approximately 115–190 feet over the AOR, with a mean of 160 feet. The top UCZ structure depth map and UCZ isochore are shown in Figures 1-15 and 1-16, respectively.

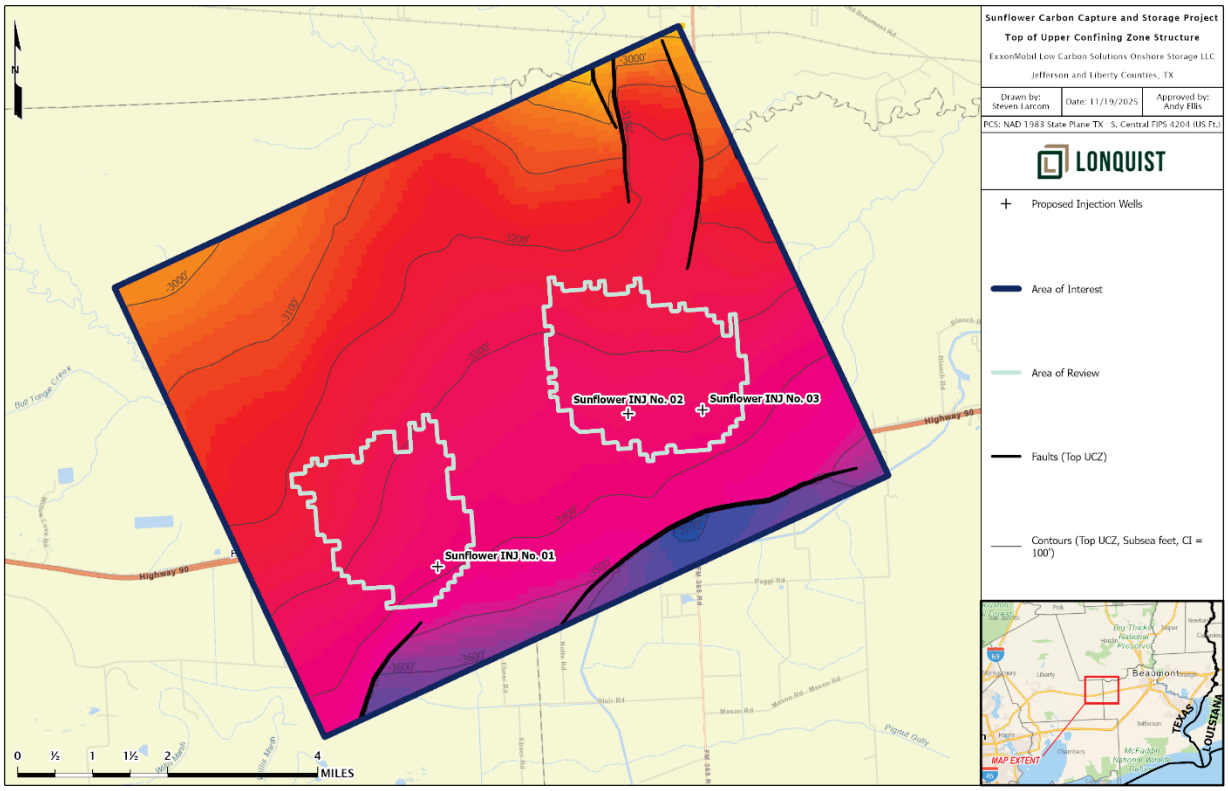


Figure 1-15 – Structure Depth Map of the Top of the UCZ

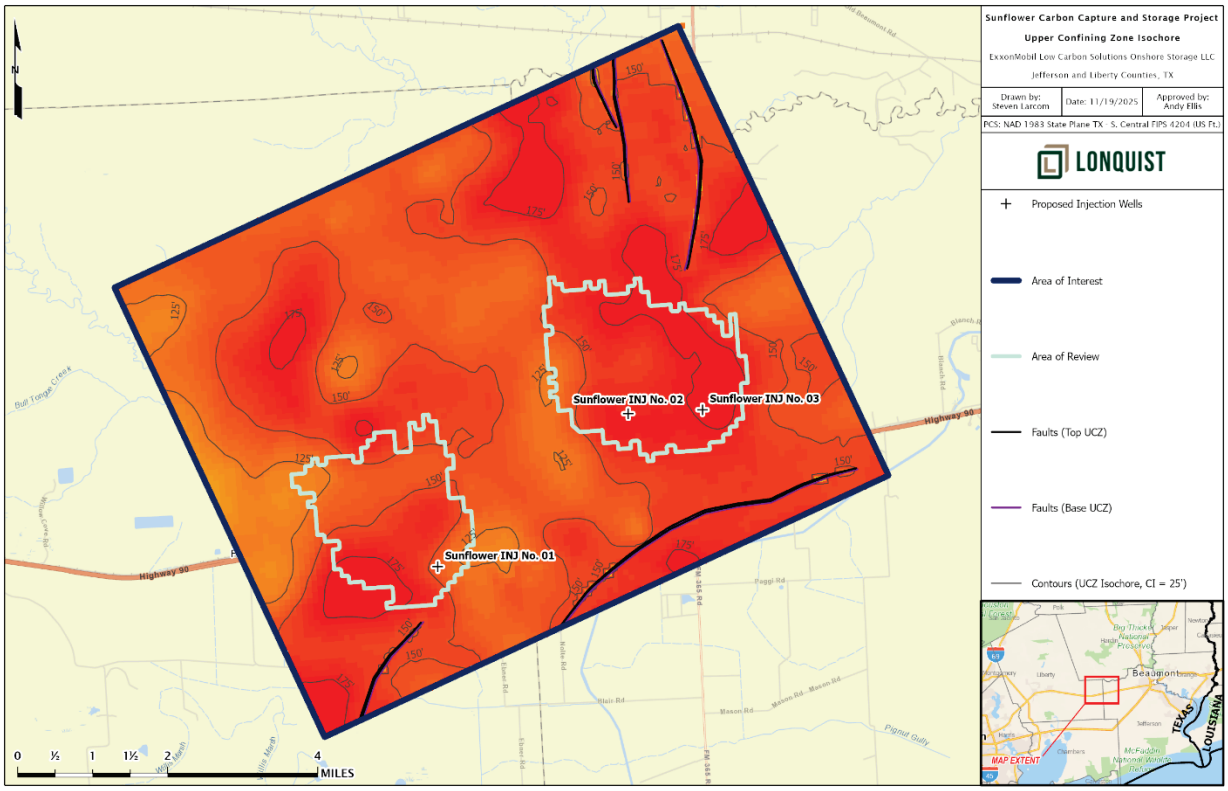
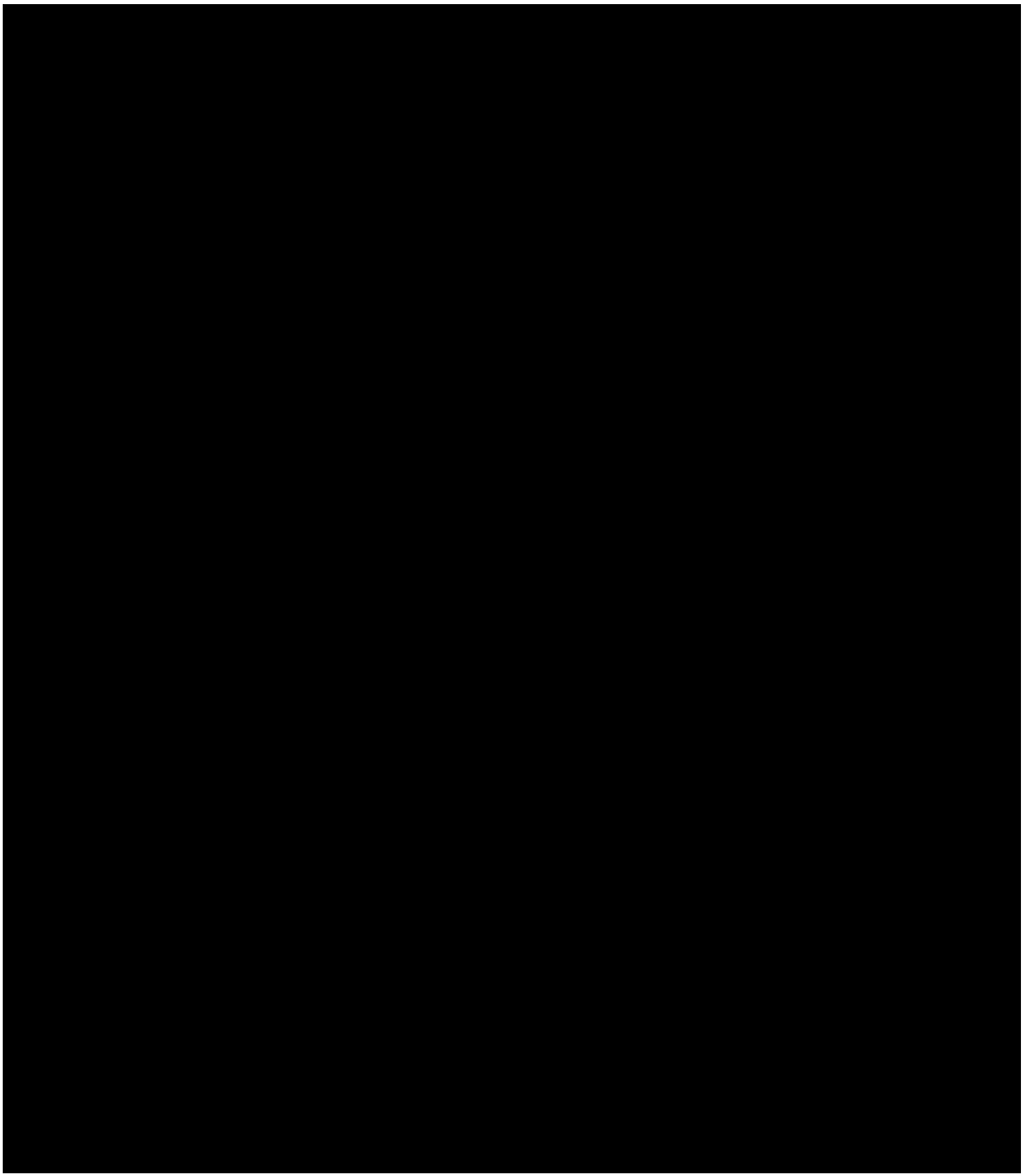


Figure 1-16 – Isochore of the UCZ

Based on data collected at the offset stratigraphic appraisal well, the UCZ is composed of high-quality, clay-rich mudstones. Mercury injection capillary pressure (MICP) analyses performed on samples from the nearby stratigraphic test well (Bead Farm Co. – 1) show capillary entry pressures that range from [redacted] pounds per square inch (psi) to [redacted] over [redacted] samples, with an average of [redacted]—indicative of excellent sealing capacity. Available samples show that the total clay content of this interval averages more than [redacted] A thin section photograph for the UCZ is shown in Figure 1-17, which shows a bioturbated clay-rich mudstone with fine-sand to silt size framework grains composed primarily of quartz and feldspathic minerals. Typical Miocene-age mudstones from the UCZ can be described as bioturbated, with very fine sand to fine silt-sized quartz and feldspar grains embedded in a clay-rich matrix with dispersed framboidal cements. Other grain types frequently observed include micaceous minerals, rock fragments, and fossil fragments. Organic matter is also common.



The UCZ layer was shown in the well cross sections in Figures 1-10 and 1-11, where the fine-grained muddy interval is evident. This layer was confirmed to exist by the analysis of the geophysical logging and sampling results of the nearby stratigraphic test well (Bead Farm Co. – 1), as well as the four additional stratigraphic test wells. The potential for vertical flow out of the injection zone was also evaluated by comparing the baseline temperature data at various depths within the injection zone and above the UCZ, as shown in Figure 1-18. Overall, the temperature measurements reflect geophysical and mineralogical differences between the intervals of interest as confirmed by the analysis of core data from Bead Farm Co. – 1.



1.3.3 Lower Confining Zone

Figures 1-10 and 1-11 displayed data beneath the Upper Frio injection interval—the lower confining zone (LCZ). Few wells in the Sunflower Project area were drilled into and beneath this section. As shown on the log cross sections, thick and pervasive shales exist below the Upper Frio injection interval and extend thousands of feet below the base of the injection zone. Bead Farm Co. – 1 was drilled into the upper 165 feet of the LCZ, and the well reached total depth within the uppermost portion of the LCZ. Rotary sidewall cores collected from this interval show that the LCZ is a high-quality, clay-rich interval with good sealing properties. A "Base LCZ" was mapped approximately 500 feet below the LCZ top, although the shales extend much deeper in available logs (Figures 1-10 and 1-11).

1.4 Formation Evaluation

1.4.1 Well Data

Petrophysical evaluations were performed on 47 wells to estimate shale volume and total porosity from wireline logs across the Fleming and Frio formations. All 47 wells had either a spontaneous potential (SP) or gamma ray (GR) log to estimate shale volume, and 14 of the wells had a compressional sonic (DTC) and/or bulk density (RHOB) log to estimate total porosity across the formations of interest. *Appendix B-2* lists the wells and log data available for each well used in this analysis.

1.4.2 Log Quality Control

ExxonMobil drilled 5 modern wells as part of the Rose Carbon Capture and Sequestration Project near the Sunflower Project area and obtained high-quality logs and core data. These data were leveraged for quality control and evaluation of the legacy wells at Sunflower. Moreover, many legacy wells were impacted by poor borehole conditions, which required additional log processing steps to ensure consistent petrophysical data were obtained across all wells. These steps are discussed in greater detail in the following section.

1.4.3 Methodology

1.4.3.1 Shale Volume

Shale volume (VSH) was primarily determined from the SP log since it was the most common lithology indicator in many wells. Raw SP logs were first baselined to read zero millivolts (mV) in thick shales, and clean sand lines were interpreted across each well based on the magnitude of the SP deflection. In the absence of SP logs, the GR log was used to estimate shale volume following a similar approach. Raw GR logs were first bulk-shifted to read approximately 100 GAPI in shales, and clean sand lines were interpreted across each well. Shale volume was then calculated from the SP or GR log using a linear scaling between the clean sand lines and shale baselines as follows (Equation 1):

(Eq. 1)

$$VSH = \left|\frac{SP_{log} - SP_{clean}}{SP_{shale} - SP_{clean}}\right| \; or \; \left|\frac{GR_{log} - GR_{clean}}{GR_{shale} - GR_{clean}}\right|$$

1.4.3.2 Total Porosity

Total porosity (PHIT) was estimated using either bulk density and/or compressional sonic logs. Density-derived porosities are generally preferred over sonic-derived porosities because the interpretation is more straightforward. However, as noted above, legacy wells are often impacted by borehole washouts, which may severely affect the reliability of the bulk density logs. In these cases, sonic-derived porosities were preferred since sonic measurements are typically less sensitive to minor borehole washouts. For wells where compressional sonic logs were unavailable, the bulk density logs were reconstructed using the deep resistivity log to correct for these effects. The equations and parameters listed in Table 1-2 were used to estimate density and/or sonic porosities in each well.

It should be noted that the sonic-derived porosities were estimated using the Raymer-Hunt-Gardner equation. This empirical equation was developed specifically for unconsolidated Gulf Coast sands where the relationship between compressional slowness and total porosity is non-linear. In addition, a variable matrix slowness was used based on VSH to correct for the increase in sonic-derived porosity with increasing shale content. The final total porosity was taken as the minimum of the sonic and density-derived porosities unless only one porosity log was available, which was then used as the final total porosity.

(Eq. 2)

$$\emptyset_D = \left(\frac{\rho_{ma} - \rho_{log}}{\rho_{ma} - \rho_f}\right)$$

(Eq. 3)

$$\emptyset_S = \left[C * \left(\frac{DTC_{log} - DT_{ma}}{DTC_{log}}\right)\right]$$

(Eq. 4)

$$DT_{ma} = [(1 - VSH) * DT_{sand} + VSH * DT_{shale}]$$

(Eq. 5)

$$\emptyset_T = min(\emptyset_D, \emptyset_S)$$

Table 1-2 – Parameters for Calculating Total Porosity from Bulk Density and Compressional Sonic Logs

Method	Parameter	Value
Density porosity, f_D	Matrix density, r_{matrix}	2.65 g/cc (default for quartz sandstones)
	Fluid density, r_{fluid}	1 g/cc for water
Sonic porosity, f_S	Field coefficient, C	0.6 – 0.71 (varied with depth)
	Clean sand matrix slowness, *DTsand*	55 µs/ft
	Shale matrix slowness, *DTshale*	80 µs/ft

*g/cc – grams per cubic centimeter; µs/ft – microseconds per foot

1.5 Geologic Structure

Regional dips are low and vary on average between 1° and 2° in the Sunflower Project AOR. Figures 1-19 and 1-20 show the structural dip maps for the Top Fleming and Frio injection intervals, respectively.

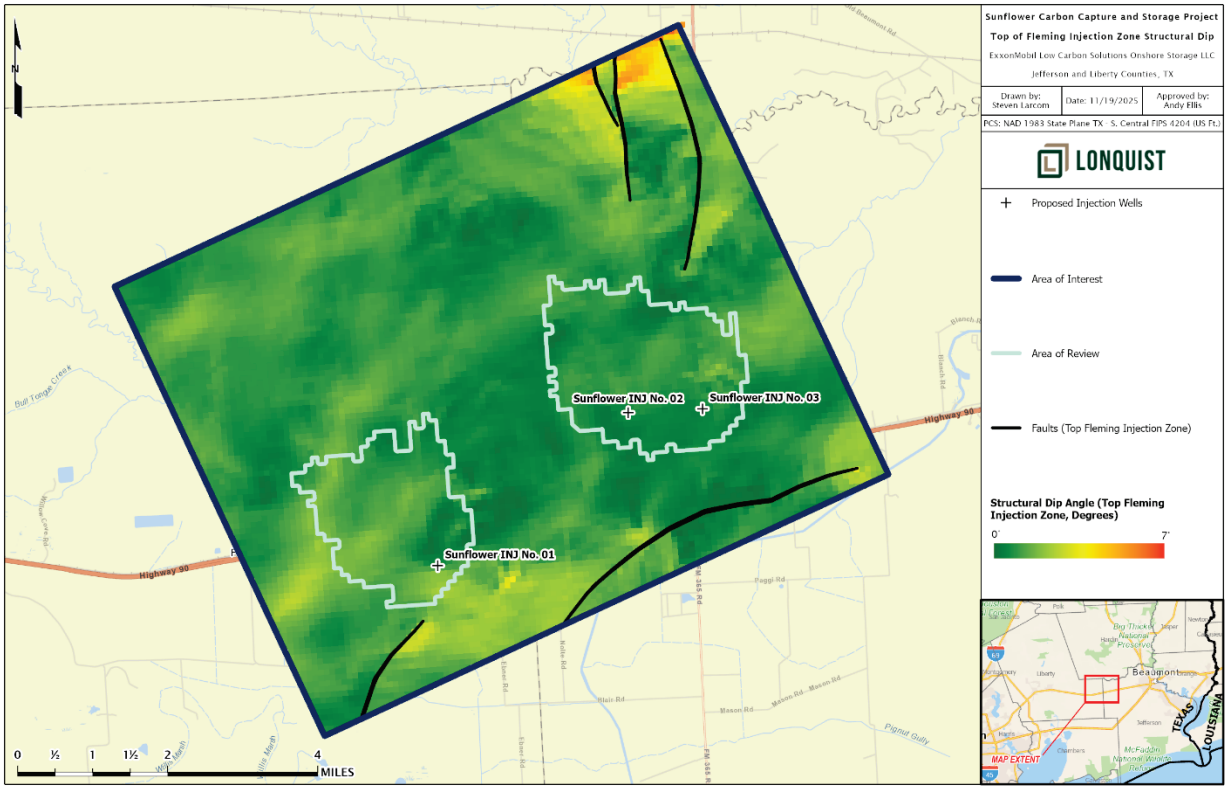


Figure 1-19 – Top Fleming Injection Interval Structural Dip Map

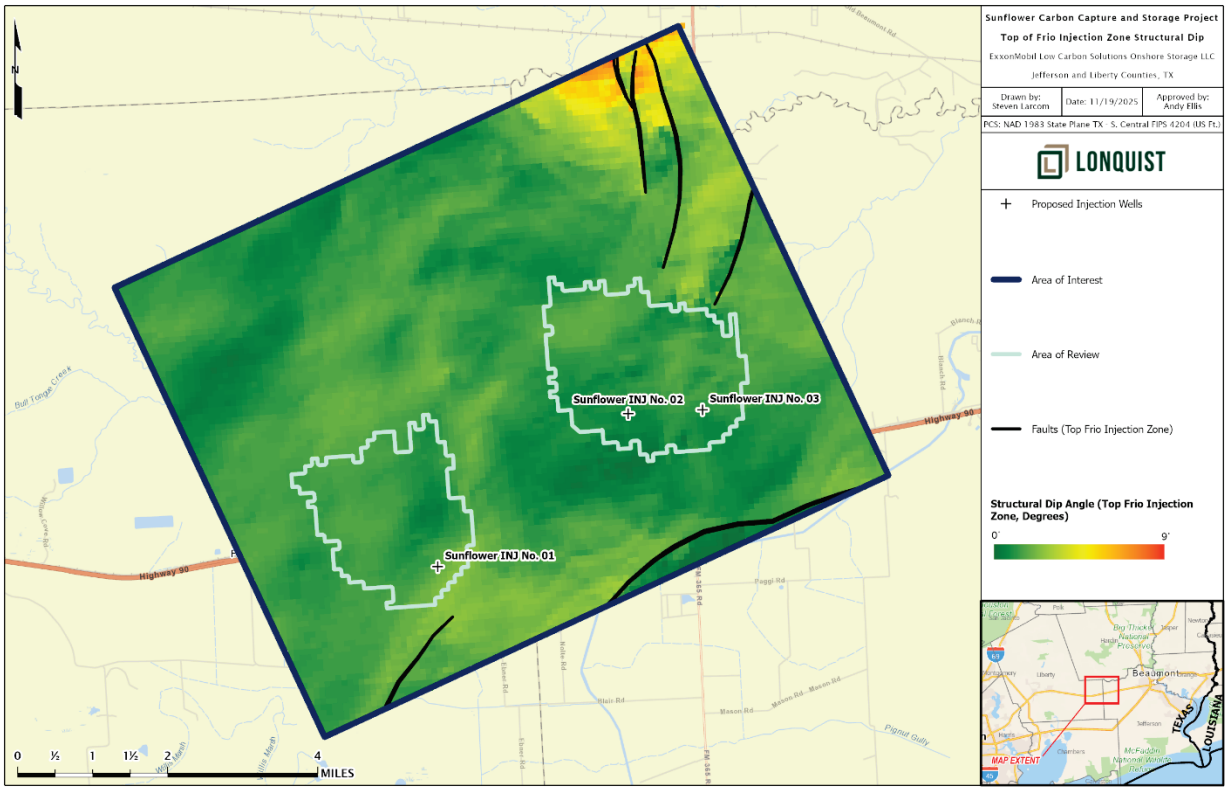


Figure 1-20 – Top Frio Injection Interval Structural Dip Map

1.5.1 Seismic Survey Data

To create the geomodel for the Sunflower Project, 3D seismic data were used that cover the entire AOI. This included the Delilah, China Nome, and Jefferson Hardin 3D seismic surveys. The resultant combined seismic-survey bin size was 110 x 110 feet, with a maximum offset of 20,000 feet from the Jefferson Hardin and China Nome surveys and 40,000 feet from the Delilah survey. The common mid-point (CMP) fold was generally 50 and above, within the AOI. An industry-leading vendor reprocessed these data together into one seismic data set in 2025, using their comprehensive workflow for land seismic data, progressing from raw field data to final migrated images using Pre-Stack Depth Migration (PSDM), velocity modeling, and advanced noise attenuation techniques. The resultant seismic image quality was high-quality.

1.5.1.1 Velocity Control and Synthetic Seismogram

The wells within and in close proximity to the AOI, that contained enough data to perform a well tie (i.e., tie the seismic survey to depth and allow the correlation of historical well logs to seismic data), were Arco Fee – 1 (API No. 4229131594), Willis Estate – 5 (API No. 4229132721), Dishman H E Gu – 1 (API No. 4224531707), and Failor P L – 1 (API No. 4224531465) (Figure 1-21). A zero-phase global statistical wavelet with a peak frequency of approximately 30 hertz (Hz) was used to perform the ties on the near stack. The results of the well ties are shown in Figures 1-22

through 1-25. Time-depth relationships were generated from the migration velocity model at the well location, and all four wells offered high-quality ties for the purposes of geologic characterization at the project site.

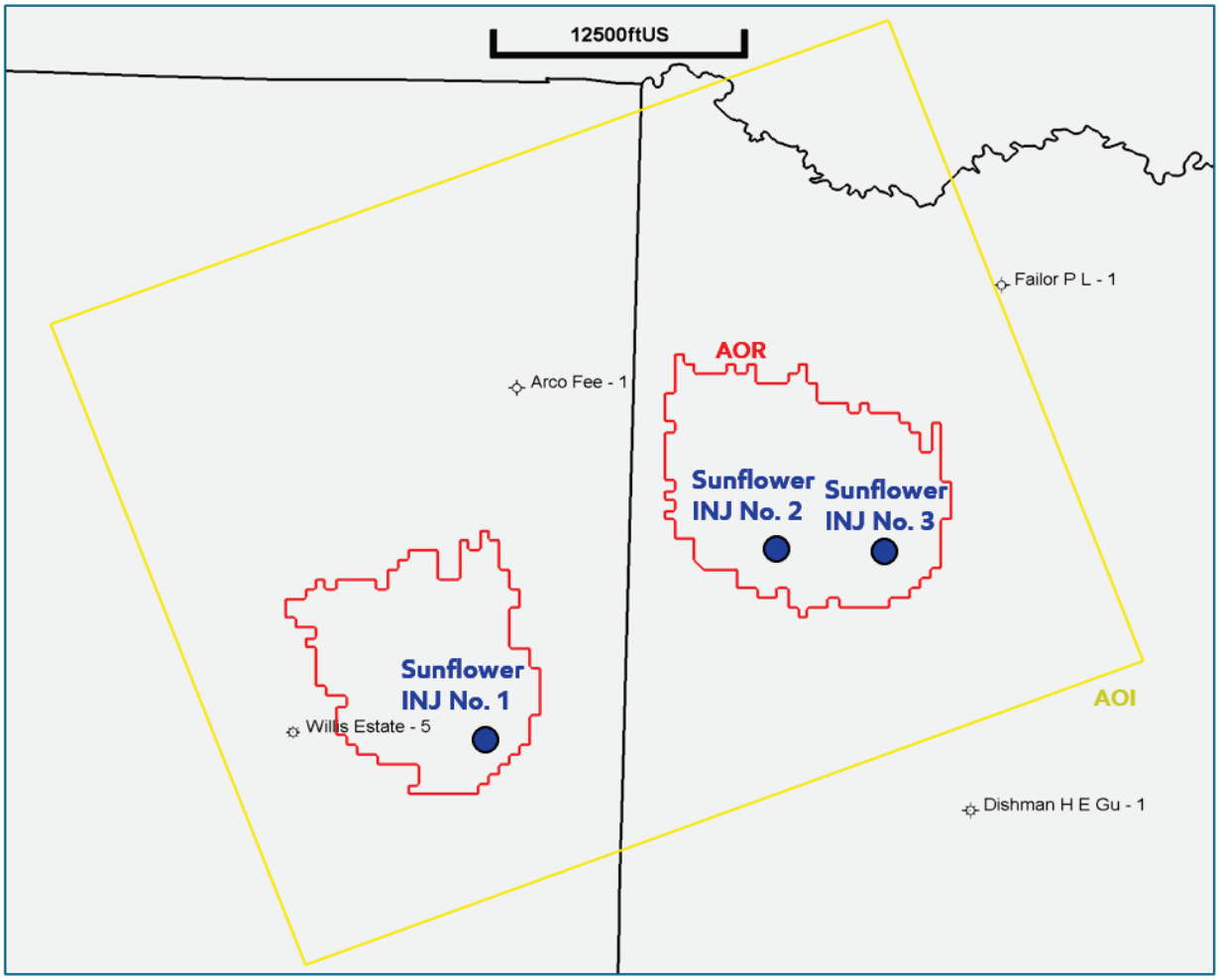
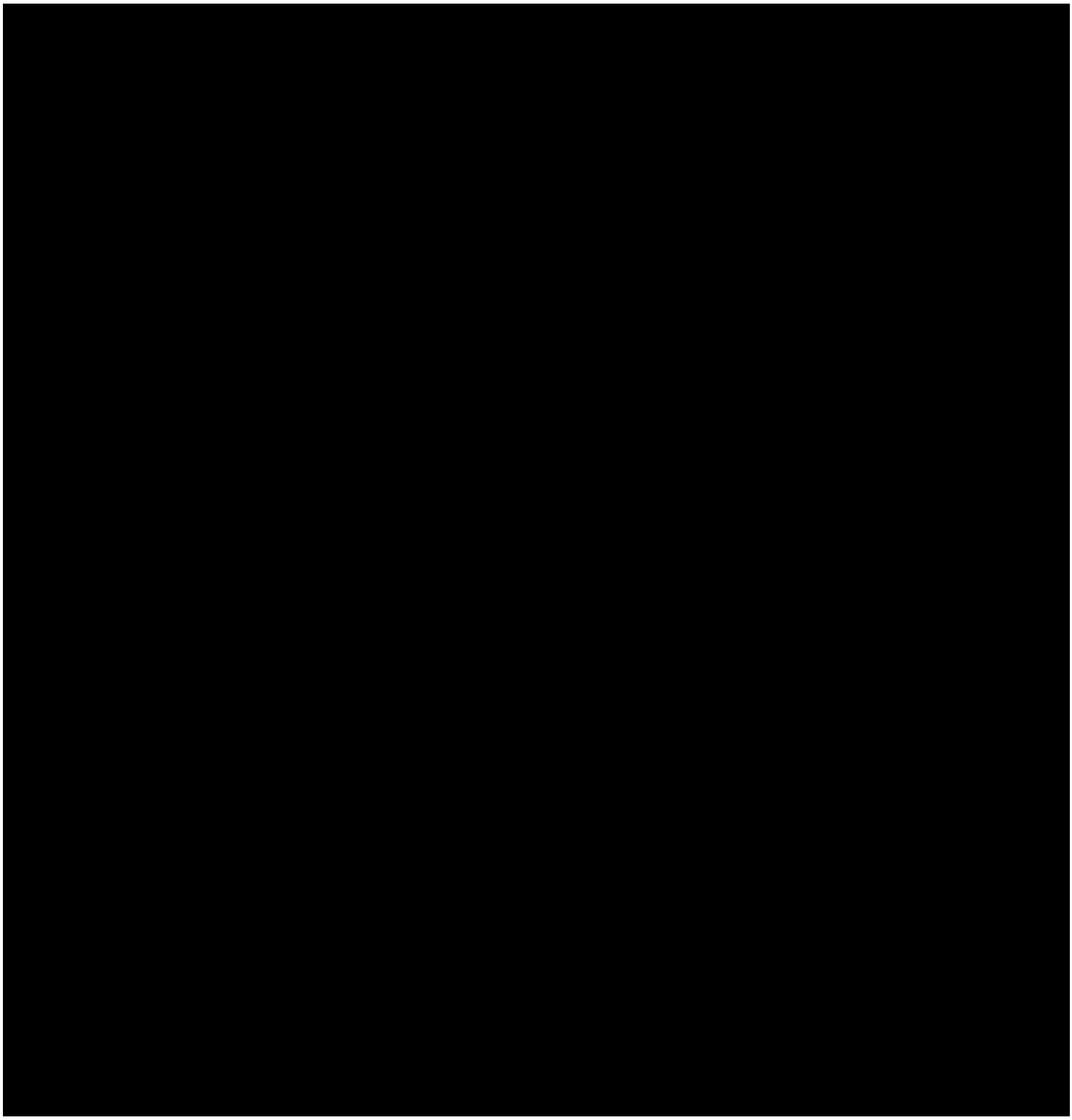
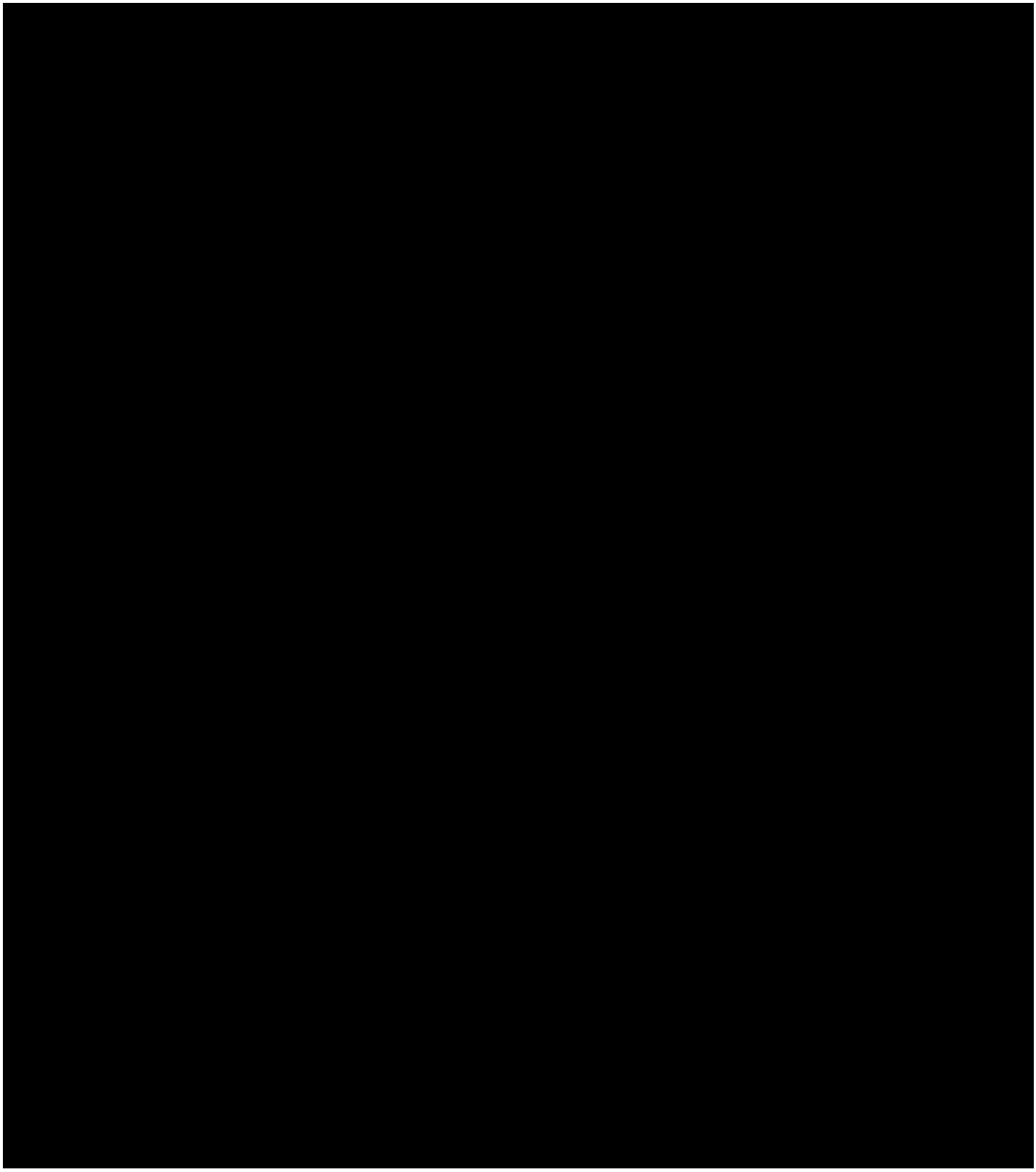
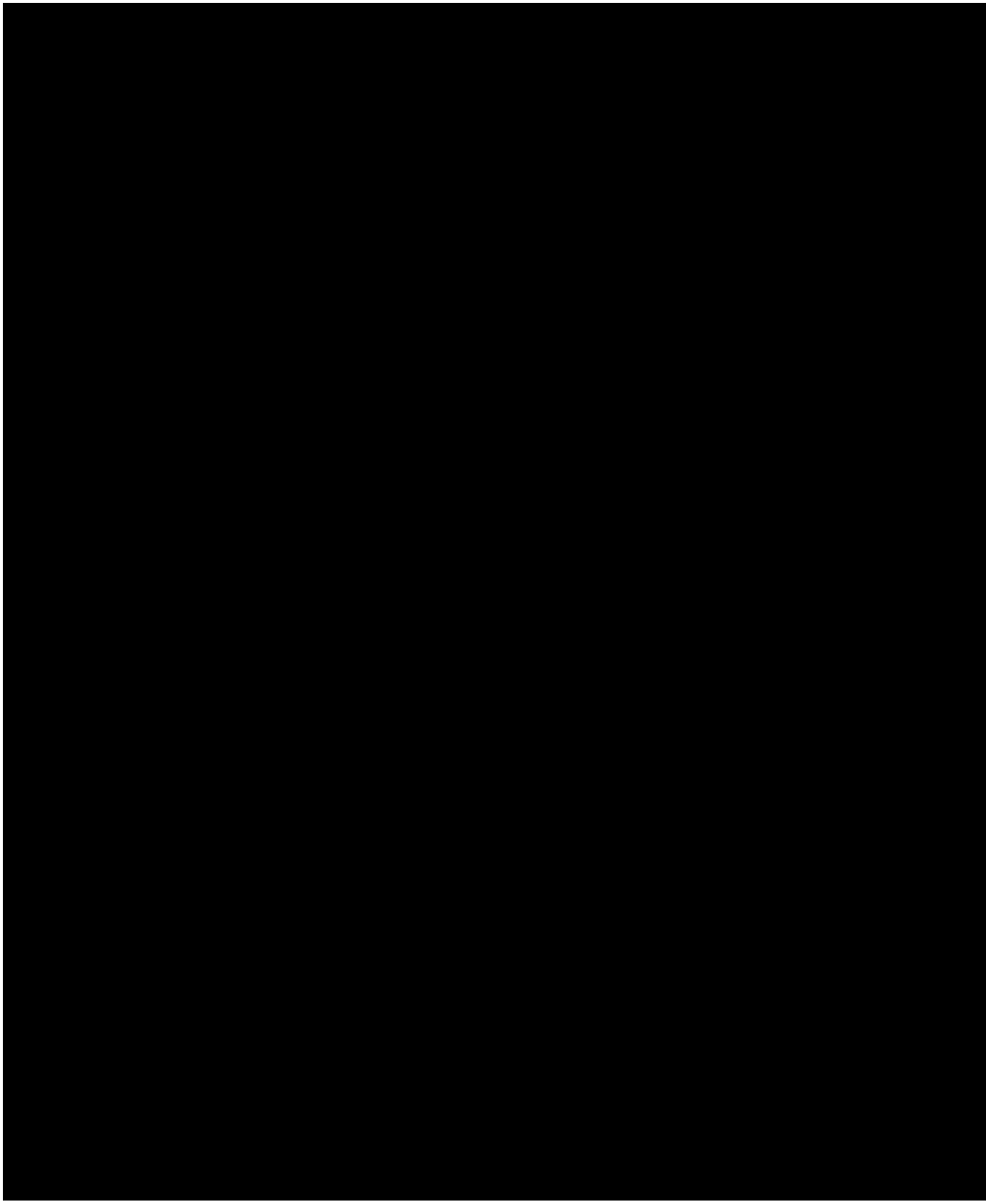
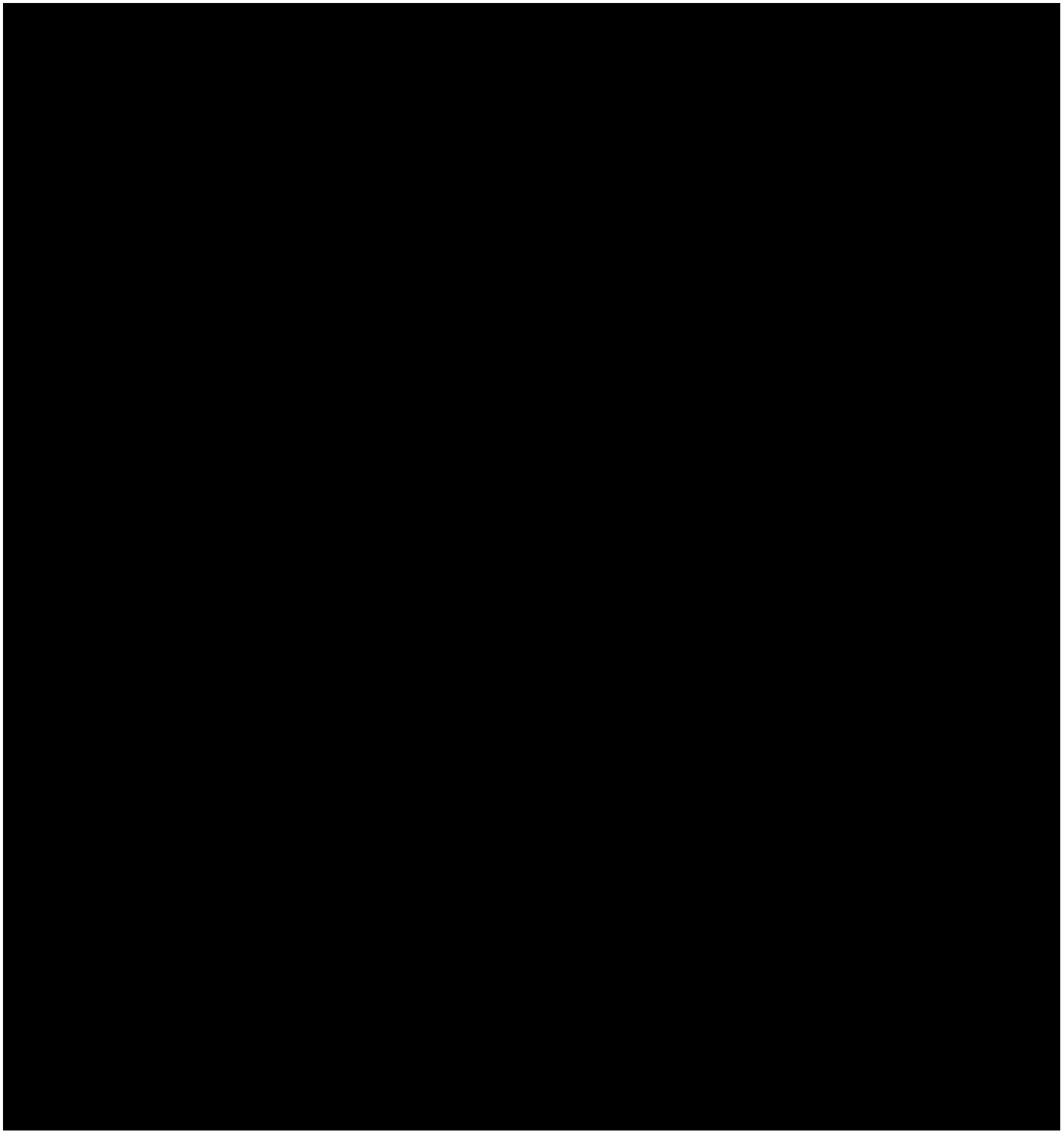


Figure 1-21 – Map showing the AOI, the AOR, and the four wells that were tied to the seismic data.









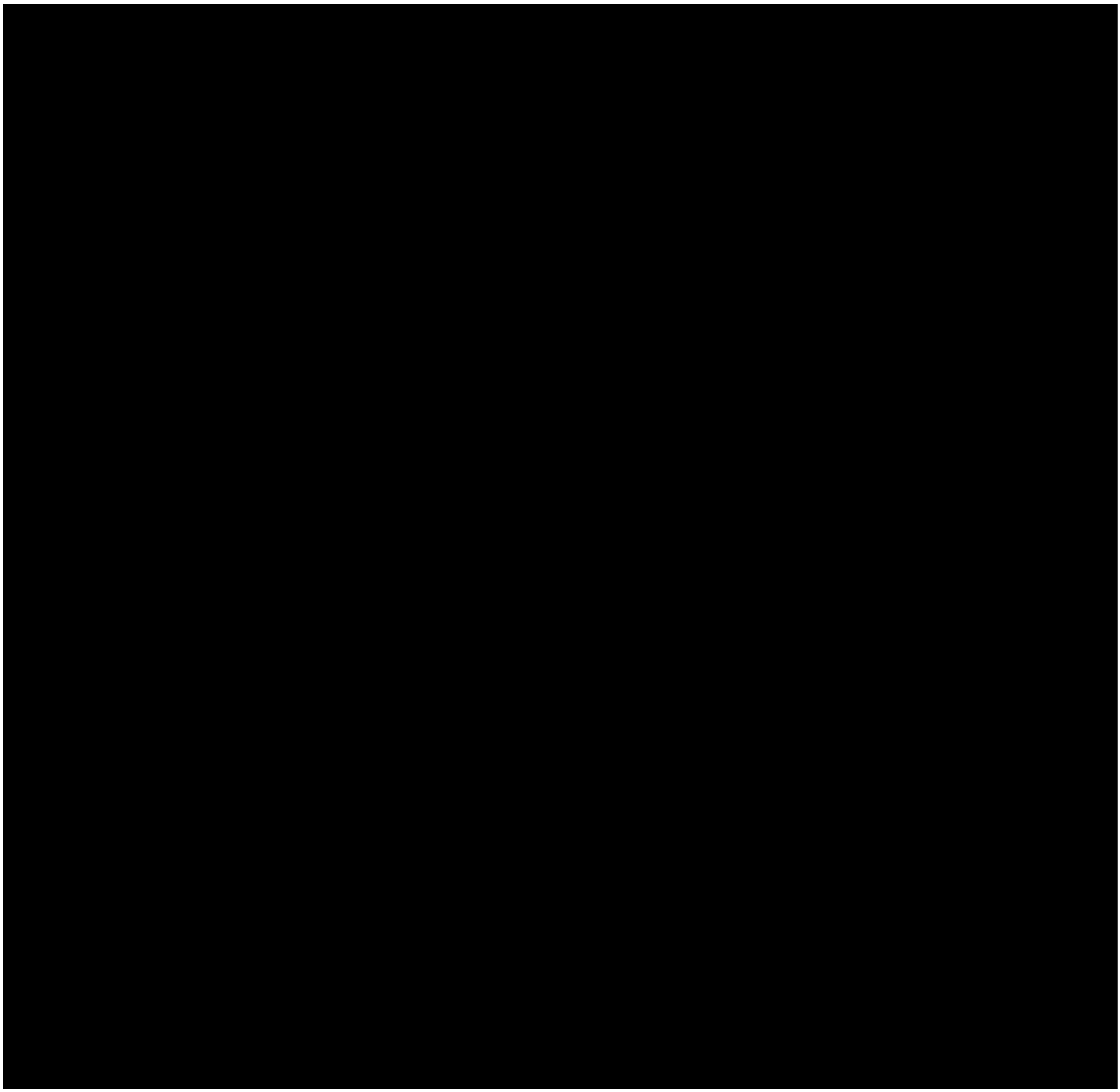
1.5.2 Faults

Based on the review of the seismic data, 5 interpreted extensional faults shallower than the Base LCZ were identified within the AOR, with 11 additional faults in the greater AOI. Maximum fault throws for the AOR faults are presented in Table 1-3, which outlines the maximum throw at the top of the UCZ and top of the Anahuac Shale—the two major sealing intervals in this permit application. The table also identifies the maximum displacement of each fault with its

corresponding formation (within the model). The discussion following Table 1-3 summarizes the fault throw as modeled through the evaluation of well tops and seismic data (geomodel), and finds that the throw within the UCZ and Anahuac Shale are not significant for the confining properties of these zones. Only one fault within the AOR (Fault 15) extends up to the Anahuac Shale, and its throw is much less than the total thickness of the confining zone.









Shale gouge ratio (SGR) calculations to predict the fault seal quality were performed on the faults within the AOR. The methodology selected for the SGR analysis was based on Yielding et al. (1997) (Figure 1-28), calculated using Equation 6, which utilizes the zone (lithology) thickness (h), clay fraction (Vshale, estimated from the SP log (see *Section 1.4.3.1*)), and the fault throw. Calibrations were based on subsequent methods provided by Manzocchi et al. (1999) and Sperrevik et al. (2002). These calibrations conclude that permeability along the fault is approximately 0.01 millidarcy (mD) or less with at least 50% clay fraction (Vshale).

(Eq. 6)

$$SGR = \frac{\Sigma(h * VShale)}{Fault\ Throw}$$

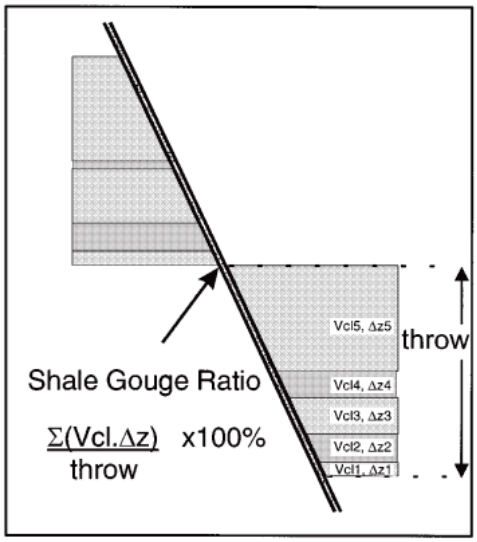


Figure 1-28 – Schematic of SGR Calculation from Yielding et al. (1997)

The SGR triangle plot (Figure 1-30) displays the calculated SGR value for a given well log, at increasing fault throw (x-axis). As an example, the Garth Co – 2 Vshale log is shown, here at 3 ft throw (approximating zero throw). As you increase throw (along x-axis) the calculated SGR values can be seen along the y-axis. SGR can also be calculated along the fault plane, utilizing the mapped surfaces and offset used in the geomodel. Examples are shown in Figures 1-31 through 1-33.

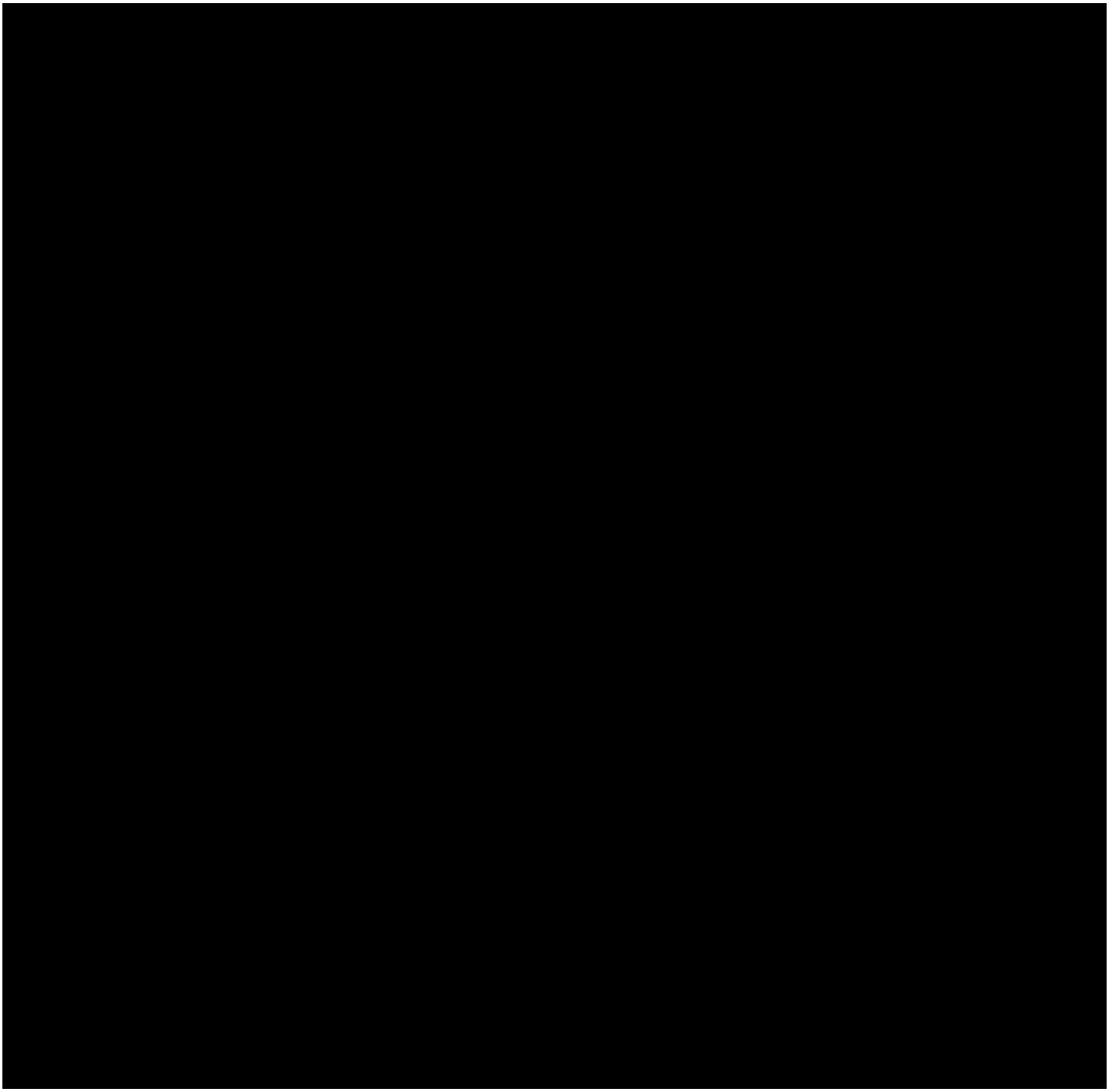
Fault 15 showed the most throw [redacted] feet at the top of the Anahuac Shale) within the AOR (Table 1-3), but significantly below the Anahuac Shale thickness (approximately [redacted] feet in the region). Fault 15 tips out in the lower Fleming 2 sand, well below the UCZ. The SGR analysis is shown in Figure 1-31.

[redacted]

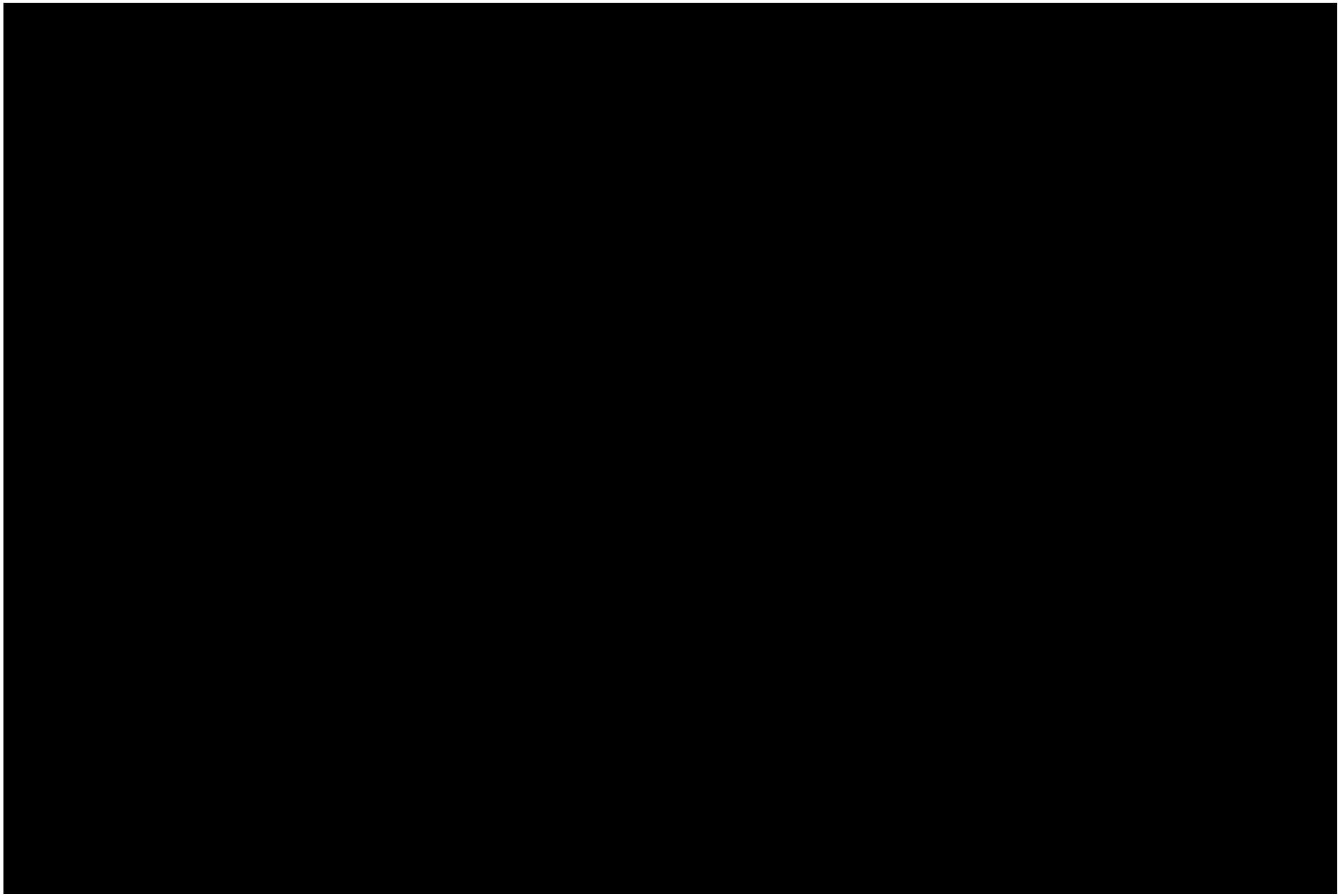


For the remaining four faults within the AOR that do not penetrate the Anahuac Shale, a review of the available evidence found no significant potential for the vertical migration of CO_2 or fluids via faults in the AOR—because (1) the four faults do not transect the UCZ or the Anahuac Shale; and (2) fault throw within the LCZ is much less than the thickness of the LCZ. Figures 1-30 through 1-33 display the fault seal analysis, where purple strata represent intervals with the highest calculated SGR (greater than 0.95). Figure 1-31 displays how the throw is much less than the Anahuac Shale thickness of approximately 270 feet in this region. In Figures 1-32 and 1-33, the fault shown is outside the AOR and will not interact with the CO_2 plume or critical pressure front.

In those figures, a gray scale represents the SGRs greater than 0.5, which is the conservative cutoff to determine whether a fault is sealing, based on Manzocchi et al. (1999) and Sperrevik et al. (2002). The yellow, orange, and red represent areas where faults are more likely to be transmissive. The following figures display the SGR analysis for two faults (Fault 13 (outside the AOR) and Fault 15 (within the AOR)) that offset one or both of the major sealing units.









Within the AOI extended geologic model review area—but outside of the AOR—11 additional faults were identified. The reviews of these faults are included to demonstrate an understanding of the local geology beyond the AOR, even though these faults will not impact the confinement of CO_2, since these faults do not intersect the AOR boundary. Throw characteristics of these faults located beyond the AOR are shown in Table 1-4. This information is provided for purposes of completeness here, including the SGR analysis completed on Fault 13 as discussed above; the CO_2 plume does not contact these faults.



In summary, five faults were identified and characterized within the AOR. The presented work supports the conclusion that there will be no vertical fluid migration along the single fault that extends across the Anahuac Shale seal (Fault 15), or the other four that terminate below the Anahuac. No fault within the AOR extends to the UCZ.

The local geologic setting is well-suited to the confident application of the SGR method to quantify the fault seal, because key geologic data requirements of the SGR method are locally met, as follows:

1. During fault movement, the stratigraphic section was relatively unlithified. This allows for both the entrainment of low-permeability shale into the fault zone and precludes the preservation of open fractures along the fault zone. The geologically young Gulf Coast stratigraphy is relatively unlithified at present and would therefore have been unlithified during any past fault motion.

2. An appropriate calibration of SGR to fault seal and permeability is available. While a specific local calibration is not available, the SGR approach was developed and calibrated within globally analogous geologic settings. To address the lack of local calibration, ExxonMobil applied a conservative scaling of SGR to seal development. A higher SGR value corresponds to better fault seal development. For example, ExxonMobil limited seal development to SGR values greater than [redacted], while published calibration expects the onset of seal development at SGR greater than [redacted].

3. The well-based stratigraphy used in the SGR calculation is representative of the stratigraphy directly adjacent to the faults under consideration. Several well logs are available within the AOI, the majority being within 0.25 miles of the analyzed faults under consideration. In addition to leveraging the nearest well, the stratigraphy from a selection of other local wells was used to constrain allowable ranges of near-fault stratigraphic character. Importantly, the key identified top seal (i.e., UCZ and Anahuac Shale) intervals are stratigraphically continuous across the region and therefore are present in all of the local wells.

4. Fault architecture is described adequately to identify relevant features and accurately characterize fault throw. Available seismic data are sufficient to identify and characterize significant faults within and surrounding the AOR. One general observation is that greater amounts of fault throw correspond to more likely potential to impact the UCZ. ExxonMobil factored in a 25% uncertainty margin on the fault seal analysis throw to acknowledge mapping uncertainties on Fault 13, for example—located outside the AOR. Additionally, smaller faults that are not identifiable on the available seismic surveys do not pose an additional seal uncertainty above the major faults, because they host lesser amounts of stratigraphic offset (throw) by default.

1.5.3 Bead Farm Co. – 1 Natural Fault and Fracture Assessment

No evidence of the potential for enhanced vertical permeability along natural fractures or faults in reservoir or sealing intervals was found in the core or borehole imagery from the Bead Farm Co. – 1 stratigraphic test well (*Appendix B-3*). As part of the site appraisal program, core from the Upper Frio, Anahuac Shale, and Lower Fleming formations was collected in the Bead Farm Co. – 1 well and was examined to document the presence of structural features in storage and sealing intervals. The objective of this evaluation was to identify whether natural structures exist that might facilitate the migration of CO_2 and/or brine vertically from the injection intervals in the Fleming and Frio sands toward overlying USDWs. No evidence of the potential for enhanced vertical permeability along natural fractures or faults in the reservoir or sealing intervals was found in the core or borehole imagery. Only a single minor fault (below seismic resolution) was observed in the core, and no natural fractures were identified, suggesting a negligible role for such features in altering expected flow behavior in the AOR.

Other natural structural features in the core are predominantly non-tectonic pedogenic slickensides; this classification is supported by multiple lines of evidence including host rock mineralogy, slickenside morphology, stratigraphic confinement, and random orientation. Pedogenic slickensides are anticipated, regionally extensive features that form prior to the burial of clay-rich soils and so are not related to any later phase of deformation that might affect fluid flow. None of the natural structural features identified in the analysis signal the presence of a pervasive tectonic or structural fabric across the Sunflower Project area, and none are considered effective pathways for fluid transmission from injection intervals to the USDW. Detailed descriptions of the natural structural features observed in Bead Farm Co. – 1 core are found in *Appendix B-3*.

1.6 Geomechanics

The information discussed in this section is from existing sources, such as publications and offset well data. Well data from the Bead Farm Co. – 1 and log data from existing wells within the Sunflower Project region were used to estimate the local stress conditions, elastic moduli, and fracture gradients of the injection and confining zones.

1.6.1 Local Stress Conditions

The World Stress Map is a "global compilation of information on the crustal present-day stress field maintained since 2009 at the Helmholtz Centre Potsdam GFZ German Research Centre for Geosciences."[1] The associated website presents the compiled regional stress data, including that for the project region as shown in Figure 1-34. Based on a review of the figure, the estimated maximum horizontal stress orientation is east-northeast at approximately 75°, approximately parallel with the coast. A normal faulting stress regime is inferred based on the World Stress Map.

[1] https://www.world-stress-map.org/

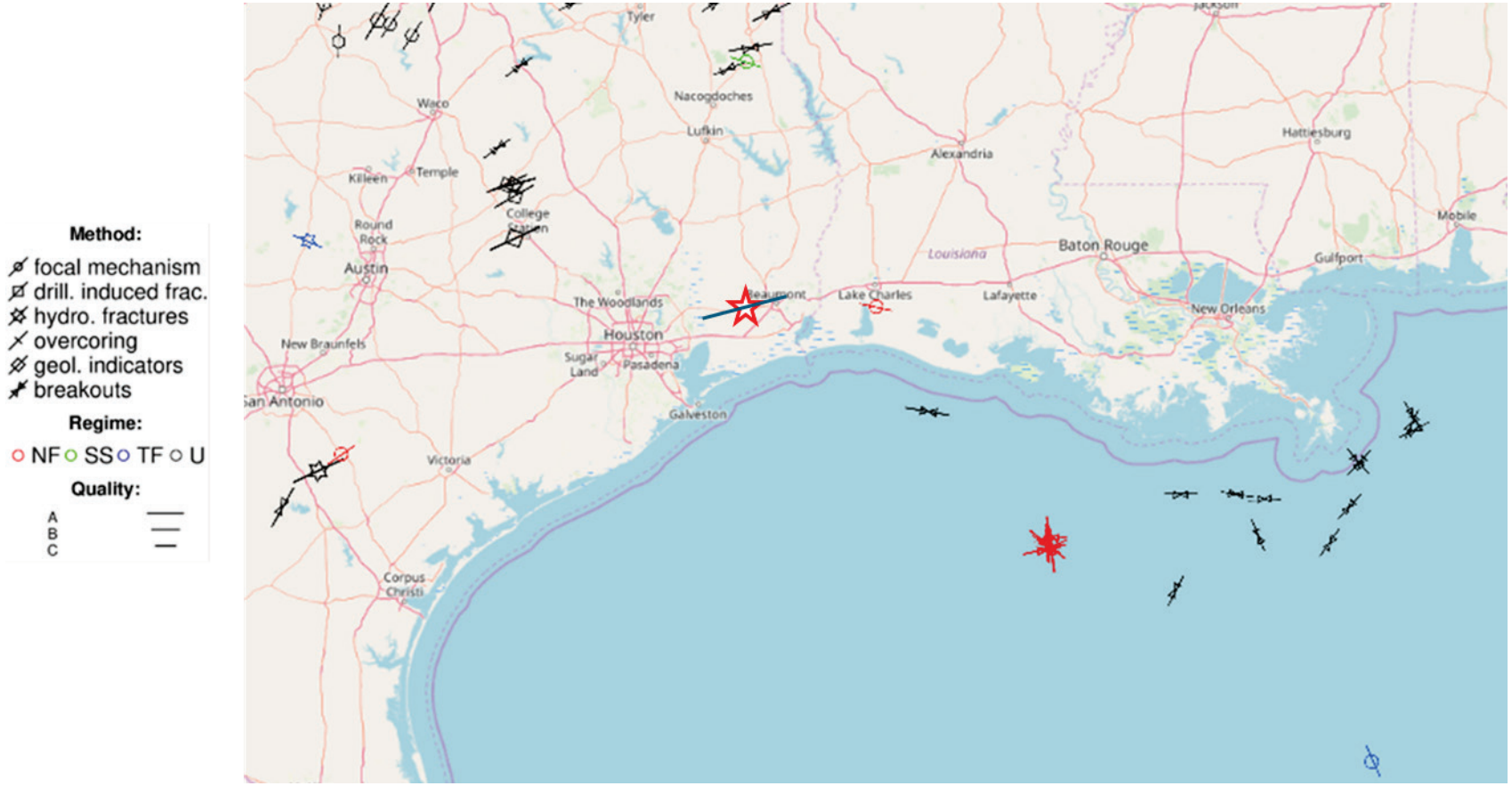


Figure 1-34 – World Stress Map showing the regional maximum horizontal stress orientation along the Texas Gulf Coast.
The red star indicates the Sunflower Project area and the dark blue line through the star indicates the interpreted orientation of the maximum horizontal stress.

1.6.1.1 Vertical Stress

Vertical stress was characterized primarily using bulk density logs from offset wells. Figure 1-35 shows the four existing wells with bulk density logs near or in the project region, together with the density log of Bead Farm Co. – 1. The figure indicates that formation bulk density in the area follows a similar trend, which can be approximated with a linear fit. Integrating the density log derived with the linear fit yields the overburden stress profile shown in Figure 1-35, which gives an average gradient of 0.933 psi/ft.



1.6.1.2 Minimum Horizontal Stress

The minimum horizontal stress, utilized to estimate the fracture gradient, was calculated in two steps: (1) calculating a Poisson's ratio using available dipole sonic log data; and (2) using Eaton's equation to estimate the minimum horizontal stress and calibrate with available measurements. ExxonMobil obtained dipole sonic log data from Bead Farm Co. – 1, where the compressional slowness (t_p) and shear slowness (t_s) log data are used in Equation 7 to calculate Poisson's ratio (ν):

(Eq. 7)

$$\nu = \frac{0.5\left(\frac{t_s}{t_p}\right)^2 - 1}{\left(\frac{t_s}{t_p}\right)^2 - 1}$$

An example using the following input parameters (Table 1-5) was presented in Equation 7 at a depth of 3,644 feet MD (within Fleming Sand 1). Using the input values from Table 1-5, the resulting Poisson's ratio is equal to 0.401.

Table 1-5 – List of Poisson's Ratio Input Values at 3,644 Feet MD

Input Parameter	Value (units)	Source
t_p	[redacted]	DTC Log from Bead Farm Co. – 1
t_s		DTS Log from Bead Farm Co. – 1

*DTS – shear sonic slowness

Minimum horizontal stress is calculated using Eaton's equation, shown in Equation 8 where v is Poisson's ratio, S_V is the vertical stress, P_p is the pore pressure (approximately [redacted] psi/ft based on test data from Bead Farm Co. – 1), while parameter C is a constant for calibration (tectonic stress) with available data.

(Eq. 8)

$$S_{hmin} = \frac{v}{1-v}(S_V - P_p) + P_p + C$$

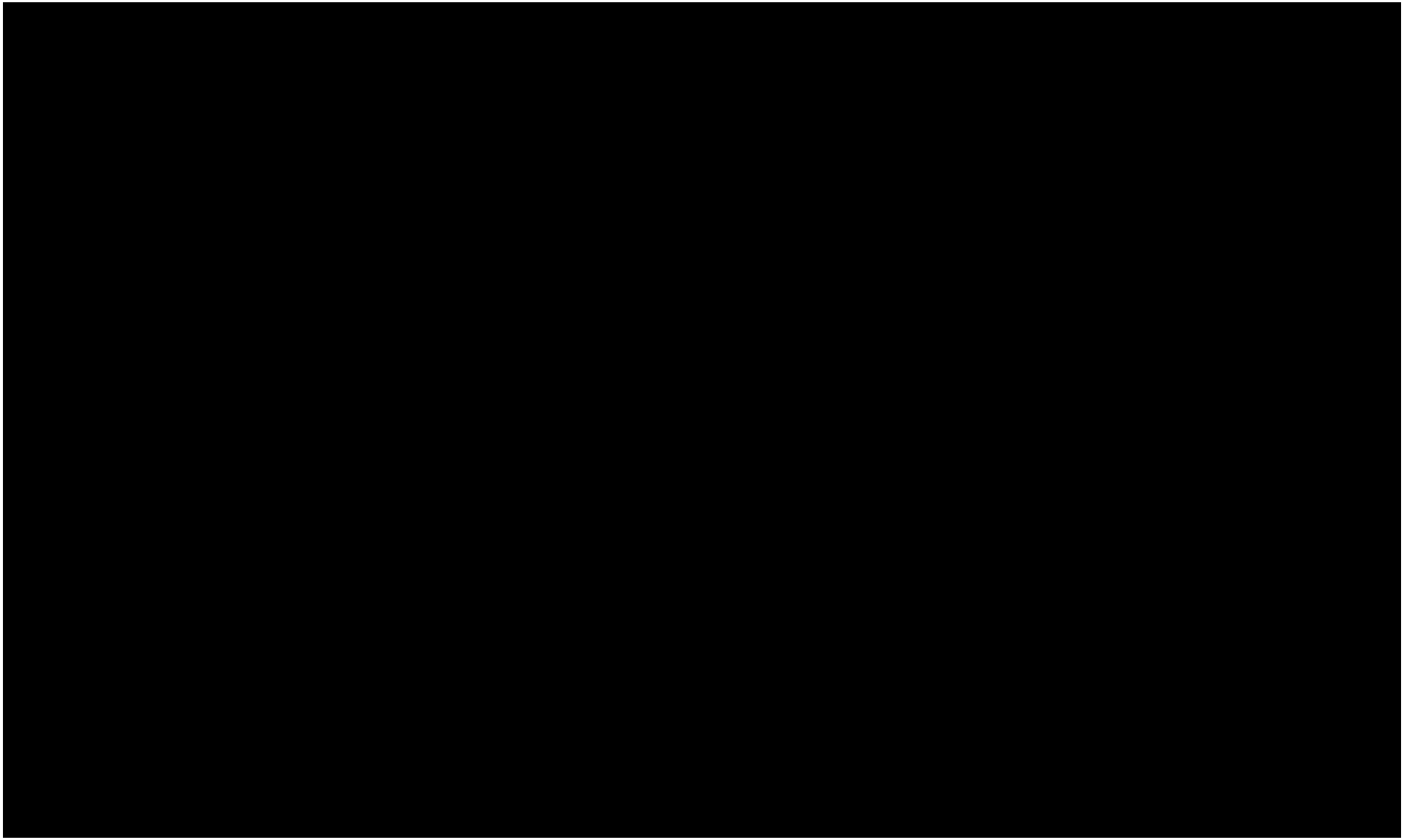
Input parameters, shown in Table 1-6, were used for Equation 8 at a depth of 3,644 feet MD within Fleming Sand 1.

Table 1-6 – List of Minimum Horizontal Stress Input Values

Input Parameter	Value (units)	Source
v	[redacted]	Equation 7
P_p	[redacted]	Measured pressure gradient from Bead Farm Co. – 1
S_V	[redacted]	Density log from Bead Farm Co. – 1
C	[redacted]	Calibration from offset formation integrity test data and step-rate tests in Bead Farm Co. – 1

The resulting minimum horizontal stress using the values in Table 1-6 is equal to [redacted]. Note that the calibration is performed with available formation integrity tests in offset wells and step-rate tests performed in the injection intervals of Bead Farm Co. – 1.

The result of these calculations shows the average best estimate, within the relevant formations, of the minimum horizontal stress for the stratigraphic test well to be [redacted] psi/ft, with depth-dependent variations along the well, shown in Figure 1-36. Log data in this figure presents gamma ray, the sonic curves, the calculated Poisson's ratio curve, and the resulting minimum horizontal stress gradient curve.



1.6.2 Elastic Moduli

Assuming that rock properties are isotropic, the dynamic Young's modulus (E_{dyn}) can be calculated using shear wave velocity and the Poisson's ratio (ν) as follows in Equation 9.

(Eq. 9)

$$E_{dyn} = 2\rho V_s^2(1+\nu)$$

where ρ is rock density and V_s is the shear wave velocity. As an example, the following input parameters (Table 1-7) were used in Equation 9 at a depth of 3,644 feet MD in Bead Farm Co. – 1 and gave a dynamic Young's modulus of [redacted]

Table 1-7 – Dynamic Young's Moduli Input Values

Input Parameter	Value (units)	Source
ν	[redacted]	Equation 7
ρ	[redacted]	Density log from Bead Farm Co. – 1
V_s	[redacted]	DTS log from Bead Farm Co. – 1

*m/s – meters per second

A linear dynamic-to-static transform was used to convert dynamic Young's modulus into static Young's modulus (E_{sta}) as shown in Equation 10.

(Eq. 10)

$$E_{sta} = \mathrm{k}E_{dyn}$$

where *k* is a simple scaling factor.

Laboratory tests have been performed on core samples collected from Bead Farm Co. – 1, and the measured Young's modulus and Poisson's ratio have been used to calibrate the values derived from sonic logs. A uniform scaling factor of *k* equal to 0.70 was used to match the log-derived static modulus in Bead Farm Co. – 1 to the measured values. An example of the workflow utilizing density and sonic logs to calculate Poisson's ratio and the Young's modulus is shown in Figure 1-37. The average Young's moduli in the proposed injection zones are summarized in Table 1-8.



Table 1-8 – Average Young's Moduli and Poisson's Ratio Derived from Logs

Formation	Young's Modulus (MMpsi)	Poisson's Ratio
Fleming Sand 2		
Fleming Sand 3		
Upper Frio Sand 1		

1.6.3 Fracture Gradient

1.6.3.1 Impact of the Sour Lake Salt Dome

The Sunflower Project area is 5-10 miles away from the Sour Lake Salt Dome in Hardin County. Since salt cannot sustain shear stress, the presence of the salt dome may disturb the regional stress state. A radial finite element model was built to understand the impact on the stress profile and fracture pressure at the proposed injection well locations, which are approximately 6.5 miles from the center of the dome.





Figure 1-38 shows that the presence of the salt dome does have a noticeable effect on stress distribution in nearby rock volumes. However, that effect diminishes with increasing distance from the salt dome. At the proposed injection well locations, as shown in Figure 1-39,

the salt dome has a very small effect on the stress state in the Fleming Formation but increases the minimum horizontal stress in the Frio by approximately 200 psi. For conservatism, the stress profiles from Bead Farm Co. – 1 (without the salt dome effect) will be used to calculate fracture pressure in both the injection zones and the confining zones.

1.6.3.2 Injection Zone

As discussed previously, Eaton's equation was used—with a measured pore pressure gradient of [redacted] psi/ft, to estimate the minimum horizontal stress in both sand and shale—and guided the estimate of the injection-zone fracture gradient. The calculated stress profile has been calibrated with formation integrity tests (FITs) from offset wells and step-rate tests (SRTs) from Bead Farm Co. – 1. For injection zones with SRTs, the measured fracture pressure is used as the fracture pressure for the entire zone. For injection zones without SRT data, the fracture pressure is calculated from the calibrated stress profile over the sandy intervals within the formation. The measured and calculated fracture gradients are shown in Table 1-9.

Table 1-9 – List of Fracture Gradients in the Injection Zones

Formation	Fracture Gradient (psi/ft)	Method
Fleming Sand 2	[redacted]	Step-rate test
Fleming Sand 3	[redacted]	Interpreted from calibrated log-based stress profile
Upper Frio Sand 1	[redacted]	Step-rate test

1.6.3.3 Confining Zone

Similarly, fracture gradients in the confining zone can also be evaluated from Figure 1-39. The calculated average values are shown in Table 1-10.

Table 1-10 – List of Fracture Gradients in the Confining Zones

Formation	Fracture Gradient (psi/ft)	Method
UCZ	[redacted]	Interpreted from calibrated log-based stress profile
Anahuac Shale	[redacted]	Interpreted from calibrated log-based stress profile

1.6.3.4 Maximum Injection Pressure Calculation

The maximum bottomhole injection pressure must not exceed 90% of the fracture pressure of the injection zone, to reduce the potential for existing fractures to propagate during normal operations. For simplicity and to be more conservative, a uniform pressure gradient of 0.6 psi/ft (less than 90% of fracture gradient) is chosen to calculate maximum bottomhole injection pressure for each injection interval. A constant reference depth (approximately middle of each perforated interval) is also used for each interval across all three injectors as perforation depths

only vary slightly between wells. The calculated maximum bottomhole injection pressures for each interval are shown in Table 1-11, which will be used to constrain CO_2 plume modeling. Note that these estimates may be revised based on site data.

Table 1-11 – Summary of Maximum Bottomhole Injection Pressures

Stage	Injection Interval Reference Depth (ft TVDSS)	Maximum Allowed BHP (psi) Assuming 0.6 psi/ft, less than 90% Fracture Gradient	Fracture Gradient (psi/ft)
1	Frio Sand 3 @ -7,500 ft	4,500	[redacted]
2	Frio Sand 2 Lower @ -7,000 ft	4,200	
3	Frio Sand 2 Upper @ -6,600 ft	3,960	
4	Frio Sand 1 @ -6,250 ft	3,750	
5	Fleming Sand 3 Lower @ -5,000 ft	3,000	[redacted]
6	Fleming Sand 3 Upper @ -4,600 ft	2,760	

*BHP – bottomhole pressure

1.7 Baseline Geochemistry

1.7.1 Assessment of Injection Interval and Confining Zone Geochemical Reactions

The evaluation of the injection zone fluid geochemistry and mineralogy includes an assessment of the compatibility of the CO_2 stream with subsurface conditions. The objective of this assessment was to predict how storage and injectivity may be impacted by potential geochemical reactions, using regional brine and mineralogical data and kinetics-based reaction-path geochemical models. The following discussion describes the potential for mineral dissolution and precipitation reactions to occur in the presence of a CO_2-saturated brine and the impact of mineral precipitation and dissolution on the total change in mineral volume and the pH of the brine phase. In all models for each formation, the changes in mineral volume as a result of the chemical reactions that occur between the formation mineralogy and the CO_2-saturated brine were predicted to occur at a magnitude that is not expected to significantly impact either the injectivity or storage capacity of the reservoirs or the integrity of the sealing units.

1.7.2 Summary of Available Geochemical Brine Data

The baseline geochemical data for fluids in the injection intervals were obtained from Bead Farm Co. – 1 and compared with the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database (Blondes et al., 2023) as shown in *Appendix B-4*. This database contains information on the likely range of geochemical parameters and the nature of connate formation brines present in the proposed injection intervals. The major cation and anion composition of water samples used to derive the starting fluid chemistries incorporated into the models described below are provided in *Appendix B-4*, along with produced water chemistry from Jefferson and Liberty Counties, Texas (Blondes et al., 2023).

Cross plots of chloride (Cl^-) versus pH, bromide (Br^-), sodium (Na^+), magnesium (Mg^{2+}), calcium (Ca^{2+}), bicarbonate (HCO^{3-}), and potassium (K^+) ions are provided in Appendix B-4. Note that a limited number of apparent anomalous produced water samples were not plotted on this figure. In general, the major cations and anions of the water samples from the Bead Farm Co. – 1 well are consistent with regional trends, with the exception of Ca^{2+} and Mg^{2+}, which tend to be slightly higher in concentration relative to the regional trend at similar Cl^- concentrations. Based on the consistency with regional data, it is believed that the chemical composition of the fluid samples from Bead Farm Co. – 1, modeled to be in equilibrium with the expected formation mineralogy, are representative of the subsurface fluids anticipated to be encountered in the AOR formations of interest. Figure 1-40 shows the locations of the wells used for regional comparison.

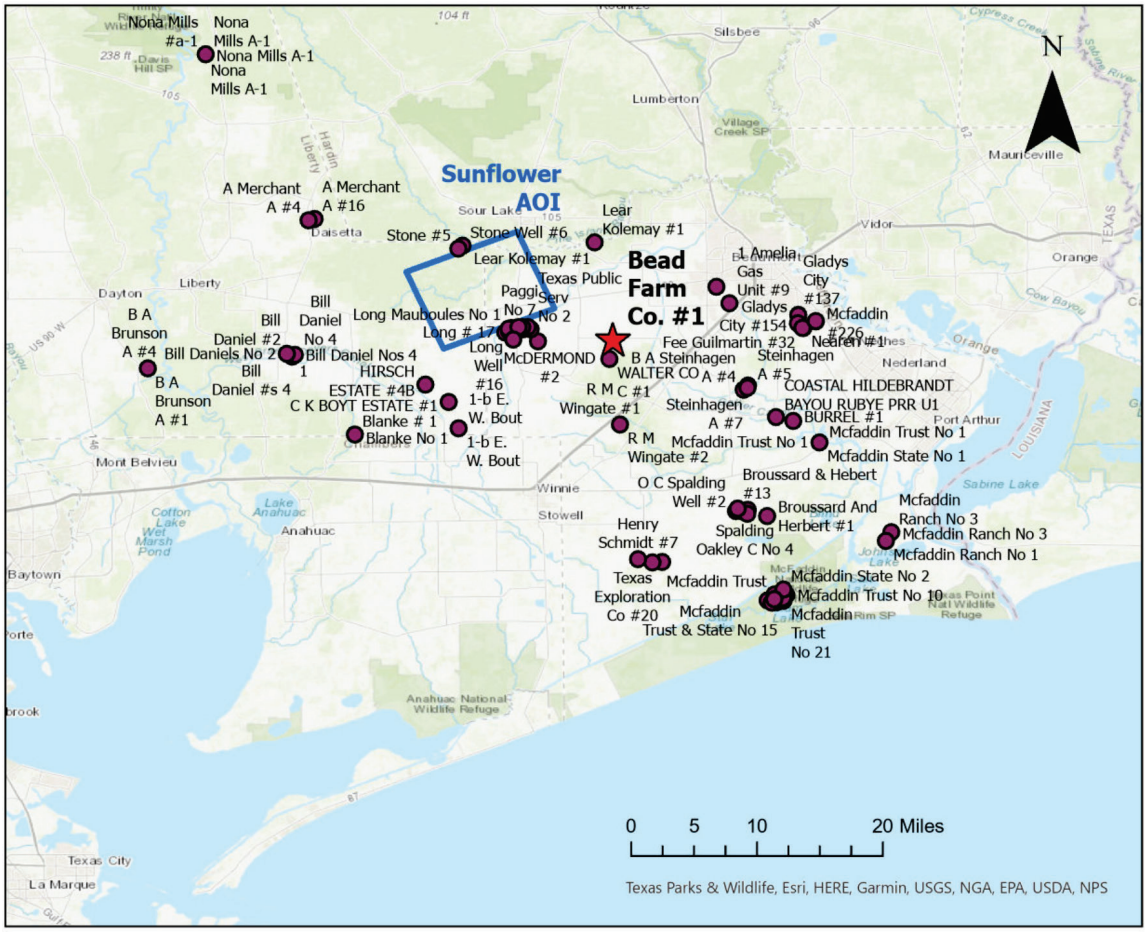


Figure 1-40 – Locations of Preexisting Produced Water Data

Elemental analysis of formation solids in the UCZ, Fleming Sand 2, Fleming Sand 3, Anahuac, and Upper Frio was performed using X-ray fluorescence (XRF), Appendix B-4. Many trace elements, including lead and uranium, are below detection limits (BDL). Arsenic was found to be BDL (less than 20 parts per million) in most samples from the injection intervals and only slightly above detection limits in the confining zones. Note that cuttings samples were used for XRF and, as such, the barium concentration is likely contaminated by barite drilling additives. Also, ruthenium concentrations were likely influenced by bleed from the rhodium tube used in the instrument.

1.7.3 Modeling Approach for Potential Geochemical Reactions

The potential for brine-mineral-CO_2 interactions was modeled to assess the potential alteration of both the reservoir and sealing lithologies during and following CO_2 injection. The injection of CO_2 results in a decrease in pH as the CO_2 dissolves into the brine phase—forming carbonic acid, which dissociates rapidly to form bicarbonate and hydrogen ions. This decrease in pH shifts the brine-mineral system in disequilibrium, and subsequent mineral phase dissolution and

precipitation reactions occur—increasing the pH and moving the system toward equilibrium with the altered brine chemistry. For example, anticipated fluid-mineral reactions include the dissolution of feldspars to precipitate kaolinite and dawsonite, and the dissolution/precipitation of carbonates such as calcite (Gaus, 2010; Shiraki and Dunn, 2000; Tang et al., 2021).

1.7.3.1 Reaction-Path Models

Kinetics-based, reaction-path models were developed using The Geochemist's Workbench (GWB) (Bethke et al., 2022) to trace mineral stability boundaries as chemical reactions progress and provide information on fluid evolution and mineral precipitation and dissolution. The models utilized here use a rate law expression and pH-dependent rate constants described in detail in Palandri and Kharaka (2004). Activation energies and neutral, acid, and base mechanism-rate constants used in the models are provided in *Appendix B-4*.

The two major inputs for these models are brine chemistry and formation mineralogy. The composition of the injectate is assumed to be pure CO_2 for model simplicity. As the models presented are only concerned with the impact of CO_2 on the brine-mineral system, and the CO_2 is likely to represent the vast majority of the injectate, this assumption is not expected to impact the results significantly. The formations modeled were all major formations within the Fleming injection interval (Fleming Sand 2 and Fleming Sand 3), the Frio injection interval (Frio Sand 1, Frio Sand 2, and Frio Sand 3), and the UCZ and Anahuac Shale confining zones.

Model Input: Brine Chemistry

The brine chemistry from the Bead Farm Co. – 1 well provided in *Appendix B-4* was used as the starting point for the reaction-path models for each modeled formation. Starting brine chemistry for the Frio Sand 2 and 3 was not available. As such, the brine chemistry of the Frio Sand 1 was used to approximate this fluid. For the UCZ and Anahuac Shale, the starting brine chemistry used was that of the permeable zone below the formations (Fleming Sand 2 and Frio Sand 1, respectively). This was done because the anticipated reactions involving CO_2 would occur at the boundary of the sealing and reservoir units, involving the CO_2-reservoir brine.

The fluid samples were assumed to be in equilibrium with quartz and feldspars based on the mineralogy; however, the analysis of the brines did not provide the concentrations of aluminum ions (Al^{3+}) or dissolved silica ($SiO_{2\,(aq)}$). To estimate these fluid components, the SpecE8 module from GWB was used, setting $SiO_{2\,(aq)}$ and Al^{3+} concentrations to be controlled by the equilibrium solubility of quartz and K-feldspar, respectively, with the brines at the temperature of the formations. This equilibration step also slightly alters the initial brine chemistry and total dissolved solids (TDS) to maintain charge balance. The equilibrated fluid compositions from SpecE8 used in the kinetics-based, reaction-path models are provided in *Appendix B-4* along with TDS, formation temperature, and pH.

Model Input: Formation Mineralogy

The representative primary mineralogy for each formation used in the geochemical models was averaged based on XRD mineralogical data from the Bead Farm Co. – 1 well. The averaged primary mineralogy used in the geochemical models is presented in *Appendix B-4*. Note that an average of the XRD results for the Frio Sand 1 was used to represent the Frio Sand 2 and Frio Sand 3.

The averaged primary mineralogies represent at least 99% of the XRD mineralogy results and also represent the major minerals that are likely to participate in chemical reactions with a CO_2-saturated brine in the subsurface at the injection site. Simplifications of the mineralogy are necessary to maintain computational efficiency. The process of selecting minerals to represent the formation mineralogy in the geochemical models was developed through a step-by-step rationalization process, consistent with a typical geochemical modeling approach. Framework grains (e.g., quartz and feldspars) and carbonates were selected. Bulk clay was chosen to be represented by smectites, illite, and kaolinite. Pyrite/marcasite was included, when present, to assess concerns of the dissolution of sulfides.

Minerals that were not consistent throughout the formation, or minerals not expected to significantly impact the modeling results (such as anatase), were not included in the models. When present, marcasite was represented as pyrite in the geochemical models. Albite was substituted for "plagioclase" and mg-biotite was substituted for "mica." The mixed, interlayered illite/smectite was subdivided into illite and smectite portions using the smectite abundance provided in the XRD results. Smectite type or composition was not distinguished in the XRD results. As such, the method by which Xu et al. (2006) estimated Na- and Ca-smectite using the weight percent ratio of Na and Ca in the formation fluid was used.

Simulating Initial Brine-Mineral Equilibrium and CO_2 Reactions

Before adding CO_2 to the brine-mineral system, the averaged brine chemistry was equilibrated with the formation mineralogy over a 3,000-year model simulation period in the React module of GWB.

The React module was also used to simulate CO_2 injection into the initial brine-mineral equilibrated system. The amount of CO_2 gas dissolved into the brine solution was limited to brine's CO_2 solubility at subsurface conditions (pressure, temperature, and brine salinity) for each modeled interval. The CO_2 solubility was calculated using Duan and Sun (2003). The CO_2 was added to the model until the solubility limit was reached, at which point the CO_2 gas fugacity was fixed to simulate a system of a CO_2-saturated brine that is in contact with a separate CO_2 fluid phase. This is expected to occur quickly and, as such, this variable CO_2 gas-fugacity step was modeled to occur within 0.05 years.

The chemical reactions that occur during the fixed CO_2 gas-fugacity model step were simulated for a 100-year period. During this time, secondary minerals may become saturated in the brine phase and precipitate. The secondary minerals used in the models were chosen based on the saturation index of various minerals at the end of a preliminary fixed-fugacity model for each

formation. The secondary minerals with a saturation index greater than unity were given proper kinetics, and the fixed fugacity model was rerun, allowing these phases to precipitate. *Appendix B-4* lists the observed secondary minerals for each of the seven models, including magnesite and siderite, which are carbonate minerals and store CO_2 in their chemical structure.

The GWB default thermo.tdat database was modified using logKcalc (Dick, 2024) to extrapolate the equilibrium constants of relevant minerals from atmospheric pressure to the formation pressure for each modeled formation. This was done because using the atmospheric pressure equilibrium constants can introduce significant error into the modeled results for systems expected to be at elevated pressures (Allen et al., 2005).

Trace metal mobilization as a result of CO_2 dissolution into formation brine was assessed using reaction-path geochemical models tracing the desorption of zinc (Zn^{2+}), cobalt (Co^{2+}), and nickel (Ni^{2+}) ions from the surface of iron oxide minerals during CO_2 injection. These elements were chosen based on the water analyses collected at various depths from the Bead Farm Co – 1 well.

1.7.4 Summary of Geochemical Modeling Results and Findings

The geochemical models were used to simulate the potential for significant mineral precipitation and dissolution to occur in the injection and confining intervals. *Appendix B-4* presents the geochemical modeling results for each formation. The results are plotted as change vs. time for these relationships:

- Mineral weight percent change vs. elapsed time
- The pH of the brine vs. elapsed time
- The total mineral volume change vs elapsed time

An example of the geochemical model results for trace metal mobilization is also provided in *Appendix B-4*.

The following findings are apparent from the review of the geochemical models and the trends in mineral phase dissolution and precipitation. None of the trends were found to have a material impact on the potential storage characteristics of the Sunflower Project site:

- All geochemical models predict that, during the interaction of CO_2-saturated brine and formation mineralogy, both precipitation and dissolution of minerals occur at a magnitude that does not alter the volume of the minerals significantly enough to result in a change to either the CO_2 sequestration capacity of the reservoir formations or the integrity of the sealing formations. In all cases, the total change in mineral volume percent (vol%) was less than 0.6.

- The presence of a significant quantity of calcite (7 weight percent or greater) in the primary mineralogy is predicted to buffer the pH of the system to a steady-state within approximately 5 years. This pH value will remain relatively constant until the brine is no

longer in contact with the separate CO_2 phase. Though not modeled here, it is expected that the CO_2-saturated brine-mineral system without a separate CO_2-rich fluid phase would tend toward higher pH values (see, for example, Zerai et al., 2006).

- The trace metal desorption trends were directionally similar in all water samples modeled, with differences in the magnitude of change resulting from different starting compositions, temperatures, and pH. The concentrations of Zn^{2+}, Co^{2+}, and Ni^{2+} increase following CO_2 injection due to desorption from iron oxide surfaces accompanying the rapid drop in pH, followed by a decrease in concentration of each element as the brine pH stabilizes. Ni^{2+} showed the largest increase in concentration associated with desorption, in some cases doubling the Ni^{2}+ concentration of the brine. There is no significant difference between the pre-injection and modeled final concentration of Zn^{2+} and Co^{2+}.

1.7.5 Potential Uncertainty in Geochemical Reaction Path Model

A review of the input data and geochemical model performance identified the potential for uncertainty to influence the model results. As outlined below, steps were taken to reduce the potential for the uncertainty in site characterization and modeling approach to impact the overall findings of the geochemical model.

There is uncertainty involved in using laboratory-derived kinetics to model natural systems. Laboratory-derived rate constants tend to be several orders of magnitude larger than what is observed in nature (Brantley, 1992). This is due to several factors, such as limited contact of fluid with minerals, and surface area impacted by natural processes. Other potential sources of error introduced by the use of kinetics include reactions occurring at laboratory conditions that are not predominate in nature, and the impact of bacteria on reaction rates (Bethke, 2022). However, as no significant impact of mineral precipitation/dissolution was predicted by the models using these laboratory-derived kinetics, it is not expected that the natural system would be significantly impacted either, as the natural rates are likely to be slower (Brantley, 1992).

Modeling brines with a high salinity is difficult for several programs, including GWB (Bethke, 2022; Allen et al., 2005)—which has a default limitation on the ionic strength of the brine used as the basis set of 3 molal. This is sufficient for all models used here. Further, to account for the salting-out effect of CO_2, the ion size parameter of $CO_{2\,(aq)}$ was adjusted to -0.5 (Allen et al., 2005; Zerai et al., 2006)

The analytical results for brine samples did not include dissolved SiO_2 and Al^{3+}, typically derived from the dissolution of quartz and feldspars. Estimated equilibrium concentrations were derived using the SpecE8 module from GWB. This approach has been shown to provide reasonable initial concentrations for reaction-path modeling. The resulting precipitation and dissolution of mineral phases were reviewed to reduce the potential for unrealistic precipitation simulated by the model. None were found.

1.7.6 Summary of Predicted Geochemical Reactions

A series of geochemical scenarios were modeled to provide predictions on the compatibility of the injection and sealing intervals expected to be encountered in the AOR, with the injection of CO_2 and the subsequent CO_2-saturated brine. These models used regional fluid chemistry and XRD mineralogical data representative of the formations of interest. All models demonstrated that, during the interaction of the CO_2-saturated brine and the formations of interest, both precipitation and dissolution of minerals are predicted to occur at a magnitude that does not alter the volume of the minerals significantly. As such, no significant change in mineral or pore-space volume in the formations was predicted by the geochemical models.

1.8 Hydrology

The following hydrologic review of Jefferson and Liberty counties was conducted for ExxonMobil's Sunflower Project area to properly characterize and protect potential USDW resources in the state of Texas. The study reviewed publicly available material published and reported by the Texas Water Development Board (TWDB), including water well and groundwater information. Reports published by the TWDB contributed to the hydrologic evaluation and were utilized to source figures included in this section.

The investigation identified one major aquifer with freshwater potential in the vicinity of the Sunflower Project—the Gulf Coast aquifer (Figure 1-41). No minor aquifers were reported to have freshwater potential near the project (Bruun et al., 2016). The Gulf Coast aquifer is present across Jefferson and Liberty counties and represents the primary source of fresh groundwater for municipal, industrial, and irrigation purposes. According to the TWDB, neither Jefferson nor Liberty counties fall within any current Underground Conservation Districts (Davidson and Mace, 2006).

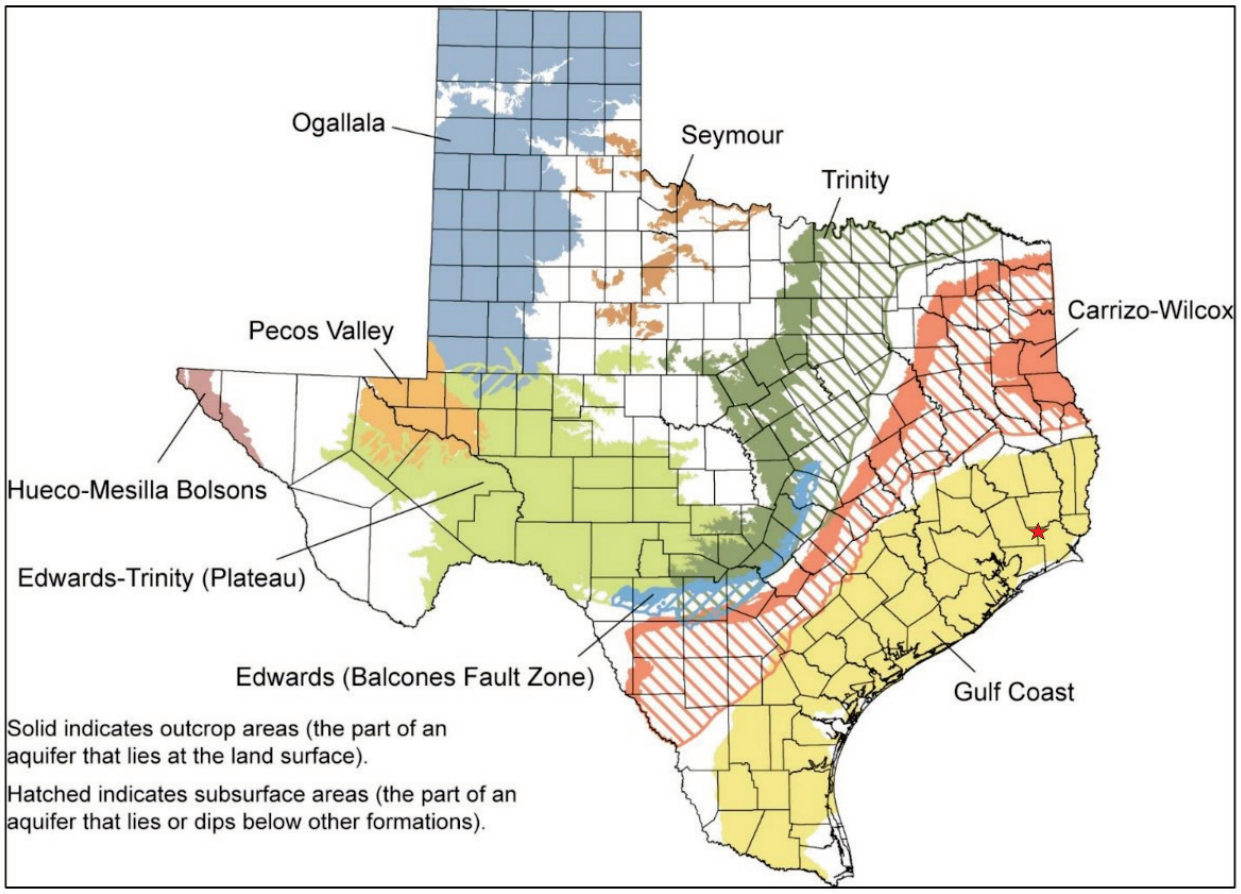


Figure 1-41 – Major aquifers of Texas. The red star represents the approximate location of the Sunflower Project (modified from Bruun et al., 2016).

1.8.1 Stratigraphy of the Gulf Coast Aquifer System

The Gulf Coast Aquifer System is comprised of several individual aquifers that parallel the Gulf of Mexico and range from Miocene to Holocene in age. Aquifers are present within discontinuous silt, sand, clay, and gravel deposits present within the Jasper, Evangeline, and Chicot formations. These aquifers are separated by localized silt and clay deposits that tend to act as confining intervals within and between aquifers.

The uppermost Chicot aquifer is comprised of the Willis Sand, Lissie Formation, and Beaumont Formation. These deposits are Pleistocene in age and represent the primary source of freshwater potential surrounding the Sunflower Project area. The Evangeline aquifer consists of the Goliad sand, which immediately underlies the Chicot aquifer and has regional freshwater potential. However, freshwater development of the Evangeline aquifer primarily occurs northwest of Jefferson County, with very few wells penetrating the aquifer in the vicinity of the project. The base of the Gulf Coast Aquifer System consists of the Oligocene Catahoula tuff, also referred to as the Catahoula confining system. The Catahoula confining system is prone to leaking; however, the Burkeville confining system provides additional protection and isolation between the Jasper

aquifer and the shallower aquifers— the Chicot and the Evangeline—that contain freshwater potential near the Sunflower Project area.

A stratigraphic column of the Gulf Coast is provided in Figure 1-42, with subdivisions established by Baker (1979) and further supported by Thorkildsen and Quincy (1990) and Chowdhury and Turco (2006). The figure clarifies stratigraphic nomenclatures introduced above and discussed herein.

The schematic cross section provided in Figure 1-43 runs southwest of the project, illustrating the regional structure and stratigraphy of the Gulf Coast Aquifer System. Gross thickness of sedimentary beds within the Cenozoic section generally increases toward the Gulf of Mexico due to the presence of growth faults associated with the loading of unconsolidated sediments. The average saturated freshwater thickness of the Gulf Coast Aquifer System is 1,000 feet (Bruun et al., 2016).

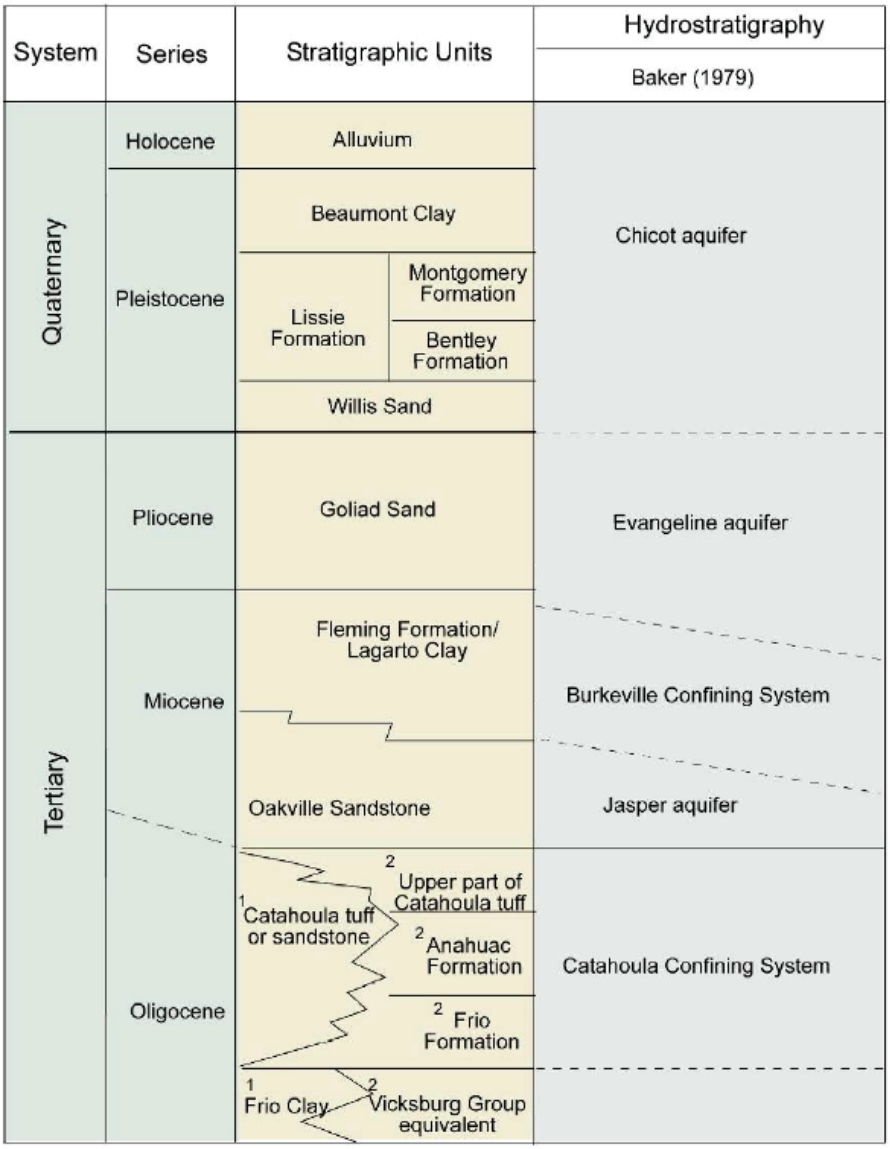


Figure 1-42 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury and Turco, 2006)

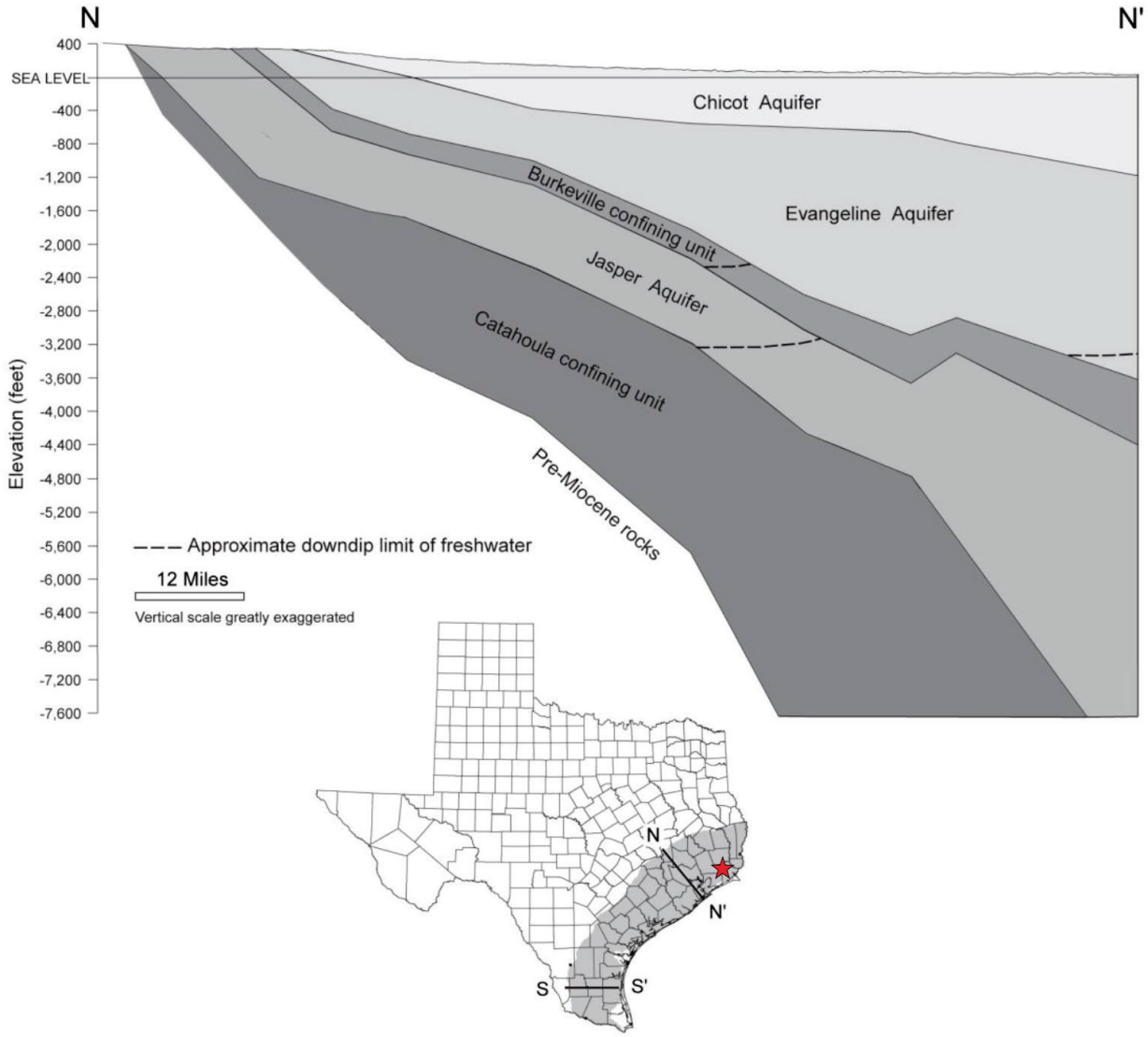


Figure 1-43 – Cross section N-N' across the Gulf Coast aquifer. The red star represents the approximate location of the Sunflower Project (modified from Bruun et al., 2016).

1.8.2 Characteristics of the Gulf Coast Aquifer System

Recharge and Discharge

The primary source of recharge to the Gulf Coast occurs from precipitation where portions of the aquifer system outcrop at the surface. Most of the regional extent of the aquifer is unconfined and contributes to the influx of freshwater; however, large amounts of precipitation are also lost to evaporation and runoff into local streams and lakes. Communication also occurs vertically between deposits where sands interfinger, depending on hydraulic conductivity and the head differential of individual deposits. Natural groundwater discharge occurs into local seeps and springs as well as from evaporation and transpiration. The primary source of discharge from the aquifer system occurs from water well withdrawals (Thorkildsen and Quincy, 1990).

Potentiometric Surface and Groundwater Flow Direction

Groundwater moves within aquifers from areas of higher hydraulic head to areas of lower hydraulic head, and the flow direction is generally perpendicular to potentiometric surface contours. A potentiometric surface map of the Chicot aquifer published by the TWDB is provided in Figure 1-44 for reference. The map suggests that groundwater historically flowed south-southeast near the Sunflower Project, as indicated by the bold black arrows.

Water Quality

The water quality of the Gulf Coast Aquifer System varies with depth and may contain local variations, but tends to improve toward the central and northeastern portions of the aquifer—where TDS values are typically less than 500 milligrams per liter (mg/L), as illustrated in Figure 1-45. According to the map, the TDS of the Gulf Coast aquifer are 1–3,000 mg/L in the project area, categorizing the aquifer as fresh to slightly saline near the project. Salinities within the Gulf Coast aquifer generally increase to the south, where the TDS range from 1,000 mg/L to more than 10,000 mg/L. The TWDB's 2016 Texas Aquifers Study suggests that areas of higher salinity are likely associated with saltwater intrusion "resulting from groundwater pumping or to brine migration in response to oil field operations and natural flows from salt domes intruding into the aquifer" (Bruun et al., 2016).

Twenty eight percent of wells sampled in the Gulf Coast Aquifer System exceed the EPA's secondary drinking water standards for chloride, iron, manganese, and TDS. Elevated iron and manganese concentrations occur mostly in the northern portion of the aquifer. Elevated chloride concentrations are associated with TDS increases that occur in the southern portion of the aquifer (Bruun et al., 2016).

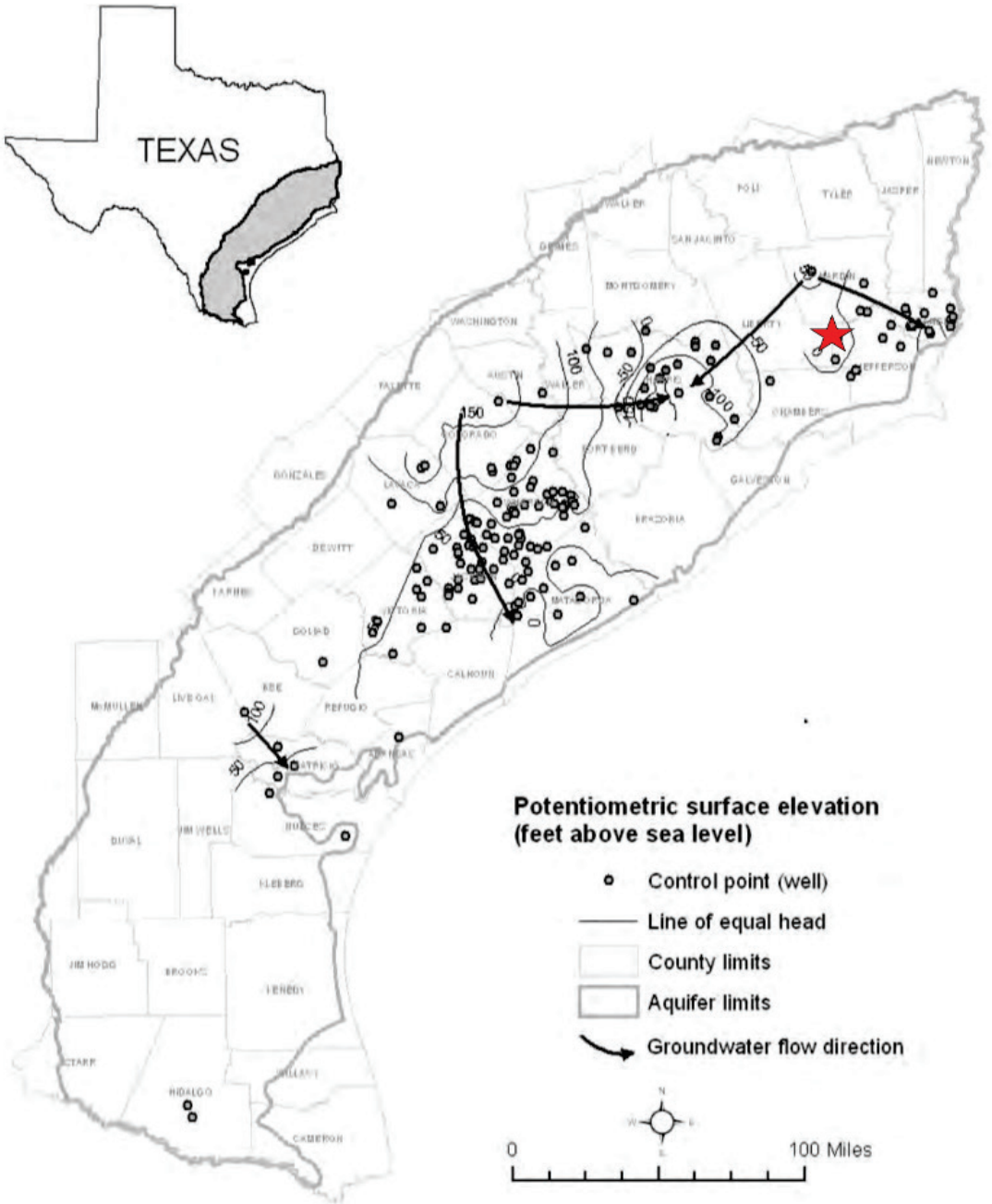


Figure 1-44 – Potentiometric surface map of the Chicot aquifer with regional groundwater flow directions. The red star represents the approximate location of the Sunflower Project (modified from Chowdhury, Boghici, and Hopkins, 2006).

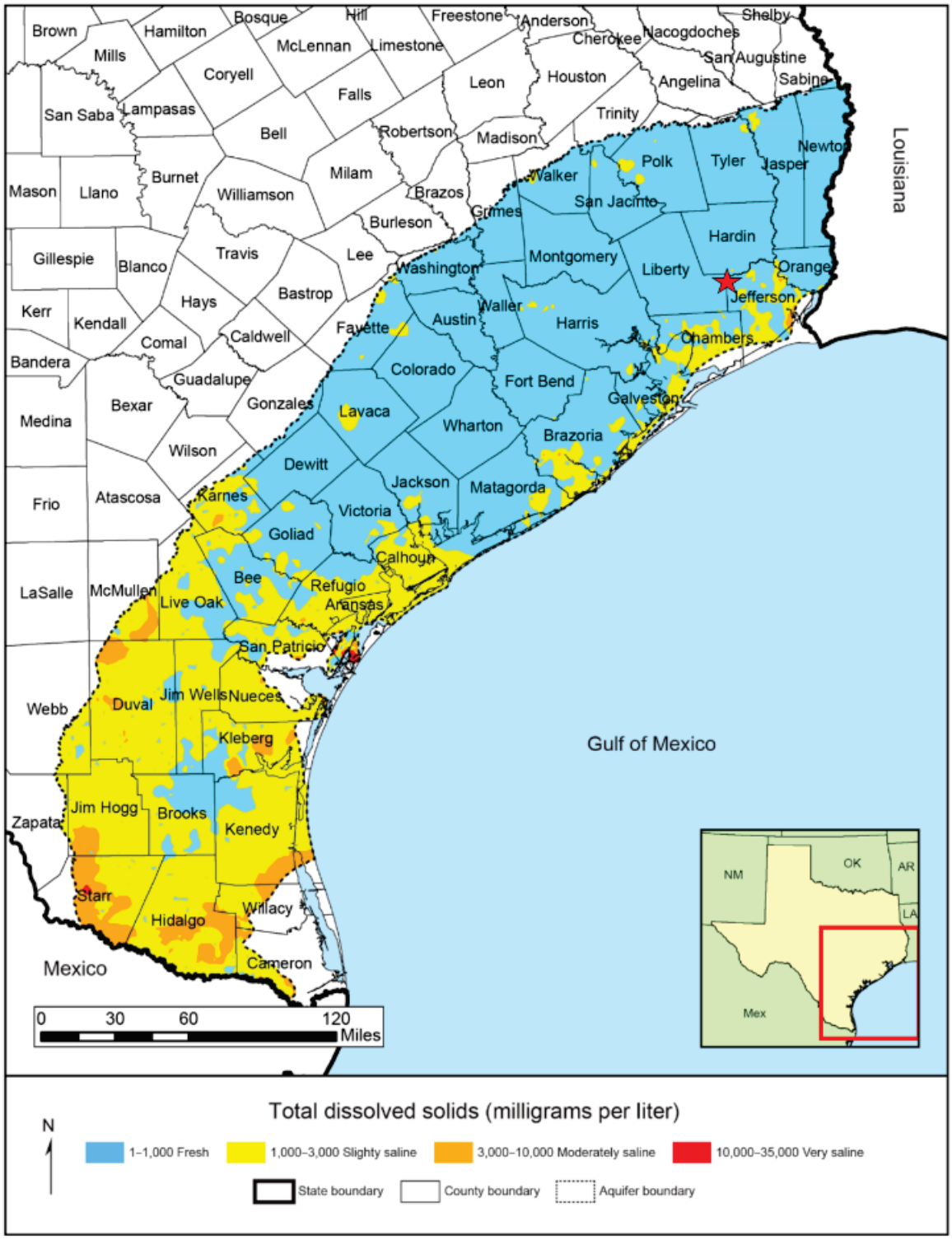


Figure 1-45 – Total dissolved solids in the Gulf Coast aquifer. The red star represents the approximate location of the Sunflower Project (modified from Bruun et al., 2016).

1.8.3 Base of USDW Determination

In 2016, Young et al. published a report contracted by the TWDB to investigate the salinities of the Gulf Coast Aquifer System and identify potential brackish groundwater production areas (TWDB Contract #1600011947). The study reviewed openhole logs of the Gulf Coast Aquifer System across the Gulf of Mexico and calculated the TDS of aquifer sands to improve understanding of regional trends within the system. The calculated values were utilized to map specific TDS intervals, including the base of usable quality water (BUQW) and the base of the USDW. The resulting maps are provided in Figures 1-46 and 1-47, represented by TDS values less than 3,000 mg/L for the BUQW, and TDS values less than 10,000 mg/L for the base of the USDW. According to the maps, the BUQW of the Gulf Coast Aquifer System occurs at a depth of approximately 1,500-2,000 ft, and the base of the USDW occurs between 2,000-2,500 feet in the vicinity of the Sunflower Project.

The study also included a series of regional cross sections aimed to profile the calculated salinity of sand packages within the Gulf Coast Aquifer System. Their interpretation of Cross Section No. 2 is provided in Figure 1-48 to illustrate potential salinity changes within the aquifer system around the project. Stratigraphic nomenclatures utilized by Young et al. (2016) in the cross section are clarified at the top of the figure, with regional nomenclatures previously established by Baker (1979) (Figure 1-42).

The Railroad Commission of Texas's (TRRC) Drilling Insight and Casing Estimator (DICE) identified the BUQW at a depth of 973 feet around the general location of the Sunflower Project, in general agreement with maps and discussions provided herein. ExxonMobil has obtained initial letters from TRRC's Groundwater Advisory Unit (GAU) (GAU Numbers: 401859, 409988, and 409989 for Sunflower INJ No. 01, No. 02, and No. 03, respectively. GAU No. 401859 listed a usable quality of water depth of 2,450' and a USDW depth of 2,700' while GAU Nos. 409988 and 409989 listed a superior quality of water depth of 850', a usable quality of water depth of 1,700', and a USDW depth of 1,950'. ExxonMobil consulted with both the GAU and TRRC's Special Injection Permits division and aligned that these depths will be confirmed, and updated as needed, based on the as-drilled conditions of the wells themselves.

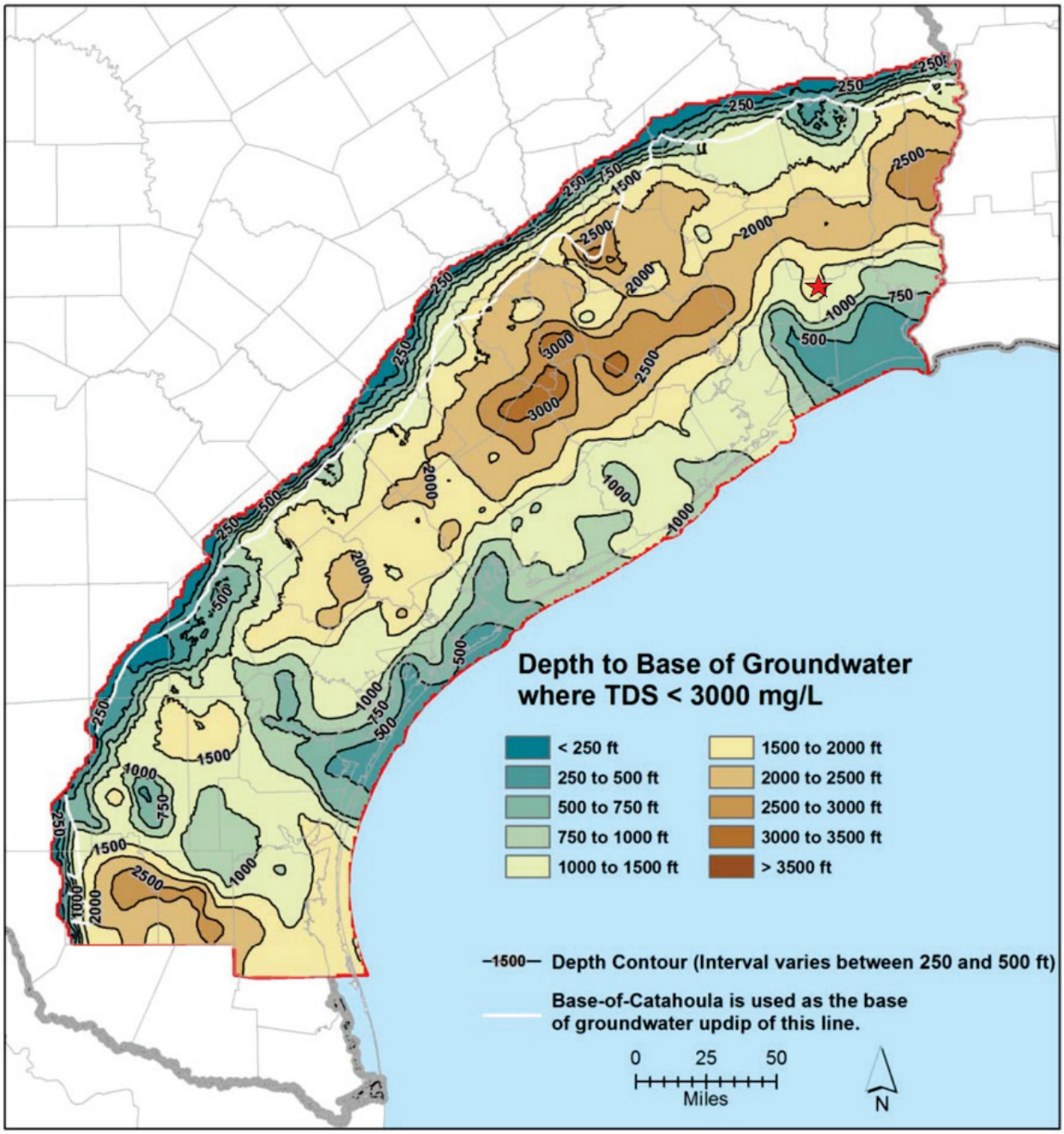


Figure 1-46 – Depth to the BUQW of the Gulf Coast Aquifer System. The red star represents the approximate location of the Sunflower Project (modified from Young et al., 2016).

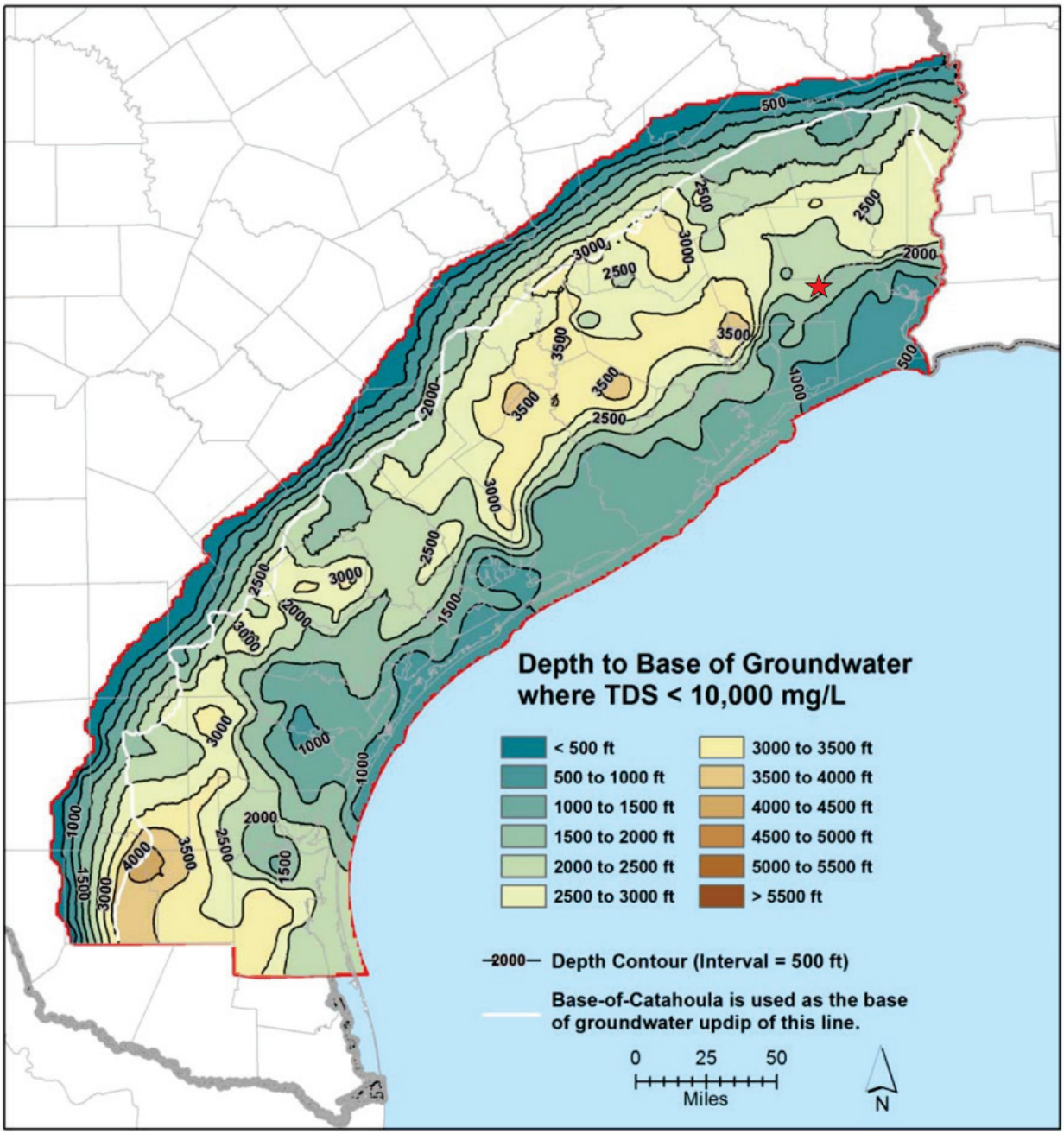


Figure 1-47 – Depth to the base of the USDW of the Gulf Coast Aquifer System. The red star represents the approximate location of the Sunflower Project (modified from Young et al., 2016).

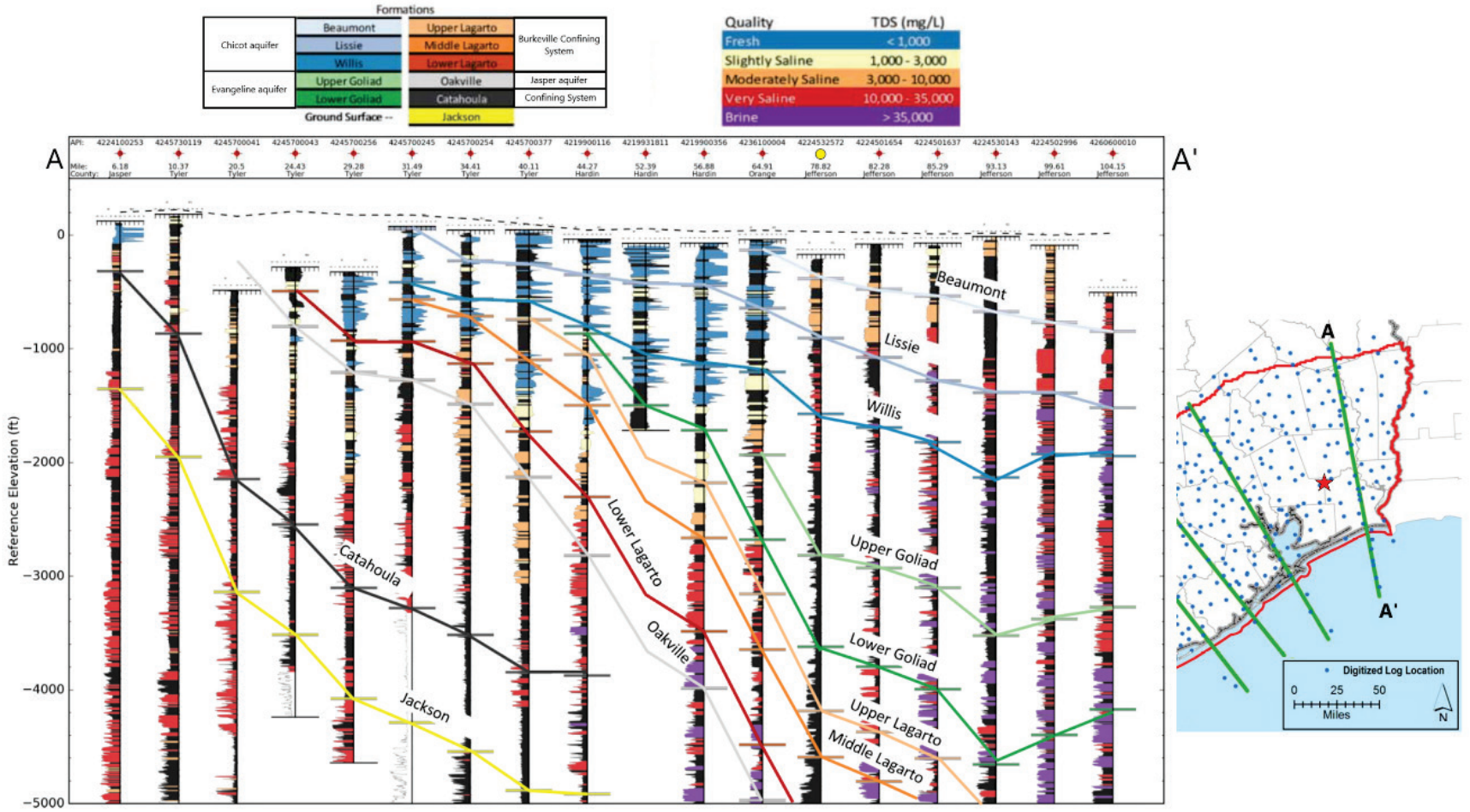


Figure 1-48 – Regional cross section: calculated water salinity of Gulf Coast Aquifer System sands from geophysical logs (modified from Young et al., 2016). The red star represents the approximate location of the Sunflower Project.
The yellow circle represents API No. 4224532572, located approximately 20 miles east of Injection Well No. 01.
Clarified nomenclatures were adapted from Chowdhury and Turco (2006).

An assessment of the USDW depth was also performed using legacy wells in the Sunflower Project area. A total of 39 wells were investigated to estimate the USDW depth based on deep resistivity logs. Sands reading less than 2 ohm-meters (ohm-m) were interpreted to have a TDS value greater than 10,000 ppm. Table 1-12 summarizes the USDW depths based on the wells available. Figure 1-49 is a USDW depth contour map across the Sunflower Project area, with the AOR polygon shown in a teal outline. This USDW map was used in a grid-based approach for determining critical pressure, and is discussed in detail in *Section 3.3.2.1*.

It is worth noting that two wells were omitted from the map due to either the vintage or quality of the logs available. The F S Wilson – 1 well was drilled in 1937, and there is limited information on the resistivity log available to determine the depth of investigation for evaluating formation brine salinity. The Lawrence Leger – 1 well was drilled in 1955 and had an inconsistent resistivity and SP response, where the SP log reversed across multiple sands with similar resistivity values to sands found shallower—where a normal SP response was observed. Additionally, two other wells were omitted due to their close proximity with offset wells, where the well with the deepest USDW depth was used, and two other wells were omitted given their proximity to the Sour Lake Salt Dome, with radial faults present, and their location outside the AOI.

Table 1-12 – List of Wells Used in the USDW Map for the Sunflower Project Area

Number	Well Name	UWI	X-coordinate	Y-coordinate	USDW Depth (ft)		Justification for Exclusion
					TVDSS	MD	
1	Grayburg Timber Co - 1	421990218600	21613957.9	8256138.2	-1702	1750	
2	Grayburg Timber Co - 2	421990218700	21613673.2	8252285.1	-1726	1770	
3	Hull Swd 1	421993342200	21550625.6	8263503.0	-2266	2345	
4	G T Garth - 1	422450000300	21610063.0	8242450.9	-1857	1905	
5	F H Carpenter - 1	422450000400	21605461.7	8237354.0	-1860	1900	
6	F Carpenter Etal - 1	422450000500	21606622.4	8236948.5	-1851	1900	
7	Garth - 1	422450000700	21617868.1	8227076.2	-1631	1670	
8	Willis B H - 1	422450000800	21609285.1	8230195.4	-1956	2005	
9	Berry-Peuitoe - 1	422450001600	21605622.7	8224876.6	-1947	2000	
10	Quinn B E - 1	422450012100	21633216.4	8242697.3	-1917	1950	
11	Kolander Etal Un A - 1	422450012300	21632800.1	8237479.0	-1836	1875	
12	Halfacre E J Etal - 1	422450012400	21623706.3	8237495.4	-1793	1845	
13	Walter Co - 1	422450321300	21629222.4	8229132.2	-1550	1600	
14	Wilson Etal - 1	422450321400	21610339.5	8235808.0	-1910	1970	
15	A M Carperter Est - 1	422450324000	21605595.2	8233442.1	-1888	1940	
16	Alma M Carpenter - 1	422450327300	21612080.1	8250104.0	-1900	1940	
17	B H Willis Est - 1	422453018400	21605883.3	8230474.4	-1906	1955	
18	Carpenter - 1	422453029000	21605226.4	8235697.4	-1900	1950	
19	C T Garth - 1	422453034400	21611121.6	8240636.0	-1899	1910	
20	Garth Co - 1	422453038900	21610989.0	8247292.7	-1700	1740	
21	Garth Co - 2	422453043800	21611819.2	8244237.2	-1873	1898	
22	Garth - 1	422453122700	21611989.9	8247382.2	-1765	1800	
23	Arco Fee Sec 74 - 1	422453156200	21621161.9	8252470.3	-1786	1820	
24	Arco Fee Sec 74 - 1	422453156200	21621161.9	8252470.3	-1786	1820	
25	Swepi/Txpo Barnes E - 1	422453184600	21601761.1	8253054.8	-2505	2580	
26	Garth - 1	422453193100	21609850.2	8238834.4	-1896	1950	
27	Failor Heirs - 1	422453212200	21615645.1	8248346.8	-1751	1800	
28	Theriot - 1	422453220100	21634409.1	8226450.9	-1495	1540	
29	Pickett Mary E - 1	422910033300	21584062.6	8235121.0	-2297	2360	
30	Fingers - 1	422913133300	21571914.6	8220410.7	-2405	2480	
31	Fingers - 2	422913142400	21568920.4	8221336.9	-2398	2472	
32	Arco Fee - 1	422913199100	21549518.8	8259591.2	-2231	2290	
33	Black Stone Min Fee - 1	422913270100	21555078.2	8249458.5	-2427	2485	
34	Carpenter Prod - 1	421993040200	21600349.6	8262764.3			Close proximity to salt dome and radial faults, outside AOI
35	Storer Frank - 1	421993168000	21598608.5	8261007.6			Close proximity to salt dome and radial faults, outside AOI
40	Carpenter Estate F - 1	422450000200	21612330.7	8250271.9			Multiple wells near fault (well with deepest USDW used)
37	F S Wilson - 1	422450000600	21613684.4	8235255.2			Insufficient information on resistivity log given vintage (1937)
38	Lawrence Leger - 1	422450000900	21603393.2	8229148.8			Inconsistent log response compared with offset wells
39	Carpenter Alma M Es - 2	422450329200	21609990.4	8242618.3			Multiple wells near fault (well with deepest USDW used)

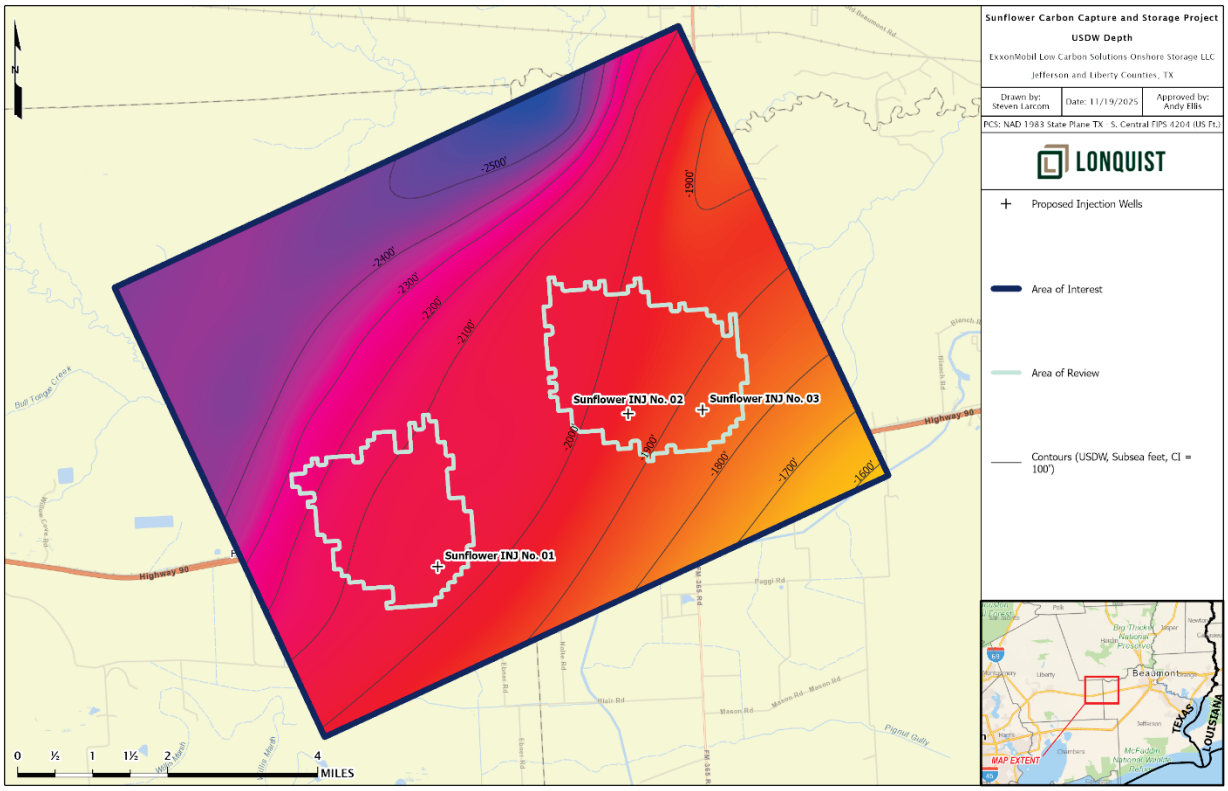


Figure 1-49 – Contour map of the USDW depth in the Sunflower Project area.
The teal outline is the simulation AOR.

1.9 Site Evaluation of Mineral Resources

1.9.1 Active Mining Near the Proposed Injection Location

A search using public data provided by the USGS Mines and Quarries geodatabase, accessed December 2, 2025, identified several nearby mineral deposits. These features include borrow pits, gravel pits, and sand pits that are mostly confined to the northeast of the Sunflower Project area. No surface mineral impacts from the project will occur at the identified pits.

A separate search using public data provided by the USGS Mineral Resources Data System was also conducted. The primary features identified during this search were Gulf Coast salt domes, the closest of which is the Sour Lake Salt Dome, the center of which is located 5.5 miles to the north of the project AOR. While no impacts from the Sunflower Project are expected to occur, it should be noted that there are still several surface operations occurring at the location, which is operated by Flint Hills, along with storage operations by Motiva. Most of the resources have been depleted since the 1950s, and a slowly growing sinkhole lake has formed in the middle of the oil field close to the dome. The features described herein are depicted in Figure 1-50.

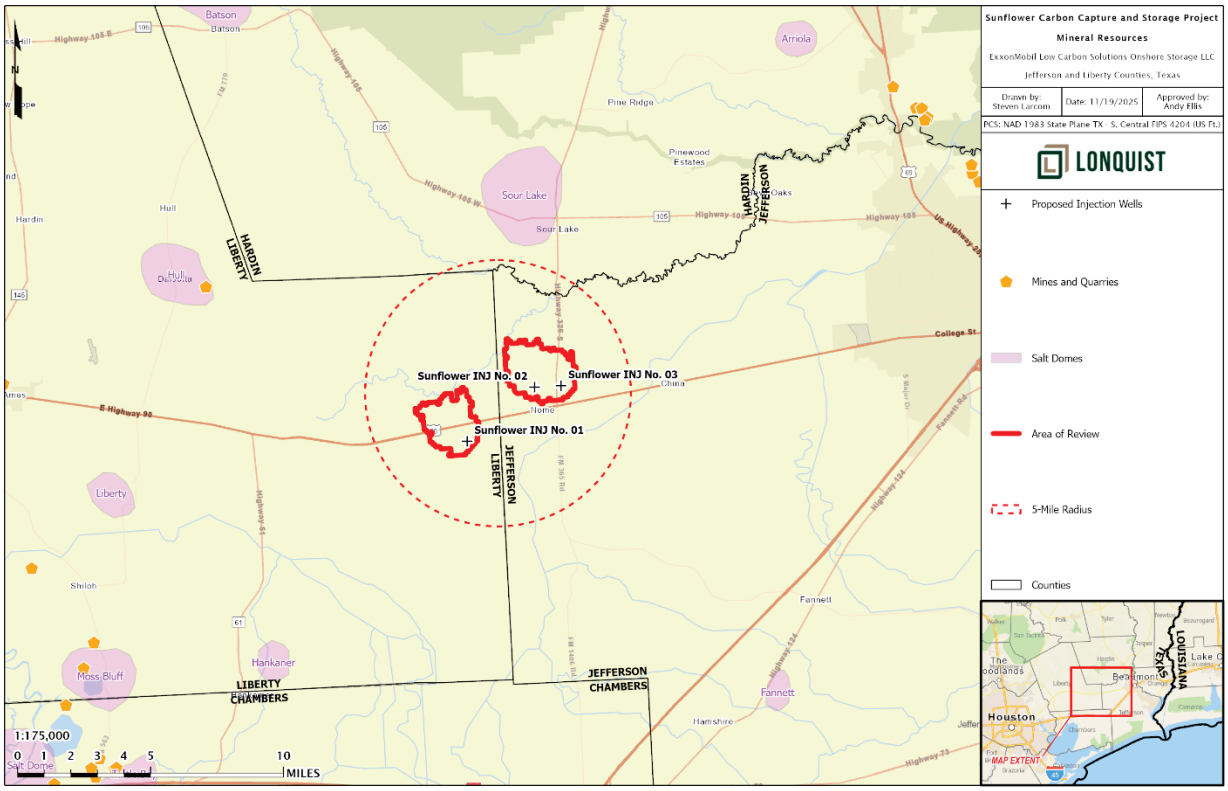


Figure 1-50 – Map of Mines, Quarries, and Salt Domes in the Region

1.9.2 Oil and Gas Resources

Much of the oil and gas exploration in this part of Texas has been ongoing since the 1950s, particularly around the aforementioned salt domes, where structural traps have been created by faulting. Most of the early drilling focused on accessing the hydrocarbons adjacent to these domes. This is evident in the northern periphery of Figure 1-51, where a large concentration of wells in the area is located on and around the Sour Lake Salt Dome. Within 5 miles of the center of the AOR, 347 wells were confirmed. Of those wells, 194 were productive (*Appendix B-5*).

The primary field within this 5-mile search radius is the Nome field, located near the town of Nome, Texas, to the south. The field cumulatively produced 36.6 million barrels of oil equivalent (BOE). The primary productive reservoirs are the Frio and Yegua. While this field is within the 5-mile search radius, it is not intersected by the modeled extent of the injected CO_2.

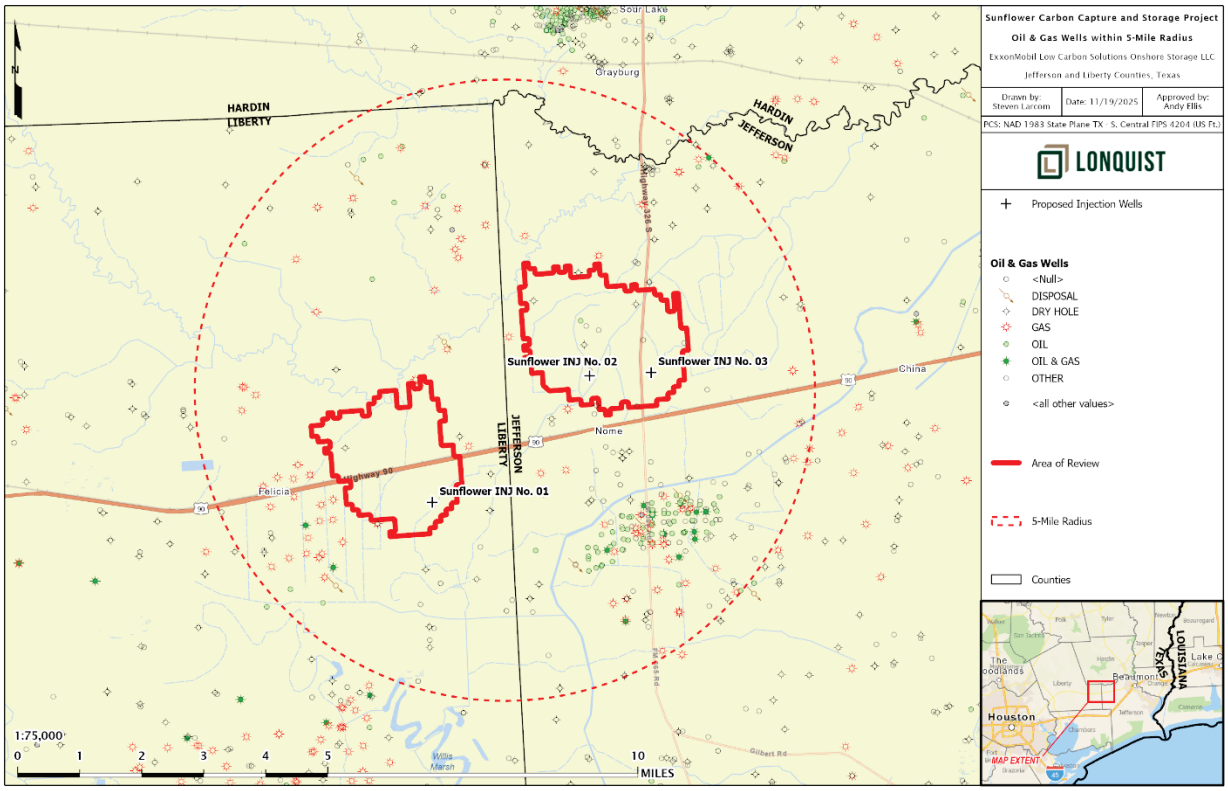


Figure 1-51 – Map of oil and gas wells within a 5-mile radius from the center of the AOR.

The closest productive well to the three proposed injection wells of the Sunflower Project is the Graham Trust No. 1, located 0.63 miles southwest of Sunflower Project Injection Well No. 2. Having first produced in 2012 from the Yegua reservoir, with a perforated interval from 11,913 feet to 11,946 feet, the Graham Trust No. 1 is primarily a gas-producing well, with cumulative production totaling 834,886 thousand cubic feet (Mcf). The well is active and has cumulatively produced 181,965 BOE. This well is also outside the modeled extent of the CO_2 plume and producing from a deep formation that does not intersect with the Sunflower Project's gross injection zone (~3,500–7,800 feet MD). Any wellbores within the AOR that are drilled through the injection interval are discussed in *Section 3 – Area of Review and Corrective Action Plan*.

After a thorough review of the AOR, the Sunflower Project is not anticipated to interfere with existing or prospective oil, gas, geothermal, or other mineral resources, or cause waste as defined by Texas Natural Resources Code **§85.046(11)**.

1.10 Seismic History

1.10.1 Historical Seismic Events

1.10.1.1 Record of Presence/Absence of Seismic Events from All Relevant Databases

There have been no recorded earthquakes in the vicinity of the proposed Sunflower Project area, based on a search of the USGS national earthquake database (with records beginning in 1900).[2] TexNet (active since 2017[3]) also yielded no recorded earthquakes in the vicinity of the project area.

1.10.1.2 Characterization of Seismic Events

The largest regional historic event since 1900 was a magnitude 4.8 event 3 km northeast of Timpson, Texas—approximately 130 miles from the Sunflower Project site—that occurred on May 17, 2012. The closest event larger than a magnitude 2.5 was a magnitude 3.8 event on October 16, 1983—1.8 km west-northwest of Sulphur, Louisiana, approximately 64 miles from the project site. The most recent event was a magnitude 4.9 located in Red River Parish, Louisiana on March 05, 2026, approximately 150 miles from the project site.

The TexNet earthquake catalog further yielded a magnitude 3.6 event on January 20, 2019, 7 km south-southwest of San Augustine, Texas, approximately 95 miles from the project site. The closest earthquake in this catalog, greater than a magnitude 1.0, was a magnitude 2.4 on December 30, 2018, located a few miles south of the magnitude 3.6 event, approximately 91 miles from the project site.

1.10.2 Regional Faults and Project Influence

Sections 1.2 (Regional Geology) and *1.6.1* (Local Stress Conditions) discuss regional faulting and stress conditions. Faults specific to the AOR are discussed in the following section.

1.10.3 Fault Slip Model

The injection pressures will be limited to values that reduce the potential for the initiation or propagation of fractures. No induced seismicity is expected to occur under the proposed permit conditions. The following evaluations were conducted to provide a site-specific technical evaluation of the seismic risk within the AOR.

Six faults within the AOI, but outside the AOR, were identified as intersecting the Top Fleming Sand 3. The faults within the AOR occur at deeper depths and tip out deeper than the Top Fleming Sand 3. The fault slip potential was assessed using a deterministic 3D approach—based on an integrated pore pressure prediction estimate of the stress gradients and the pore pressure increase at fault-formation interfaces. The modeled output is the approximated pore pressure needed for the fault to slip at each point on the fault. [redacted]

[2] https://earthquake.usgs.gov/earthquakes/search/#%7B%22currentfeatureid%22%3Anull%2C%22mapposition%22%3A%5B%5B29.67135%2C-94.88548%5D%2C%5B30.18609%2C-93.8308%5D%5D%2C%22autoUpdate%22%3A%5B%22autoUpdate%22%5D%2C%22feed%22%3A%22search_undefined%22%2C%22listFormat%22%3A%22default%22%2C%22restrictListToMap

[3] https://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog

The orientation of the maximum horizontal stress was taken from the World Stress Map, trending N75E +/- 10° to account for slight rotations of the stresses in the AOI. The coefficient of friction value was derived from a triaxial compression test completed on a sidewall core from the Bead Farm Co. – 1 well, where the residual strength was calculated on the failure plane (37°) following shear failure. The resultant coefficient of friction for the failure plane is 0.63. To account for a variability along a fault associated with compositional differences, the coefficient of friction is varied between 0.58–0.68.

The amount of pore pressure required for fault slip is defined as the horizontal distance between the Mohr circle and the failure line. By constraining the stress state and pore pressure at each location along the fault, based on regional leak-off test data (Shmin) and the integration of the density log (Sv)—as well as the fault geometry (fault dip and fault strike)—the critical pore pressure for fault slip can be computed by assuming a friction coefficient for faults.

This methodology neglects poroelastic stresses due to the rock frame deformation and assumes that the regional stresses are representative of the stresses at the fault location. The resulting deterministic approach indicates that injection activities would have to increase pore pressures by more than 385 psi at the shallower Top Fleming Sand 3 injection interval to induce fault slip along the southernmost fault (Fault 9) within the AOI. Its orientation, with respect to the minimum and maximum horizontal stress directions, causes the fault to require less of an increase in pore pressure (385 psi vs. approximately 900 psi) than the other faults (7, 11, 12, 13, and 15) in the AOI, to induce reactivation. This fault, however, is not present within the AOR and therefore poses a very low risk for reactivation—irrespective of pore pressure increases. The current estimate of the maximum pore pressure increase anywhere in the injection zone, based on the simulation model, is less than 140 psi, indicating that the potential for induced seismic risk based on this methodology is low.

Figure 1-52 shows the estimated pore pressure increase required to induce fault slip along mapped faults surrounding the AOR, intersecting at the Top Fleming Sand 3 surface. The pore pressure increase along each fault trace is below the fault slip criterion. Results are presented as a probability, with P5 representing a five percent likelihood of occurrence. Fault traces are represented by spheres, colored by the pressure needed to induce reactivation. The base map is contoured by maximum pressure change during CO_2 injection, which occurs after one year of injection into the Frio 3.



Figure 1-53 shows a 3D representation of fault reactivation pressure along the surfaces of each fault within the Sunflower Project AOI. Results are presented as a probability, with P5 representing a five percent likelihood of occurrence. Fault 9 (the southernmost fault depicted) shows the lowest activation pressure, concentrated at the shallower depths. All faults in the AOI show higher reactivation pressures with depth.



The salt dome to the north of the AOI was investigated to evaluate the effect that its presence has on the magnitudes of the principal stresses (discussed in *Section 1.6.3.1*). It was found to increase the magnitude of the Shmin and decrease the magnitude of Shmax, thereby reducing the overall pressure increase needed to reactivate faults. The radial faults (11, 12, 13, and 15) showed the greatest change from the base case scenario calculated; however, it was only a maximum reduction of 100 psi, resulting in an 800–900 psi pressure increase needed to reactivate faults (instead of 900–1,000 psi).

1.10.4 Seismic Hazard

The Sunflower Project area is reported by the USGS to be of very low seismic hazard (low peak acceleration [4–6% acceleration of gravity (%g)] seismic hazard—that is, a 2% chance in 50 years of peak ground acceleration at 4–6 %g). The seismic hazard determination by the USGS is shown in Figure 1-54 (USGS, 2023). In addition, there have been no recorded earthquakes in the vicinity of the project area since 1973, based on a search of the USGS national earthquake database.

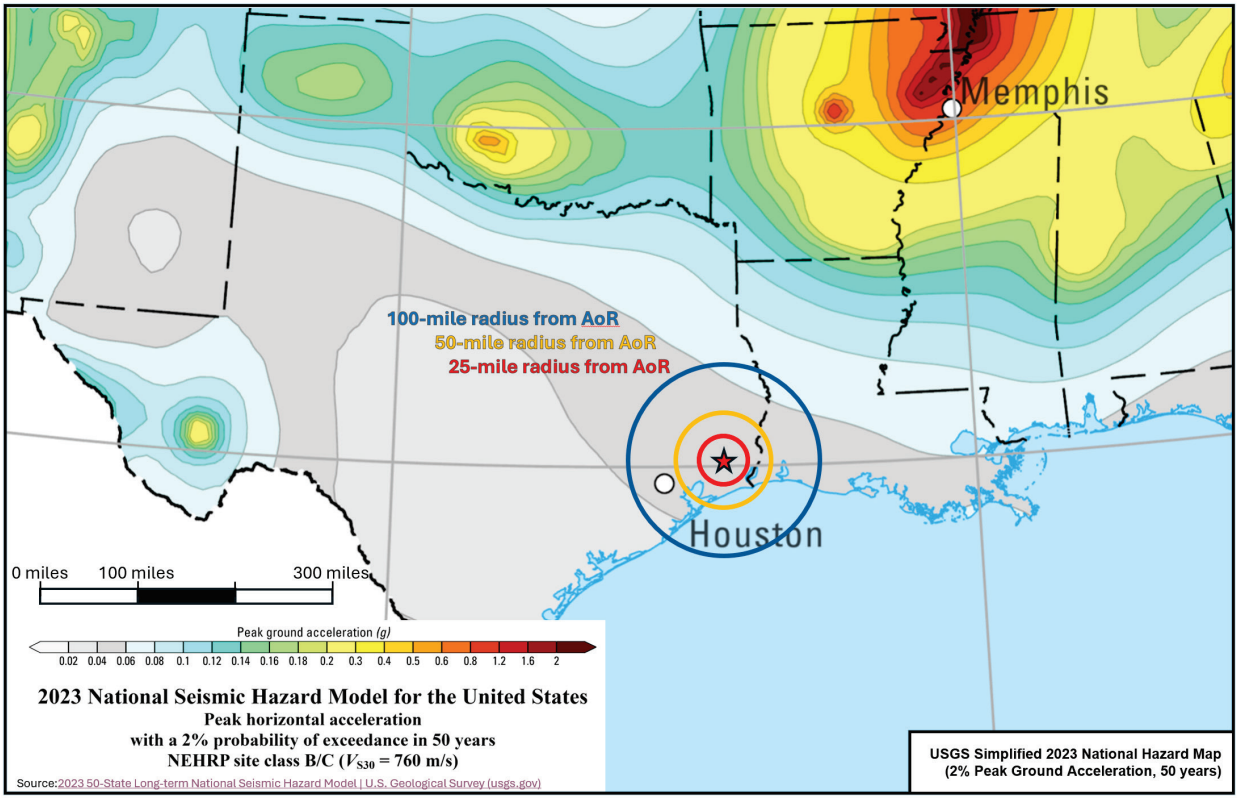


Figure 1-54 – National Seismic Hazard Model for the United States

Based on the seismic history of the Sunflower Project area and the conforming pore pressure calculations, the potential for induced seismicity from CO_2 injection at the project area is not a significant risk.

1.11 Conclusion

The Sunflower Project site is a suitable location for carbon dioxide injection and storage operations. The upper confining zone is characterized by low porosity and permeability, modeled to impede upward migration of injected fluids—and will provide a seal of sufficient thickness and lateral continuity to protect all area USDWs. The injection zone is sufficiently thick, porous, and permeable to support the proposed injection operations. The lower confining zone provides hundreds of feet of impermeable shale to contain injected fluids to the proposed injection zone.

- Mineralogy and other petrophysical characteristics of the injection and confining zones are favorable for CO_2 storage.
- The area structure is well constrained by 3D seismic survey data and high-confidence well ties, indicating a low dip within the injection and confining zones of the AOI.
- Faults have been identified, characterized, and analyzed in the project area. No faults reach the UCZ within the AOR. Shale gouge ratio was calculated for Faults 15 (within the AOR) and 13 (outside the AOR) and is determined to seal across the UCZ, therefore it is

not anticipated to provide a conduit for fluid outside of the injection zone. No other known conduits exist.

- Geomechanical properties and local stress conditions support the proposed project's operations.
- Baseline geochemistry and geochemical modeling of the in situ fluid and injectate support the containment of injected fluids to the injection zone.
- Hydrologic units above the proposed injection zone are characterized and mapped. Dynamic modeling demonstrates the USDWs will not be affected by the Sunflower Project's operations.
- Proposed operations are not anticipated to affect offset mineral resources.
- The Sunflower Project area is reported by the USGS to be of very low seismic hazard.
- Fault slip potential was assessed and no induced seismicity is expected to occur under the proposed operating conditions.

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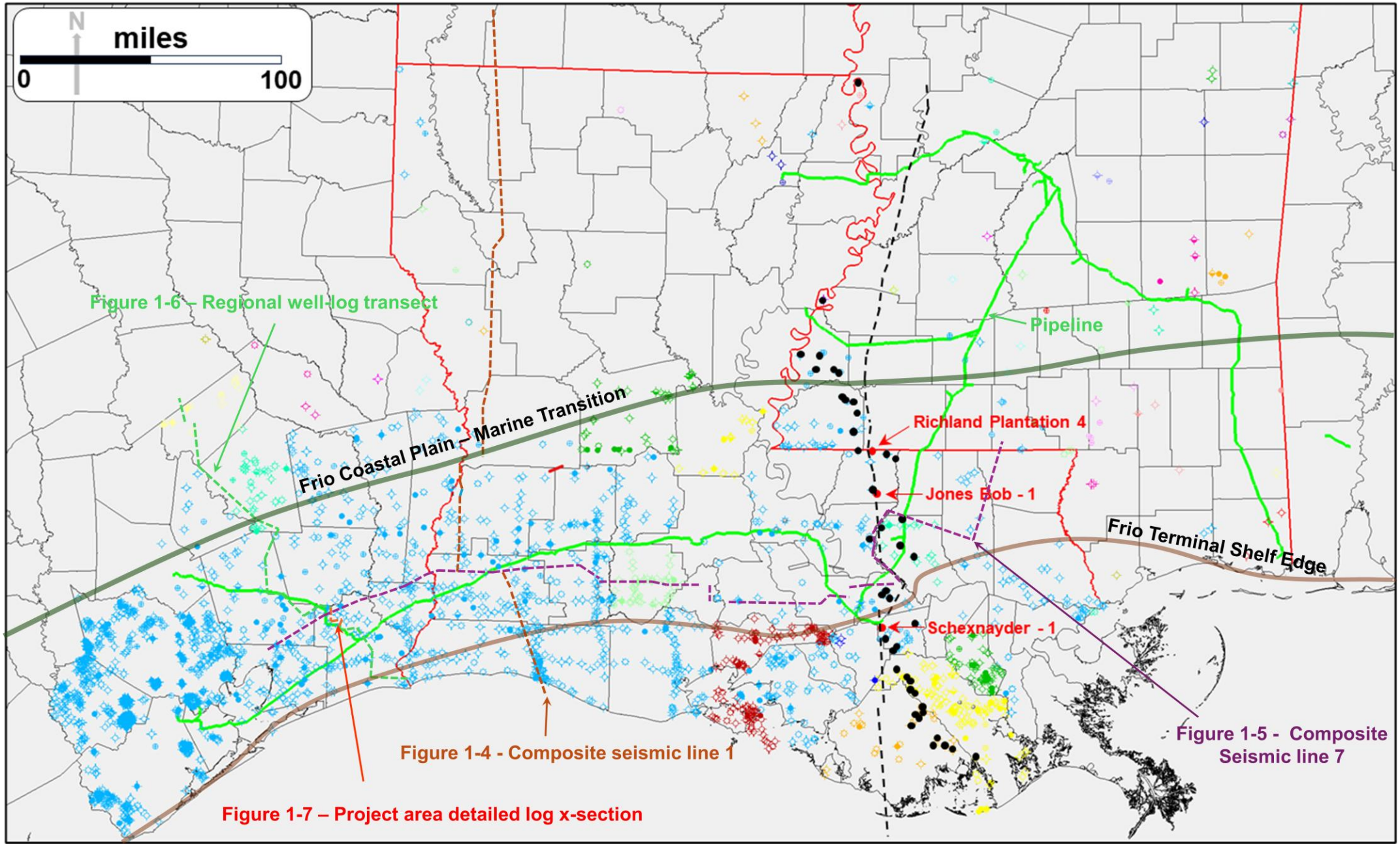
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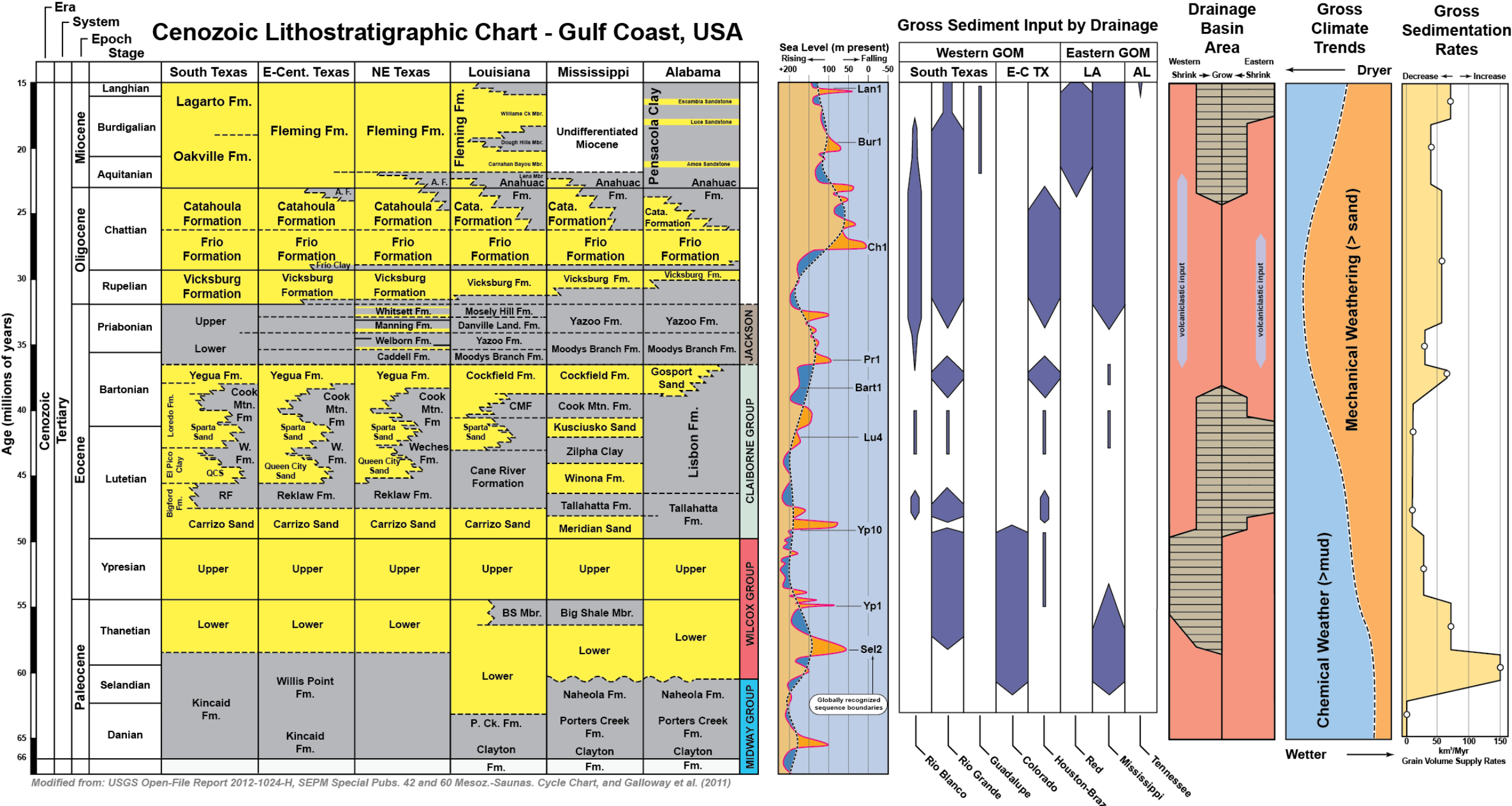
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Appendix B – Site Characterization

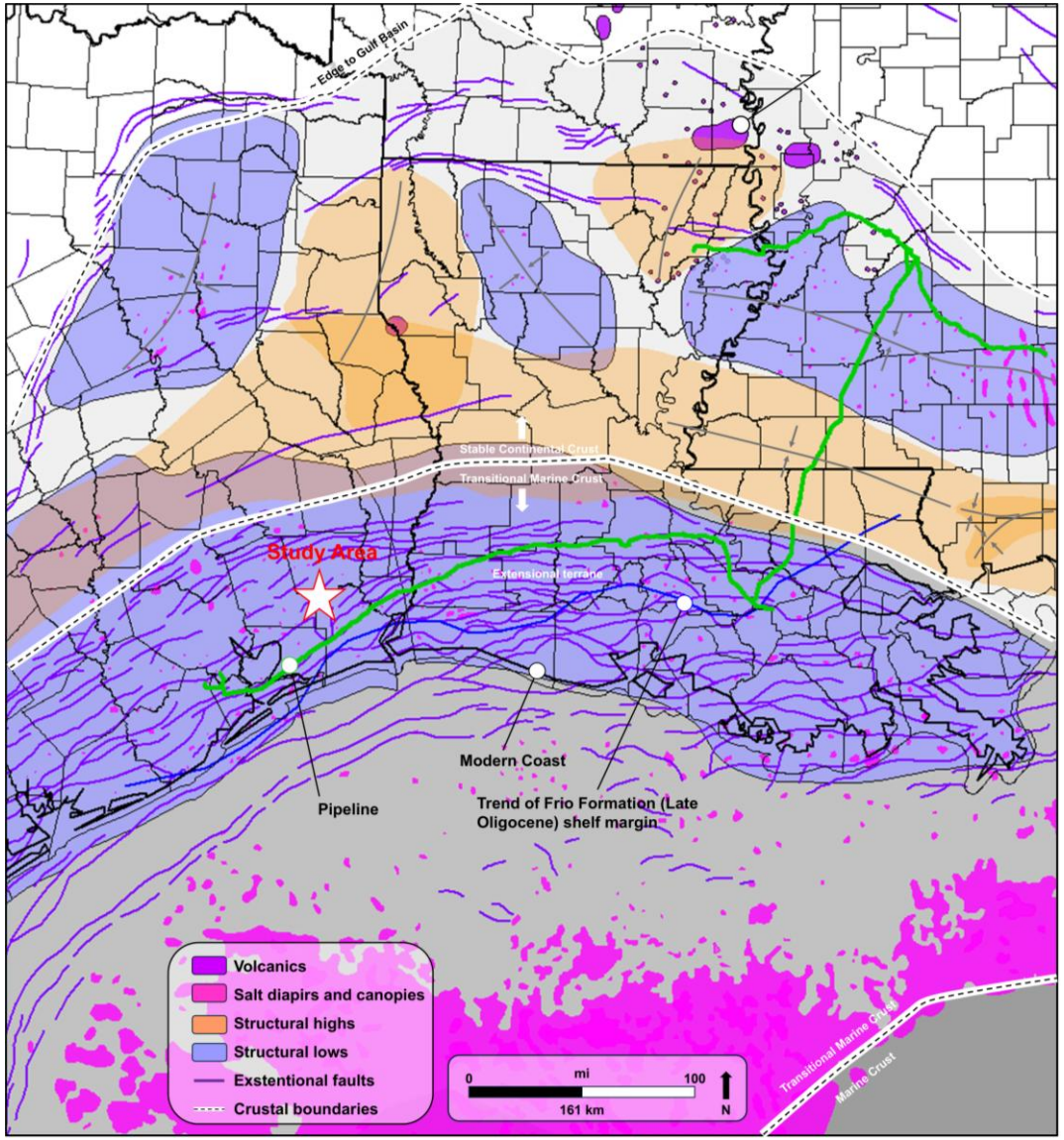
Appendix B1 – Regional Geology



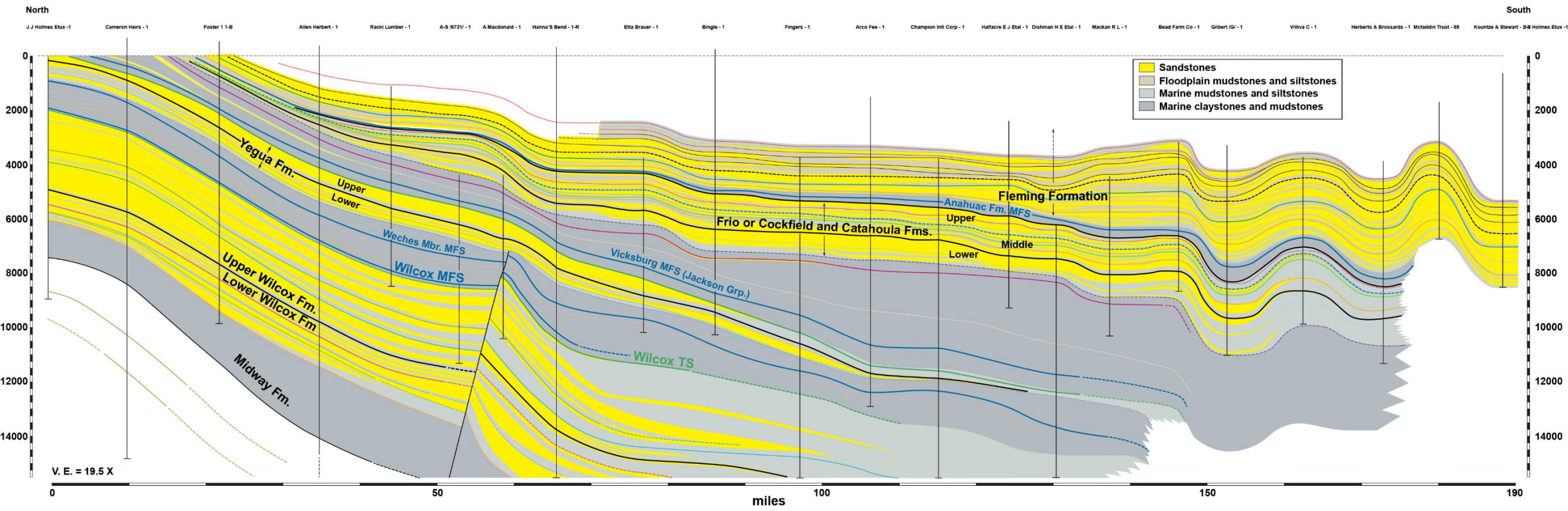
FIG□RE □□□: Base map for t□e Gulf of Mexico□ □ ells used in t□e regional analysis are depicted as circles□
Das□ed lines represent seismic sections and □ell□log sections s□o□n in Figures □□4 t□roug□ □□□□ □Figure □□3 presents t□e □asin margin and limits of t□e study area□□ Initial coastal plain to marine transition □one and t□e terminal s□elf edge □oundary for t□e Frio Formation are s□o□n □see Gallo□ay et al□□2□□□□□



FIG□RE □2: Lit□ostratigrap□ic correlation c□art for t□e nort□ern portion of t□e Gulf of Mexico Basin □left□Yello□ formations represent more sandy inter□als and gray formations represent more muddy inter□als□ A comparison of stratigrap□ic forcing mec□anisms□relati□e to t□e de□elopment of formations □it□in t□e □asin□is s□o□n to t□e rig□t□

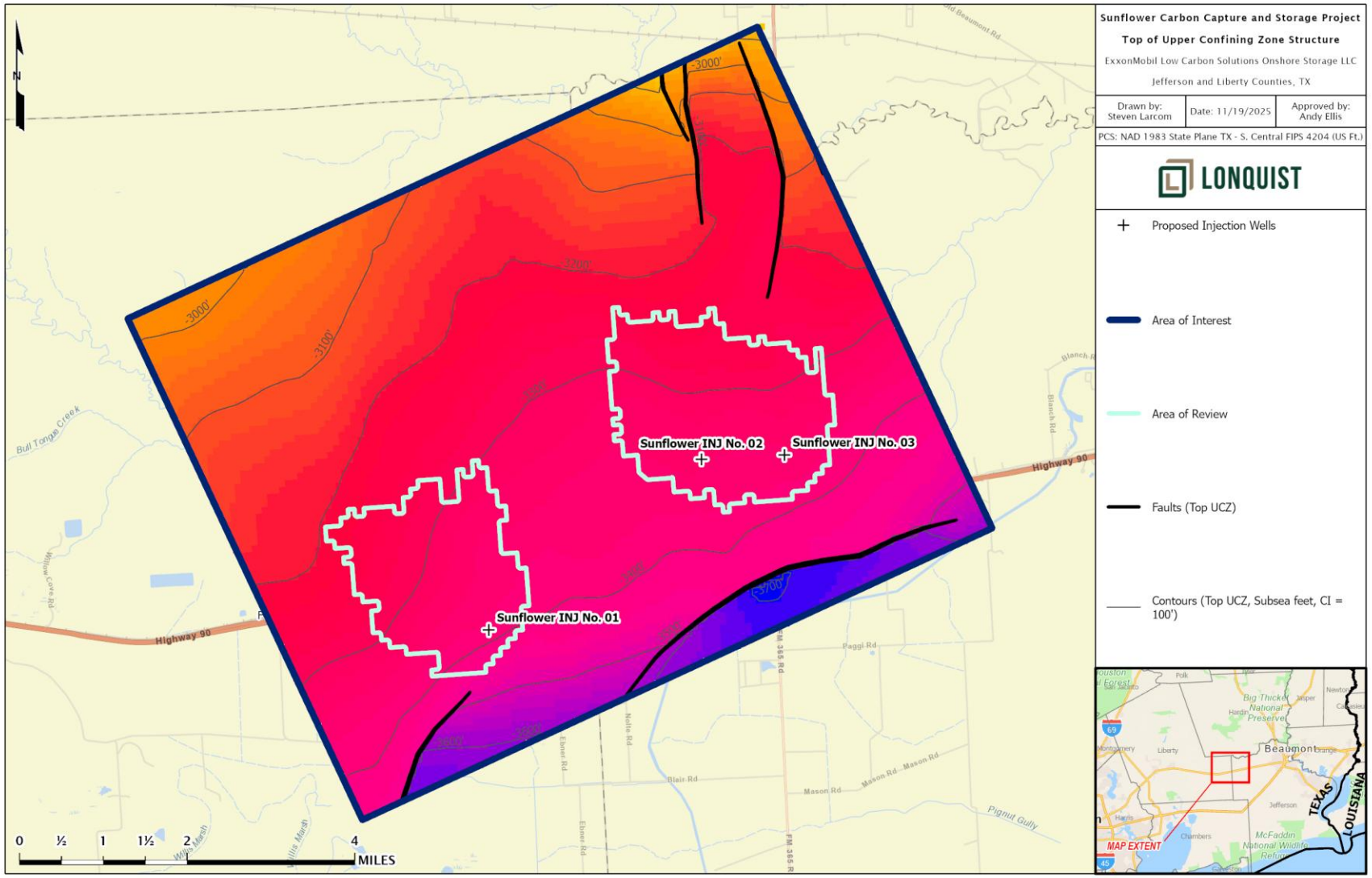


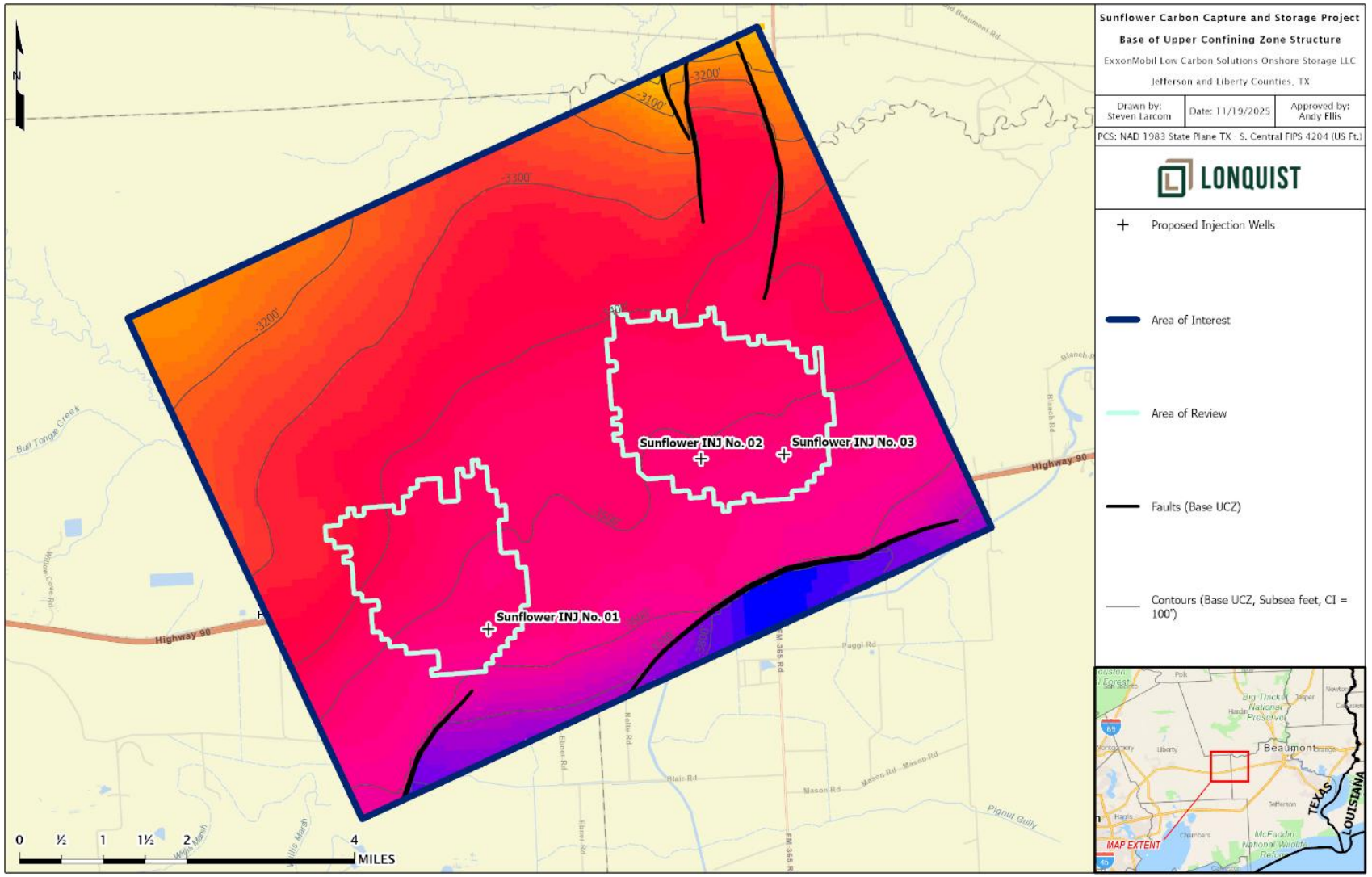
FIG□RE □□3:Structural elements of t□e nort□ern Gulf Basin□
See Gallo□ay □2□□□□and Snedden and Gallo□ay □2□□□□for more detailed discussion of t□e de□elopment of structural features□

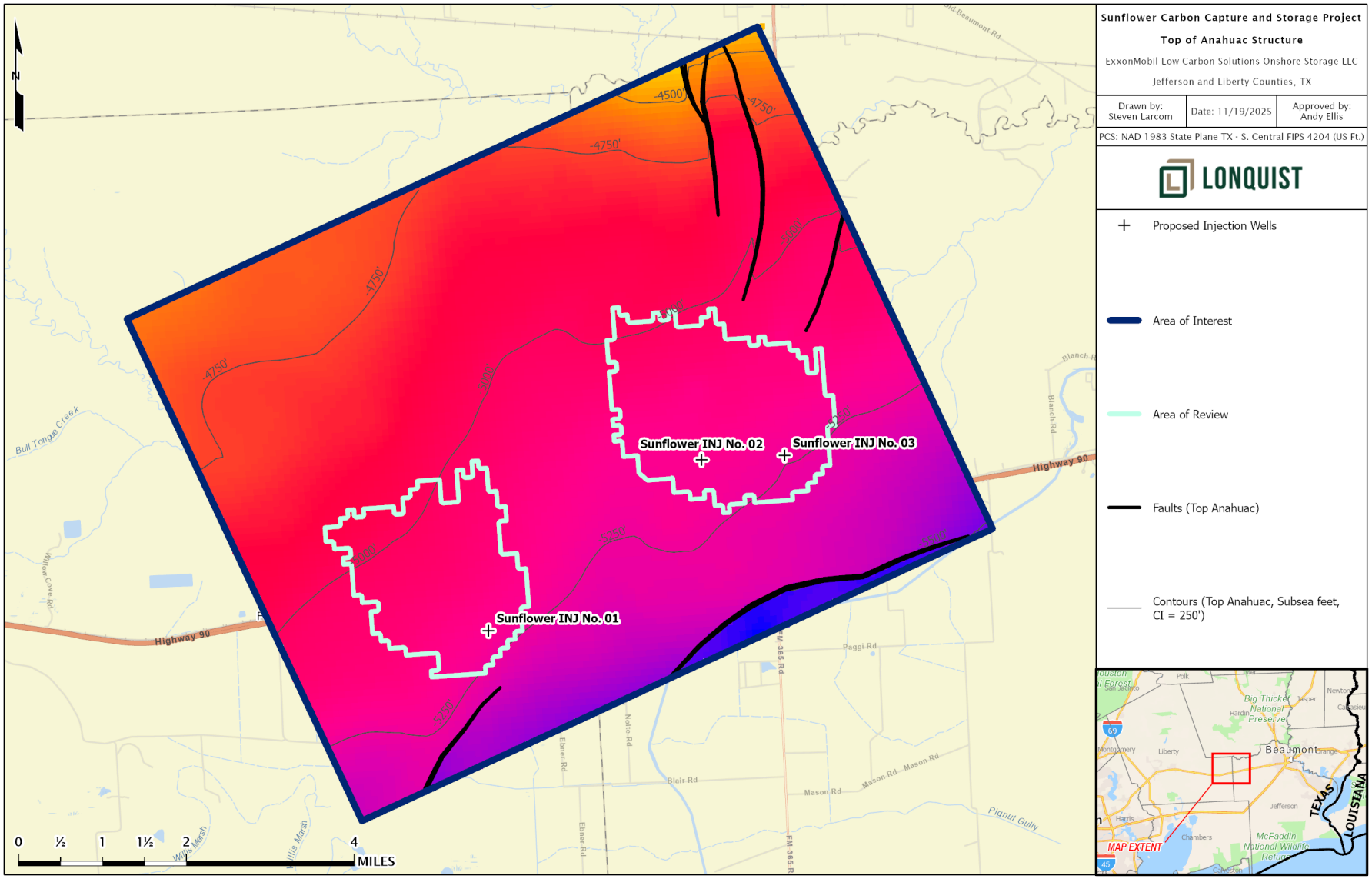


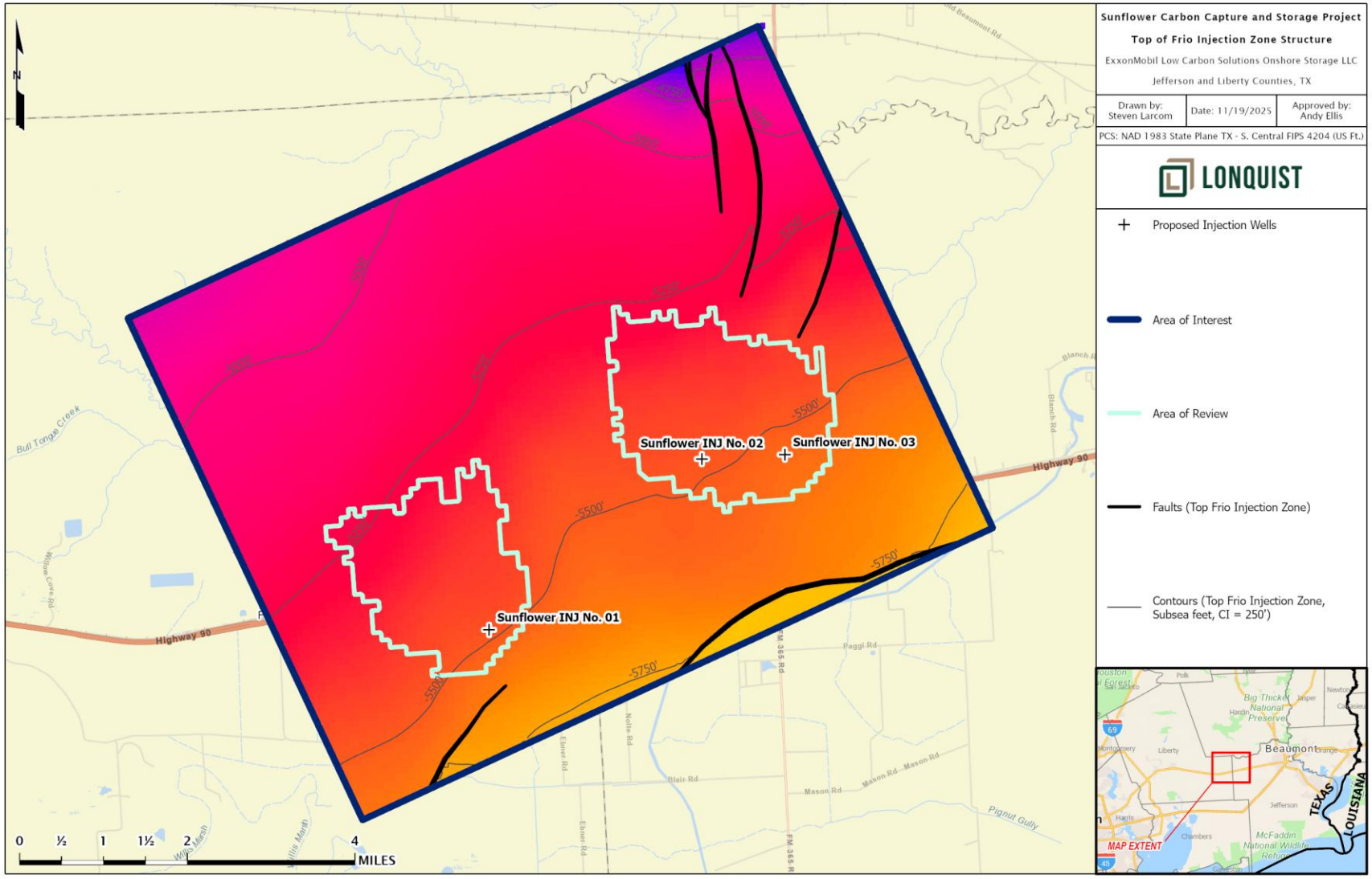
FIG□RE □□□: Sc□ematic□nort□□sout□ or dip□oriented cross section t□roug□ t□e greater Sunflo□er Pro□ect study area□
□ote t□e fold axis or □inge line in t□e nort□ern portion of t□is diagram□as □ell as t□e truncation of older stratigrap□y o□er t□e □inge line location near t□e modern surface□

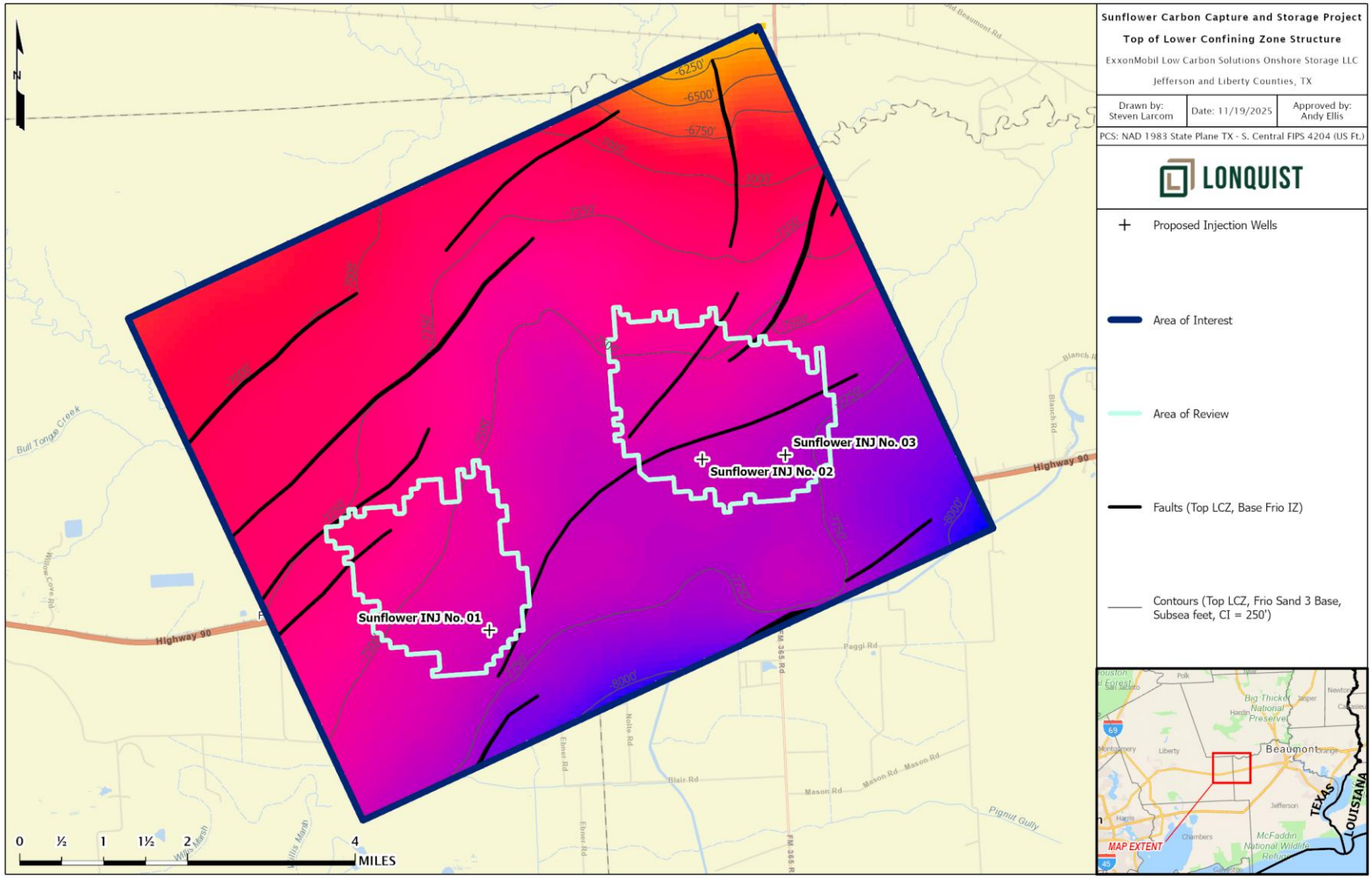
Appendix B2 – Site Geology

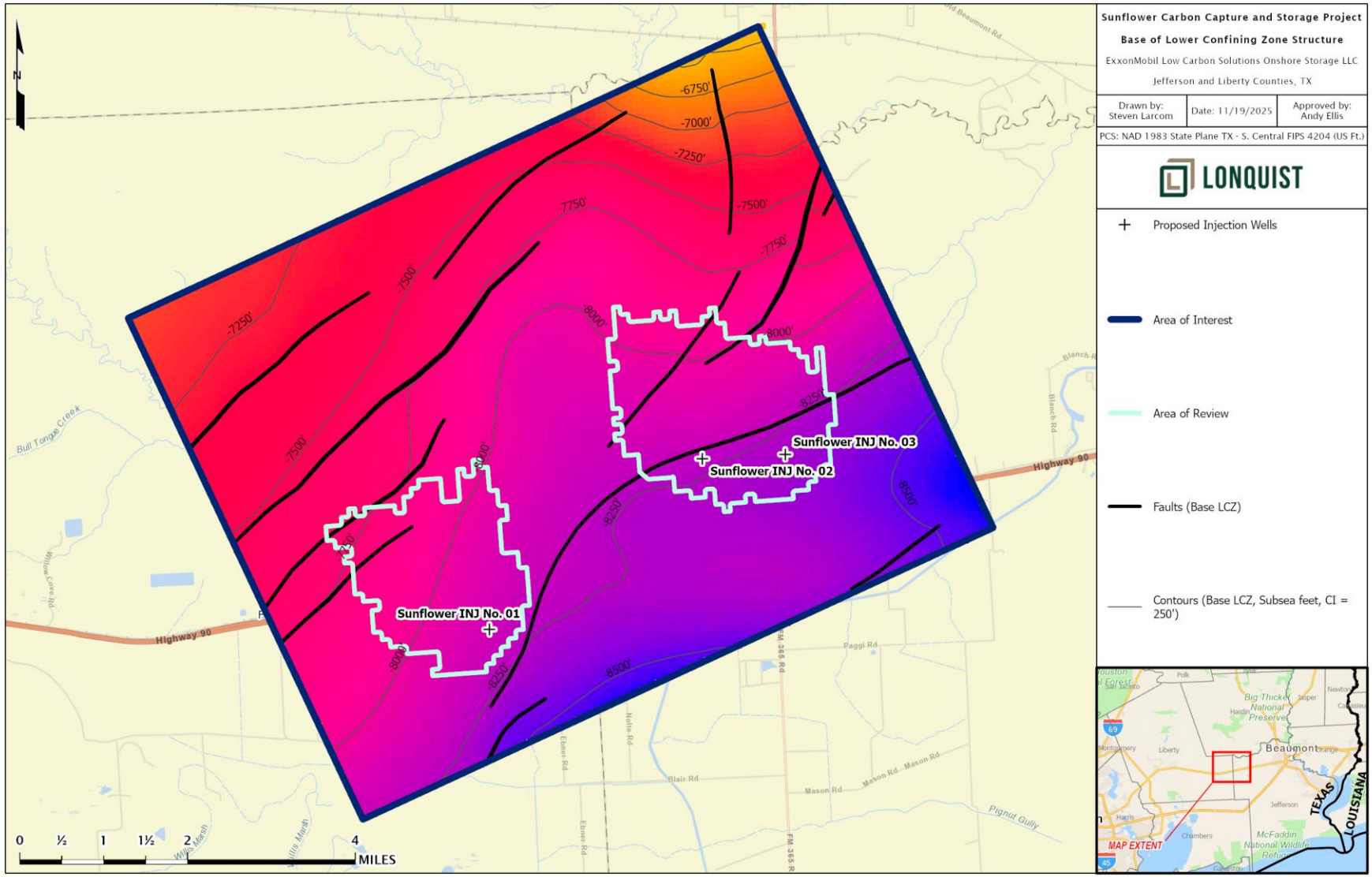

Sunflower Carbon Capture and Storage Project
Top of Upper Confining Zone Structure
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S, Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Top UCZ)
Contours (Top UCZ, Subsea feet, CI = 100')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
-3000'
-3100'
-3200'
-3300'
-3400'
-3500'
-3600'
-3700'
Highway 90
Bull Tongue Creek
Blanch Rd
Paggi Rd
Blair Rd
Mason Rd
Pignut Gully
FM 365 Rd
Ebner Rd
Nolte Rd
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
Beaumont
TEXAS
LOUISIANA

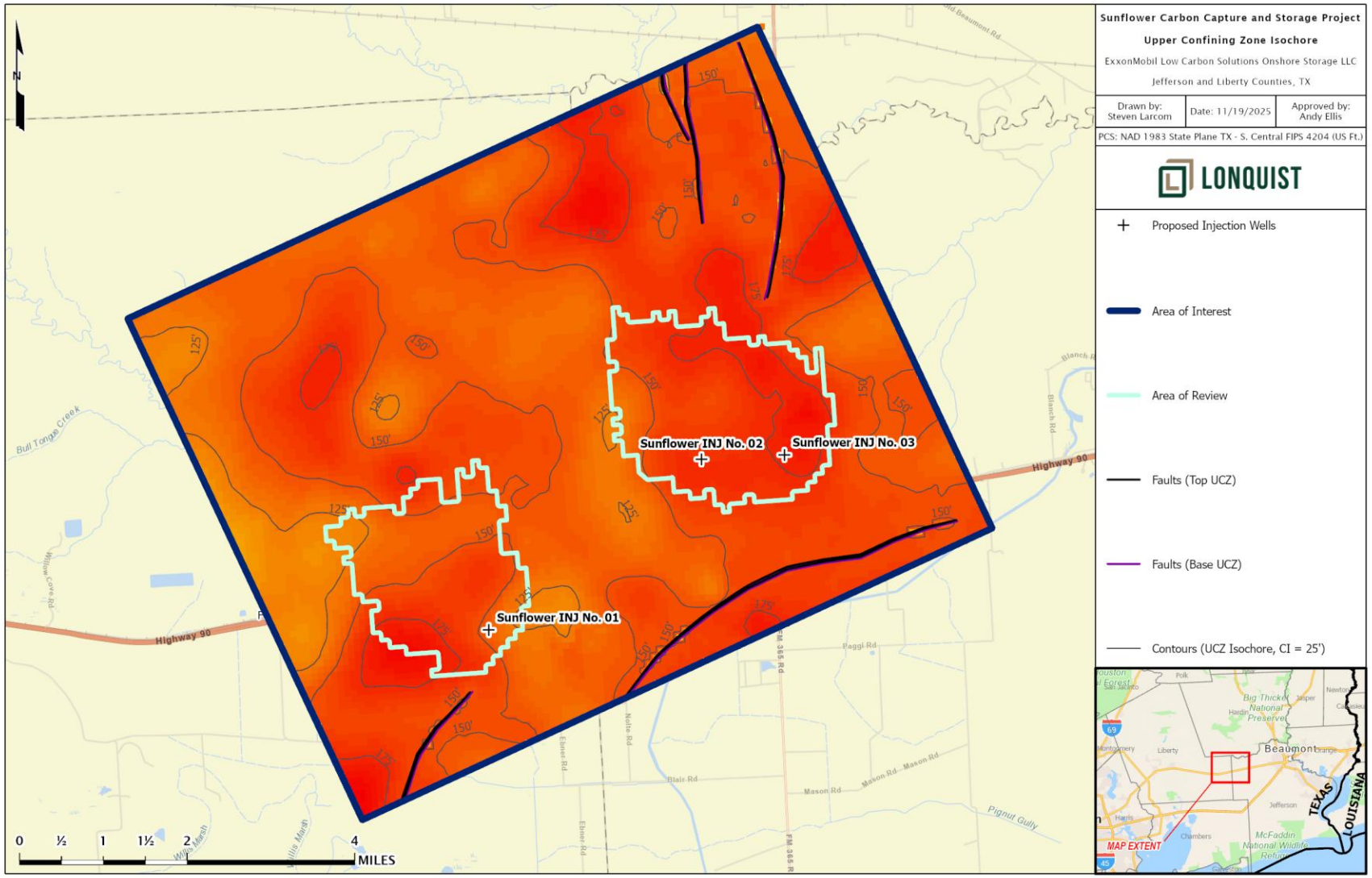

Sunflower Carbon Capture and Storage Project
Base of Upper Confining Zone Structure
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Base UCZ)
Contours (Base UCZ, Subsea feet, CI = 100')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
-3200'
-3100'
-3300'
Highway 90
Bull Tonge Creek
Pignut Gully
Paggi Rd
Blair Rd
Mason Rd
Blanch Rd
FM 365
0 ½ 1 1½ 2 4 MILES
Beaumont
TEXAS
LOUISIANA
MAP EXTENT

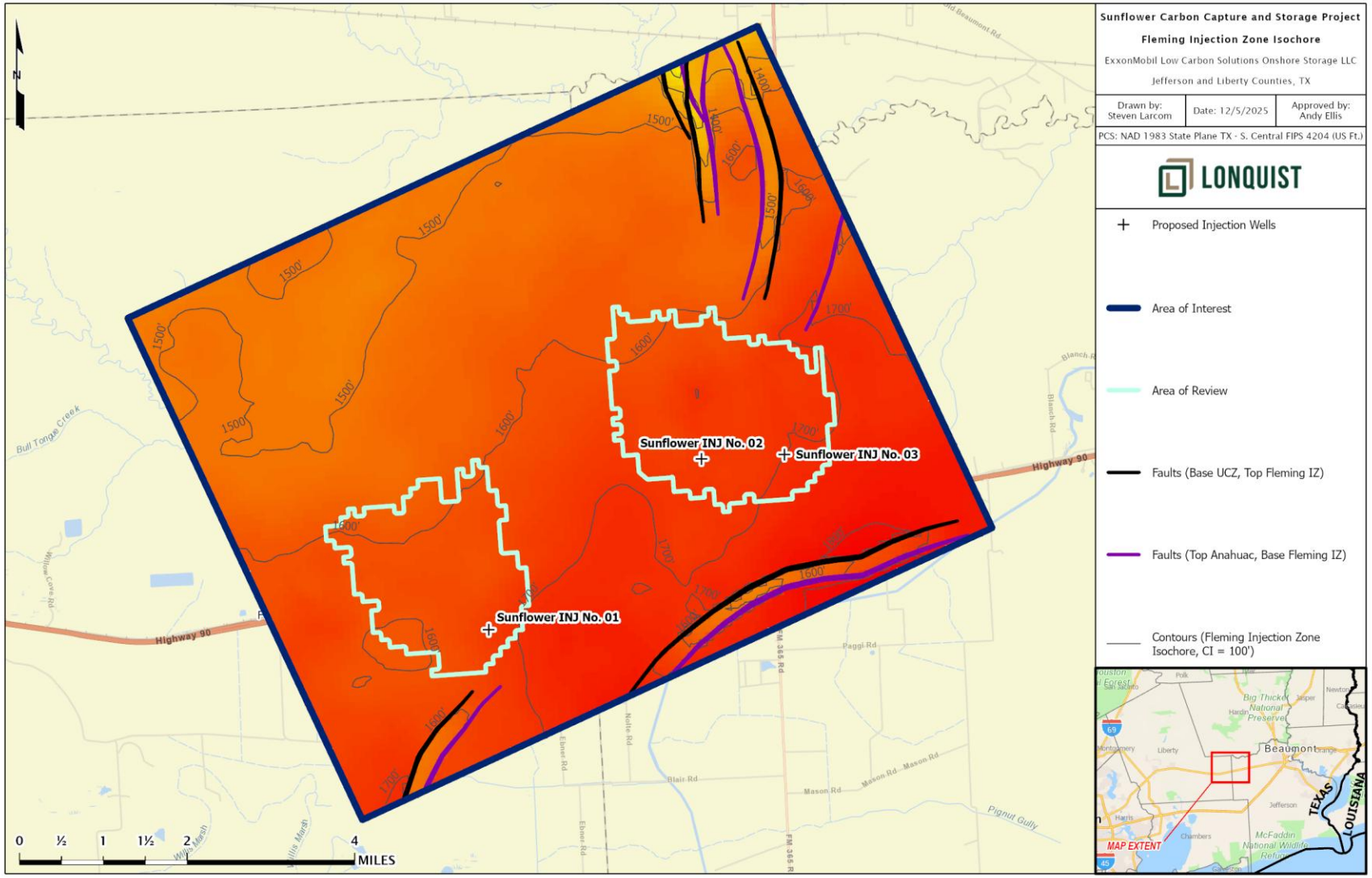

Sunflower Carbon Capture and Storage Project
Top of Anahuac Structure
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Top Anahuac)
Contours (Top Anahuac, Subsea feet, CI = 250')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
-4500'
-4750'
-5000'
-5250'
Highway 90
Bull Tongue Creek
Willow Cove Rd
Blanch Rd
Old Beaumont Rd
Paggi Rd
Blair Rd
Mason Rd
Ebner Rd
Nolte Rd
FM 365 Rd
Pignut Gully
Willis Marsh
White Marsh
0 ½ 1 1½ 2 4 MILES
N
MAP EXTENT
Beaumont
TEXAS
LOUISIANA
Big Thicket National Preserve
McFaddin National Wildlife Refuge

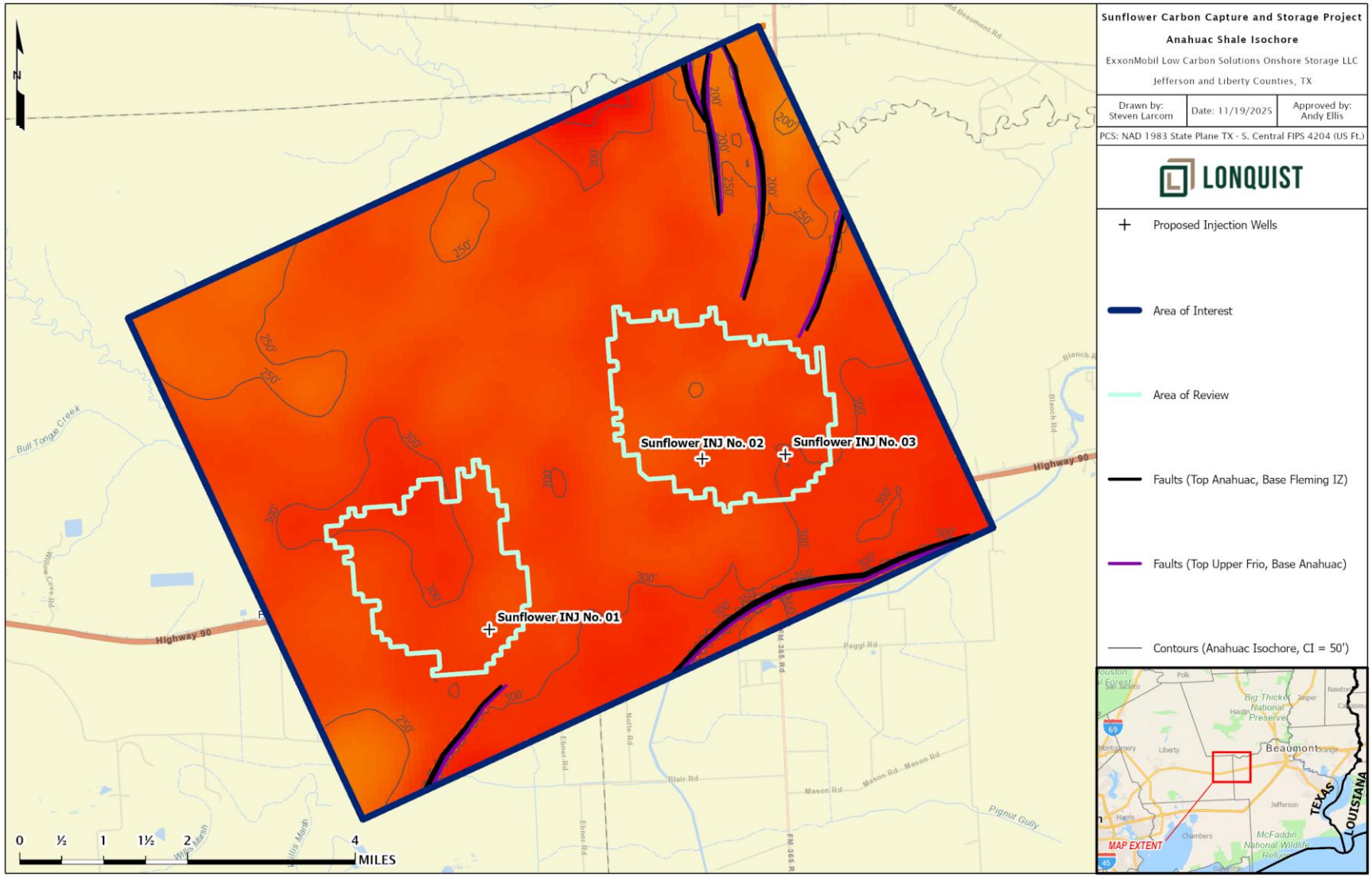

Sunflower Carbon Capture and Storage Project
Top of Frio Injection Zone Structure
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Top Frio Injection Zone)
Contours (Top Frio Injection Zone, Subsea feet, CI = 250')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
-5500'
-5750'
Highway 90
Bull Tongue Creek
Blair Rd
Mason Rd
Pignut Gully
FM 365 Rd
Ebner Rd
Paggi Rd
Blanch Rd
Old Beaumont Rd
Willis Marsh
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
Beaumont
TEXAS
LOUISIANA

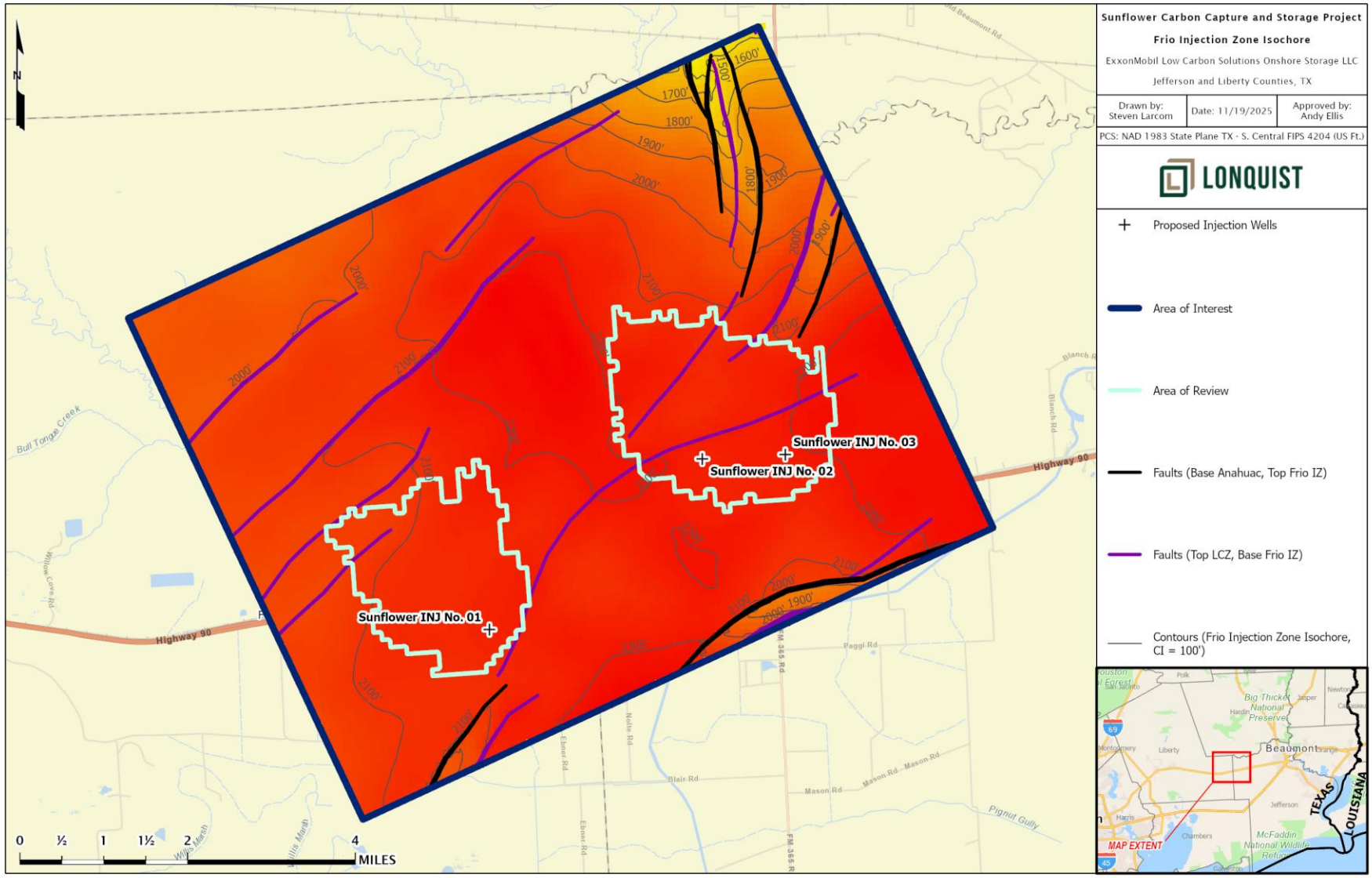

Sunflower Carbon Capture and Storage Project
Top of Lower Confining Zone Structure
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Top LCZ, Base Frio IZ)
Contours (Top LCZ, Frio Sand 3 Base, Subsea feet, CI = 250')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
-6250'
-6500'
-6750'
-7000'
-7250'
-7500'
-7750'
-8000'
-8250'
-8500'
-8750'
-9000'
-9250'
Highway 90
Bull Tongue Creek
Willow Cove Rd
Blanch Rd
Old Beaumont Rd
Paggi Rd
Mason Rd
Blair Rd
Nolte Rd
Ebner Rd
FM 365 Rd
Pignut Gully
Willis Marsh
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
Beaumont
TEXAS
LOUISIANA

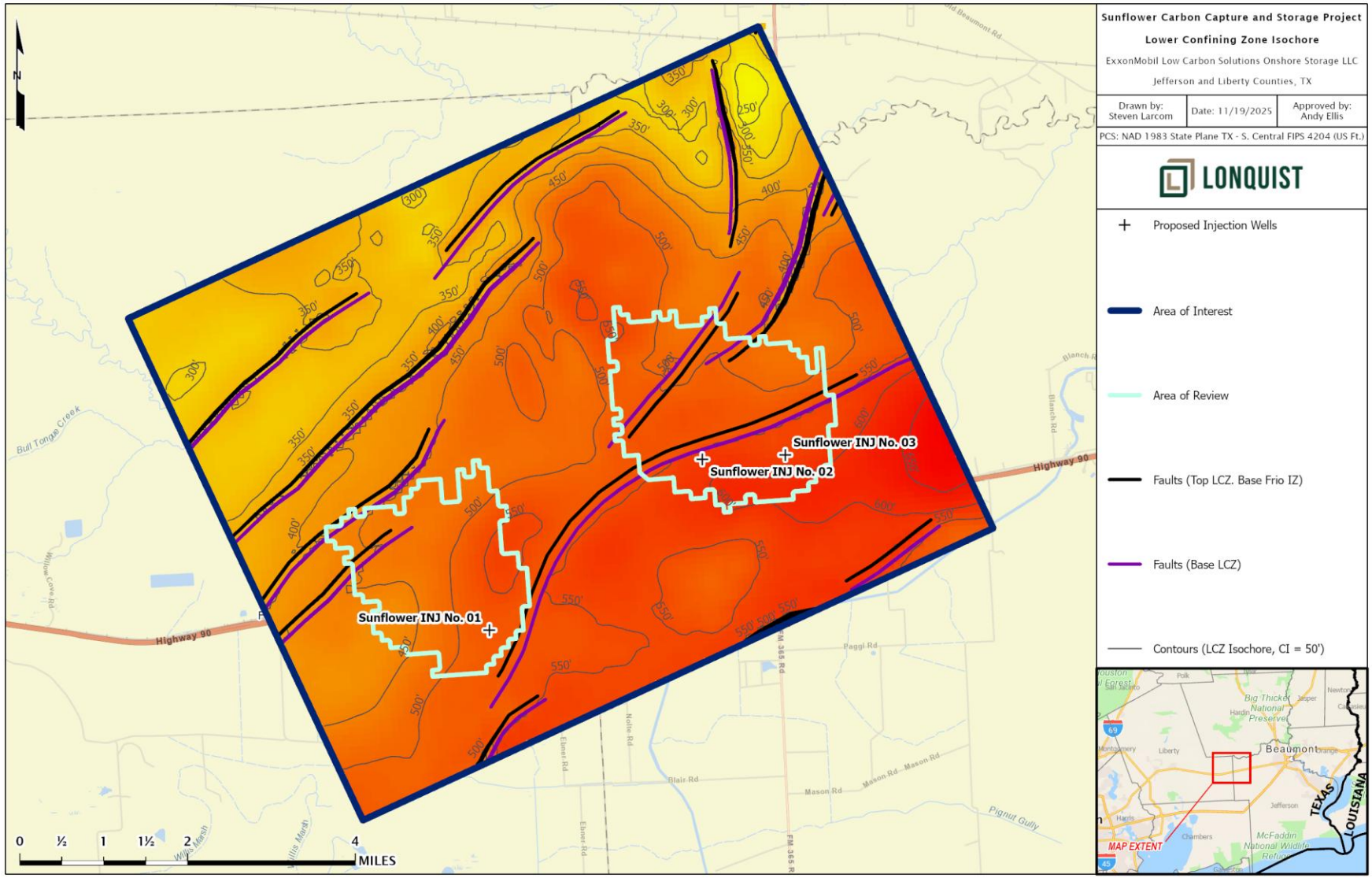

Sunflower Carbon Capture and Storage Project
Base of Lower Confining Zone Structure
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Base LCZ)
Contours (Base LCZ, Subsea feet, CI = 250')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
-6750'
-7000'
-7250'
-7500'
-7750'
-8000'
-8250'
-8500'
Highway 90
Bull Tonge Creek
Willow Cove Rd
Old Beaumont Rd
Blanch Rd
Paggi Rd
FM 365 Rd
Neche Rd
Ebner Rd
Blair Rd
Mason Rd
Pignut Gully
Wolf Marsh
Willis Marsh
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
Beaumont
TEXAS
LOUISIANA


Sunflower Carbon Capture and Storage Project
Upper Confining Zone Isochore
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Top UCZ)
Faults (Base UCZ)
Contours (UCZ Isochore, CI = 25')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
Highway 90
Bull Tongue Creek
Blair Rd
Mason Rd
Paggi Rd
Pignut Gully
FM 365 Rd
Ebner Rd
Nolte Rd
Blanch Rd
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
Beaumont
TEXAS
LOUISIANA


Sunflower Carbon Capture and Storage Project
Fleming Injection Zone Isochore
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 12/5/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Base UCZ, Top Fleming IZ)
Faults (Top Anahuac, Base Fleming IZ)
Contours (Fleming Injection Zone Isochore, CI = 100')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
Highway 90
Bull Tongue Creek
Blanch Rd
Paggi Rd
Blair Rd
Mason Rd
Pignut Gully
FM 366 Rd
Nolte Rd
Ebner Rd
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
TEXAS
LOUISIANA
Beaumont


Sunflower Carbon Capture and Storage Project
Anahuac Shale Isochore
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Top Anahuac, Base Fleming IZ)
Faults (Top Upper Frio, Base Anahuac)
Contours (Anahuac Isochore, CI = 50')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
Highway 90
Bull Tongue Creek
Blanch Rd
Paggi Rd
Blair Rd
Mason Rd
Pignut Gully
FM 365 Rd
Nolte Rd
Ebner Rd
0 ½ 1 1½ 2 4 MILES
N
MAP EXTENT
Beaumont
TEXAS
LOUISIANA


Sunflower Carbon Capture and Storage Project
Frio Injection Zone Isochore
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Base Anahuac, Top Frio IZ)
Faults (Top LCZ, Base Frio IZ)
Contours (Frio Injection Zone Isochore, CI = 100')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
Highway 90
Bull Tongue Creek
Willow Cove Rd
Blanch Rd
Paggi Rd
Blair Rd
Mason Rd
Nolte Rd
Ebner Rd
FM 365 Rd
Pignut Gully
Wills Marsh
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
Beaumont
TEXAS
LOUISIANA
Big Thicket National Preserve
McFaddin National Wildlife Refuge


Sunflower Carbon Capture and Storage Project
Lower Confining Zone Isochore
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Faults (Top LCZ. Base Frio IZ)
Faults (Base LCZ)
Contours (LCZ Isochore, CI = 50')
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
Highway 90
Bull Tongue Creek
Willow Cove Rd
Blanch Rd
Paggi Rd
Blair Rd
Mason Rd
Nolte Rd
Ebner Rd
FM 365 Rd
Pignut Gully
0 ½ 1 1½ 2 4 MILES
N
MAP EXTENT
Beaumont
TEXAS
LOUISIANA

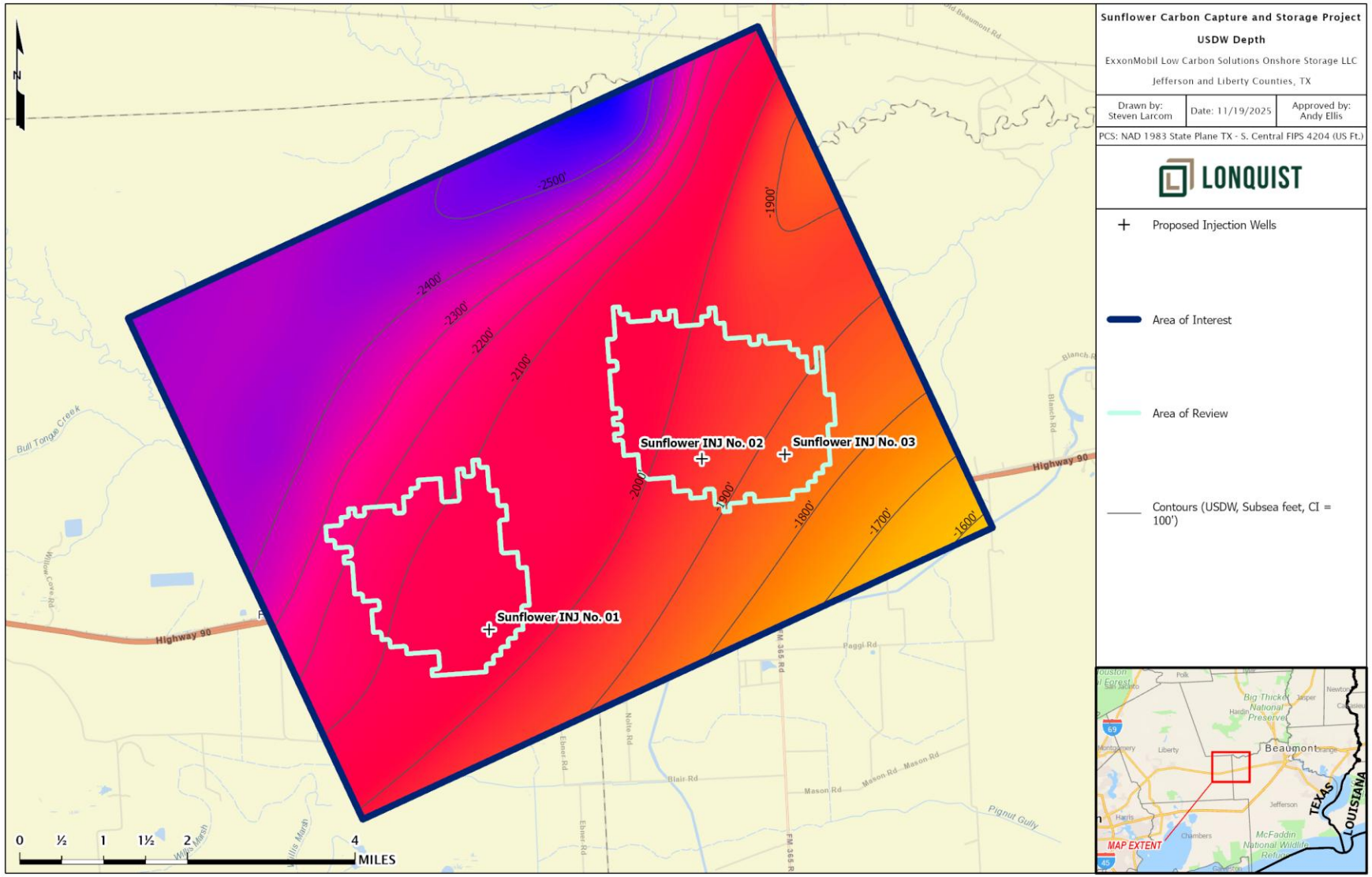

Sunflower Carbon Capture and Storage Project
USDW Depth
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson and Liberty Counties, TX
Drawn by: Steven Larcom
Date: 11/19/2025
Approved by: Andy Ellis
PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)
LONQUIST
Proposed Injection Wells
Area of Interest
Area of Review
Contours (USDW, Subsea feet, CI = 100')
N
-2500'
-2400'
-2300'
-2200'
-2100'
-1900'
-2000'
-1900'
-1800'
-1700'
-1600'
Sunflower INJ No. 01
Sunflower INJ No. 02
Sunflower INJ No. 03
Highway 90
Highway 90
Bull Tonge Creek
Willow Cove Rd
Blanch Rd
Old Beaumont Rd
Paggi Rd
FM 365 Rd
Nalle Rd
Ebner Rd
Blair Rd
Mason Rd
Mason Rd
Mason Rd
Pignut Gully
Wolf Marsh
Willis Marsh
0 ½ 1 1½ 2 4 MILES
MAP EXTENT
Beaumont
TEXAS
LOUISIANA
Big Thicket National Preserve
McFaddin National Wildlife Refuge
Liberty
Jefferson
Chambers
Harris
Montgomery
Polk
Jasper
Newton
Orange

Table of Wells Used in Petrophysical Evaluation

Well Name	UWI	SP	GR	DTC	RHOB	NPHI	VSH	PHIT
Champion Int - 1	421993257000	X	X	X	X	X	X	X
Carpenter Estate F - 1	422450000200	X					X	
G T Garth - 1	422450000300	X					X	
F H Carpenter - 1	422450000400	X					X	
F Carpenter Etal - 1	422450000500	X					X	
F S Wilson - 1	422450000600	X					X	
Willis B H - 1	422450000800	X					X	
Lawrence Leger - 1	422450000900	X					X	
Mauboules - 1	422450001300	X					X	
Berry-Peuitoe - 1	422450001600	X					X	
Wilson Etal - 1	422450321400	X					X	
A M Carpenter Est - 1	422450324000	X					X	
B H Willis Est - 1	422453018400	X					X	
Carpenter - 1	422453029000	X					X	
C T Garth - 1	422453034400	X					X	
Garth Co - 1	422453038900	X					X	
Garth Co - 2	422453043800	X					X	
J E Burrows - 7	422453045100	X	X	X	X		X	X
Garth Co - 1	422453146400	X	X				X	
Champion Intl Corp - 1	422453149100	X		X			X	X
Swepi/Txpo Barnes E - 1	422453184600	X	X	X			X	X
Garth - 1	422453193100	X	X		X	X	X	X
Carpenter - 1	422453214900	X	X				X	
Mcclintock - 1	422453245700		X				X	
Nome-Beavers Gu - 2	422453254400		X				X	
Leger - 1	422453256800		X				X	
Graham Trust - 1	422453272800		X				X	
Big Prairie - 1	422453287700		X				X	
Stone - 4	422910032900	X					X	
Stone - 7	422910033100	X					X	
R Hankamer - 1	422910033200	X					X	
B H Willis Est - 1	422910033400	X					X	
Vinton Gene R Etal - 1	422913148300	X	X	X	X	X	X	X
Arco Fee - 1	422913159400	X	X	X	X	X	X	X
Stone - 1	422913206200	X	X				X	
Wilson F S - 1	422913207100	X	X				X	
Stone - 2	422913207500	X	X	X	X	X	X	X
Arco Fee - 1	422913215900	X	X	X			X	X
Arco Fee - 2	422913217700	X	X		X	X	X	X
Stone - 1	422913220900	X	X	X			X	X
Champion Internatio - 1	422913221100	X	X				X	
Federal Royalty Par - 1	422913247800	X	X				X	
Henderson - 1	422913249400	X	X		X	X	X	X
Stone A - 1	422913250300	X	X				X	
Federal Royalty Prtn - 1	422913263000		X				X	
Willis Estate - 5	422913272100	X	X	X	X	X	X	X
Hankamer Cypress - 1	422913274200	X	X	X	X	X	X	X

Appendix B3 – Geologic Structure

Conventional Core Natural Fracture Evaluation and USDW Impact Assessment

B-3.1 Summary

As part of the site appraisal program, core from the Bead Farm Co. - 1 (API No. 4224532908) stratigraphic well was examined to document the presence of structural features in storage and sealing intervals. The objective of this evaluation was to identify whether structures exist that might facilitate the migration of carbon dioxide (CO2) and/or brine vertically from the injection intervals in the Fleming and Frio sands toward overlying underground sources of drinking water (USDW).

The core analysis revealed no natural fractures, stylolites, deformation bands, or significant faults in the slabbed cores, the core computed tomography (CT) scans, or the borehole imagery (BHI). A single minor (below seismic resolution) fault that crosses the full width of the core was identified in Core 7 (Anahuac Shale). The only natural structural features observed in the core are non-tectonic pedogenic slickensides, expected features that form prior to burial of the regionally extensive clay-rich sediments found across the Gulf Coast region. In eight cores (from the Upper Composite Confining Zone - UCCZ, three intermediate shales, and two reservoir sands) no faults or fractures signifying a structural or tectonic fabric overprinting the stratigraphy were identified, nor is there evidence of fluid flow along the pedogenic slickensides. Therefore, nothing in the core suggests a potential impact on USDW resources due to enhanced vertical permeability along flow pathways related to natural structural features.

B-3.2 Methods for Structural Feature Classification and Evaluation

Upon core extrusion, a slabbing orientation was selected that ensured structural features roughly parallel the core axis would be intersected and visible in the one-third slab used for the fracture and core descriptions. The perpendicular orientation was chosen relative to the orientation(s) of potential structural features observed as sinusoids in core CT scans and/or that were revealed where the core broke during the extrusion process.

Several observations were used to classify natural features (e.g. non-tectonic shear planes, fractures, and faults) and distinguish them from man-made breaks in the core (e.g. from drilling, core handling, defrosting, or fluid desiccation). These observations include the following:

- Natural structural features are commonly characterized by the presence of slickensides and slickenlines (Figure B-3-1), and offset stratigraphy usually indicates a natural structure, although it can be difficult to identify at the core scale;
- Shear smooths structural planes, and though they may retain a degree of irregularity and undulation, they are typically free of high-frequency changes in orientation. Natural fractures grow gradually, propagating at each tip from their center, and are similarly smooth-edged. Shear on structural planes may also result in grain size reduction, especially in coarser grained sediments. In contrast, induced fractures are more jagged, are characterized by sharp steps and truncations at lithological boundaries and display no change in grain size (Figure B-3-2a);
- Opening mode fractures are wider in the middle of the fracture and taper towards the fracture tips; this space may be filled by mineral precipitation resulting from fluid flow. Natural faults often accommodate fluid flow as well and so may also contain mineral precipitation. Because this process takes time, man-made induced fractures will not contain mineral precipitates or cements;

- Populations of natural structural features can commonly be distinguished based on similarity in orientation, and although induced features may take advantage of pre-existing weaknesses, they are likely to display a greater degree of randomness (Figure B-3-2b);
- Fractures may form when the core is thawed after having been frozen for stabilization, or from desiccation of formation fluids; these induced fractures are often aligned roughly parallel to the core edge (Figure B-3-2c).

Using these criteria, probable natural faults, fractures, and non-tectonic shear planes were marked along the core, counted, recorded according to depth, and photographed.

Methods for quantifying the density of structural features in core or outcrop combine the dimension of the measurement (i.e., feature length, area, or volume) and the dimension of the sample (i.e., core/outcrop length, area, or volume) (e.g., Dershowitz and Herda, 1992; Figure B-3-3). Because most features observed in the stratigraphic well core samples cross the entire width of the core, the feature length, area and volume cannot be measured. The feature intensity and concentration were assessed by tallying the number of natural (non-induced) features in every foot of core (Figure B-3-4). A P10 value (Figure B-3-3) provides a measure of feature intensity over the length of a core. Planar features that may be natural or induced are also identified and measured using azimuthally oriented borehole imagery. In most cases, classifying the planar feature is unlikely to occur and lower dip (less than approximately30°) planes are difficult to resolve. Efforts were made to use measurements from borehole images cover the whole length of the well bore to support the evaluation and compliment the core measurements.

B-3.3 Structural Features in the Core and Borehole Imagery

Abundant (n = 245) irregularly curved and undulatory surfaces characterized by slickensides and slickenlines are the primary structural feature identified in the Upper Composite Confining Zone (UCCZ), Fleming Shale 2 and in a shale bed in the Fleming Sand 2 (Figure B-3-1). The slickensides and slickenlines were found only in the mud-prone 'shale' sections of Cores 1-4, with intensities of up to 8 per foot (Figure B-3-4) and in two roughly orthogonal orientations with a range in dip from near horizontal to up to 60° (Figure B-3-1). No mineralization or cementation was observed on any of these surfaces. Small faults internal to the core with millimeter offset were commonly observed and not considered significant for the evaluation (Figure B-3-2a). One fault large enough to cut across the width of the core was observed as a single, distinctly flat plane with light mineral precipitation and subtle slickensides and slickenlines (Core 7, Anahuac Shale); no accompanying distributed fault or fracture zone is apparent (Figure B-3-5). Because the fault is not visible in seismic and because there are no visible strain markers recording relative offset in the core, the net displacement could not be measured. Jagged and stepped fractures truncated at lithologic boundaries were observed throughout the core (Figure B-3-2); fracture orientation ranged from random (Figure B-3-2b) to roughly parallel to the core axis (Figure B-3-2c).

A total of 81 planar features were observed in the borehole images collected with an SLB CAST ultrasonic imager (Figure B-3-6). Of these, 12 planar features were identified across the cored intervals, far fewer than were identified in the cores themselves (Figure B-3-7). Structural surface type could not be identified from the borehole images. Only two planar features were seen in sand intervals, with the remainder found in shale intervals (assuming v-shale cutoff of 50%; Figure B-3-8), consistent with the core observations. The measured dip magnitude ranged from 30° to 74° (median dip of 49°) and the dip direction was essentially random with a slight peak around approximately 300° (northwest) (Figure B-3-

7a,c). The 12 features identified at core equivalent depths have a median dip of 50° and no common dip direction (Figure B-3-7b).

B-3.4 Origin and Significance of Structural Features

The only fractures identified in the core were induced, related either to handling, core recovery, freeze/thaw, or fluid desiccation (Figure B-3-2). The single minor fault observed in Core 7 (Anahuac Shale) is not suggestive of a pervasive fault zone or system within this formation or across the AOR. The structural surfaces identified in the fine-grained sections of Cores 1-4 (UCCZ, Fleming Shale 2, shale within the Fleming Sand 2) are interpreted to be non-tectonic pedogenic slickensides in paleo-vertisols. The absence of natural fractures or pervasive faulting suggests that there are no tectonically induced high permeability pathways for fluid migration within the AOR. Furthermore, pedogenic slickensides are original features of the clay-rich paleo-vertisol that are components of sealing intervals trapping hydrocarbons across the Gulf Coast, and so evidently do not accommodate vertical fluid flow.

The shale sections in Cores 1 to 4 are predominantly buried vertisols – clay-(smectite) rich soils that formed during prolonged subaerial exposure of fine-grained sedimentary deposits (e.g., Ahmad, 1983; Coulombe et al., 1996; Kvoda, 2020). A universal characteristic of vertisols is the presence of irregular, concave-convex well-developed pedogenic slickensides. These form over the course of multiple wet-dry cycles as clays swell upon rehydration, leading to elevated horizontal compressional stress ($\sigma_1 \approx \sigma_2 > \sigma 3$) and eventual shear failure (Wilding and Tessier, 1988; Gray and Nickelsen, 1989; Nachum et al., 2022). According to Mohr-Coulomb failure criterion, shear failure should theoretically occur along planes dipping at approximately 45°, but in practice pedogenic slickensides, like faults and fractures in nature, have been observed dipping from 10 to 60° (Blokhuis et al., 1990; Coulombe et al., 1996), with random azimuthal orientations. It is reasonable to suppose that compaction during eventual burial causes additional shear, slickenside development and dip rotation.

The interpretation of the observed shear planes as non-tectonic pedogenic slickensides is supported by 1) the identification of the fine grained intervals as vertisols and the presence of slickensides within, 2) the irregular undulatory character of the slickenside surfaces, 3) the confinement of these surfaces to the clay-rich intervals, 4) the range of dips observed in the core and borehole imagery, and 5) the randomness in dip direction azimuth observed in the borehole imagery. Critically, the absence of cementation or mineralization of the slickenside surfaces suggests they have not served as pathways for fluid transmission and do not pose a threat to USDW sources by increasing vertical permeability from injection zones.

Two observations are consistent specifically with a non-tectonic origin for the slickensides. First, they are contained within the clay-rich intervals and do not appear to propagate into over- and underlying stratigraphy (Figure B-3-9) as would be expected for structures formed in response to regional stresses. Second, if they were tectonic, instead of the random spread of dip directions that is observed it would be reasonable to expect a dominant orientation parallel to the south-southeast dipping network of growth faults that traverse the region. The relative abundance of features with dip directions between ~260-360° (Figure B-3-7a) identified in the borehole images suggests a subset of planes that are roughly parallel, if antithetic, to regional fault strike. However, since we cannot distinguish between natural and induced features in the borehole imagery, and because there is still significant scatter in dip direction among the remaining features, ascribing a tectonic origin would be unwarranted. The fact that dip direction can vary widely within even relatively small (<100 ft; Figure B-3-7c) depth ranges is further

evidence of a disorganized, non-tectonic origin. Because the pedogenic slickensides are non-tectonic, their presence is not an indication of the presence of a pervasive structural fabric in the reservoir and seal rocks that could enhance vertical fluid migration.

The only other natural structural feature was the single fault observed in Core 7 (Anahuac Shale; Figure B-3.5). This structure may be related to the regional system of south dipping faults, though because it was not visible in the borehole imagery its orientation remains unknown. As it is not resolvable in the seismic either, it can have at most a few tens of feet of throw and so is a minor structure. Because it was the only such feature identified in any of the core sections it is not considered evidence of a wider fault system within the AOR that could permit vertical fluid flow.

B-3.5 Conclusions

The following conclusions can be drawn from the Bead Farm Co. -1 conventional core fracture analysis:

- No evidence of the potential for enhanced vertical permeability along natural fractures or faults in reservoir or sealing intervals was found in the core or borehole imagery.
- None of the natural structural features identified in the analysis signal the presence of a pervasive tectonic or structural fabric across the AOR and none are considered effective pathways for fluid transmission from injection intervals to USDW.
- Natural structural features in the core are predominantly non-tectonic pedogenic slickensides; this classification is supported by multiple lines of evidence including host rock mineralogy, slickenside morphology, stratigraphic confinement, and random orientation. Pedogenic slickensides are anticipated, regionally extensive features that form prior to burial of clay-rich soils and so are not related to any later phase of deformation that might affect fluid flow.
- Only a single minor (below seismic resolution) fault was observed in the core, and no natural fractures were identified, suggesting a negligible role for such features in altering expected flow behavior in the AOR.

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Appendix B4 – Baseline Geochemistry

Geochemical Modeling Report Figures and Tables

Appendix B5 – Site Evaluation of Mineral Resources

Productive Oil and Gas Wells within 5 Miles of Sunflower Project Site

API	Well Name	Field	County	Producing Status	Production Type	Reservoir	Measured Depth (TD)	First Prod Date	Last Prod Date
4229132943	CRAWFORD 1	HATHAWAY	LIBERTY (TX)	P & A	GAS	EY-2B	11650	1/1/2022	10/1/2022
4224532877	BIG PRAIRIE 1	BIG PRAIRIE	JEFFERSON (TX)	P & A	GAS	EY-3	9623	6/1/2020	6/1/2021
4224532626	MCDERMOND 5	REBEL	JEFFERSON (TX)	INACTIVE	GAS	YEGUA	15400	4/1/2016	5/1/2022
4224532604	KEELAND GAS UNIT 1	CLAUDE WATTS	JEFFERSON (TX)	ACTIVE	GAS	YEGUA 12600	13067	9/1/2014	8/1/2025
4224532645	BUBBA 'D' GU 1	REBEL	JEFFERSON (TX)	P & A	GAS	YEGUA	12946	9/1/2015	9/1/2015
4224532529	NOME-BEAVERS 1ST	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-3 SAND	13512	8/1/2013	11/1/2013
4229132720	IMPERIAL 1	HATHAWAY, SW.	LIBERTY (TX)	INACTIVE	GAS	YEGUA EY 2A	14200	3/1/2014	8/1/2019
4224532529	NOME-BEAVERS GAS UNIT 1ST	REBEL	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA	13512	6/1/2013	6/1/2013
4224532728	GRAHAM TRUST 1	REBEL	JEFFERSON (TX)	ACTIVE	GAS	YEGUA	12585	6/1/2012	8/1/2025
4224532568	LEGER 1	NOME	JEFFERSON (TX)	INACTIVE	GAS	YEGUA MIDDLE EY	14488	6/1/2012	9/1/2023
4224532724	J. H. BROUSSARD 1	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8050	5/1/2012	6/1/2017
4224500073	PAGGI, ED 3	NOME	JEFFERSON (TX)	INACTIVE	OIL		8103	2/1/1969	6/1/1976
4229132846	STONE 'B' 1	CYPRESS POND	LIBERTY (TX)	ACTIVE	GAS	UPPER COOK MTN	11997	5/1/2011	8/1/2025
4224500035	LONG 9	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-2A SAND	8000	5/1/1977	10/1/1979
4224532648	MASON ROAD 1	NOME	JEFFERSON (TX)	P & A	GAS	YEGUA MIDDLE EY	16050	11/1/2010	12/1/2010
4224500064	CARPENTER, A.M. 12	NOME	JEFFERSON (TX)	INACTIVE	OIL	R4	8071	6/1/1986	6/1/1986
4224531893	LONG 29	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-A	8020	10/1/1987	7/1/2007
4224500035	LONG 9 L	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	1/1/1969	1/1/1977
4224500041	LONG 16	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	10/1/1953	9/1/2014
4224500023	BURROWS, J. E. 6	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8015	11/1/1953	3/1/1974
4224500051	LONG 26	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	7500	5/1/1994	7/1/2004
4224500051	LONG 26	NOME	JEFFERSON (TX)	INACTIVE	OIL		7500	10/1/1979	7/1/2001
4229131760	DUNAGAN, J.A. 3	FELICIA, S.	LIBERTY (TX)	INACTIVE	OIL	YEGUA 11160	13503	7/1/1984	12/1/1990
4224500073	PAGGI, ED 3	NOME	JEFFERSON (TX)	INACTIVE	OIL	FRIO T-2	8103	10/1/1970	7/1/1971
4224500065	CARPENTER, ALMA 13	NOME	JEFFERSON (TX)	INACTIVE	OIL	"S-1" SAND	8110	7/1/1985	8/1/2011
4224500031	LONG 5	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	6976	11/1/1958	1/1/2017
4224500039	LONG 14	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	10/1/1953	9/1/2014
4224500039	LONG 14	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-3 SAND	8000	10/1/1953	9/1/1970
4224500039	LONG 14	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8000	11/1/1958	1/1/2012
4224500091	PAGGI EST. 14	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8050	1/1/1948	5/1/1971
4224500080	PAGGI ESTATE 3 U	NOME	JEFFERSON (TX)	INACTIVE	OIL	6730	8658	1/1/1941	6/1/1970
4224500072	PAGGI, ED 2	NOME	JEFFERSON (TX)	INACTIVE	OIL		6055	2/1/1969	6/1/1976
4224500072	PAGGI, ED ESTATE 2	NOME	JEFFERSON (TX)	INACTIVE	OIL	FRIO T	6055	8/1/1975	3/1/1979
4224500026	LONG-MAUBOULES 3	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	7/1/1954	3/1/1988
4224500037	LONG 12	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	8/1/1972	7/1/2007
4224500037	LONG 12	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-2A SAND	8000	9/1/1972	3/1/1973
4224532320	GREY WOLF 1	NOME	JEFFERSON (TX)	ACTIVE	OIL	MARGINULINA	8006	1/1/2004	7/1/2025
4224531962	CARPENTER, ALMA 17	NOME	JEFFERSON (TX)	INACTIVE	OIL	"S-1" SAND	6200	3/1/1989	11/1/1991
4224500043	LONG 18 U	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8003	11/1/1958	6/1/2019
4229131666	DUNAGAN, J.A. 2	FELICIA, S.	LIBERTY (TX)	INACTIVE	OIL	YEGUA 11160	12050	1/1/1984	11/1/1988
4224531707	DISHMAN, H. E. 1	NOME	JEFFERSON (TX)	INACTIVE	OIL		14500	6/1/2000	6/1/2000
4224532531	SUN-HARDER 1	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8324	2/1/2008	2/1/2015
4224532137	LONG 1	NOME	JEFFERSON (TX)	INACTIVE	OIL	YEGUA MIDDLE EY FB2	13900	7/1/2004	5/1/2009
4224531955	CARPENTER, ALMA M. 16	NOME	JEFFERSON (TX)	INACTIVE	OIL	S-1	6290	1/1/1989	8/1/2011
4224500080	PAGGI, ED ESTATE 3	NOME	JEFFERSON (TX)	INACTIVE	OIL	FRIO T	8658	8/1/1975	6/1/1980
4224500036	LONG 10 C	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8000	11/1/1958	10/1/2018
4224500064	CARPENTER, ALMA 12	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8071	1/1/1951	10/1/1983
4224500083	PAGGI, ED. 6 U	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8106	8/1/1958	2/1/1980
4224531851	ED PAGGI ESTATE 9	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND, LOWER	8014	9/1/1985	9/1/1985
4224531851	PAGGI, ED ESTATE 9	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8014	9/1/1988	2/1/1992
4224500088	PAGGI ESTATE 11	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	7359	5/1/1966	7/1/1979
4224500046	LONG 21	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	10/1/1954	9/1/2014

4224500046	LONG 21	NOME	JEFFERSON (TX)	INACTIVE	OIL		8000	1/1/1956	1/1/2017
4229131586	DUNAGAN, J.A. 1	FELICIA, S.	LIBERTY (TX)	INACTIVE	OIL	YEGUA 11160	13500	3/1/1983	7/1/2023
4224500048	LONG 23	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	7984	11/1/1954	4/1/1976
4224500048	LONG 23	NOME	JEFFERSON (TX)	INACTIVE	OIL		7984	1/1/1956	4/1/1976
4229100330	STONE 5	HATHAWAY	LIBERTY (TX)	INACTIVE	OIL	EY-2B	10811	10/1/1981	5/1/1996
4224500090	PAGGI ESTATE 13	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8005	5/1/1966	7/1/1979
4224500040	LONG 15	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	10/1/1953	6/1/1984
4224500029	LONG 3	NOME	JEFFERSON (TX)	INACTIVE	OIL		6056	1/1/1956	2/1/1981
4224500054	CARPENTER, ALMA 2	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8050	3/1/1980	12/1/1980
4224500045	LONG 20	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	4/1/1954	7/1/2007
4224500028	LONG 2	NOME	JEFFERSON (TX)	INACTIVE	OIL		6056	1/1/1956	3/1/1968
4224531305	MCDERMOND, F. 4	NOME SE.	JEFFERSON (TX)	INACTIVE	OIL	FRIO, UP	8409	6/1/1979	11/1/2022
4229100327	STONE 2D	HATHAWAY	LIBERTY (TX)	INACTIVE	OIL	EY-2B	10000	3/1/1960	5/1/1996
4224530114	CARPENTER, ALMA 14R	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8273	2/1/1971	10/1/1983
4224500052	LONG 27	NOME	JEFFERSON (TX)	INACTIVE	OIL		6120	4/1/1956	1/1/1987
4224502459	JUNKER-SPENCER ETAL FEE 5	FANNETT	JEFFERSON (TX)	INACTIVE	OIL		7013	10/1/1963	11/1/1978
4224500082	PAGGI ESTATE 5	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	7333	5/1/1966	7/1/1979
4224530109	CARPENTER, ALMA 14A	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8216	12/1/1970	7/1/1976
4224531287	MCDERMOND, F. 2	NOME SE.	JEFFERSON (TX)	ACTIVE	OIL	FRIO, UP	8366	3/1/1979	8/1/2025
4224500049	LONG 24	NOME	JEFFERSON (TX)	INACTIVE	OIL		6085	10/1/1991	7/1/2001
4224500049	LONG 24	NOME	JEFFERSON (TX)	INACTIVE	OIL		6085	10/1/1988	8/1/1991
4224500042	LONG 17	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8854	1/1/1954	9/1/1999
4224500042	LONG 17	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-2A SAND	8854	11/1/1999	3/1/2000
4224500022	BURROWS, J. E. 5 U	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8000	5/1/1968	6/1/1972
4229130672	STONE 8	HATHAWAY	LIBERTY (TX)	INACTIVE	OIL	EY-2B	10700	4/1/1977	6/1/1977
4224500022	BURROWS, J. E. 5	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	1/1/1945	3/1/1974
4229104855	STONE 6	HATHAWAY	LIBERTY (TX)	INACTIVE	OIL	EY-2B	10700	4/1/1976	2/1/1996
4224500047	LONG 22	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8100	9/1/1954	2/1/1976
4224500044	LONG 19	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8100	3/1/1954	1/1/2017
4224500038	LONG 13	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-2A SAND	8000	10/1/1953	3/1/1973
4224500038	LONG 13	NOME	JEFFERSON (TX)	INACTIVE	OIL	V	8000	11/1/1958	4/1/2018
4224500083	PAGGI, ED 6 L	NOME	JEFFERSON (TX)	INACTIVE	OIL	V-3 SAND	8106	2/1/1954	2/1/1971
4224500024	LONG-MAUBOULES 1	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	7915	1/1/1944	3/1/1988
4224531906	LONG 21A	NOME	JEFFERSON (TX)	INACTIVE	OIL		6020	8/1/1991	10/1/1992
4224530228	PAGGI, ED 8	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8000	5/1/1973	10/1/1983
4224500043	LONG 18 L	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	8003	2/1/1954	7/1/2007
4224500066	CARPENTER, ALMA 14	NOME	JEFFERSON (TX)	INACTIVE	OIL	X SAND	7908	10/1/1953	10/1/1983
4224532652	HARDER 1	NOME N.E.	JEFFERSON (TX)	P & A	GAS	12800	17697	7/1/2010	9/1/2016
4224532645	BUBBA "D" GU 1	CLAUDE WATTS	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA	12946	9/1/2010	5/1/2015
4224532626	MCDERMOND 5	NOME	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA MIDDLE EY	15400	2/1/2010	10/1/2015
4229132759	HENDERSON 7	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11300	7/1/2008	12/1/2019
4224532604	KEELAND GAS UNIT 1	CLAUDE WATTS	JEFFERSON (TX)	INACTIVE	GAS	YEGUA	13067	7/1/2009	8/1/2014
4229132739	HENDERSON 6	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11510	3/1/2008	8/1/2009
4229132758	HENDERSON 8	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11420	10/1/2008	12/1/2019
4229132773	HENDERSON 11	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11600	10/1/2008	10/1/2008
4229132745	HENDERSON 5	FELICIA	LIBERTY (TX)	ACTIVE	GAS	YEGUA	11600	4/1/2008	5/1/2025
4224532568	LEGER 1	NOME	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA MIDDLE EY FB2	14488	2/1/2009	3/1/2012
4229132720	IMPERIAL 1	BUYE	LIBERTY (TX)	INACTIVE	GAS	LOWER COOK MTN. 3	14200	10/1/2007	2/1/2014
4224532550	SUN-HARDER A 2	REBEL	JEFFERSON (TX)	ACTIVE	GAS	YEGUA	13413	8/1/2008	8/1/2025
4229132733	DUNAGAN 1	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11496	1/1/2008	2/1/2020
4229132721	WILLIS ESTATE 5	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11500	11/1/2007	7/1/2014
4224532547	NOME-LONG 3	NOME	JEFFERSON (TX)	P & A	GAS	YEGUA MIDDLE EY FB2	14500	6/1/2008	5/1/2013
4224532544	NOME-BEAVERS GAS UNIT 2	NOME	JEFFERSON (TX)	INACTIVE	GAS	YEGUA MIDDLE EY	14410	5/1/2008	5/1/2013

4224532539	HARDER-DISHMAN 2	NOME	JEFFERSON (TX)	P & A	GAS	YEGUA MIDDLE EY FB2	14584	4/1/2008	12/1/2016
4224532515	BEVIL 1	NOME	JEFFERSON (TX)	INACTIVE	GAS	YEGUA MIDDLE EY FB2	16500	2/1/2008	5/1/2012
4224532529	NOME-BEAVERS GAS UNIT 1	NOME	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA MIDDLE EY	13512	3/1/2008	3/1/2013
4229132738	PIC REALTY CORP 1	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11600	3/1/2008	8/1/2014
4224532516	NOME-LONG 2	NOME	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA MIDDLE EY FB2	14410	1/1/2008	2/1/2010
4224532509	SUN FEE 2	NOME N.E.	JEFFERSON (TX)	P & A	GAS	12800	12635	11/1/2007	5/1/2014
4224532503	HARDER-DISHMAN 1	NOME	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA MIDDLE EY FB2	15000	9/1/2007	12/1/2014
4224532423	B.A.M. LAND COMPANY 1	CLAUDE WATTS	JEFFERSON (TX)	INACTIVE	GAS	YEGUA 12600	14203	9/1/2007	6/1/2010
4224531893	LONG 29	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-A	8020	8/1/2007	4/1/2018
4224500043	LONG 18	NOME	JEFFERSON (TX)	P & A	GAS	X SAND	8003	8/1/2007	7/1/2017
4229132694	KERR-MCGEE 3	BUYE	LIBERTY (TX)	ACTIVE	GAS	LOWER COOK MTN. 3	14809	5/1/2007	8/1/2025
4224532491	NOME HARDER 1 ST 1	NOME	JEFFERSON (TX)	INACTIVE	GAS	YEGUA MIDDLE EY FB2	15000	6/1/2007	5/1/2014
4224532457	MCCLINTOCK 1	HATHAWAY, SE.	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	HARDY EY-4	12200	4/1/2007	3/1/2010
4224532463	NOME-DISHMAN 1	REBEL	JEFFERSON (TX)	ACTIVE	GAS	YEGUA	14207	2/1/2007	8/1/2025
4224532453	NOME-LONG 1	NOME	JEFFERSON (TX)	P & A	GAS	YEGUA MIDDLE EY FB2	15800	12/1/2006	5/1/2013
4229132630	FEDERAL ROYALTY PARTNERS 1	WEST NOME	LIBERTY (TX)	INACTIVE	GAS	YEGUA EY-1	12200	6/1/2006	3/1/2011
4224532423	B. A. M. LAND COMPANY 1	CHINA	JEFFERSON (TX)	INACTIVE	GAS	YEGUA EY-3	14203	1/1/2006	6/1/2007
4229132653	KERR-MCGEE 2	BUYE	LIBERTY (TX)	ACTIVE	GAS	LOWER COOK MTN. 3	14975	7/1/2006	8/1/2025
4229132620	HENDERSON 4	FELICIA, S.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 11160	11146	2/1/2006	12/1/2019
4229132613	DUNAGAN, BAXTER 2	FELICIA, S.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 11160	11630	10/1/2005	4/1/2007
4229132415	ARCO FEE 4	FELICIA CREEK	LIBERTY (TX)	P & A	GAS	Y-6 SAND	12128	11/1/2002	9/1/2003
4229132588	KERR-MCGEE 1	BUYE	LIBERTY (TX)	INACTIVE	GAS	LOWER COOK MTN. 3	14898	6/1/2005	5/1/2013
4229132534	TEMPLE INLAND "A" 1	CYPRESS POND	LIBERTY (TX)	P & A	GAS	UPPER COOK MTN	11695	6/1/2004	9/1/2021
4229132546	HENDERSON 3	FELICIA	LIBERTY (TX)	ACTIVE	GAS	YEGUA	11017	9/1/2004	8/1/2025
4229132543	WILLIS ESTATE 4	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11020	8/1/2004	4/1/2016
4229132537	WILLIS ESTATE 3	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11000	7/1/2004	1/1/2007
4224532083	SUN FEE 1	NOME N.E.	JEFFERSON (TX)	ACTIVE	GAS	12800	15000	5/1/2004	8/1/2025
4229132531	WILLIS ESTATE 2	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	10950	5/1/2004	11/1/2020
4229132494	HENDERSON 1	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	11000	3/1/2004	8/1/2015
4229132525	WILLIS ESTATE 1	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	10950	4/1/2004	8/1/2021
4229132513	HENDERSON 2	FELICIA	LIBERTY (TX)	INACTIVE	GAS	YEGUA	12000	3/1/2004	6/1/2014
4229132477	RANKIN 1	HATHAWAY, SW.	LIBERTY (TX)	P & A	GAS	YEGUA EY 2A	10800	12/1/2003	7/1/2011
4224532320	GREY WOLF 1	NOME	JEFFERSON (TX)	RECLASSIFIED TO ANOTHER TYPE OF ENTITY	GAS	NODOSARIA	8006	6/1/2003	11/1/2003
4224532128	BOWER, JONES 1	CHINA	JEFFERSON (TX)	P & A	GAS	YEGUA CONS.	14522	6/1/2003	11/1/2019
4229132426	DUNAGAN, BAXTER 1	FELICIA, S.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 11160	11600	12/1/2002	5/1/2005
4229132417	HENDERSON NO. 2 UNIT 2	FELICIA, S.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 11160	11600	2/1/2002	8/1/2009
4229132406	HENDERSON 1	FELICIA, S.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 11160	11600	11/1/2001	12/1/2008
4224532227	MCDERMAND UNIT 1R	NOME S.	JEFFERSON (TX)	INACTIVE	GAS	NODOSARIA -A-	9187	12/1/1999	7/1/2005
4229132180	ARCO FEE 3	FELICIA CREEK	LIBERTY (TX)	P & A	GAS	Y-4 SAND	13040	2/1/1999	7/1/2005
4224532137	LONG 1	NOME	JEFFERSON (TX)	INACTIVE	GAS	YEGUA MIDDLE EY FB2	13900	12/1/1996	6/1/2004
4224532128	BOWER, JONES 1	CHINA	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA EY	14522	6/1/1996	5/1/2003
4229132159	ARCO FEE 1	FELICIA CREEK	LIBERTY (TX)	P & A	GAS	Y-4 SAND	13008	9/1/1995	3/1/2013
4229132180	ARCO FEE 3	FELICIA CREEK	LIBERTY (TX)	WORKED OVER TO ANOTHER ZONE	GAS	Y-6 SAND	13040	10/1/1995	1/1/1999
4229132211	CHAMPION INTERNATIONAL CORP	HATHAWAY, E.	LIBERTY (TX)	P & A	GAS	YEGUA EY-3	10520	12/1/1994	4/1/2014
4229132209	STONE 1	HATHAWAY, E.	LIBERTY (TX)	INACTIVE	GAS	YEGUA EY-3	10596	10/1/1994	10/1/1997
4224532083	SUN FEE 1	NOME	JEFFERSON (TX)	WORKED OVER TO ANOTHER ZONE	GAS	YEGUA MIDDLE EY	15000	4/1/1994	8/1/2003
4229132180	ARCO FEE 3	FELICIA CREEK	LIBERTY (TX)	INACTIVE	GAS	Y-4 SAND	13040	11/1/1993	7/1/1995
4229132062	STONE 1	HATHAWAY, SE.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 1	10800	8/1/1993	5/1/2006
4229132075	STONE 2	HATHAWAY, SE.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 1	10720	7/1/1993	5/1/2006
4229132159	ARCO FEE 1	FELICIA CREEK	LIBERTY (TX)	INACTIVE	GAS	Y-6 SAND	13008	1/1/1993	8/1/1995
4229132075	STONE 2-L	HATHAWAY, SE.	LIBERTY (TX)	INACTIVE	GAS	YEGUA 3B	10720	9/1/1990	7/1/1993
4224531956	CARPENTER, ALMA M. 15	NOME	JEFFERSON (TX)	INACTIVE	GAS	L-4400	4620	3/1/1990	4/1/1993
4224531962	CARPENTER, A. M. 17	NOME	JEFFERSON (TX)	INACTIVE	GAS	"LO" SAND	6200	3/1/1990	12/1/1990

4229132075	STONE 2-U	HATHAWAY, SE.	LIBERTY (TX)	INACTIVE	GAS	HARDY EY-4	10720	10/1/1989	9/1/1990
4229132071	WILSON, F. S. 1	HATHAWAY, SE.	LIBERTY (TX)	INACTIVE	GAS	HARDY EY-4	11200	9/1/1989	2/1/1991
4229132062	STONE 1	HATHAWAY, SE.	LIBERTY (TX)	INACTIVE	GAS	HARDY EY-4	10800	3/1/1989	6/1/1992
4224531956	CARPENTER, A. M. 15	NOME	JEFFERSON (TX)	INACTIVE	GAS	"LO" SAND	4620	1/1/1989	2/1/1990
4224531946	CARPENTER, A. M. 1	BIG PRAIRIE	JEFFERSON (TX)	INACTIVE	GAS	EY-3	12007	10/1/1988	5/1/1992
4224531851	PAGGI, ED ESTATE 9	NOME	JEFFERSON (TX)	INACTIVE	GAS	W-1A	8014	6/1/1987	8/1/1988
4224531778	BLANCH, GRACE 1	CLAUDE WATTS	JEFFERSON (TX)	INACTIVE	GAS	YEGUA 12600	14500	7/1/1986	5/1/1991
4224531851	ED PAGGI ESTATE 9	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8014	5/1/1986	6/1/1987
4224531851	PAGGI, ED ESTATE 9	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND, LOWER	8014	9/1/1985	5/1/1986
4224530228	PAGGI, ED EST. 8 U	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8000	12/1/1984	5/1/1986
4224531778	GRACE BLANCH 1	CLAUDE WATTS	JEFFERSON (TX)	INACTIVE	GAS	YEGUA	14500	12/1/1984	5/1/1986
4224531707	DISHMAN, H. E. GAS UNIT 1	REBEL	JEFFERSON (TX)	INACTIVE	GAS	YEGUA	14500	6/1/1984	6/1/1984
4224500065	CARPENTER, ALMA 13	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8110	11/1/1983	7/1/1985
4224530228	PAGGI, ED 8 L	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND, LOWER	8000	11/1/1983	9/1/1984
4224531399	PICA INVESTMENT CO. 1	NOME N.E.	JEFFERSON (TX)	INACTIVE	GAS	10500	13750	11/1/1980	2/1/1983
4224500090	PAGGI ESTATE 13	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8005	5/1/1979	11/1/1988
4224500064	CARPENTER, A. M. 12	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8071	10/1/1978	6/1/1983
4224530389	GARTH CO. 1	NOME, NORTH	JEFFERSON (TX)	INACTIVE	GAS	YEGUA	10720	6/1/1977	7/1/1977
4224530440	LONG 28 U	NOME	JEFFERSON (TX)	INACTIVE	GAS	VZ	8012	4/1/1977	10/1/1980
4224530440	LONG 28 L	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8012	4/1/1977	11/1/1980
4224500035	LONG 9	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8000	3/1/1976	10/1/1976
4224500022	BURROWS,J.E. 5	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8000	5/1/1974	11/1/1978
4224500073	PAGGI, ED, ET AL 3	NOME	JEFFERSON (TX)	INACTIVE	GAS	FRIO T-1	8103	8/1/1971	5/1/1973
4224500088	PAGGI ESTATE 11	NOME	JEFFERSON (TX)	INACTIVE	GAS	V	7359	6/1/1969	1/1/1974
4224500089	PAGGI ESTATE 12	NOME	JEFFERSON (TX)	INACTIVE	GAS	X SAND	8000	6/1/1969	2/1/1989
4224500035	LONG 9 M	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-3 SAND	8000	2/1/1969	9/1/1972
4224500035	LONG 9 U	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-O	8000	2/1/1969	3/1/1970
4224500080	PAGGI ESTATE 3 L	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-O	8658	12/1/1968	4/1/1969
4224500040	LONG 15	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-O	8000	11/1/1968	9/1/1969
4224500073	PAGGI, ED 3 U	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-O	8103	10/1/1968	5/1/1970
4224500073	PAGGI, ED 3 L	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-OO	8103	10/1/1968	5/1/1970
4224500073	PAGGI, ED 3 U	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-1	8103	1/1/1968	7/1/1968
4224500073	PAGGI, ED GAS UNIT 3 L	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-2	8103	1/1/1968	4/1/1968
4224500036	LONG 10 T	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-1	8000	10/1/1967	10/1/1968
4224500080	PAGGI ESTATE 3	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-2	8658	3/1/1966	6/1/1967
4224500088	PAGGI ESTATE 11	NOME	JEFFERSON (TX)	INACTIVE	GAS	V-2	7359	11/1/1959	2/1/1966

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 2 – PLUME MODEL

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 2: May 2026

SECTION 2 – PLUME MODEL

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2.1 Introduction

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson and Liberty Counties, Texas, to sequester approximately 25.3 million metric tons (MMT) over 11 years. The following discussion of the plume model was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5.

This section describes the key details of the reservoir model. The model establishes the required pore space, defines the area of review (AOR), outlines comprehensive corrective action plans, and assesses the overall feasibility of the project within the specified regulatory framework. Both *Section 3 – Area of Review and Corrective Action Plan* and *Section 5 – Testing and Monitoring Plan* utilize the forecasted plume to help determine the best strategies and plans to minimize the impact of carbon sequestration.

ExxonMobil is pursuing individual Class VI permits for three injection wells consistent with 16 TAC **§5.203**. Given the proximity of the proposed injection wells for the Sunflower Project, ExxonMobil plans to obtain approval from the Underground Injection Control (UIC) Program director (UIC Director) to delineate the AOR and prepare the Corrective Action Plan to represent the collective effects of the three injection wells within the project AOR. Although the effects were evaluated in the collective, the required maps showing the delineated AOR and the Corrective Action Plan for artificial penetrations are submitted separately for each well so that they may be incorporated into each injection well's Class VI permit.

2.2 Objectives

A comprehensive modeling and evaluation effort was undertaken to accomplish the following objectives, consistent with the requirements of 16 TAC **§5.203 (d)(1)**:

- Predict the extent of the CO_2 plume and pressure front, which form the basis for the AOR using computational modeling, and identify all wells that require corrective action (16 TAC **§5.203(d)(1)(A)(i)**).

- Provide a plan to perform the required corrective action on artificial penetrations in the AOR (16 TAC **§5.203(d)(1)(C)**) that could threaten underground sources of drinking water (USDWs).

- Support the development of effective monitoring strategies for the Testing and Monitoring Plan by identifying the locations where groundwater quality or pressure monitoring should be performed.

- Help direct emergency response planning by identifying potential vulnerable areas within or near the AOR that could require consideration when implementing an emergency response.

- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AOR (16 TAC **§5.205(b)(3)**).

- Provide a guide for periodic AOR reevaluations to inform site management and monitoring over the life cycle of the injection project (16 TAC **§5.206(g)**).

- Retain modeling inputs and data used to support AOR reevaluations for 10 years (16 TAC **§5.206(g)(5)**).

2.3 Modeling and Simulation Framework

2.3.1 Software

2.3.1.1 Petrel™ Software Suite

To create a detailed geologic model for the Sunflower Project site, SLB's Petrel software suite (ver. 2023.6) was chosen. This state-of-the-art software is used worldwide and provides a platform to integrate subsurface data—including well logs, cores, and seismic data—to build a reliable representation of the subsurface reservoir. The Petrel-developed geologic model incorporates the different geologic layers of the site, including the upper confining zone (UCZ, upper seal), Fleming and Frio Formations (injection zones), and the lower confining zone (LCZ, lower seal). Using Petrel, the porosity and permeability properties of the reservoirs were distributed using industry-standard geostatistical methods, incorporating the subsurface characterization results. This integrated subsurface characterization and geologic modeling workflow ensures a more precise depiction of the reservoir in the model.

2.3.1.2 Carbon Storage Simulation Using Intersect Suite

The geologic model developed in Petrel was used as an input into SLB's Intersect (ver. 2023.6) simulator. Intersect is a widely recognized petroleum-engineering simulation tool specializing in modeling compositional and unconventional reservoirs. The simulator enables the user to define an initial solution in terms of the pressure, saturation, and composition of each fluid phase, and to advance this solution forward in time. This is achieved by solving mathematical equations that express the fact that mass is conserved in the reservoir and that the fluid phases are in thermodynamic equilibrium.

Specific functionalities have been developed in Intersect for CCS modeling, including CO_2 solubility in brine by using the Component Solubility in Water (CSIW) module. The software can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

2.3.2 Data Sources

The data sources needed to build the geologic and dynamic model include 3D seismic data, offset well logs, core data, and publicly available literature.

Public databases and literature were initially reviewed at both a regional and site-specific level. The regional review identified the major trends in the project area and the surrounding region. These trends were compared to more site-specific data to provide a higher confidence in the reservoir properties. Reservoir salinity, temperature trends, rock compressibility, and relative permeability are based on data collected from a nearby stratigraphic test well (Bead Farm Co. – 1; API No. 4224532908) completed by ExxonMobil. These input parameters are further discussed in *Section 2.6.*

Offset well log analysis was conducted to further characterize the reservoir and populate the geologic model. Openhole log data included various analyses such as gamma ray, spontaneous potential (SP), resistivity, porosity (sonic, neutron, density), photoelectric factor, caliper, and other related analyses. These well logs helped determine formation tops, rock properties, and temperature gradients. Petrophysical analysis was performed on 47 wells in the project vicinity to appraise the target injection zone and subsequent confining layers.

To enhance the characterization of the reservoir, 3D seismic data was used in conjunction with formation tops identified through log analysis to identify major structural horizons, as shown in *Appendix B-2*. The 3D seismic data also allows for greater clarity of the subsurface, such as faults, salt domes, or any other structural changes in the subsurface. These data enhanced the accuracy of the geologic model by providing a clearer understanding of the targeted stratigraphy. Well log and core data were used to determine the porosity-permeability relationship in the Frio and Fleming injection formations. These data are discussed in greater detail in *Section 2.5*.

Additional data will be collected during the drilling of wells for the proposed CCS project. A detailed description of the Pre-Operational Testing Plan is outlined in *Section 4 – Well Construction Plan and Operating Conditions*.

2.4 Trapping Mechanisms

In a CCS project, four primary trapping mechanisms exist that sequester the supercritical CO_2, schematically represented in Figure 2-1. Discussed in the sections following are structural and stratigraphic, residual, solubility, and mineral trapping mechanisms—all except for mineral trapping being present in the current model.

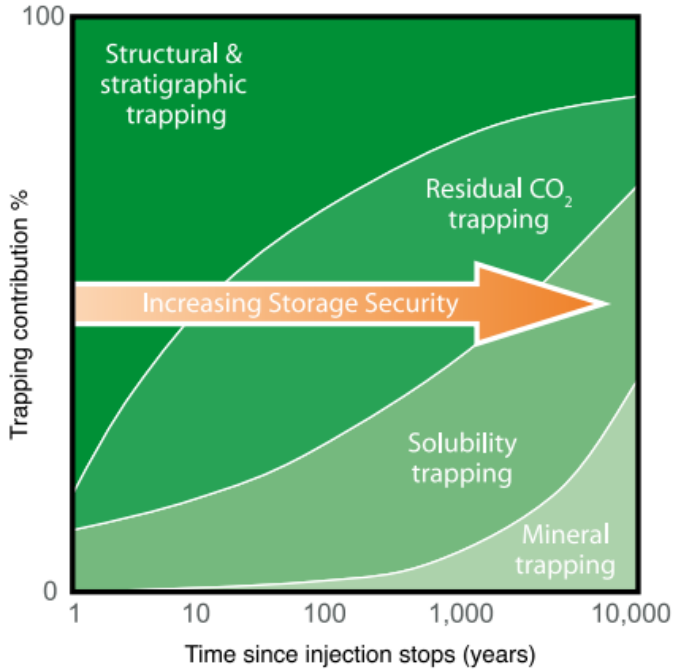


Figure 2-1 – CO_2 Storage Mechanisms (IPCC, 2005)

2.4.1 Structural and Stratigraphic Trapping

Structural and stratigraphic trapping is a physical form of trapping where injected CO_2 is immobilized by the presence of sealing faults or stratigraphic pinchouts, or other forms of geologic traps. Like naturally occurring hydrocarbon reservoirs, CO_2 can be stored in anticlinal folds. Supercritical CO_2 is a low-viscosity fluid, less dense than the surrounding brine found in the injection zone. The CO_2 will continue to rise until its buoyant forces are no longer greater than the capillary entry pressure of the caprock. For this model, the CO_2 mass density ranges between 43.8 pounds per cubic feet (lb/ft^3) in the shallowest injection interval and 45.7 lb/ft^3 in the deepest intervals. The surrounding brine density is 68.4 lb/ft^3.

Equation of state (EOS) calculations are performed to determine the phase of CO_2. These formulae can predict the density of the injected fluid at any location based on pressure and temperature. Intersect's compositional fluid modeling adopts the Redlich-Kwong-Soave-Peng-Robinson family of EOS in cubic form, which has long been the industry standard in compositional reservoir simulation. The method implemented here is Peng-Robinson.

2.4.2 Residual Gas Trapping

Residual gas trapping, or capillary trapping, is a form of physical trapping. During active injection, viscous force drives CO_2 into brine-filled pore space and displaces water. When the CO_2 front moves, the trailing end of the CO_2-filled pore space undergoes hysteresis and water displaces CO_2. Depending on CO_2 saturation and capillary force, some CO_2 will remain residually trapped within

the pore space. This usually becomes the primary trapping mechanism for saline aquifer carbon storage.

Hysteresis modeling is used in the model to accurately predict the amount of residually trapped supercritical CO_2. Important parameters include trapped gas saturation and relative permeability hysteresis paths, which will be discussed further in *Section 2.6.3*.

2.4.3 Solubility Trapping

Solubility trapping is a form of physical trapping between supercritical CO_2 and surrounding brine. Injected CO_2 is soluble in the aqueous phase, and its solubility depends on temperature, pressure, and the aqueous phase salinity. Spycher and Pruess (2009) have developed a method to calculate the mutual solubility of CO_2 and H_2O for pressures up to 600 bar and temperatures ranging from 12°C to 300°C in addition to accounting for brine salinity. Intersect implemented this method for the CO_2 storage process.

Component solubility in water is the compositional module in Intersect recommended for CO_2 storage into saline aquifers. The module allows modeling of three phases: liquid, vapor, and aqueous. Water stays only in the aqueous phase; as a result, near-wellbore vaporization of water cannot be modeled in CSIW. While there can be many components in the hydrocarbon phase (including CO_2), only one component can dissolve in water. Hence this module is ideally only applicable for brine-pure CO_2 systems.

The vapor component densities and fugacities are calculated using cubic EOS. The viscosities are handled using the Lorenz-Bray-Clark model. The composition of CO_2 (or hydrocarbon component) in the aqueous phase is calculated using the solubility table provided within the software. The aqueous phase density and viscosity are also provided by the user in the solubility table. Salt is not modeled explicitly in Intersect; therefore, the brine properties are provided as a part of the solubility table.

2.4.4 Mineral Trapping

Mineral, or geochemical, trapping is a form of chemical trapping that occurs due to reactions between CO_2 and the geochemistry of the formation. During injection of CO_2 into the reservoir, four primary drivers interact with each other: (1) CO_2 in supercritical phase, (2) in situ hydrochemistry of the connate brine, (3) aqueous CO_2, and (4) the geochemistry of the formation rock. The interaction of these components results in CO_2 often being precipitated out as a new mineral. This new mineral is typically Ca-CO_3, or calcium carbonate (i.e., limestone). Mineral trapping can also occur due to the adsorption of CO_2 onto clay minerals.

While geochemical trapping can have a greater impact on CO_2 over hundreds or thousands of years, the short-term effects of these trapping mechanisms are small, and fluid movement is dominated by hydrodynamic and solubility trapping. Geochemical trapping mechanisms were not assumed in the current model.

2.4.5 Trapping Summary

Figure 2-2 shows the breakdown of the trapping mechanism. Once injection stops (Year 11), the mobile CO_2 quickly decreases as gaseous-phase CO_2 migrates through pore space and is trapped. Over the life of the Sunflower Project, residual trapping of supercritical CO_2 has the greatest effect among the trapping mechanisms. At stable plume (50 years post cease of injection) approximately 55% of the injected fluid is safely sequestered by residual trapping within the pore space. The solubility of CO_2 into the connate brine will safely store approximately 28% of the CO_2. The remaining 17% of the injectate will be safely, structurally and hydrodynamically trapped.

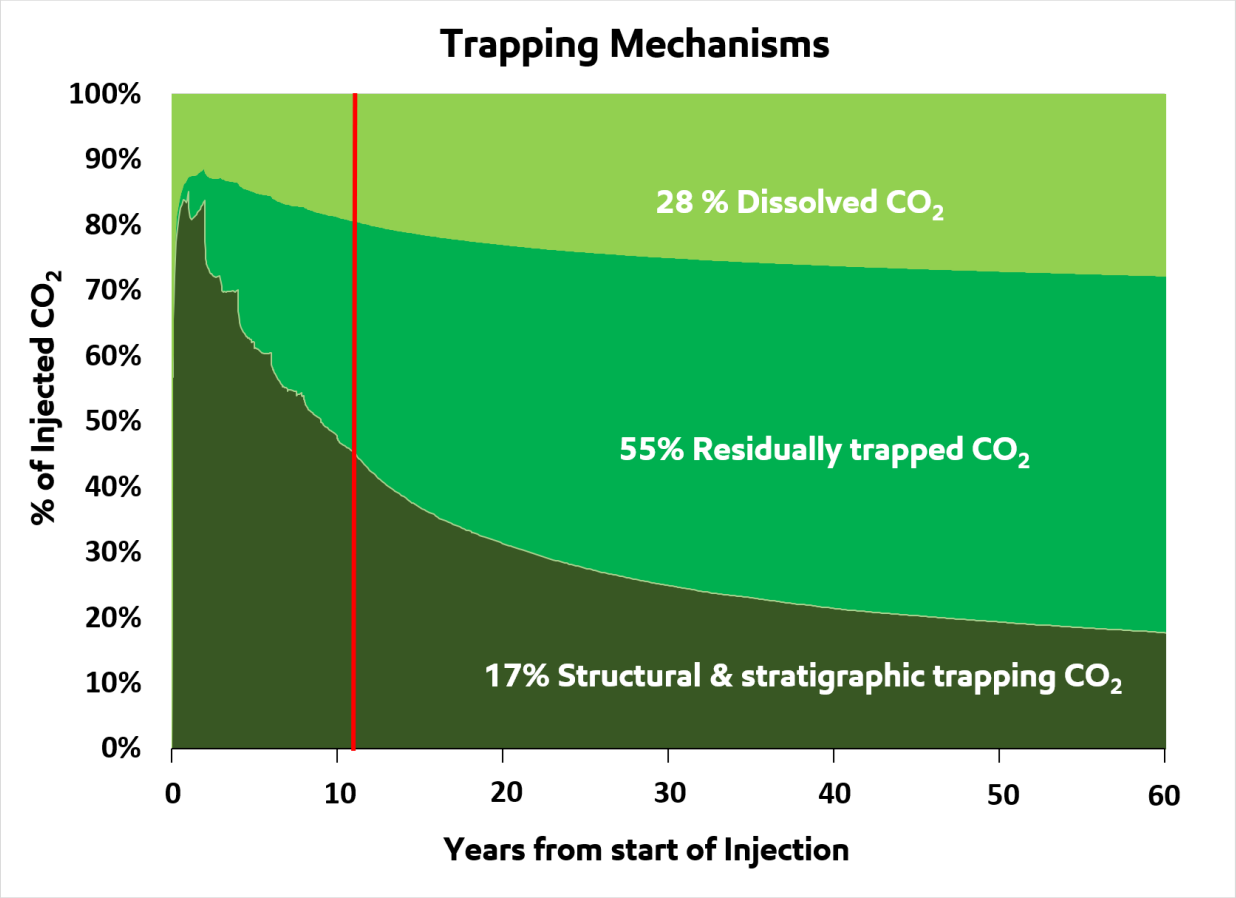


Figure 2-2 – Modeled Trapping Mechanisms (the red line designating end of injection)

2.5 3D Geologic Model

Characterization of the Fleming and Frio formations was carried out within the confining and injection zones to develop an understanding of the sealing effects of the confining zone and characterize the reservoir heterogeneity within the injection zone. Based on the analysis and

understanding of the Sunflower Project area, a 3D geologic model was developed to estimate the storage potential for the CO_2 and evaluate its confinement, both laterally and vertically.

2.5.1 Geologic Model of the AOR

Using available data, an integrated geologic model was developed for the site to represent the structural setting and depositional environment, as well as distribute petrophysical properties within the model boundaries. This model provides a 3D grid to enable predictive CO_2 plume and pressure modeling over time. Available site data used to inform the 3D geologic model included seismic surveys and legacy well logs, such as SP (original log for volume of shale, used in most of the Vshale calculations), gamma ray logs (another lithologic log that can also be used to calculate Vshale, used sparingly in this geologic model), resistivity, bulk density (density porosity), and sonic logs (sonic porosity). The geologic model incorporates regional core, log, and seismic data to characterize structural configuration, net sand, facies and property distribution, and porosity-permeability relationships.

Log properties were upscaled to model resolution and populated in a 3D grid over an area that exceeded the spatial limit of the AOR. The geological model was built with a lateral grid resolution of [redacted] feet oriented in a north-south direction, and an average vertical resolution of [redacted] feet. The total cell count is approximately 12 million cells. The geologic model covers [redacted] acres ([redacted] square miles) and extends well beyond the predicted plume or AOR boundaries to negate any potential for model-edge effects. The overall workflow adopted for geologic modeling is shown in Figure 2-3.

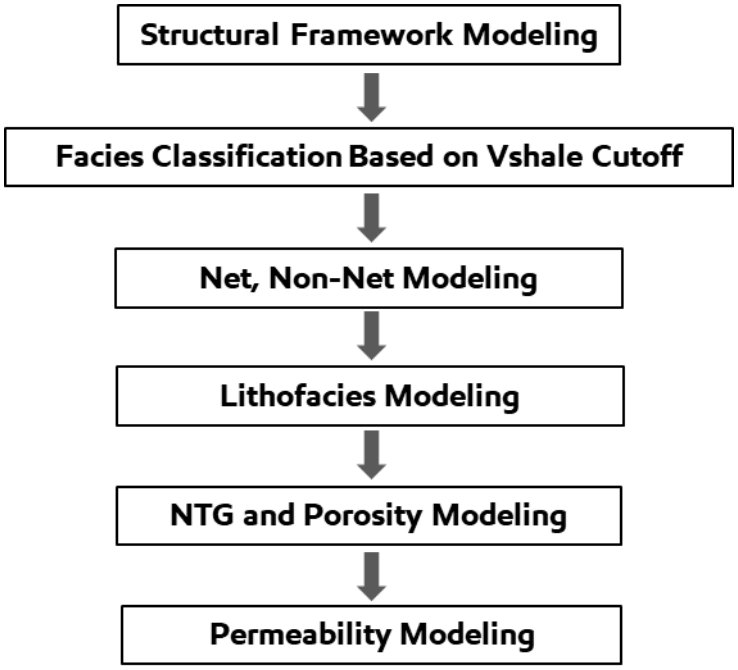


Figure 2-3 – Geologic Modeling Workflow

The model will be updated as more information becomes available through drilling activities. In addition, the model will be updated periodically during and following injection activities.

2.5.2 Structural Model

Seismic interpretation was carried out using 3D seismic data that covers the full model area. The fault framework model was built with 16 interpreted faults within the geologic model study area and zones of interest, 5 of which are located inside the AOR, as detailed in *Section 1.5.2*. The structural model captures the throw relationships that were interpreted in the seismic data. No impediment to CO_2 flow was imposed where sand-on-sand juxtaposition across a fault plane occurs. In sand-on-shale juxtaposition, the shale would act as a barrier and restrict flow across the fault. Figure 2-4 shows the relative offsets of injection and confining zones across some of the faults in the 3D model. Section 1.5.2 demonstrates that the faults do not pose a significant threat to the USDW, because the faults show no significant offset across the confining zones (none reach the UCZ within the AOR)—hence, would not reduce the confining properties of these zones. Moreover, these faults exhibit no significant transmissive potential for CO_2 or fluids.

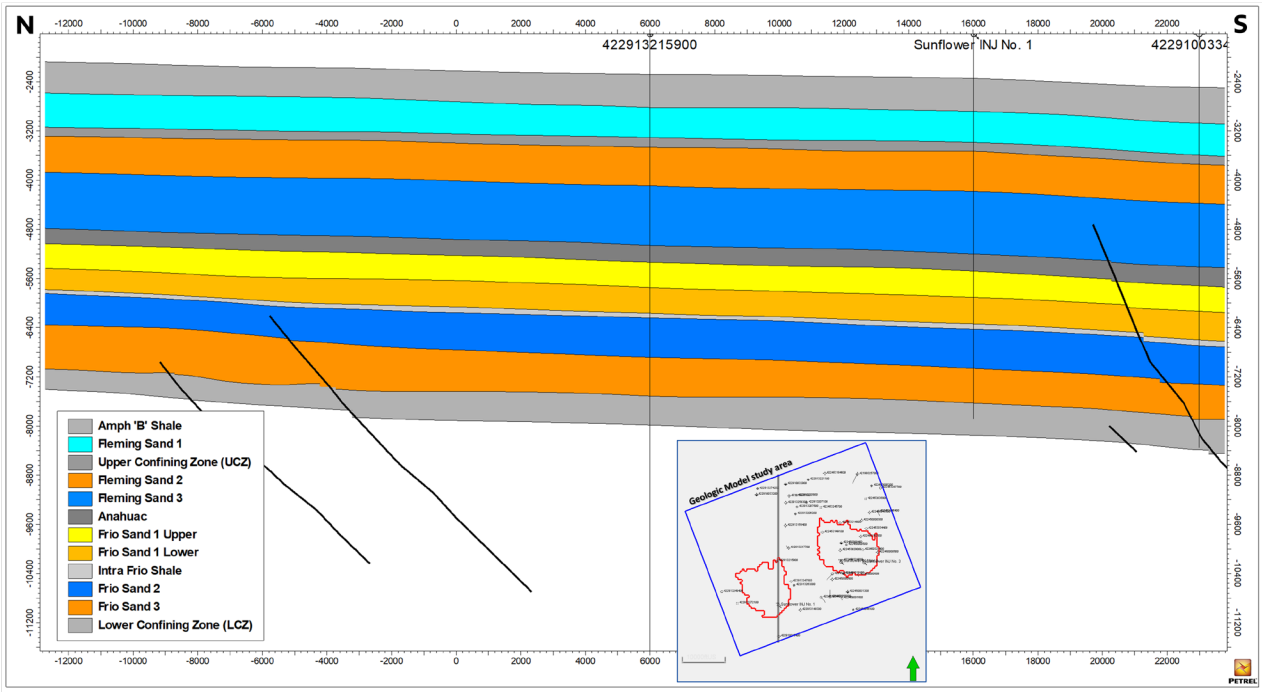


Figure 2-4 – Model Structural Grid Cross Section (North-South)

The horizon model was built using interpreted seismic horizons. The well data suitable to assign interpreted formation tops were used to tie the seismic data for formation depths. The layers within the zones are modeled using a stratigraphic layering method. The Frio Sand 1 was further subdivided into two "pseudozones"—Frio Sand 1 Upper and Frio Sand 1 Lower. This helped in better understanding of lateral and vertical variations in facies and properties within each zone and aided in using trends in the geomodel. Figure 2-4 showed a model cross section that runs

north to south through the proposed Sunflower INJ No. 01 and legacy wells Arco Fee – 1 (API No. 4229132159) and B H Willis Est – 1 (API No. 4229100334). This cross section depicts the Fleming and Frio injection zones along with upper confining zone (UCZ), lower confining zone (LCZ), and other intraformational shale layers within the AOR. The 3D visualization in Figure 2-5 shows where the cross section is located within the model.

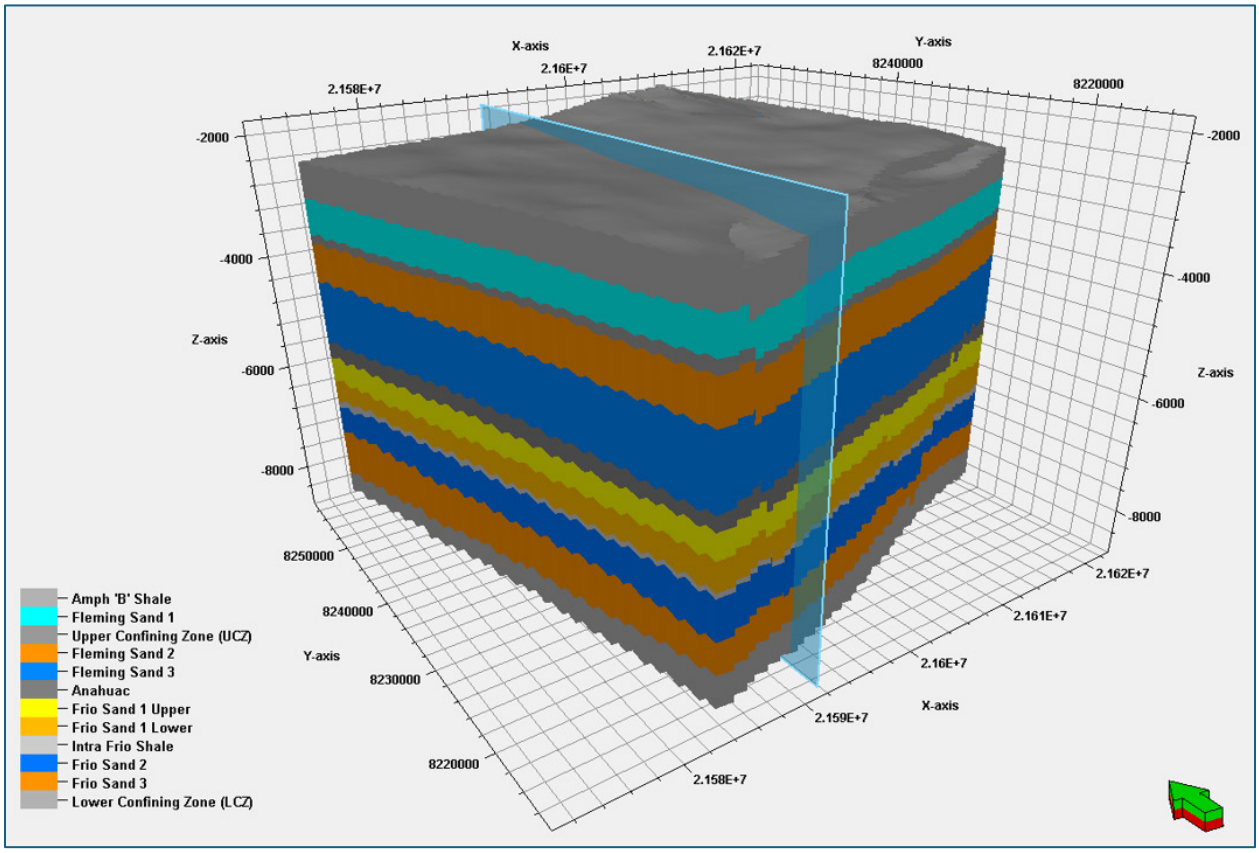


Figure 2-5 – Model Structural Grid 3D View

2.5.3 Net and Non-Net Model

To provide an accurate and representative sand distribution in the geologic model, relevant seismic data, well data, and available evaluations of regional depositional environments were considered. A two-step facies modeling approach was adopted to capture the heterogeneity of the injection intervals. The first step was net and non-net modeling that captured the distribution of the net and non-net components of the geological model laterally and vertically. The second step was the modeling of different lithofacies (coarser sand, sand, and silty sand) within the net regions defined in the first step.

Forty-seven wells within the model boundary with lithological logs (SP or gamma ray) were used for net reservoir modeling (Appendix B-2, Figure 2-6). Figures 2-7 and 2-8 present well cross sections illustrating the lithological variation across the AOR. While the confining and injection

zone formations are continuous across the AOR, internal variations within each of these zones (e.g., the changing bed thicknesses, intrazonal shales, and lithological variations) were identified in the well logs. To estimate the volume of shale in each well, a shale baseline and a sand baseline were chosen according to the SP or gamma ray log character of each well. Using the baselines (100% sand and 100% shale values) of the individual SP or gamma ray log for each well, a volume of shale curve was calculated. A "net reservoir" quality rock is defined in well logs where the reservoir is predicted to have less than [redacted] of shale volume.

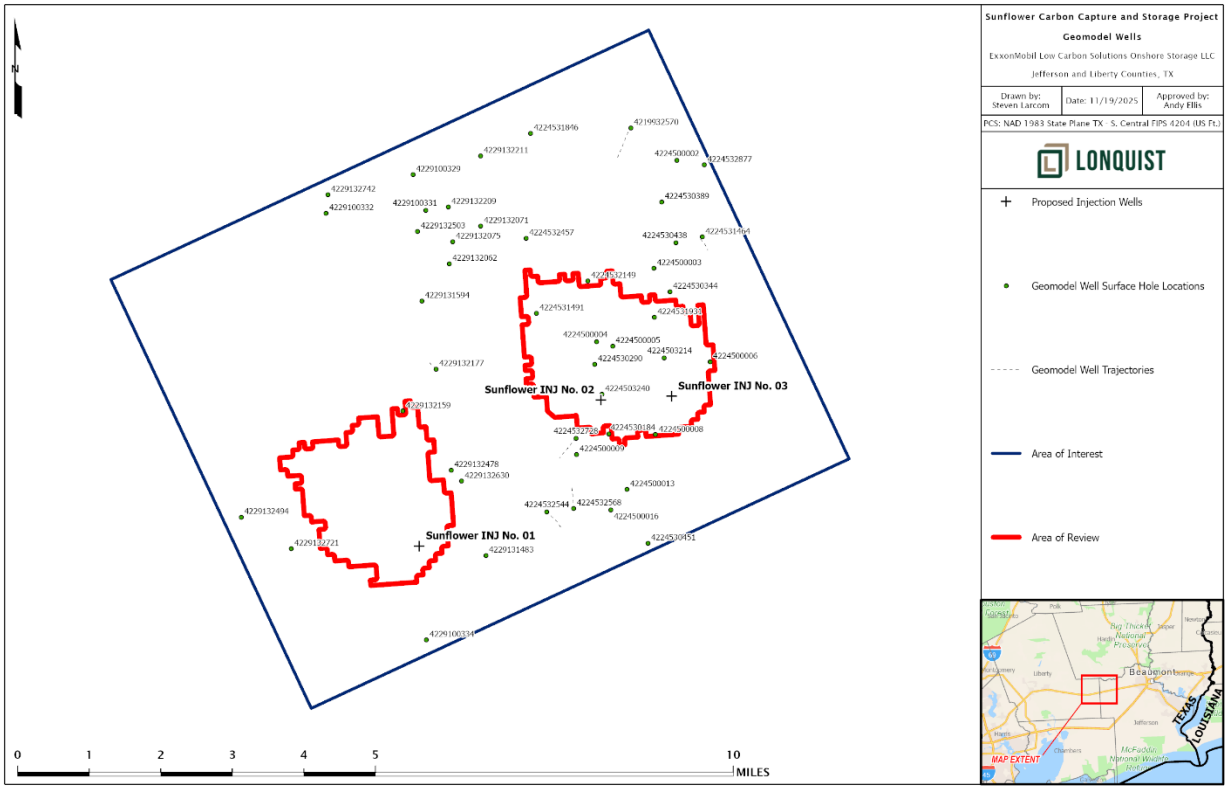
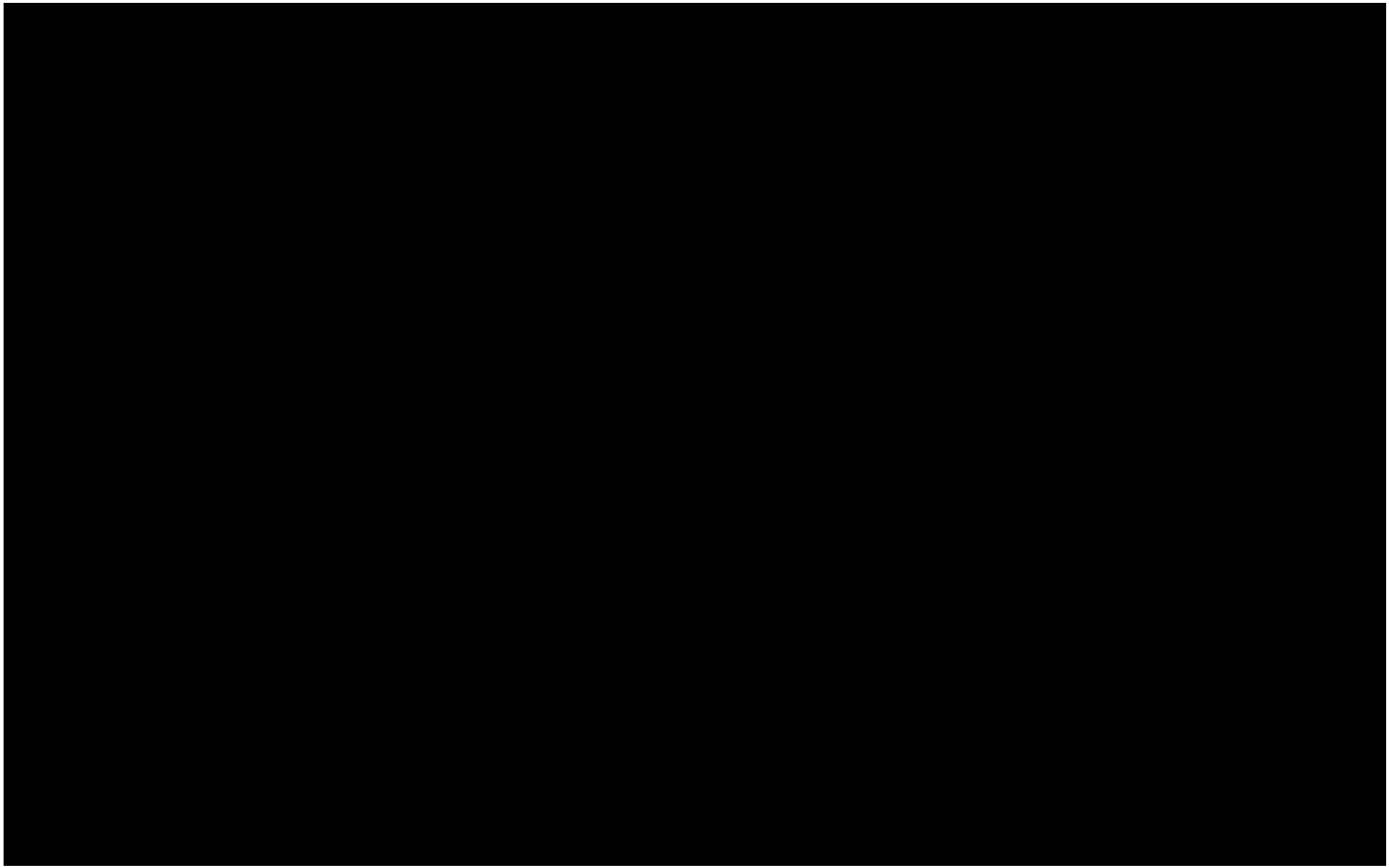
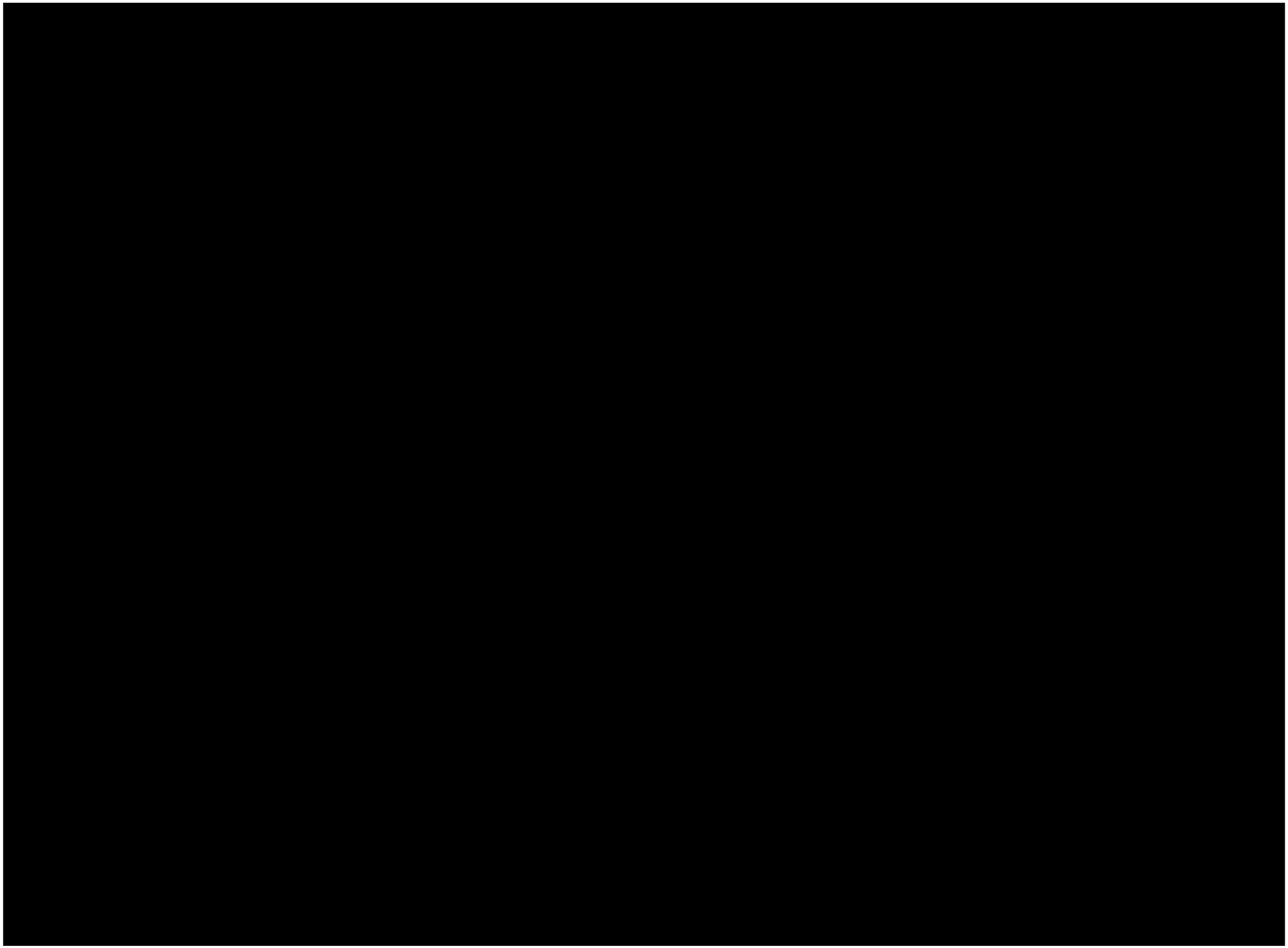


Figure 2-6 – Wells Utilized for the Geologic Model





The interpreted net and non-net logs were upscaled to model resolution then distributed within the 3D model using truncated Gaussian simulation (TGS) and multipoint simulation (MPS) algorithms. Examples of upscaled net and non-net logs in the model are shown in Figure 2-9. This modeling approach was adopted to adequately capture the reservoir heterogeneity while preserving the concept of fluvial channels and deltaic lobes within the fluvio-deltaic environment of deposition.



Based on both seismic and well data, the Frio reservoir zones (except Frio Sand 1 Lower) are interpreted to be deposited in a shoreface environment of deposition (EOD) and were modeled using the TGS algorithm. Due to the lack of correlation of available seismic volume with net reservoir distribution, considering the EOD, proportion trend maps were prepared using available well data inside the model boundary. These trend maps were used to guide the net reservoir distribution for the reservoir zones.

On the other hand, the Frio Sand 1 Lower reservoir zone is interpreted to be deposited in a fluvial dominated shoreface environment and was modeled using the MPS simulation algorithm. For the Fleming reservoir zone a probability volume derived from the 3D seismic volume was used to guide the net reservoir distribution. These different modeling approaches were adopted to adequately capture the reservoir heterogeneity while preserving the concept and facies assemblage for shoreface and fluvial channels-deltaic lobes within the fluvio-deltaic environment of depositions.

The MPS modeling method starts with generating a 3D training image, which is a conceptual statistical model of the geology that has to be simulated. Given a fluvial-dominated shoreface environment, the object-based modeling was determined to be a suitable approach to characterize the training images as channelized architecture. Seismic attributes and present-day analogues were leveraged to define the dimensions of these channel bodies. Table 2-1 shows the dimensions used for the training images. Figure 2-10 shows a conceptual illustration of how these parameters are used for defining the channel features. Once the training image is ready, the next step is to use it in net and non-net modeling, maintaining the target proportions derived from the upscaled well logs. The proportion of the net and non-net (e.g., shale) for each of the injection intervals is presented in Table 2-2.

Table 2-1 – Dimensions Used to Define Training Images of Channel Bodies

	Channel Dimension			
	Mean amplitude (ft)	Mean wavelength (ft)	Mean width (ft)	Mean thickness (ft)
Frio Sand 1 Lower	[redacted]	[redacted]	[redacted]	[redacted]



Table 2-2 – Proportion of Net and Non-Net Reservoir Within the Injection Intervals

Formation/Injection Zone	Net Reservoir	Non-Net Reservoir
Fleming Sand 2	[redacted]	[redacted]
Fleming Sand 3	[redacted]	[redacted]
Frio Sand 1 Upper	[redacted]	[redacted]
Frio Sand 1 Lower	[redacted]	[redacted]
Frio Sand 2	[redacted]	[redacted]
Frio Sand 3	[redacted]	[redacted]

The net and non-net properties were used to create the net thickness maps for the injection intervals, shown in Figures 2-11 through 2-15. Also, the net shale (non-net) thickness maps were created from this property to represent the net shale distribution of UCZ, the Anahuac Shale and LCZ, shown in Figures 2-16 through 2-18, respectively. Note that base of LCZ was mapped approximately 500 feet below the LCZ top, although the shales extend much deeper in available logs (Figures 2-7 and 2-8).

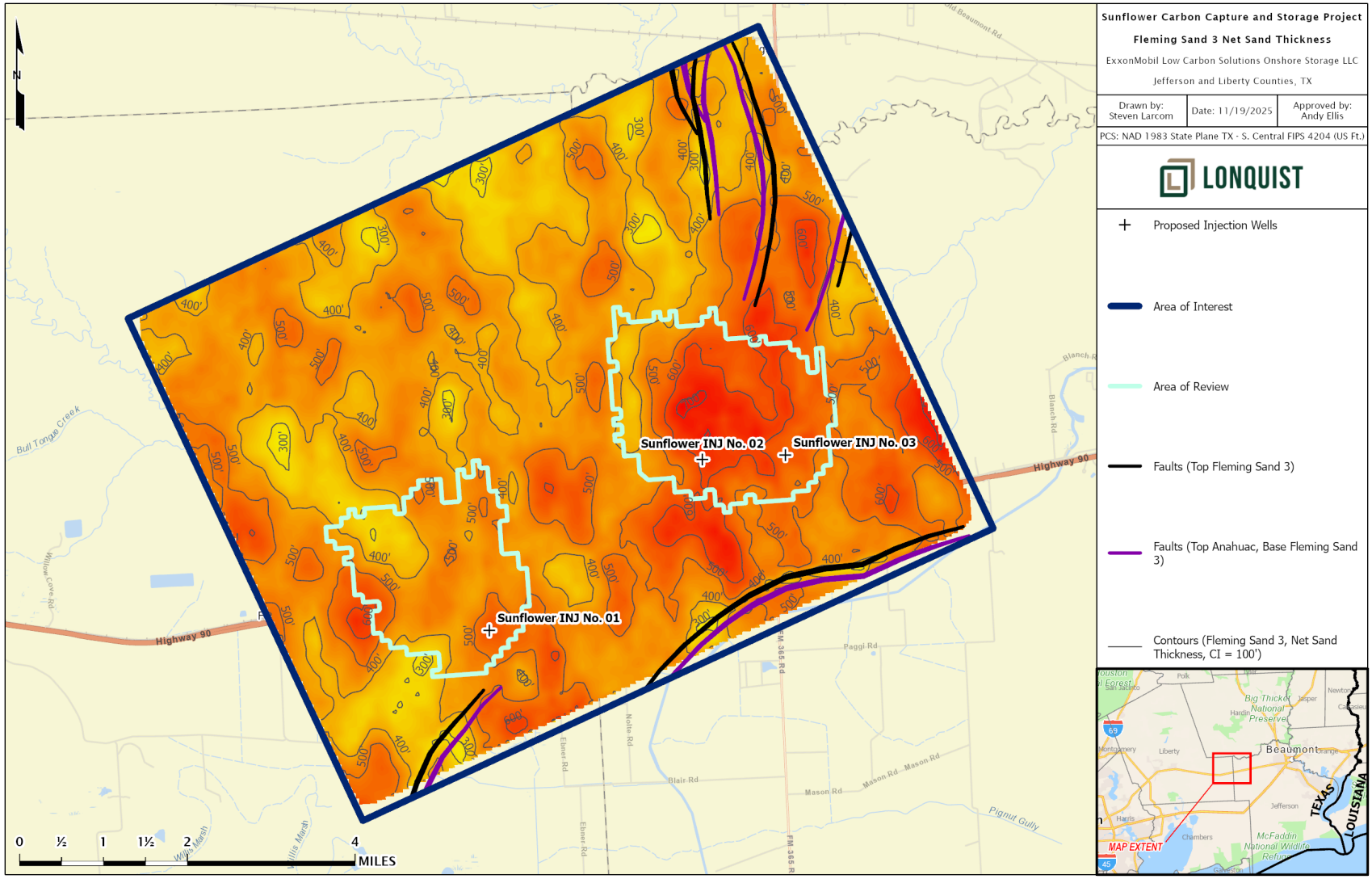


Figure 2-11 – Net Sand Thickness Map – Fleming Sand 3

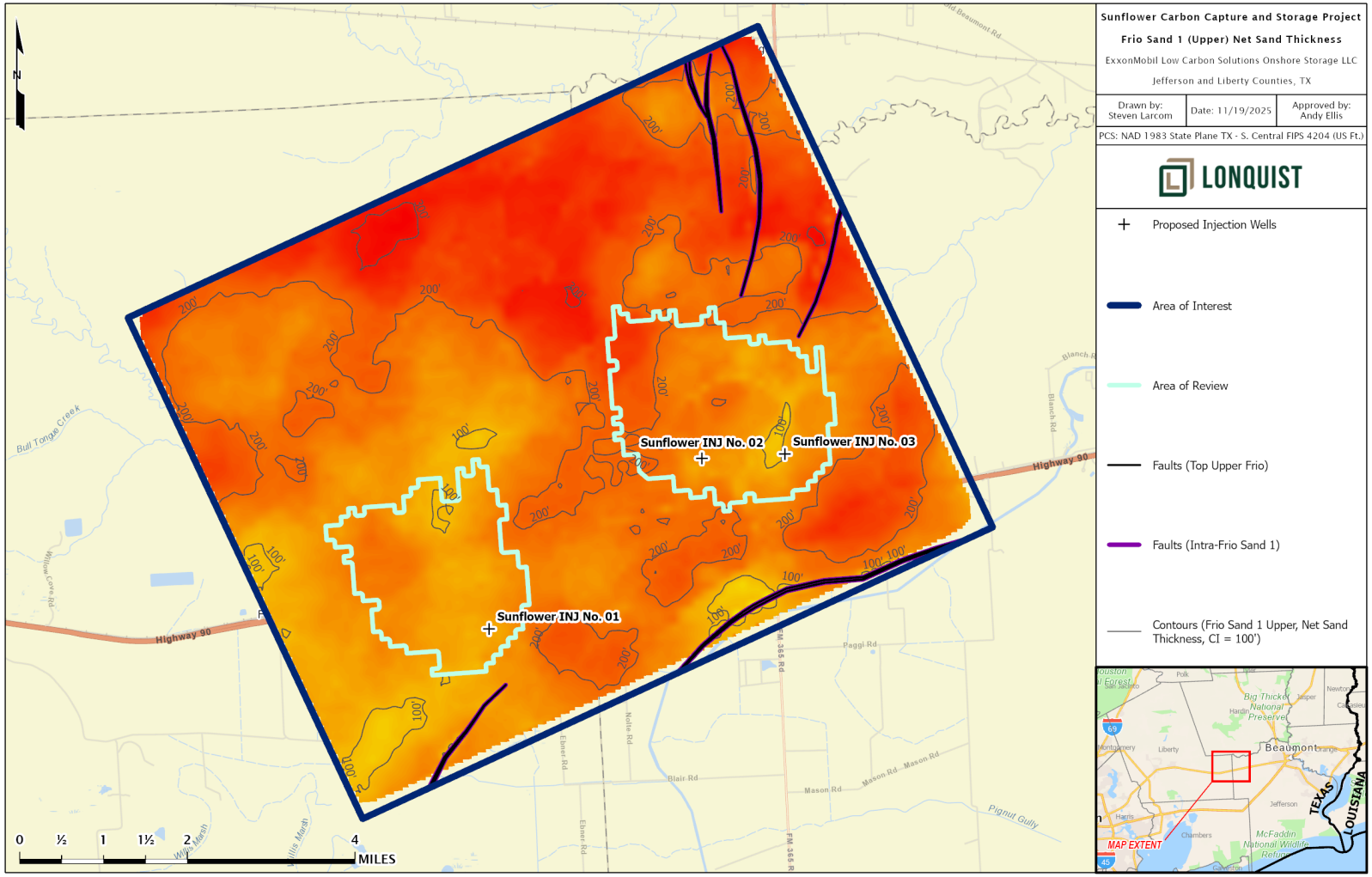


Figure 2-12 – Net Sand Thickness Map – Frio Sand 1 Upper

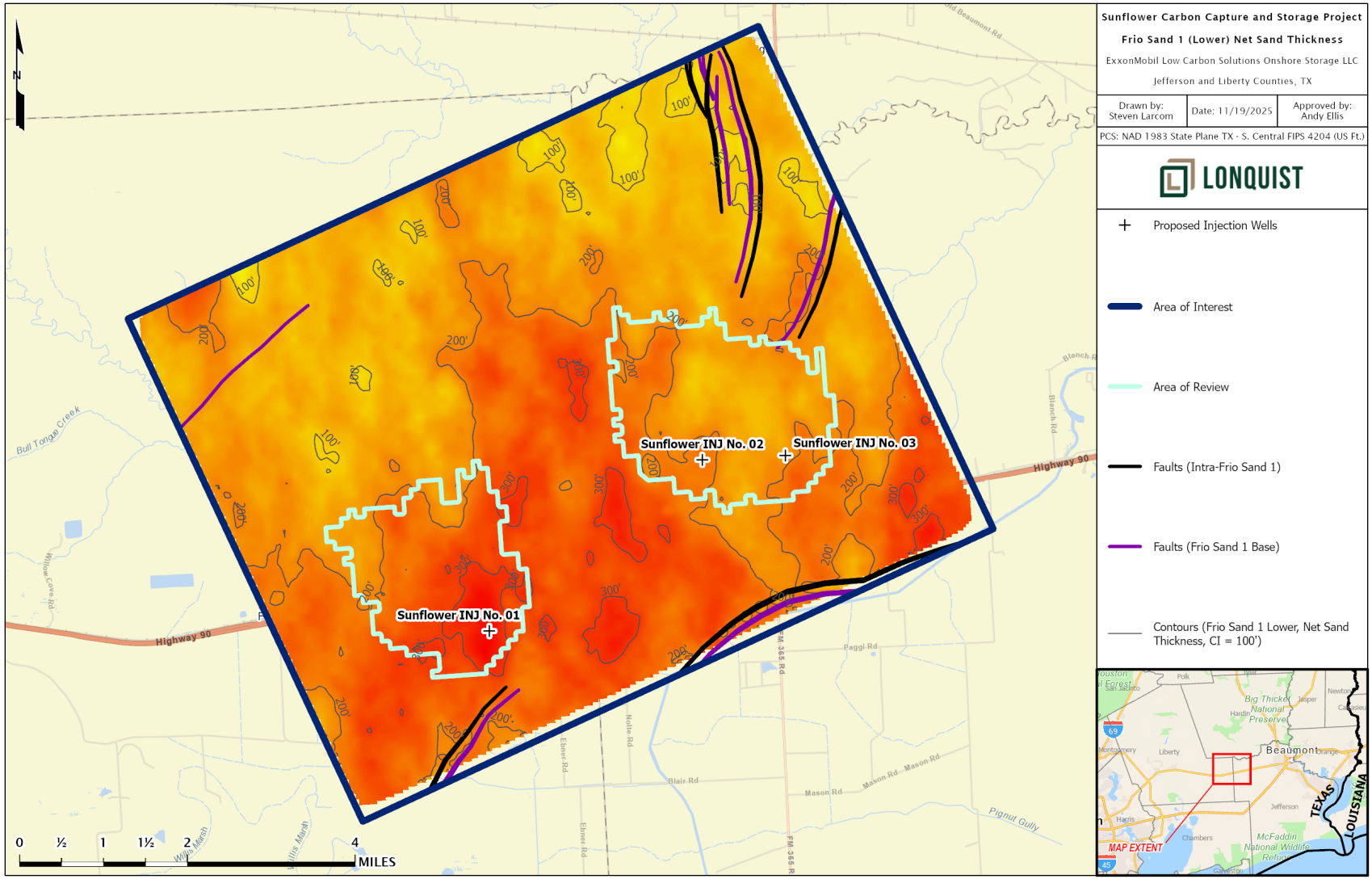


Figure 2-13 – Net Sand Thickness Map – Frio Sand 1 Lower

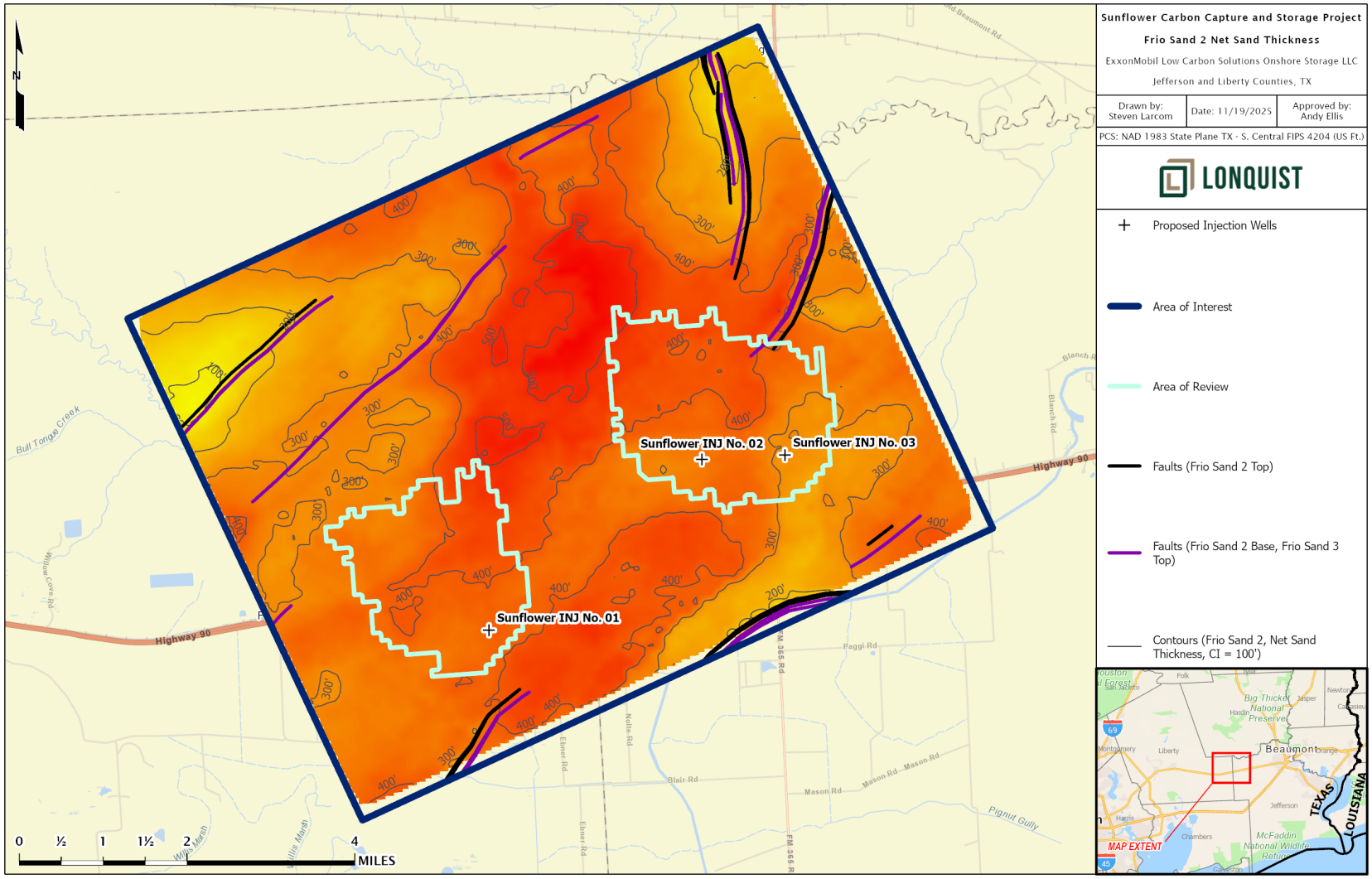


Figure 2-14 – Net Sand Thickness Map – Frio Sand 2

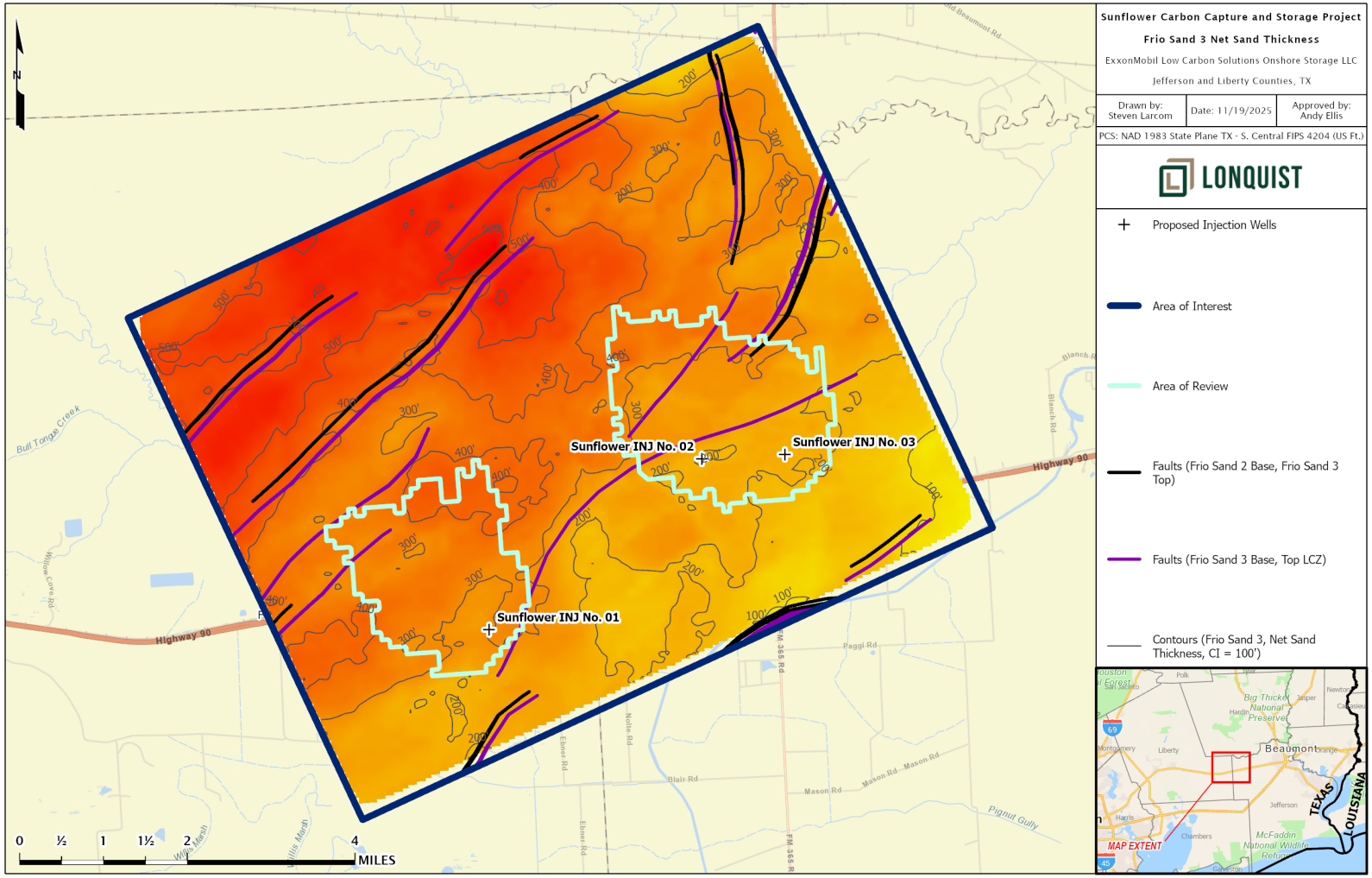


Figure 2-15 – Net Sand Thickness Map – Frio Sand 3

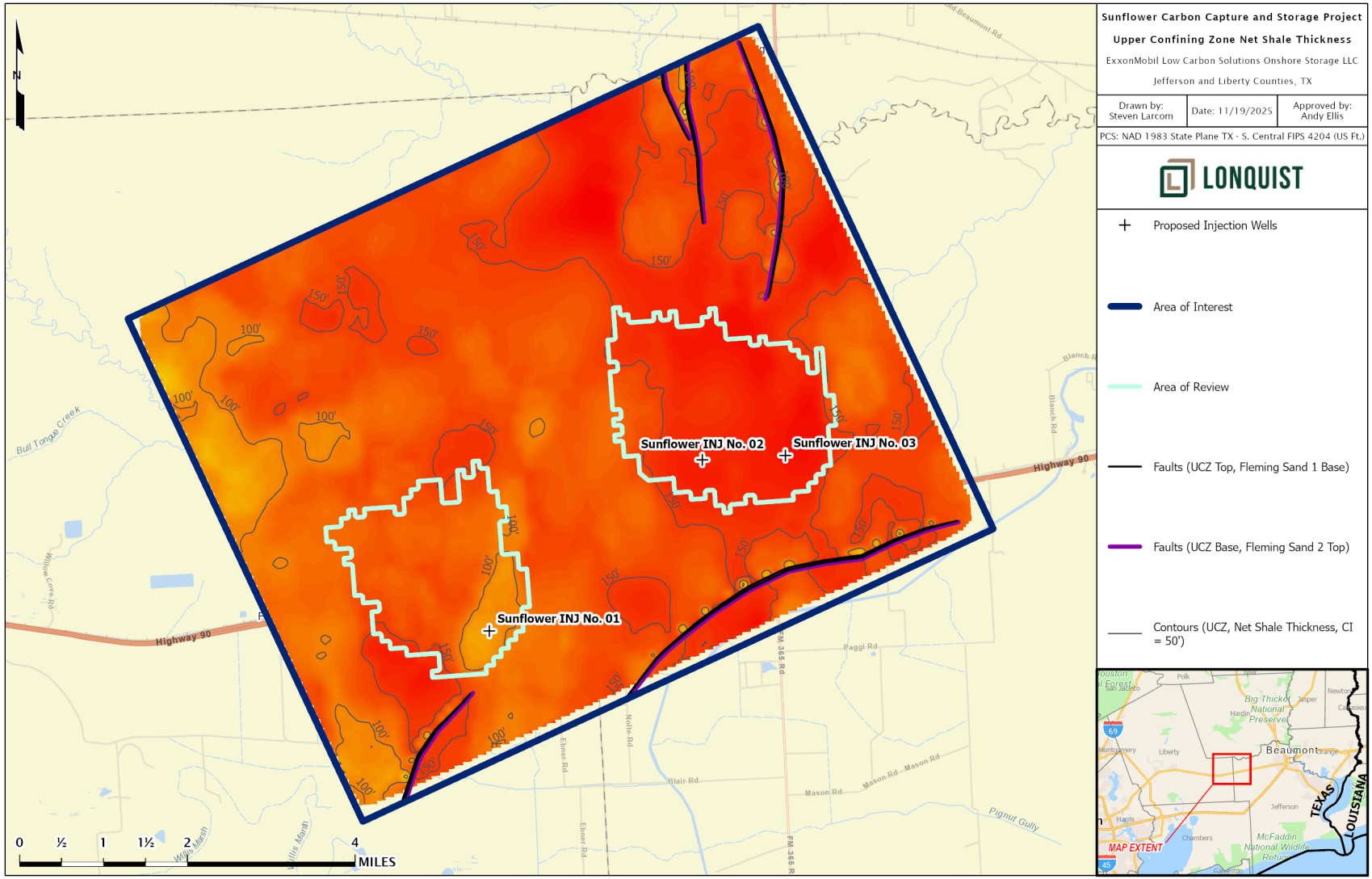


Figure 2-16 – Net Shale Thickness Map – Upper Confining Zone

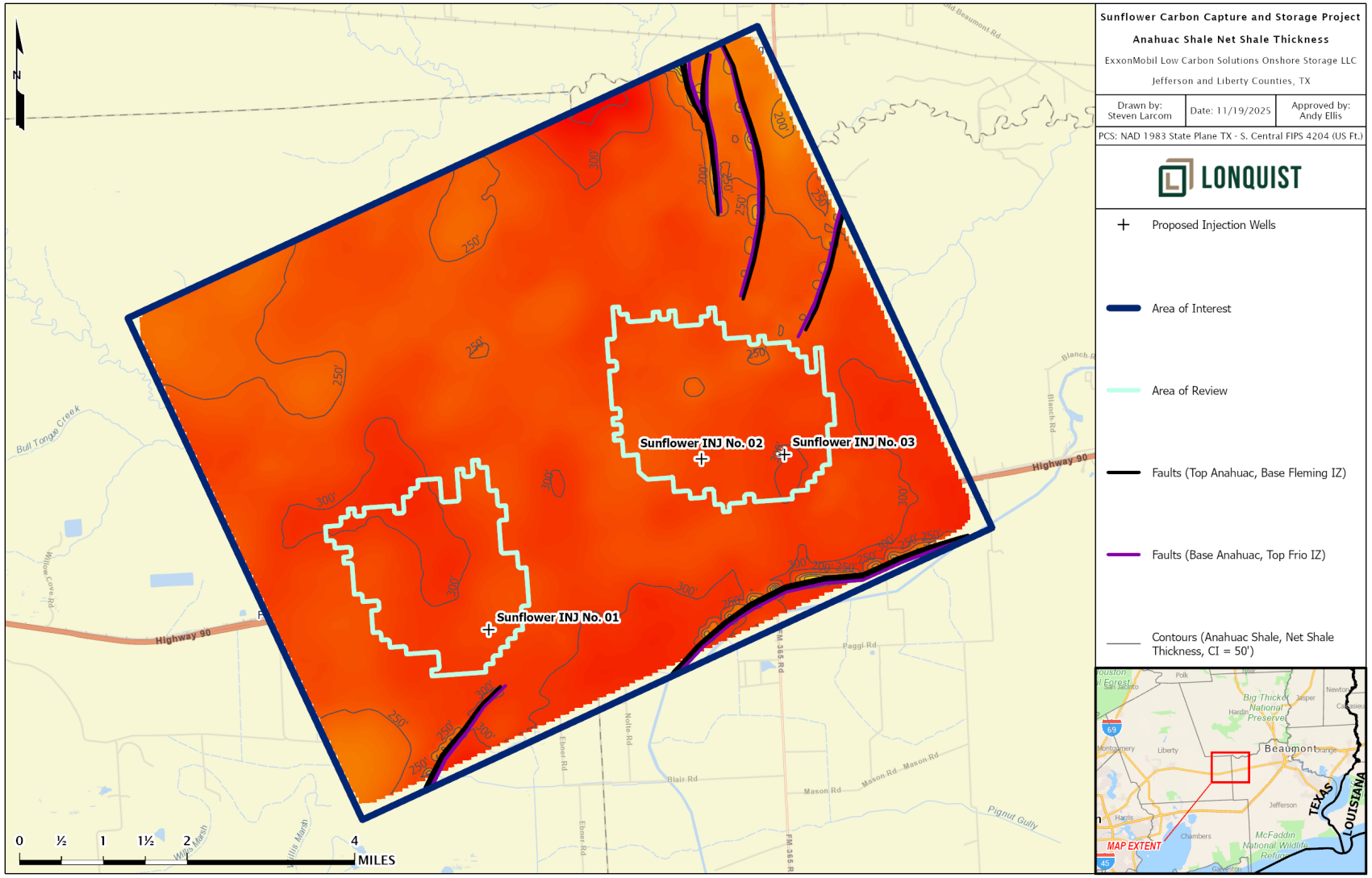


Figure 2-17 – Net Shale Thickness Map – Anahuac Shale

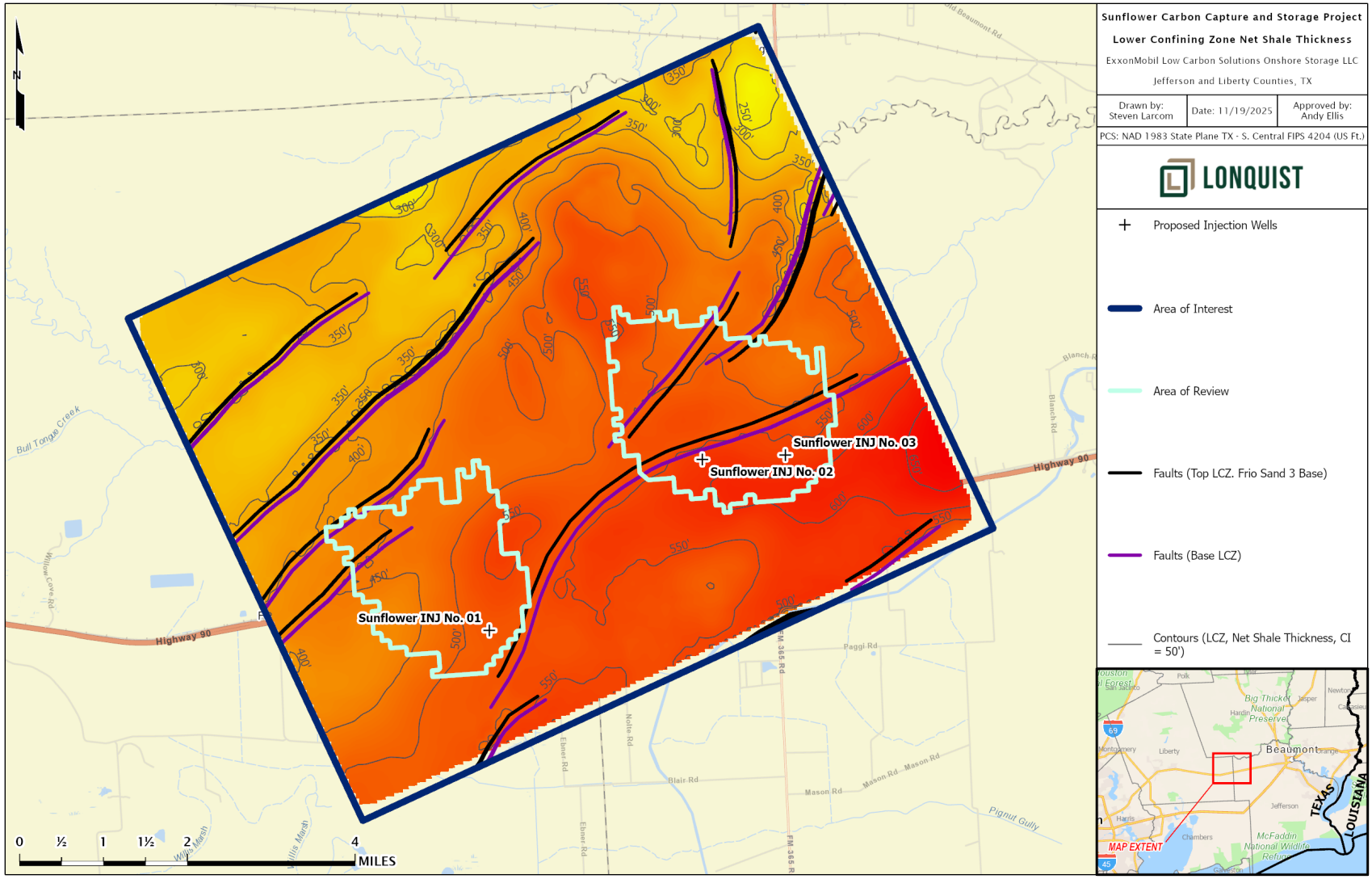


Figure 2-18 – Net Shale Thickness Map – Lower Confining Zone

2.5.4 Lithofacies Model

The Vshale log was based mostly on SP, which was the most common lithological log in the data set. In some cases, only gamma ray without SP was available and was used for the volume of shale log determination. However, these cases made up fewer than 10% of the total cases modeled. To normalize SP values for upscaling lithologies, the SP log was drift-corrected to force the shale baseline to zero millivolts (mV). In cases of the gamma ray log, the drift correction for the shale baseline (100% shale) was assigned as 150 GAPI units. The volume of shale log was then used to determine lithofacies using a cutoff based on the lithology-porosity relationship discussed below.

The injection zone facies classifications are shown in Figure 2-19, where four facies were identified based on the Vshale log. Those classifications are then described in Table 2-3.

[redacted]

Table 2-3 – Description of the Injection Zone Facies Classifications

Facies	Volume of Shale (%)
Coarser Sand	[redacted]
Sand	[redacted]
Silty Sand	[redacted]
Shale	[redacted]

The UCZ and shale beds within the injection zone (Anahuac) possess a non-net ([redacted]) component greater than [redacted] in each interval, indicating that the majority of these intervals

are shale. A statistical overview of net and non-net rocks within these intervals is given in Figure 2-20, demonstrating the high content of shale present.



The interpreted lithofacies logs were upscaled to model resolution with a bias to the modeled net and not-net intervals. The upscaled lithofacies were then distributed in the 3D model, conditioned to the net and non-net regions using the TGS algorithm. The shale facies is assigned to the non-net (Vshale greater than), while coarser sand, sand, and silty sand are assigned to the net facies (Vshale less than). The statistical parameters and trend volumes helped to distribute coarser sand along the core of the net geobodies (e.g., channels, lobes), and sequentially distribute sand and silty sand toward the flank.

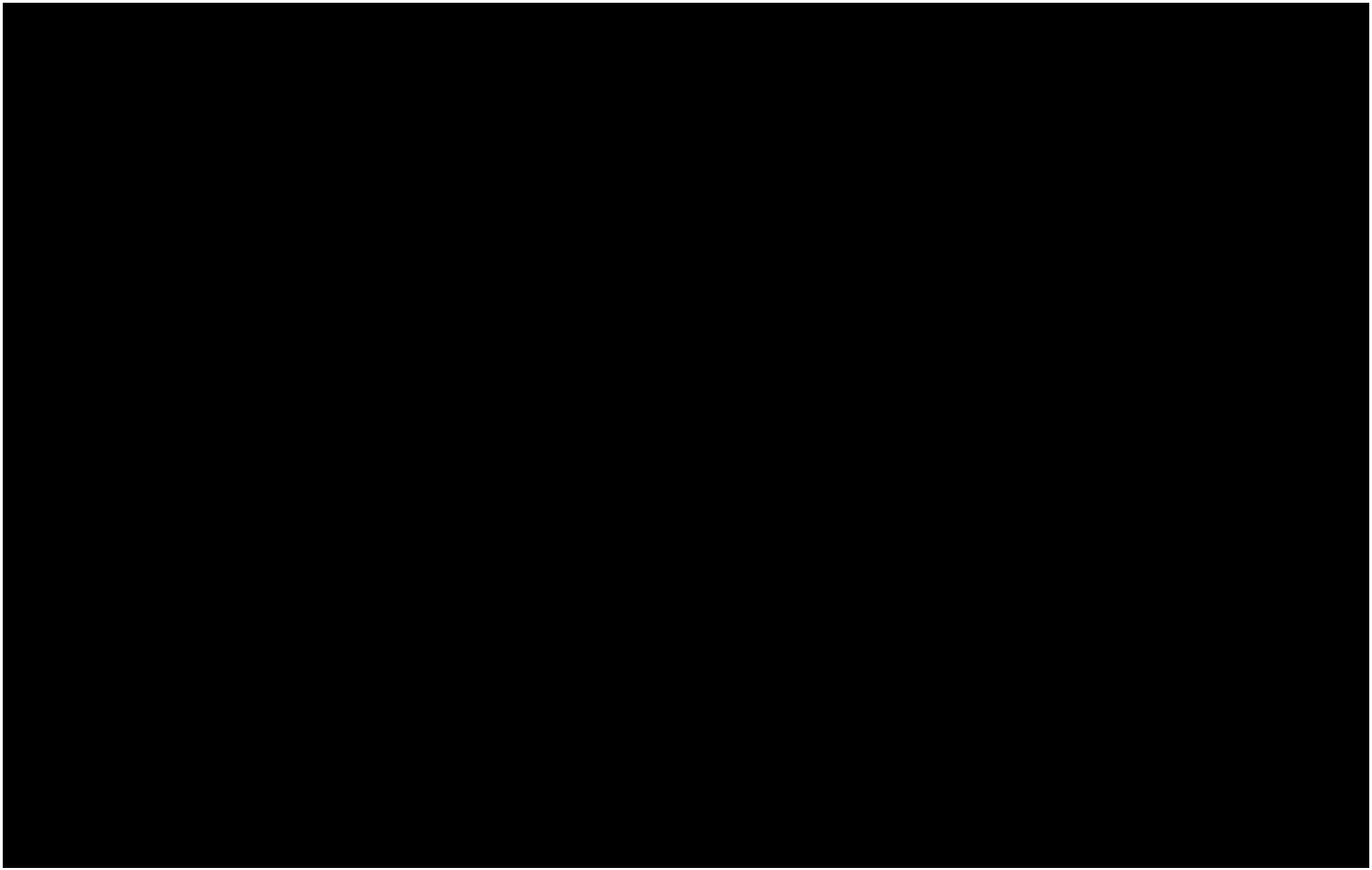
The variograms for facies modeling are determined based on the geological feature dimensions used in net and non-net modeling along with geological concepts. The values considered for different intervals are shown in Table 2-4:

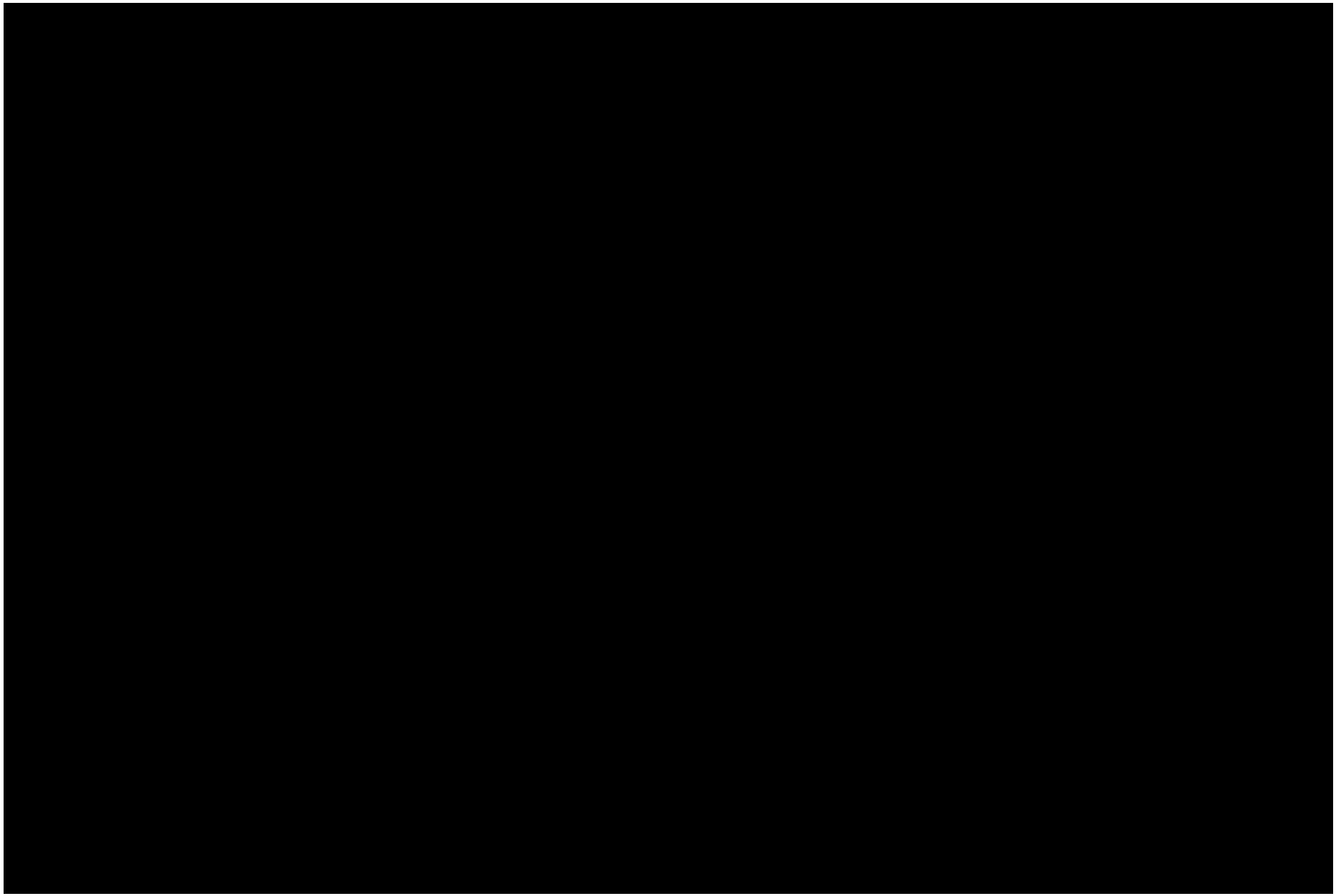
Table 2-4 – Summary of Facies Variogram Ranges

	Facies				
	Major (ft)	**Minor (ft)**	**Vertical (ft)**	**Dip (degree)**	**Azimuth (degree)**
Fleming Sand 2					
Fleming Sand 3					
Frio Sand 1 Upper					0
Frio Sand 1 Lower					
Frio Sand 2					
Frio Sand 3					

Figures 2-21 and 2-22 present two cross sections across the AOI through different wells, showing modeled lithofacies in the geologic model. The results show excellent correlation between the modeled facies and log assignment. The figures also illustrate the distribution of lithofacies away

from the wells. Figure 2-23 presents the map-view of representative layers for the Fleming and Frio injection intervals. Both net and lithofacies on the figure were mapped based on the interpreted depositional environment for the injection intervals.







The net reservoir proportion calculated for each interval was summarized in Table 2-2 and a further breakdown of the facies within the net reservoir is summarized in Table 2-5.

Table 2-5 – Lithofacies Fractions Within the Net Reservoir for the Injection Zones

Formation/Injection Zone	Coarser Sand	Sand	Silty Sand
Fleming Sand 2			
Fleming Sand 3			
Frio Sand 1 Upper			
Frio Sand 1 Lower			
Frio Sand 2			
Frio Sand 3			

2.5.5 Net-to-Gross Model

The net-to-gross (NTG) model was used to address the upscaling effect from log scale to the 3D geologic model scale. While performing facies upscaling, the geologic model cell will assign the facies code that has the highest fraction from the respective well log interval. Therefore, for interbedded reservoirs, the model cells that are assigned to the net facies code represent a mixture of net/non-net.

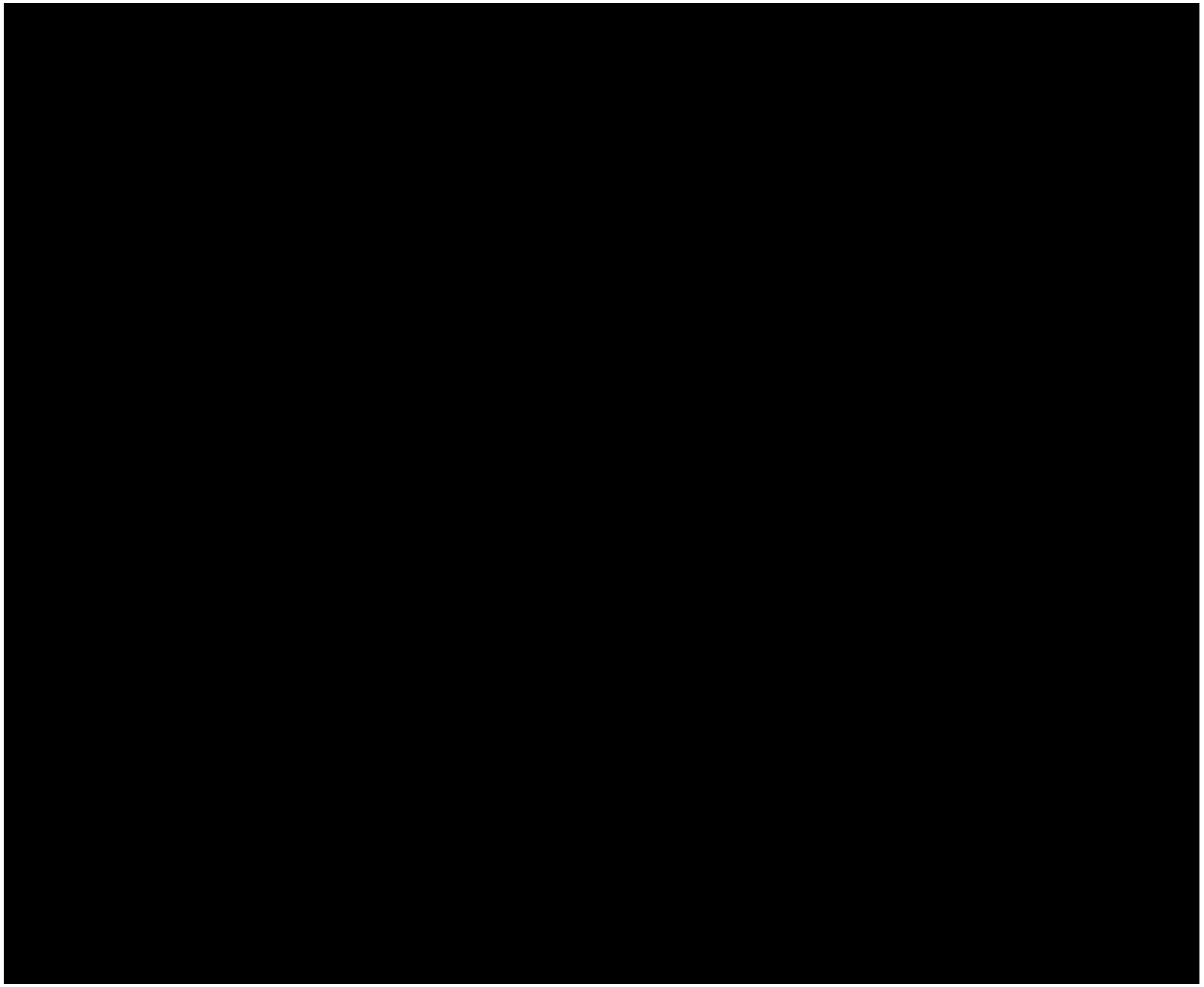
The NTG property is introduced to compensate for this upscaling effect, which is mostly observed in silty sand and shale facies. To perform NTG property modeling, first the NTG log is created based on the facies code. For net facies, the NTG value equals 1—otherwise NTG equals zero. As a result, the proportion of net facies (i.e., coarser sand, sand, and silty sand) to non-net facies (shale) within a grid cell is represented as NTG.

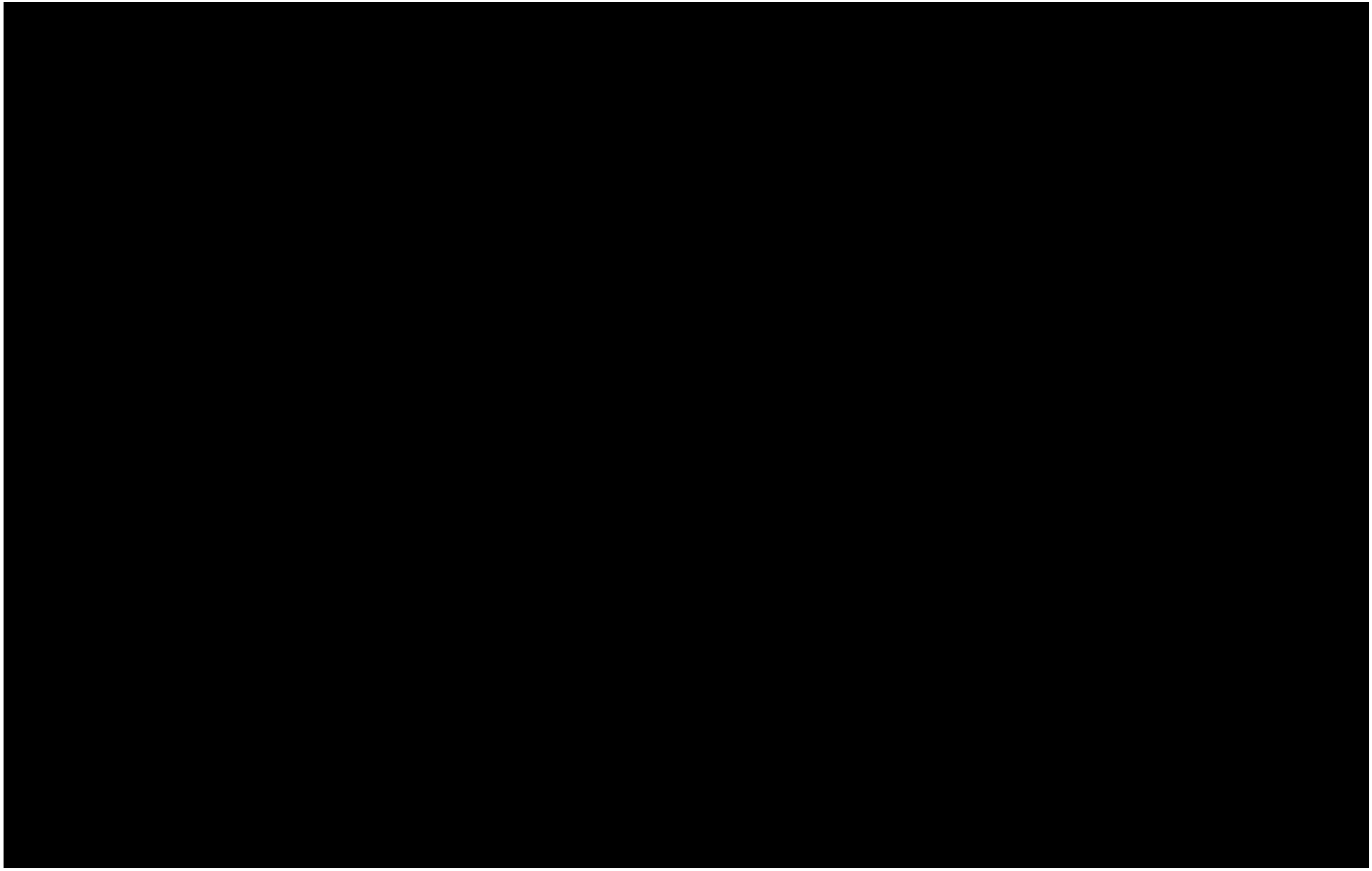
The second step upscales the NTG log into the geologic model, which recalculates the proportion of net within a grid cell as a fraction between 0 and 1.

The third step is to derive the NTG distribution per zone per facies. The upscaled NTG values equal to 1 for coarser sand and sand facies. For silty sand and shale, the statistical distribution (range) of NTG, derived from the upscaled well logs corresponding to the injection intervals in the Fleming and Frio formations, is used as a key model-input parameter—and is shown in Figure 2-24. The Gaussian random function simulation (GRFS) algorithm, using the upscaled NTG log and statistical distribution as input, was applied to build the NTG model for silty sand, ensuring that the NTG target from upscaled cells was honored for each zone. For shale facies, in addition to the above inputs, co-kriging with a trend volume was used to build the NTG model. The trend was generated by smoothing the net/non-net (net region) property and then filtering out the net region to derive the desired trend near the boundaries of modeled net/non-net region. The workflow for NTG modeling in shale facies is illustrated in Figure 2-25.

Example cross sections of the NTG model results are shown in Figures 2-26 and 2-27, which identify the variability of the net thickness between the wells and how the geologic model handled the upscaling.



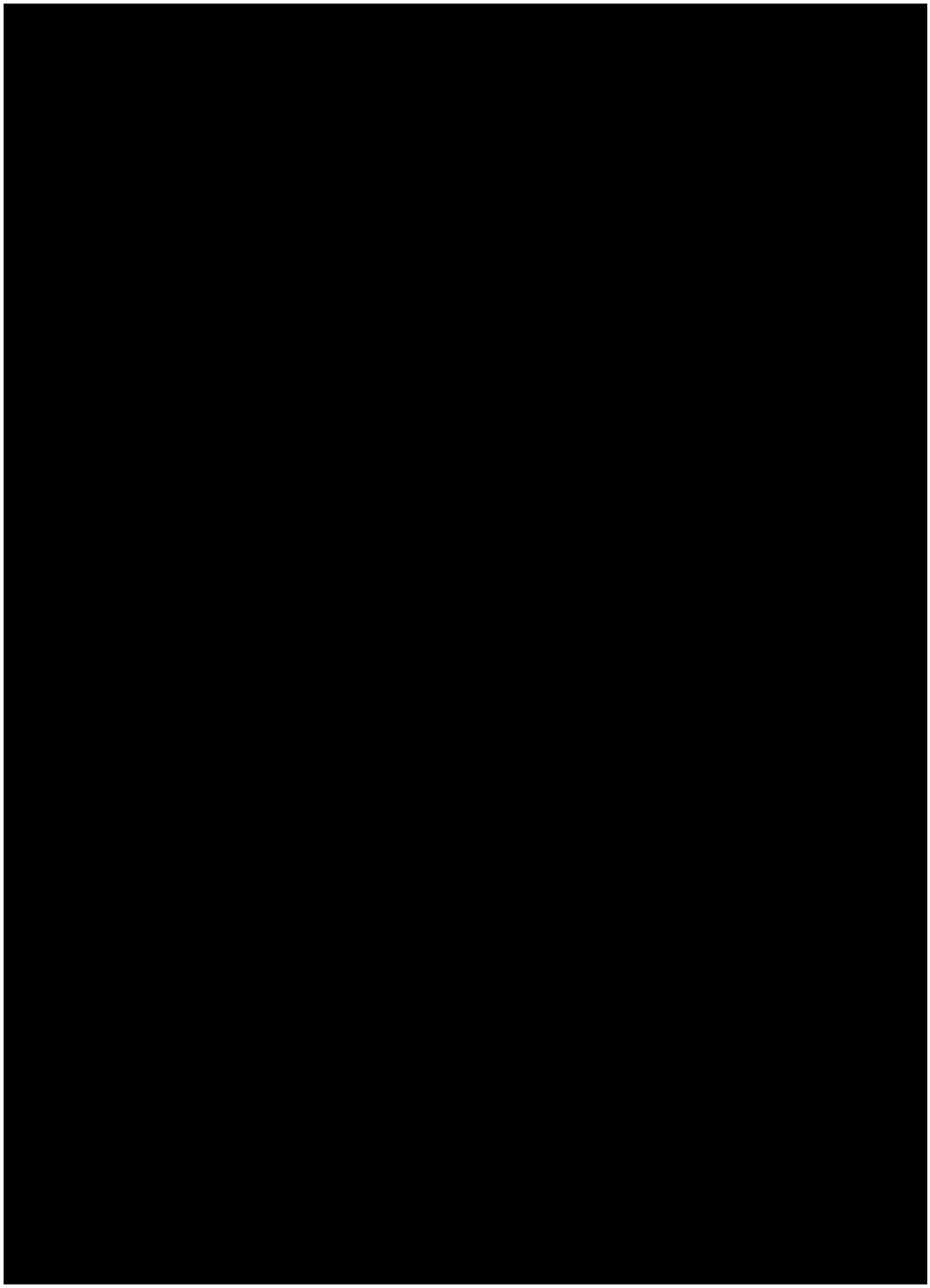






2.5.6 Porosity Model

Compressional sonic data are the most common porosity data source, but some bulk density data also informed porosity estimation. Figure 2-28 shows the Vshale, total porosity, and permeability log calculated for various intervals, including the UCZ, Fleming injection interval, Anahuac Shale, and Frio injection intervals for Arco Fee – 1 (API No. 4229132159).



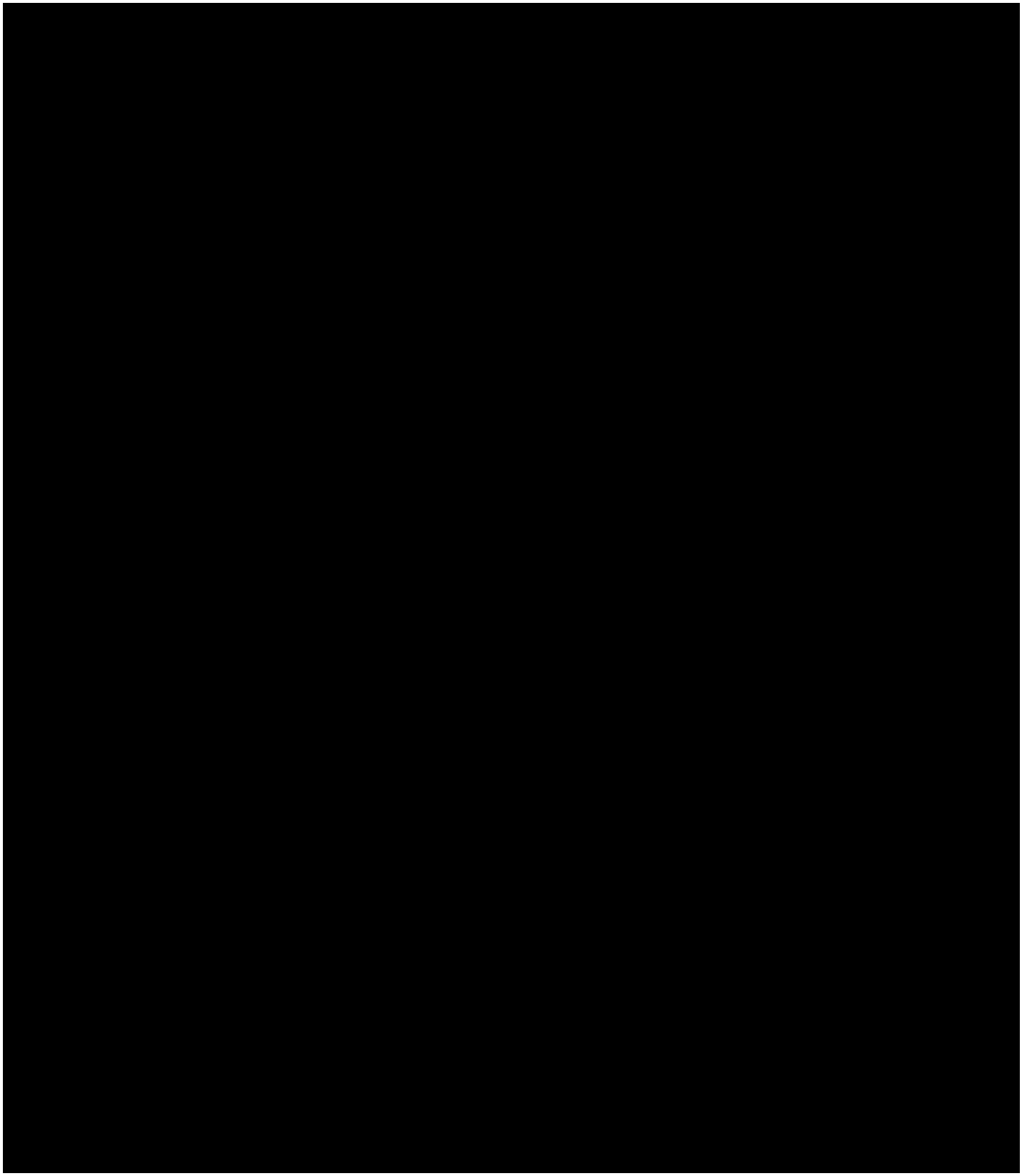
The estimated average total porosity and permeability of the net reservoirs within the Fleming and Frio injection intervals are presented in Table 2-6. For the non-net reservoirs within confining zones, the average total porosity is [redacted] and permeability is less than [redacted] millidarcy (mD).

Table 2-6 – Average Total Porosity and Permeability of Net Reservoir for the Injection Intervals

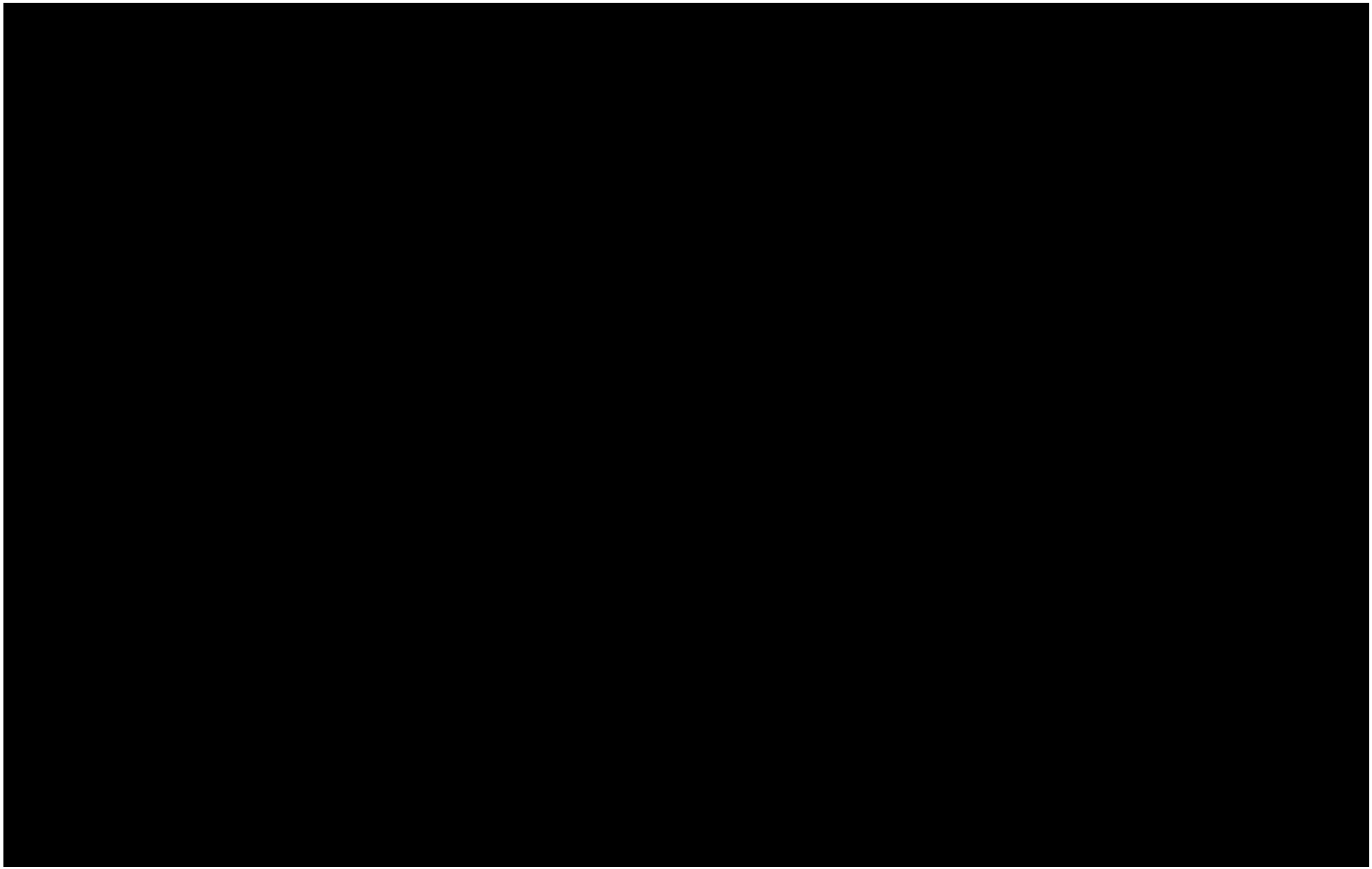
Formation	Avg. Total Porosity (%)	Avg. Permeability (mD)
Fleming	[redacted]	[redacted]
Frio	[redacted]	[redacted]

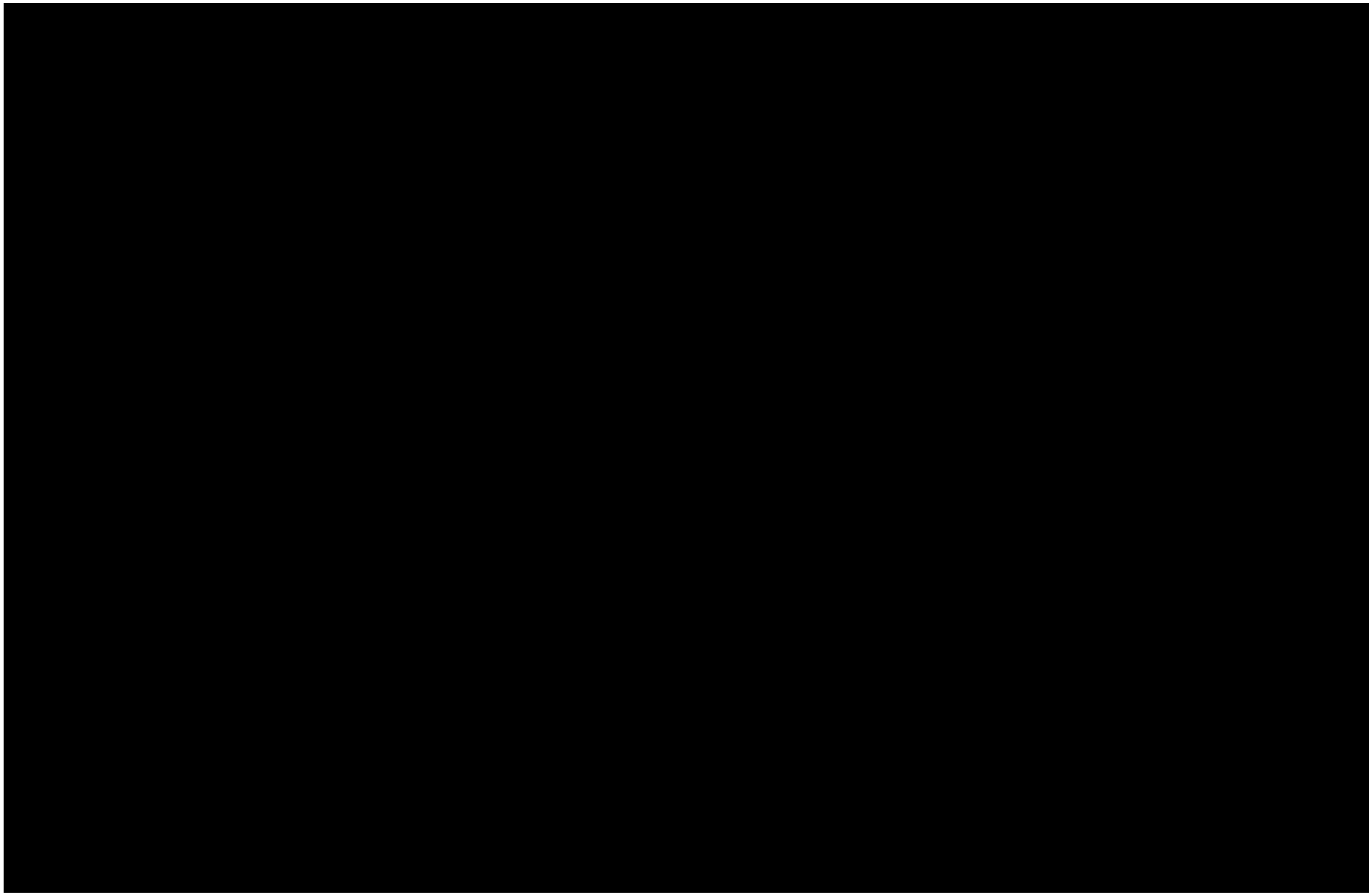
As part of the modeling process, total porosity logs were then upscaled, with a bias to the modeled facies. The upscaled porosity data for each facies per zone was used to define the input porosity distribution (range). The facies-wise porosity distribution within the Fleming and Frio intervals (Fleming Sand 2, Fleming Sand 3, Frio Sand 1 Upper, Frio Sand 1 Lower, Frio Sand 2 and Frio Sand 3) are shown in Figure 2-29.

The porosity model is built for each facies per zone using a GRFS algorithm, ensuring that the porosity distributions are being honored. The total porosity distribution for silty sand facies at each zone was also used for shale facies with non-zero NTG, as poorer reservoir facies are more likely at those interbeds. Finally, this modeled total porosity volume is multiplied with the modeled NTG volume to derive the effective porosity volume.



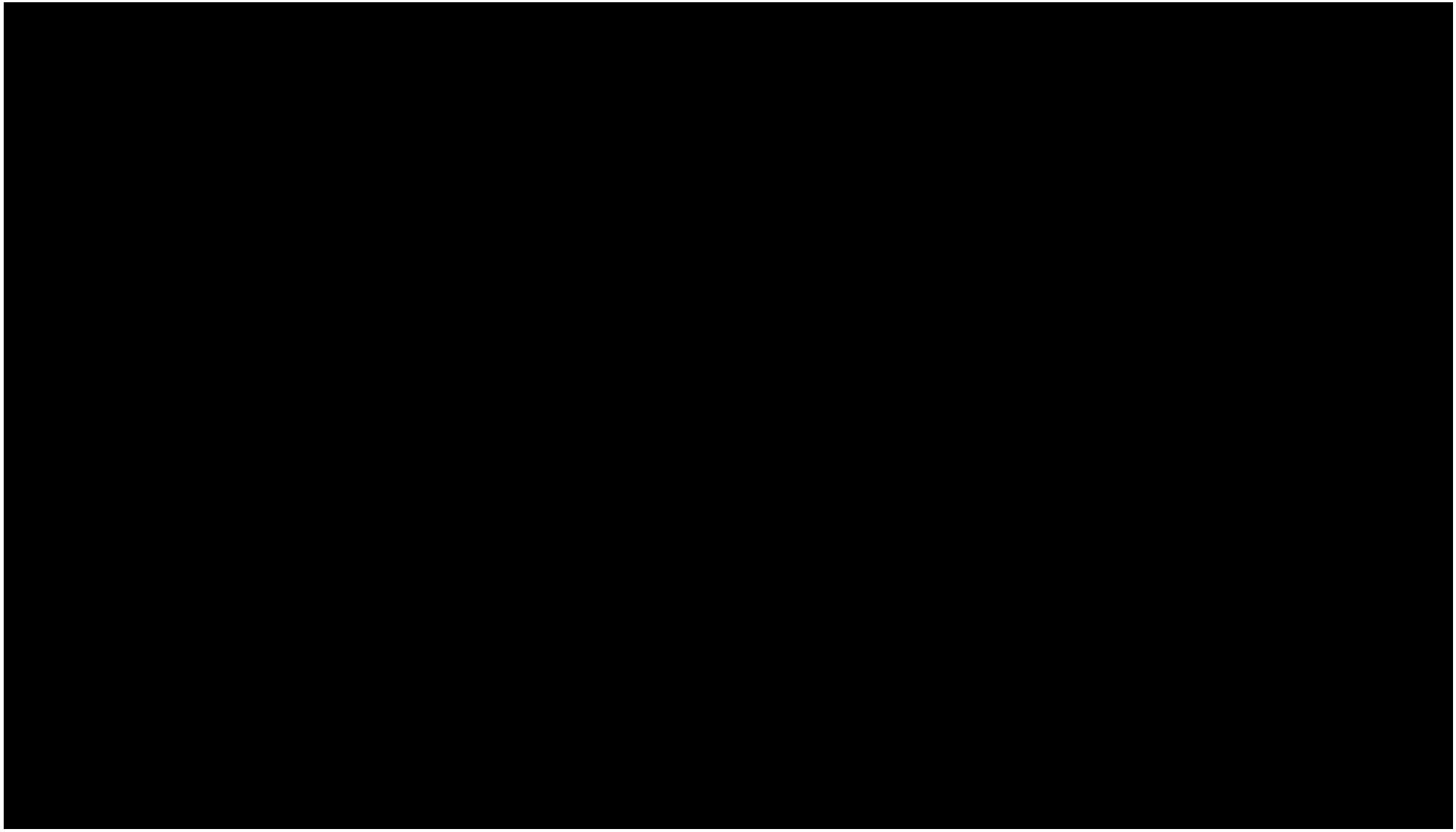
Example cross sections (A-A’ and B-B’) of the total porosity model are shown in Figures 2-30 and 2-31, respectively.



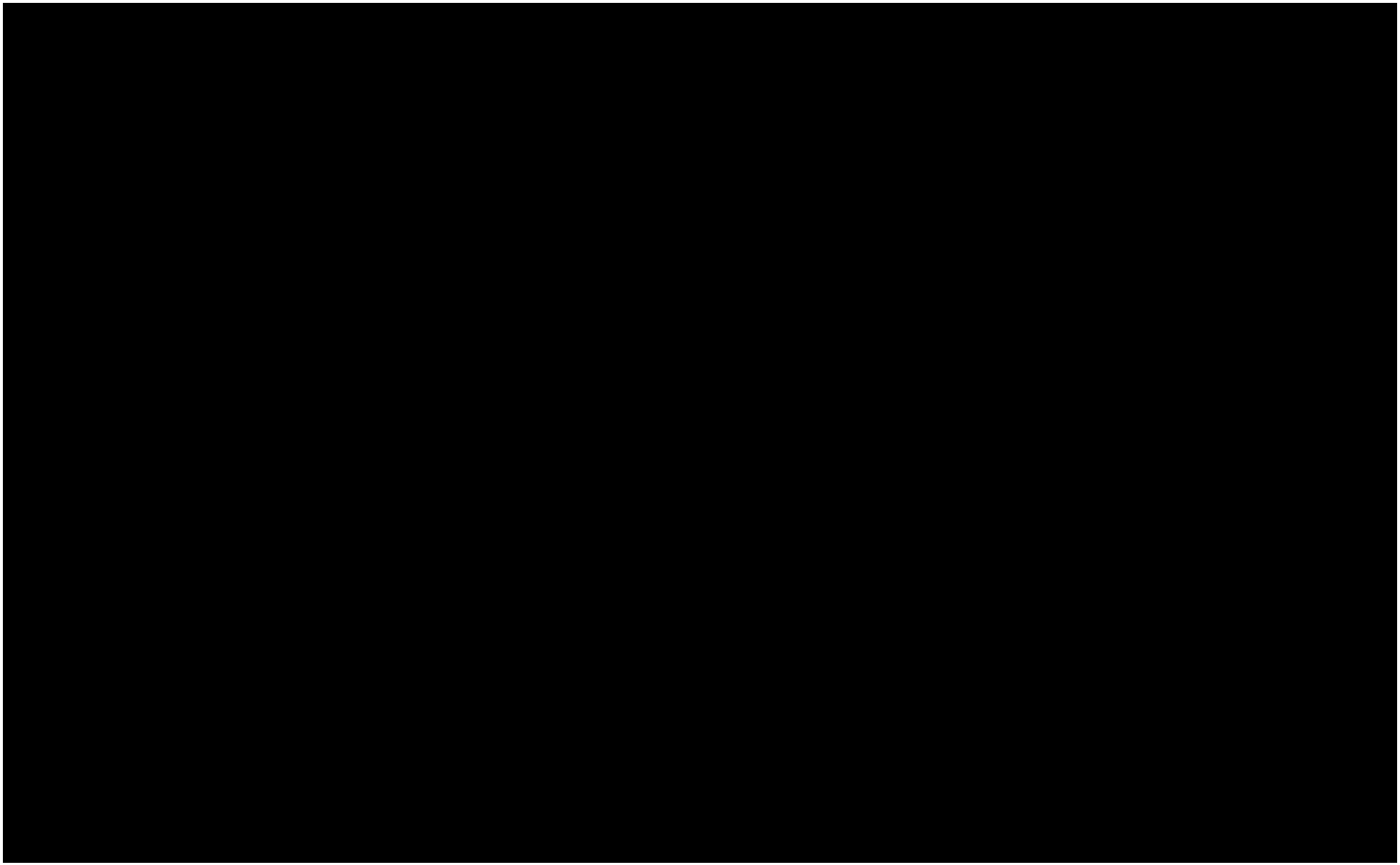


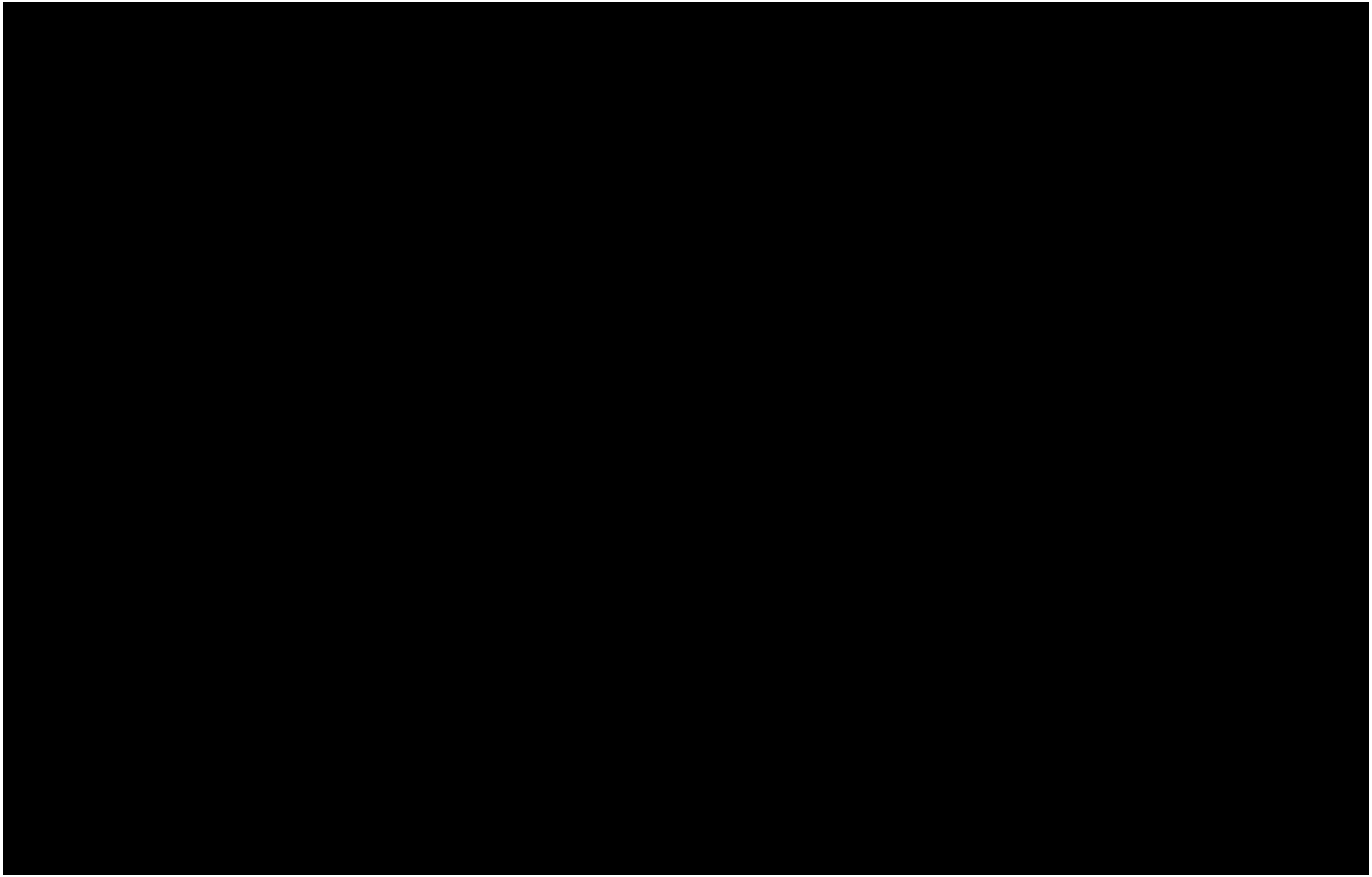
2.5.7 Permeability Model

Permeability was modeled based on select data from the Rose Carbon Capture and Sequestration Project site. Separate porosity-permeability transforms were developed for each facies (coarser sand, sand, and silty sand). The nuclear magnetic resonance (NMR) logs were calibrated against core data and used to define porosity-permeability functions across the range of net reservoir facies (Figure 2-32). This function was then used in the geomodel to generate permeability volumes from modeled porosity volume. Finally, a scatter data set generated using standard Gaussian distribution was added to the permeability volume to mimic the original NMR log-based distribution. The modeled permeability volume was capped at [redacted] to remove the uncertainty of the transform function corresponding to higher porosity and permeability values. This permeability volume is multiplied with the modeled NTG volume to derive an effective permeability volume.



Example cross sections (A-A’ and B-B’) of the permeability model are shown in Figures 2-33 and 2-34, respectively.





2.5.8 Model Uncertainties

The following is a list of uncertainties inherent to the workflow presented regarding the generation of the geologic model:

- Variation of reservoir properties between wells in the injection zone
- Vertical vs. horizonal permeability relationships adopted based on the log data
- Presence of intrazonal flow barriers, baffles, and pinchouts (permeability architecture)

Based on the available data used in the geologic model, these uncertainties—though present—are not expected to have a significant impact on the model results and delineation of the AOR. A detailed discussion on sensitivity analysis is presented in Section 2.7.5. The available geologic data are sufficient to characterize the overall depositional system and, in turn, key geologic features in the project area. Geologic characterization data collected from future drilling activities will be used to further refine the model and reduce these uncertainties.

2.6 Dynamic Model

2.6.1 Model Background

The Petrel-developed geologic model was used as an input into the Intersect numerical reservoir simulator to build the dynamic plume and pressure prediction model. The initial input parameter values in Table 2-7 were used to initialize the model.

2.6.2 Model Scope and Boundary Conditions

The geologic model domain extends significantly beyond the predicted plume boundaries to reduce the potential for the model-domain boundary artifacts.

When choosing the simulation model size and the boundary condition, there are two essential rules: first, the simulation model size should be large enough that stabilized CO_2 migration is well within the model boundary. Second, the boundary condition for the simulation model needs to properly reflect areal aquifer connectivity and volume to accurately capture field pressure response. With CO_2 injection, reservoir pressure rises. In a high-quality sand reservoir, that pressure perturbation may extend well beyond the limited simulation model boundary. It is not practical to include all areal extension where pressure is perturbed in the simulation. A traditional practice to represent the additional aquifer volume beyond the simulation model boundary is implementing pore volume multipliers at the edge of the simulation model while reducing transmissibility.

The Fleming and Frio injection intervals at the Sunflower Project site are characterized as highly connected throughout the region. Therefore, an infinite-acting reservoir boundary condition was selected for the four edges of the rectangular model domain to better simulate the pressure response from CO_2 injection. In the model, a "volume multiplier" of 1,516 was applied uniformly

along the four edges of the model domain. The effective aquifer volume in communication with the model is approximately 50 times greater than the modeled region pore volume. In addition, a transmissibility reduction of 1/1,516 was applied to the edge of the model grid. This approach follows common industry practice to represent aquifer volume not explicitly captured in the model domain.

2.6.3 Derivation of Input Parameter Values for Dynamic Modeling

ExxonMobil recognizes that parameter values for the prediction of the AOR are to be based on site-specific data to the extent possible. Core samples were collected from the nearby stratigraphic test well (Bead Farm Co. – 1; API No. 4224532908), as well as three additional stratigraphic test wells, to obtain the necessary geologic characterization data of the Sunflower Project site for the CO_2 plume model. Additionally, where appropriate, the parameter values were estimated from standard values published for similar rock types and relationships in the scientific literature. As outlined below, ExxonMobil derived initial estimates of compressibility, relative permeability, capillary pressure, reservoir pressure and temperature from the available information, with emphasis on the available stratigraphic test well data and test results, as appropriate.

The site-specific characteristics that make the project site ideal for carbon sequestration are described in *Section 1.11* of *Section 1 – Site Characterization*. In summary, the sands of the Fleming and Frio formations exhibit high porosity and permeability that are ideal for CO_2 storage and are "of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the carbon dioxide stream" (16 TAC **§5.206(b)(6)(A)**). Both the UCZ and Anahuac Shale are thick, continuous sealing intervals across the AOR and are sufficient to "contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone" (16 TAC **§5.206(b)(6)(B)**).

Table 2-7 – Summary of Input Parameter Values for the Model

Input Parameters	Value
Average Porosity (%)	[redacted]
Average Permeability (mD)	[redacted]
k_v/k_h Ratio	[redacted]
Pore Pressure Gradient (psi/ft)	[redacted]
90% Fracture Pressure Gradient (psi/ft)	[redacted]
Mean Surface Temperature (°F)	[redacted]
Temperature Gradient (°F/100 ft)	[redacted]
Salinity as Total Dissolved Solids (mg/L or parts per million)	[redacted]

k_v/k_h – vertical to horizontal permeability ratio; psi/ft – pounds per square inch per foot; mg/L – milligrams per liter

2.6.3.1 Rock Compressibility

Based on the rock compressibility measurements for the sandstone samples collected at the stratigraphic test well (Bead Farm Co. – 1), an average value of [redacted] was selected for the Frio sands and [redacted] for the Fleming sands. Figure 2-35 provides a literature-based relationship between pore volume compressibility and initial porosity. The average rock compressibility values derived from various cored intervals of the stratigraphic test well are demonstrated in Figure 2-36. These values are consistent with the literature-based ranges described in Figure 2-35.

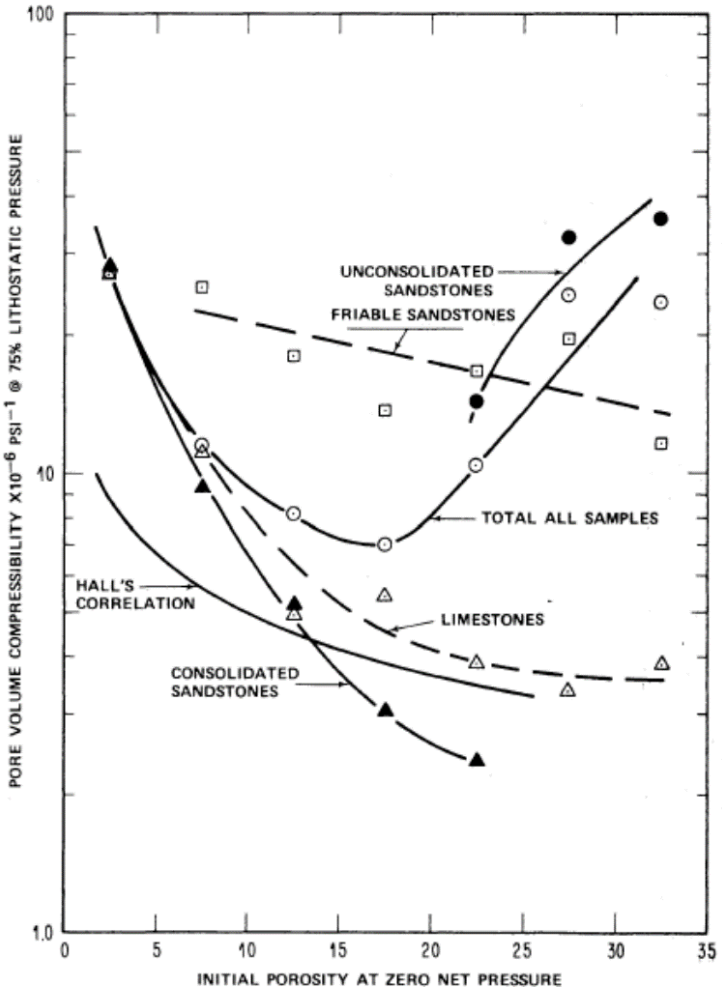


Figure 2-35 – Pore Volume Compressibility as a Function of Initial Porosity (Newman, 1973)



2.6.3.2 Relative Permeability

Relative permeability curves were generated based on research of analogous depositional environments. Traditional core testing has difficulty accurately measuring the end points of the curves, resulting in high irreducible water saturations and low CO_2 endpoints (Benson et al., 2013). In drainage CO_2-brine relative-permeability experiments, as water saturation decreases, capillary forces become larger (i.e., capillary pressure (P_c)) and increase rapidly in the approach to the irreducible water saturation. During the experiment, the increase in capillary forces limits further reduction in water saturation (i.e., the viscous force is too small relative to the capillary force). This causes the experimental relative-permeability measurements to end at water saturations higher than the actual irreducible water saturation. For this reason, it is recommended to fit a Corey-Brooks expression to the experimental data and to extrapolate the curve to a representative value of irreducible water saturation.

In a recent study conducted by researchers at the University of Texas, a Corey-Brooks function was fitted to experimental data to generate relative permeability curves at a lower irreducible water saturation (Chen et al., 2017). Using similar methodologies and the nearby stratigraphic test well (Bead Farm Co. – 1) core data, relative permeability curves were generated for use in the simulation model. The quality of sands was differentiated to reflect the different capillary threshold pressures, irreducible water saturations, and trapped gas saturations of each sand. The sands were categorized into five permeability bins, as shown in Table 2-8.

Table 2-8 – Relative Permeability Bins and Associated Parameters

Perm (mD)	S_{wirr}	Corey Gas Drainage	Corey Gas Imbibition	Corey Water	k_{rw} End	k_{rg} End	S_{gt}	$P_{c,th}$ (psi)
[redacted]								

S_{wirr} = irreducible water saturation fraction; k_{rw} = relative permeability to water; k_{rg} = effective permeability to gas for a given gas saturation; $P_{c,th}$ = threshold pressure; S_{gt} = trapped gas saturation

The irreducible water saturation was assumed to be in the range of [redacted] to [redacted] based on published values for various sand qualities in the available Gulf Coast regional data. Fitting the end points to the experimental data resulted in brine and CO_2 exponents of [redacted] and [redacted], respectively. The geologic model's permeability property is based on absolute gas permeability, as shown in Figure 2-37 for sand with permeability greater than 500 mD.

[redacted]

The Corey function for gas and water relative permeability is defined as follows, in Equation 1, where the Corey exponents were listed in Table 2-8.

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

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

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

Gas hysteresis behavior was incorporated into the displacement curves to account for trapped gas as a CO_2 storage mechanism. The approach represents CO_2 replacing water as gas saturation, and the amount of CO_2 increases until it reaches maximum gas saturation. Afterward, during the imbibition process, water drives CO_2 out of the pore space, and gas saturation decreases until it reaches trapped gas saturation (S_{gt}).

2.6.3.3 Capillary Pressure

Capillary pressure functions were formed using the Corey-Brooks capillary pressure model (Equation 2):

(Eq. 2) $$P_c = P_{c,th} \times {S_{wn}}^B$$

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

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

A range of $0 < P_{c,th} < 4$ pounds per square inch (psi) was assumed for each permeability bin, which is reasonable for clastic rock at reservoir conditions. The values chosen for each S_{wirr} bin were listed in Table 2-8. In Equation 3, exponent B is related to pore-size distribution index I and estimated based on Burdine's theory:

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

In a gas-water system, the Corey-Brooks capillary pressure model (Eq. 3) indicates that the capillary pressure curves steepen as they approach the irreducible water saturation point. The five sets of capillary curves are plotted in Figure 2-38.

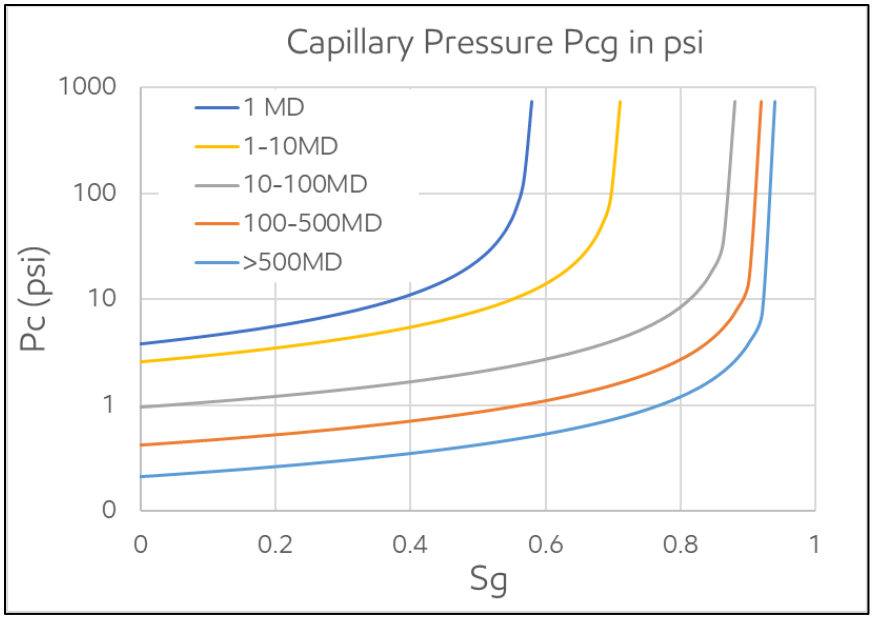


Figure 2-38 – Capillary Pressure Functions

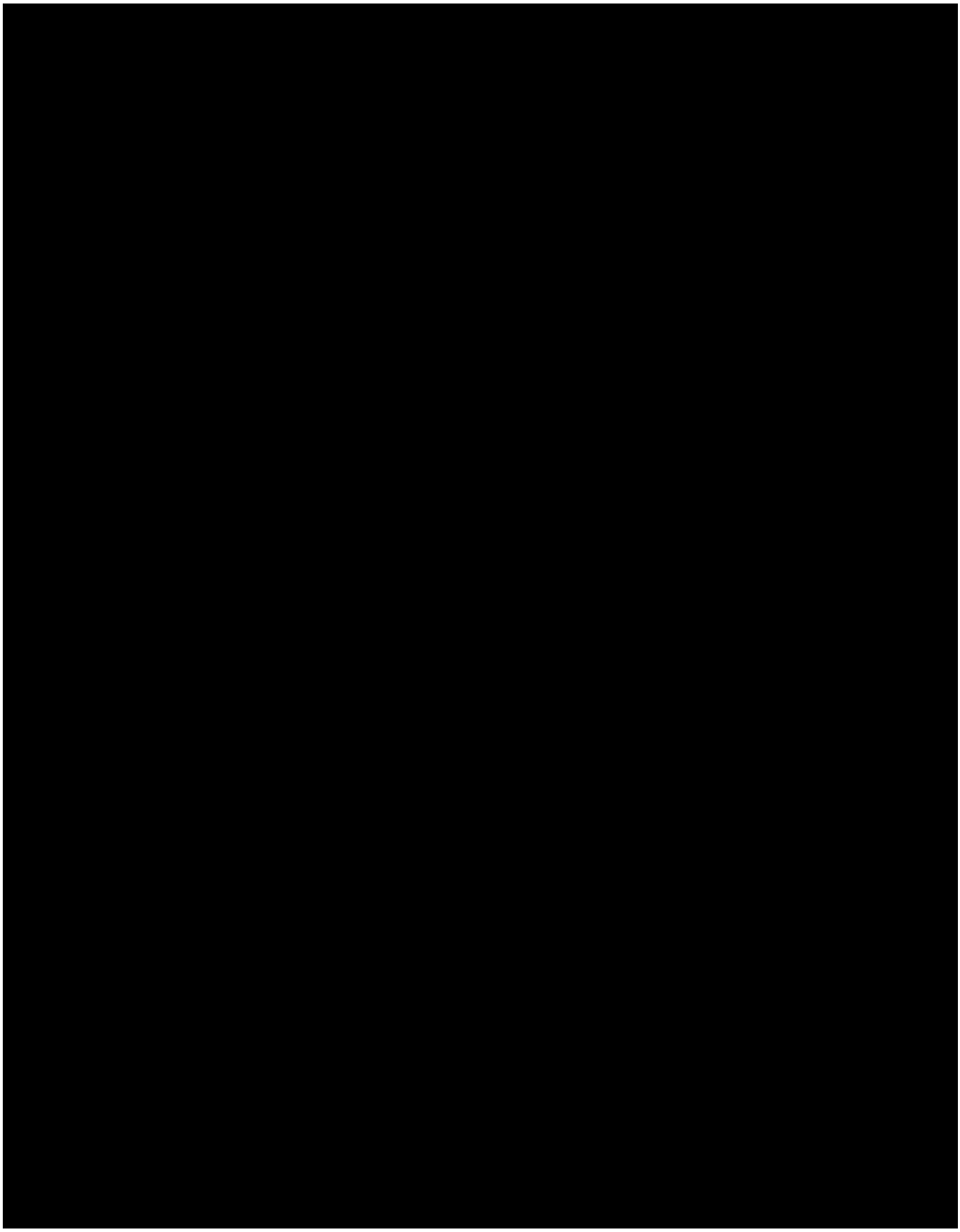
2.6.3.4 Fluid Pressure

The average formation fluid pressure gradient was derived from 17 formation pressure data points acquired from the stratigraphic test well. The pressure gradient value is 0.45 psi/ft and represented in Figure 2-39. This original reservoir pressure gradient was based on data points collected from 3,200–8,400 feet and was considered representative of the sand intervals to be used for injection. The measured site-specific values are consistent with expected values obtained from available literature, which reported an average value of approximately 0.45 psi/ft (Kreitler, Akhter, and Donnelly, 1988).



2.6.3.5 Temperature

Based on data collected from the stratigraphic test well, the temperature gradient is [redacted] per [redacted] The mean surface temperature was assigned [redacted] The original temperature was assigned to be consistent with this temperature and the temperature gradient throughout the model domain. The temperature gradient is presented in Figure 2-40.



2.6.3.6 Initial Saturation

A review of the available literature (Kreitler, Akhter, and Donnelly, 1988) indicates that the target Fleming and Frio injection intervals in this area of the Gulf Coast are expected to be saline aquifers of 100% water saturation. For the purposes of the simulations, an initial 0% mole fraction of CO_2 was assumed.

2.6.4 Derivation of Input Parameter Values for Fluid Properties

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

For this model, the CO_2 sequestration compositional modeling method CSIW was used, which can accurately evaluate fluid density and viscosity based on the following:

- The vapor component densities and fugacities are calculated using a cubic EOS.
- The aqueous phase density and viscosity are provided in a solubility table. To generate the tables, the Spycher and Pruess pressure-volume-temperature (PVT) model was used.
- The viscosities are handled using the Lorenz-Bray-Clark model.

The source of the CO2 for the Sunflower CCS Project is ExxonMobil's USGC CO2 Pipeline fed by high-concentration industrial emitters throughout the US Gulf Coast. For this simulation, 100% CO_2 injection was assumed.

2.6.5 Fluid Composition

Fluid samples were collected from the nearby stratigraphic test well and analyzed. The results of laboratory analyses for total salinity are summarized in Table 2-9. Based on this data and to be conservative, the simulation model was initialized assuming a uniform salinity of 100,000 parts per million (ppm), at a reference depth of 6,523 feet. A detailed fluid analysis is presented in *Section 1.7* of *Section 1 – Site Characterization*.

Table 2-9 – Bead Farm Co. – 1 Fluid Sampling Results

Formation	Depth (ft)	Salinity (ppm)
Fleming Sand 3	4,967	110,000
Upper Frio	6,523	104,000

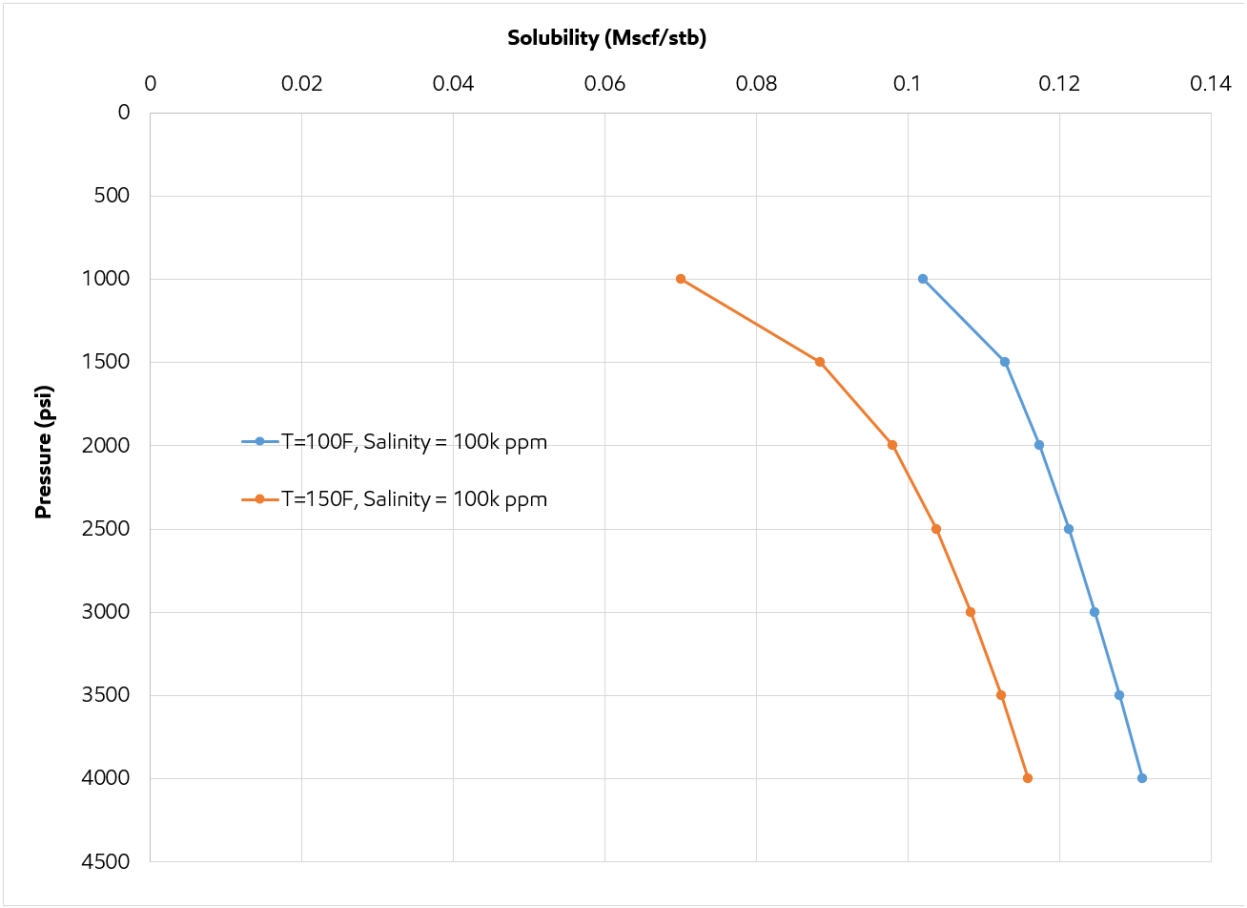
The source of the CO_2 for the Sunflower CCS Project is ExxonMobil's USGC CO_2 Pipeline fed by high-concentration industrial emitters throughout the US Gulf Coast. For this simulation, 100% CO_2 injection was assumed.

2.6.5.1 Aqueous Solubility

Carbon dioxide can dissolve in water and dissolved CO_2 is considered permanently sequestered in the saline aquifer. Therefore, dissolution is an important sequestration mechanism.

The Intersect simulator models mutual solubilities of CO_2 and water based on matching experimental data for typical CO_2 storage conditions: 54–480°F and up to 8,700 psi, which includes the pressure and temperature range for the operational condition at the current storage site. The mutual solubilities are calculated following the procedure given by Spycher and Pruess (2009), based on fugacity equilibration between water and a CO_2 phase. Water and CO_2 fugacity are calculated using a modified Redlich-Kwong EOS.

A sample calculated CO_2 solubility is presented in Figure 2-41. The CO_2 solubility is dependent on temperature, pressure, and salinity.



*Mscf/stb – thousand standard cubic feet per stock tank barrel

Figure 2-41 – CO_2 Solubility in Brine at Different Temperatures

2.6.5.2 Solubility in Carbon Dioxide

Brine has a very minor dissolution capacity in CO_2. This behavior is captured by the Intersect simulation forecasts; however, it has a negligible impact on storage potential.

2.6.5.3 Fluid Density and Viscosity

Carbon dioxide can dissolve in brine and vice versa, and the saturated CO_2 and brine will have slightly altered density and viscosity. A sample table for pure phase and saturated phase CO_2, and brine density and viscosity are illustrated in Table 2-10.

Table 2-10 – Pure Phase and Saturated Phase CO_2 and Brine Density and Viscosity

Depth (ft)	Pressure (psi)	Temperature (F)	Pure Phase Properties				Saturated Phase Properties			
			CO_2		Brine (100,000 ppm)		CO_2		Brine (100,000 ppm)	
			density (g/cm^3)	viscosity (cp)	density (g/cm^3)	viscosity (cp)	density (g/cm^3)	viscosity (cp)	density (g/cm^3)	viscosity (cp)
3,400	1,530	112.2	0.583	0.045	1.067	0.737	0.591	0.046	1.073	0.732
4,000	1,800	120.0	0.611	0.047	1.066	0.686	0.618	0.048	1.071	0.681
5,000	2,250	133.0	0.639	0.050	1.064	0.615	0.645	0.051	1.069	0.611
6,000	2,700	146.0	0.658	0.053	1.062	0.556	0.663	0.053	1.067	0.552
7,000	3,150	159.0	0.671	0.054	1.059	0.508	0.676	0.055	1.064	0.504
8,000	3,600	172.0	0.681	0.056	1.056	0.467	0.687	0.057	1.061	0.463

*g/cm^3 – grams per cubic centimeter
cp – centipoise

Figures 2-42 and 2-43 illustrate density variation for CO_2 and brine vs. depth. Dense-phase CO_2 becomes denser with increased pressure at deeper intervals, which is partially offset by temperature increases, but the general trend is that CO_2 density increases at deeper depths. Brine density is the opposite trend. At a fixed salinity, brine density decreases slightly with depth due to a combined temperature and pressure impact. Note that saturated CO_2 and brine have a slightly higher density compared to pure phase. As brine dissolution in CO_2 is marginal, it has a negligible impact on CO_2 behavior. However, a brine density increase with CO_2 saturation may result in CO_2-saturation brine migration downward over time, which enhances mixing and increases CO_2 storage potential.

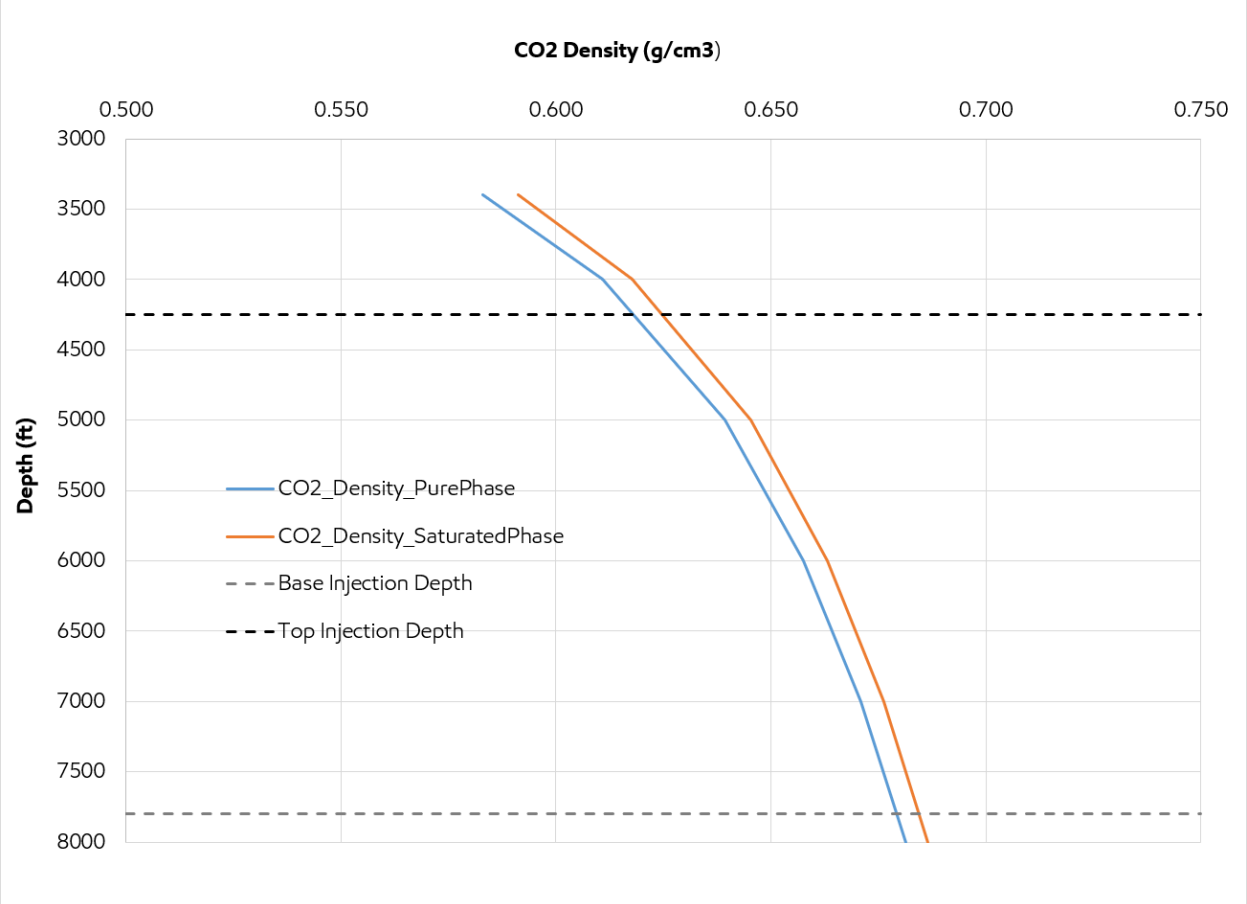


Figure 2-42 – Pure Phase and Saturated Phase CO_2 Density vs. Depth

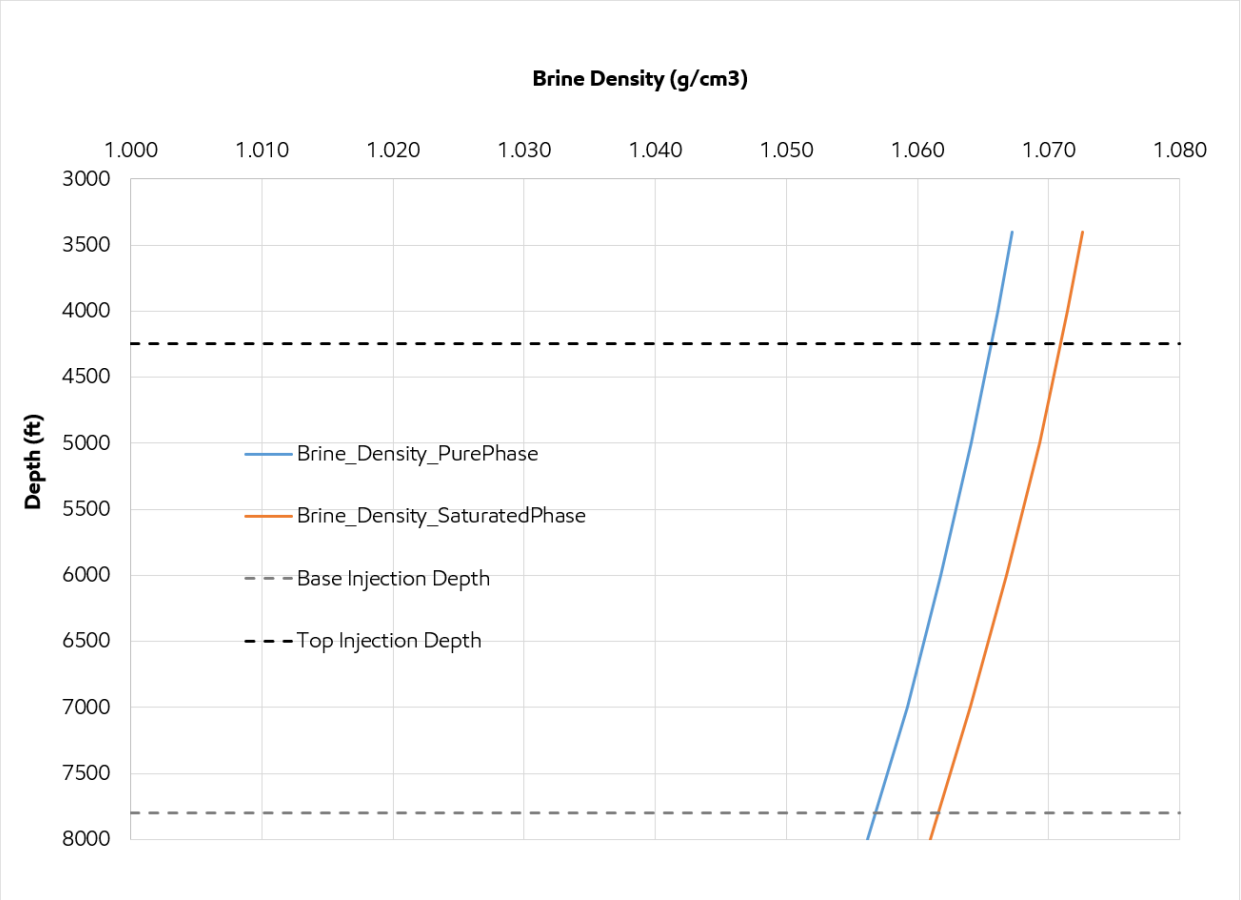


Figure 2-43 – Pure Phase and Saturated Phase Brine Density vs. Depth for Salinity = 100,000 ppm Case

2.6.5.4 Fluid Compressibility

Brine is often considered to be an incompressible fluid but has a small compressibility in the range of 2.5–3.5 µsips, depending on pressure and temperature. Brine compressibility is handled by the simulator based on original conditions extrapolated from the stratigraphic test well measurements and predicted conditions that develop during simulation runs. The range of pressure and compressibility is illustrated in Figure 2-44. While the injected CO_2 for the Sunflower Project will remain in dense phase from wellhead to the reservoir, its density can vary with pressure and temperature. The compressibility of CO_2 is typically higher compared to formation and brine, as illustrated in an earlier study that showed a range of 50–80 µsips (Law and Bachu, 1996). In this simulation study, CO_2 compressibility is automatically handled by the simulator based on an EOS calculation.

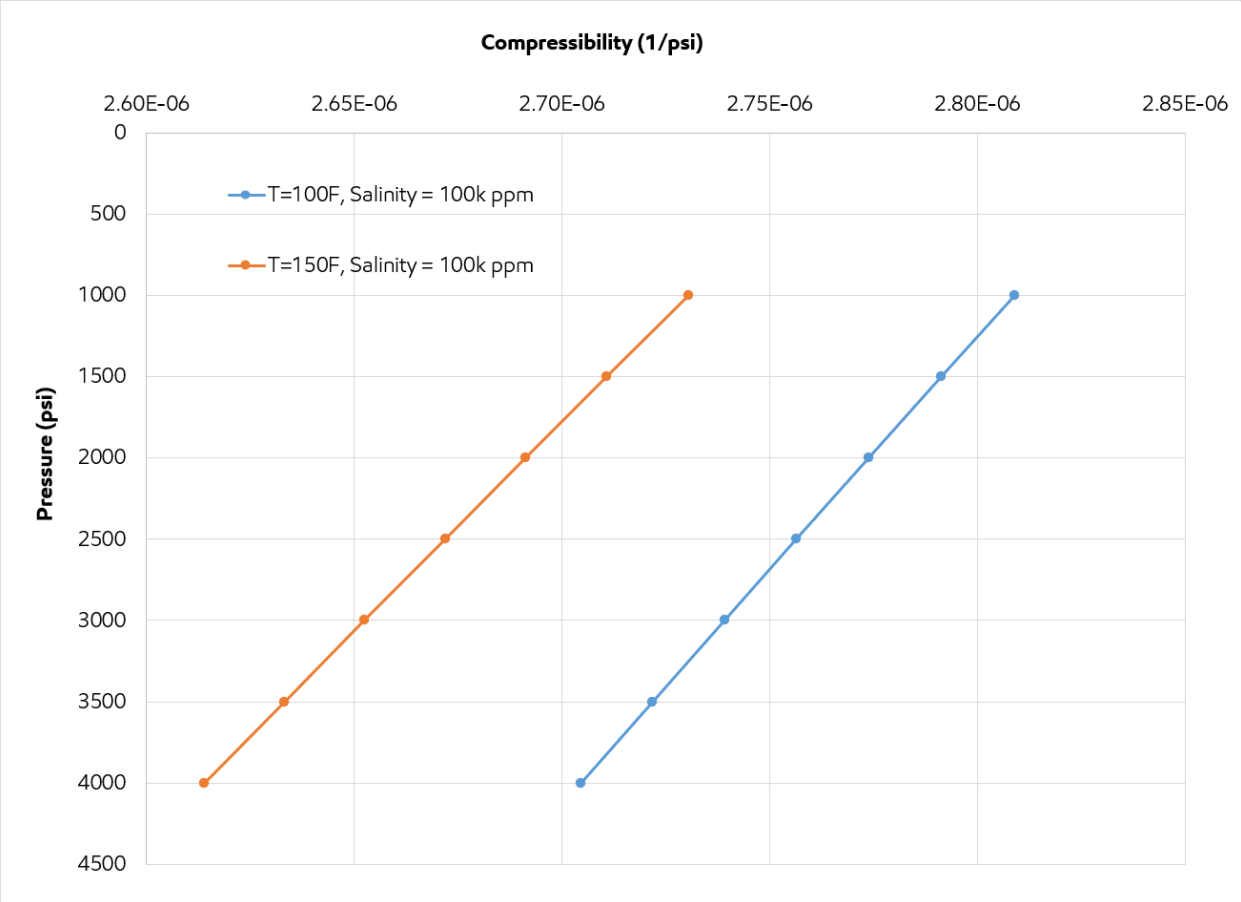


Figure 2-44 – Brine Compressibility at Different Pressures and Temperatures

2.6.6 Well Operating Parameters

2.6.6.1 Fracture Pressure and Fracture Gradient

As discussed in *Section 1.6* of *Section 1 – Site Characterization*, a log-based approach was utilized to evaluate the undisturbed stress state at the Sunflower Project area. The approach incorporated density and dipole sonic logs collected at the nearby stratigraphic test well (Bead Farm Co. – 1).

The calculated stress profile has been calibrated with formation integrity tests (FITs) from offset wells and step-rate tests (SRTs) from Bead Farm Co. – 1. For injection zones with SRTs, the measured fracture pressure gradient is used as the fracture pressure gradient for the entire zone. For injection zones without SRT data, the fracture pressure gradient is calculated from the calibrated stress profile over the sandy intervals within the formation. The fracture gradients shown in Table 2-11 have been calculated for the proposed injection zones.

Table 2-11 – Calculated Fracture Gradients for the Proposed Injection Zones

Formation	Fracture Gradient (psi/ft)
Fleming	[redacted]
Frio	[redacted]

Using the formation tops consistent with *Section 1 – Site Characterization*, the maximum allowed bottomhole injection pressures for the injection stages are shown in Table 2-12. For simplicity and to be conservative, the injection pressure limits were set based on a uniform pressure gradient of 0.6 psi/ft, less than 90% of estimated fracture pressure.

Table 2-12 – Maximum Modeled Bottomhole Injection Pressures

Stage	Injection Interval Reference Depth (ft TVDSS)	Input Constraint Maximum Allowed BHP (psi) Assuming 0.6 psi/ft, less than 90% Fracture Gradient	Output Maximum Modeled BHP (psi)			Fracture Gradient (psi/ft)
			Sunflower INJ No.1	Sunflower INJ No.2	Sunflower INJ No.3	
1	Frio Sand 3 @ -7,500	4,500	3,450	3,482	3,500	[redacted]
2	Frio Sand 2 Lower @ -7,000	4,200	3,216	3,200	3,157	
3	Frio Sand 2 Upper @ -6,600	3,960	3,054	3,128		
4	Frio Sand 1 @ -6,250	3,750	2,835	2,837	2,845	
5	Fleming Sand 3 Lower @-5,000	3,000	2,267	2,269	2,288	[redacted]
6	Fleming Sand 3 Upper @ -4,600	2,760	2,060	2,048	2,087	

*BHP – bottomhole pressure

2.6.6.2 Fluid Injection Rates

The proposed injection wells were simulated using the wellbore design schematics along with the primary constraints and input parameters provided in Tables 2-13 and 2-14.

Table 2-13 – Summary of Input Parameter Values for the Injection Wells

Input Parameter	Value
Pressure Constraint Gradient (psi/ft)	0.6 psi/ft (less than 90% of fracture gradient)
Skin Factor	[redacted]
Compressor Outlet Temperature (°F)	[redacted]

Table 2-14 – Summary of Rate Constraints for the Injection Wells

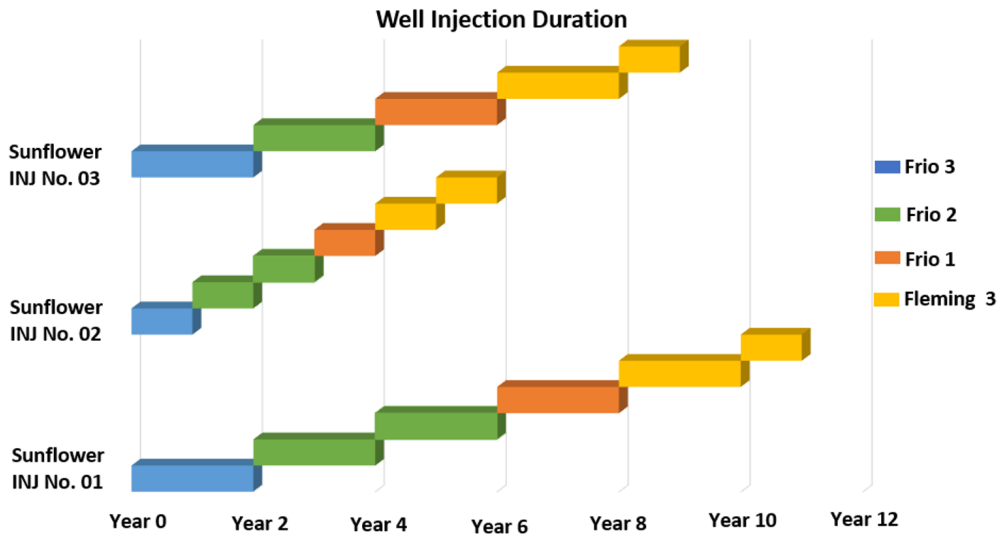
Stage	Injection Formation	Sunflower INJ No. 1		Sunflower INJ No. 2		Sunflower INJ No. 3	
		Target Injection Rate (MMTPA)	Injection Duration Years	**Target Injection Rate (MMTPA)**	Injection Duration Years	**Target Injection Rate (MMTPA)**	Injection Duration Years
1	Frio 3	1.2	2	1.0	1	0.8	2
2	Frio 2 Lower	1.0	2	1.2	1	1.2 **	2
3	Frio 2 Upper	0.5	2	1.2	1		
4	Frio 1	1.0	2	1.0	1	1.0	2
5	Fleming 3 Lower	1.0	2	1.0	1	1.0	2
6	Fleming 3 Upper	1.0	1	1.0	1	0.5	1

*MMTPA – million metric tons per annum

** For Sunflower INJ No.3 Stages 2 & 3 are combined

The injection wells are divided into multiple completion stages to optimize the use of available pore space. Bottom-up completion in each stage represents a portion of the reservoir that will

be injected into at a given time. Figure 2-45 shows the planned completion strategy for each injection well.



Stage	Injection Formation	Maximum Injection Rate Constraint (MMTPA)			Total Per Zone (MMT)
		Sunflower INJ No. 01	Sunflower INJ No. 02	Sunflower INJ No. 03	
1	Frio 3	1.2	1.0	0.8	5.0
2	Frio 2 Lower	1.0	1.2	1.2 *	7.8
3	Frio 2 Upper	0.5	1.2		
4	Frio 1	1.0	1.0	1.0	5.0
5	Fleming 3 Lower	1.0	1.0	1.0	7.5
6	Fleming 3 Upper	1.0	1.0	0.5	
Total Per Well (MMT)		10.4	6.4	8.5	**Site Total (25.3)**

* For Sunflower INJ No.3 stages 2 & 3 are combined.

[redacted]

Figure 2-45– Summary of Injection Intervals and Durations for Each Injection Well

Six injection stages within the Project injection zone are planned for each injection well. The modeled perforation depths and injection durations are summarized in Tables 2-15 through 2-17. The perforation depths are based on the current geologic model and will be adjusted based on injection well results.

Table 2-15 – Summary of Completion Stages for Sunflower INJ No. 1

Stage	Sand Interval	Completion Date (years post-startup)	Top Depth (ft MD)	Bottom Depth (ft MD)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)
1	Frio Sand 3	0	-7,378	-7,638	415	205	2
2	Frio Sand 2 Lower	2	-6,768	-7,272	546	276	2
3	Frio Sand 2 Upper	4	-6,590	-6,710	236	180	2
4	Frio Sand 1	6	-5,962	-6,409	857	469	2
5	Fleming Sand 3 Lower	8	-4,841	-5,271	484	299	2
6	Fleming Sand 3 Upper	10	-4,398	-4,759	549	251	1

Table 2-16 – Summary of Completion Stages for Sunflower INJ No. 2

Stage	Sand Interval	Completion Date (years post-startup)	Top Depth (ft TVDSS)	Bottom Depth (ft TVDSS)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)
1	Frio Sand 3	0	-7,187	-7,707	538	222	1
2	Frio Sand 2 Lower	1	-6,974	-7,143	237	103	1
3	Frio Sand 2 Upper	2	-6,506	-6,900	430	237	1
4	Frio Sand 1	3	-5,651	-6,420	859	378	1
5	Fleming Sand 3 Lower	4	-4,816	-5,267	491	349	1
6	Fleming Sand 3 Upper	5	-4,254	-4,768	541	255	1

Table 2-17 – Summary of Completion Stages for Sunflower INJ No. 3

Stage	Sand Interval	Completion Date (years post-startup)	Top Depth TVDSS (ft)	Bottom Depth TVDSS (ft)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)
1	Frio Sand 3	0	-7,207	-7,756	603	242	2
2&3	Frio Sand 2	2	-6,650	-7,146	606	283	2
4	Frio Sand 1	4	-5,989	-6,448	836	296	2
5	Fleming Sand 3 Lower	6	-4,868	-5,309	451	262	2
6	Fleming Sand 3 Upper	8	-4,587	-4,851	618	270	1

2.7 Model Results

2.7.1 Active Injection Operations of Proposed CO_2 Injection Wells

At each new completion, the primary control is the target injector rate. In addition, the maximum allowed bottomhole pressure (with safety factor) is applied as a secondary constraint, so that if the bottomhole pressure reaches the constraint, the rate will be reduced so that the constraint is not violated. In the proposed Sunflower Project injection wells, the reservoir quality is sufficient to accommodate the injection rate without the bottomhole pressure getting close to this pressure constraint.

Tables 2-18 through 2-20 summarize the injection rate and pressure parameters corresponding to all stages in each well. Bottomhole pressures are reported at injection interval reference depth listed in table 2-12.

Table 2-18 – Modeled Injection Rates and Pressures for Sunflower Project Injection Well No. 1

Stage	Year	Modeled Injection Rate (MMTPA)	Max. BHP (psi)	Avg. BHP (psi)	Max. WHP (psi)	Avg. WHP (psi)
1	0	1.2	3,537	3,497	1,112	1,088
2	2	1.0	3,489	3,182	1,083	1,029
3	4	0.5	3,164	3,092	1,022	960
4	6	1.0	3,085	2,861	955	941
5	8	1.0	2,855	2,300	940	836
6	9	1.0	2,280	2,077	830	776

Table 2-19 – Modeled Injection Rates and Pressures for Sunflower Project Injection Well No. 2

Stage	Year	Modeled Injection Rate (MMTPA)	Max. BHP (psi)	Avg. BHP (psi)	Max. WHP (psi)	Avg. WHP (psi)
1	0	1.0	3,490	3,483	1,070	1,066
2	1	1.2	3,488	3,224	1,069	1,048
3	2	1.2	3,197	3,134	1,043	1,016
4	3	1.0	3,128	2,859	1,013	935
5	4	1.0	2,840	2,306	929	830
6	5	1.0	2,270	2,057	823	762

Table 2-20 – Modeled Injection Rates and Pressures for Sunflower Project Injection Well No. 3

Stage	Year	Modeled Injection Rate (MMTPA)	Max. BHP (psi)	Avg. BHP (psi)	Max. WHP (psi)	Avg. WHP (psi)
1	0	0.8	3,503	3,493	1,073	1,067
2 & 3	2	1.2	3,491	3,171	1,066	1,034
4	4	1.0	3,148	2,858	1,026	939
5	6	1.0	2,849	2,302	936	842
6	8	0.5	2,288	2,104	835	769

Continuous injection rates, injection pressures, and associated pressure constraints for each well are illustrated in Figures 2-46 through 2-48. As shown, the operational bottomhole pressure remains well below the allowed maximum pressure, with at least a 600 psi margin in each zone.

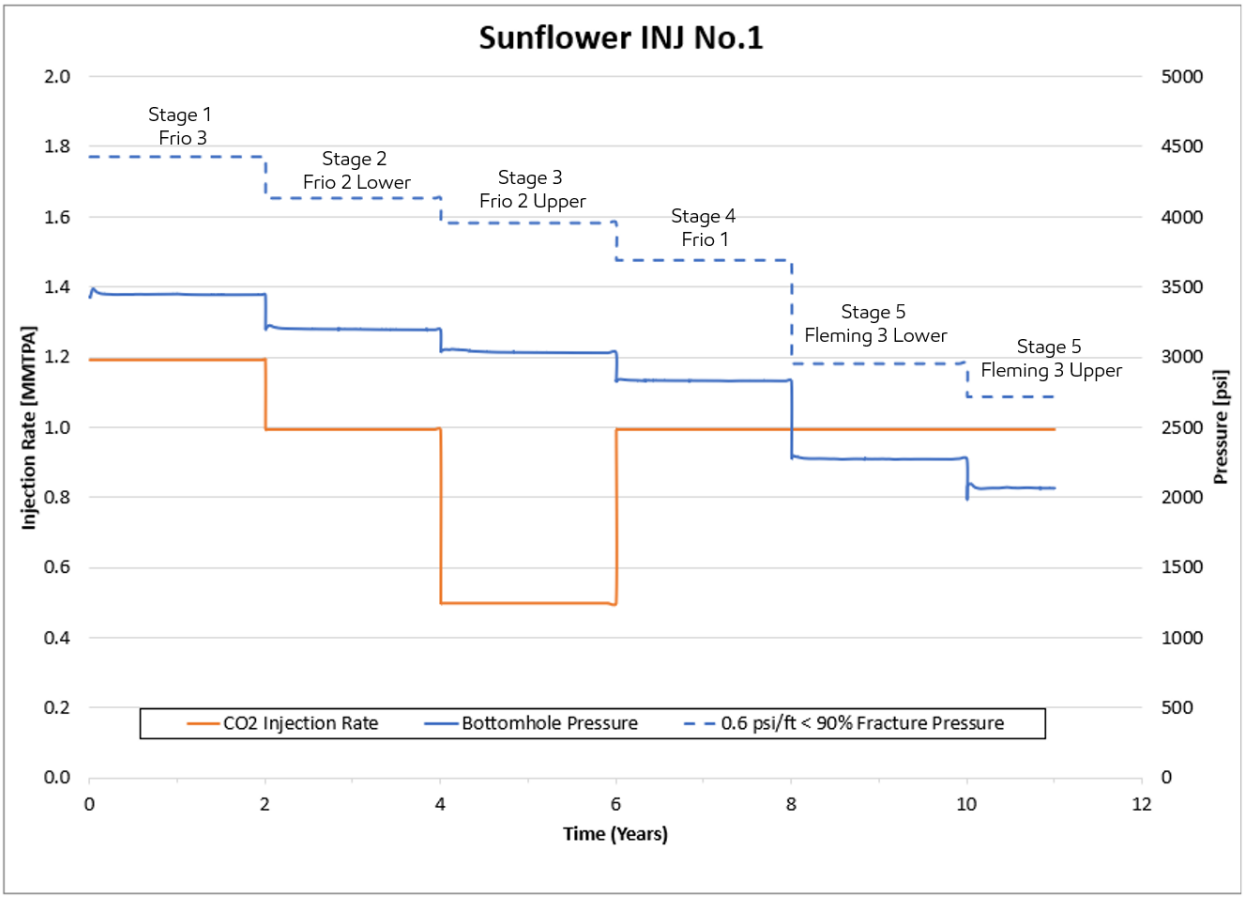


Figure 2-46 – Injection Rates and Bottomhole Pressures – Sunflower Project Injection Well No. 01

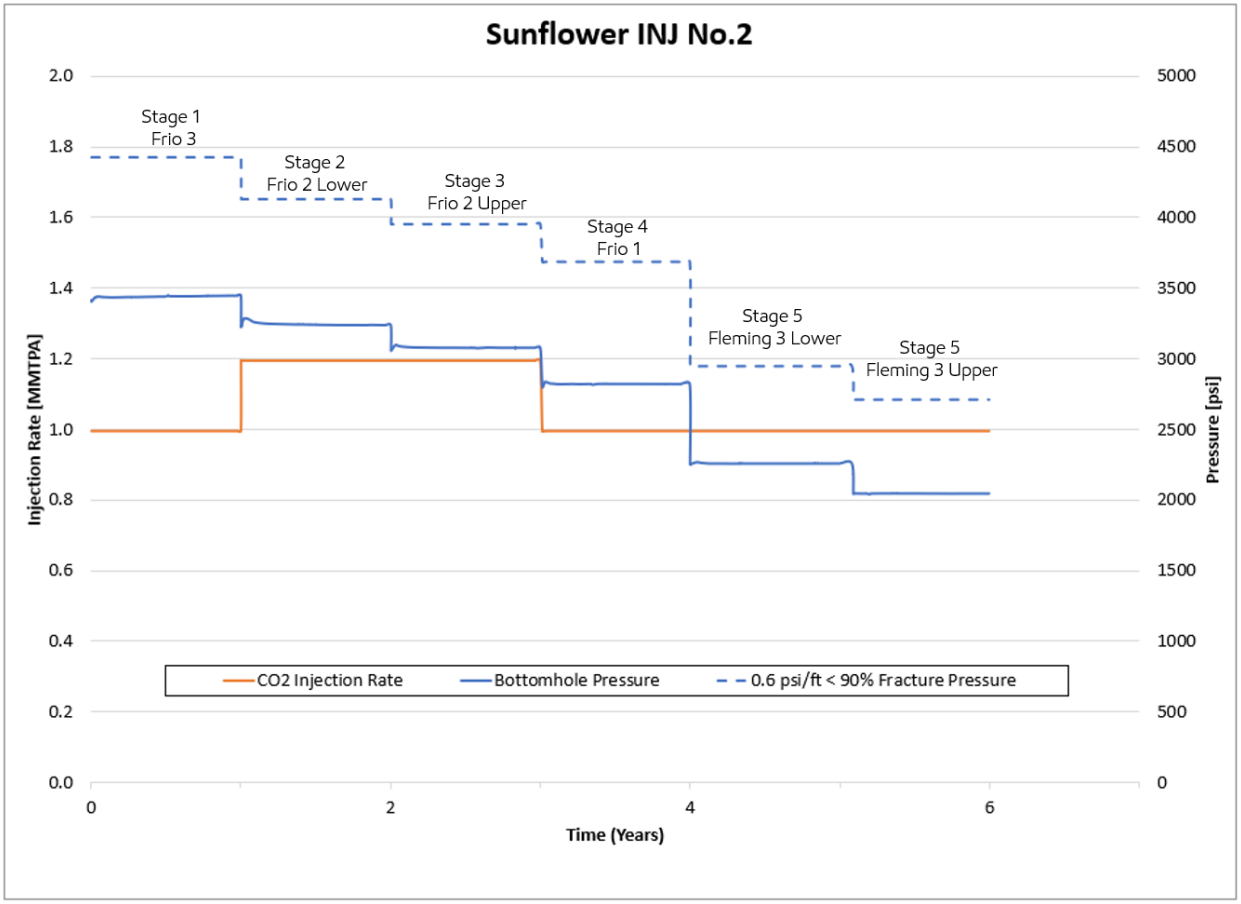


Figure 2-47 – Injection Rates and Bottomhole Pressures – Sunflower Project Injection Well No. 02

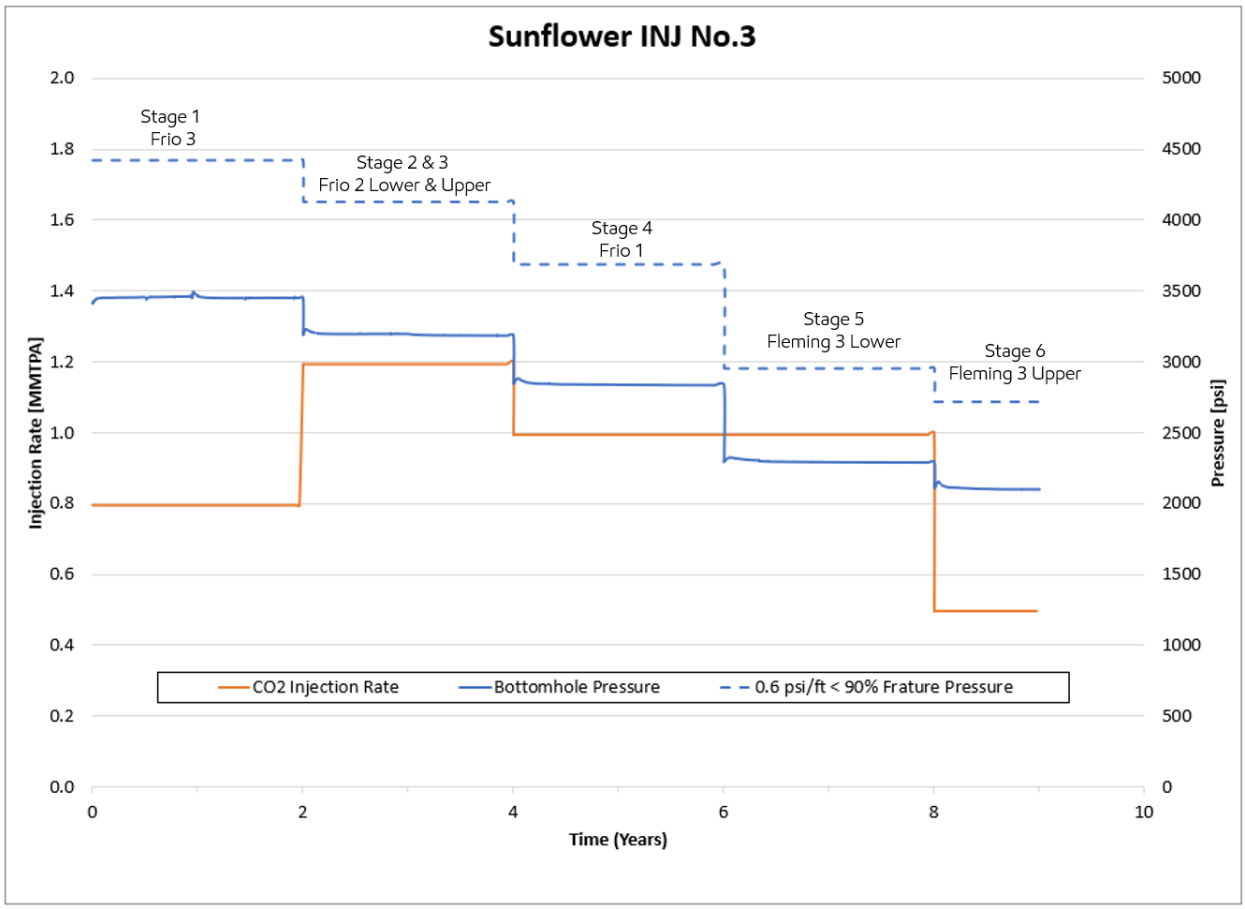


Figure 2-48 – Injection Rates and Bottomhole Pressures – Sunflower Project Injection Well No. 03

The elevated pressure in the saline aquifer quickly dissipates once active-injection operations cease. Eleven years post-injection, all injection wells are shut in; the reservoir pressure stabilizes close to initial conditions. Figure 2-49 represents the maximum pressure gradient throughout the life of the project. As shown, the pressure gradient never exceeds the constraint (0.6 psi/ft less than 90% of the fracture gradient) imposed on each well, to allow for the safe injection of supercritical CO_2.

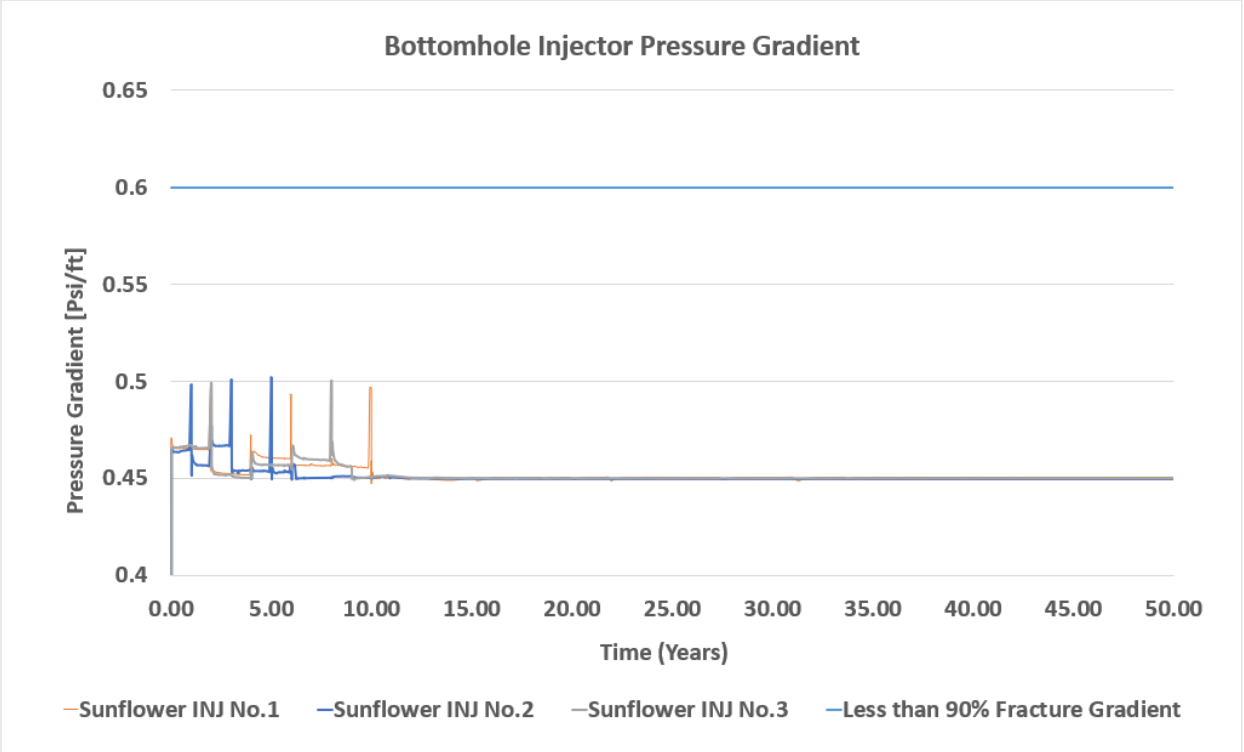


Figure 2-49 – Pressure Gradient for the Life of the Sunflower Project Injection Wells

2.7.2 Extent of CO_2 Plume

In accordance with 16 TAC **§5.203(d)**, areal grid block size in the model was selected to optimize model runtimes, limit grid distortion effects, and allow for sufficiently accurate contouring of the plume extent. The operational and geologic input parameters were used in the Intersect model to generate projections of plume and pressure migration vs. time. Each well was initially completed and then recompleted into incrementally shallower portions of the injection intervals per the schedule presented in Figure 2-45.

Figure 2-50 presents the time-dependent, maximum areal extent of the CO_2 plume projected to be present in any of the injection zone layers from the start of operations. The CO_2 saturation and the areal extent of the plumes generated by CO_2 injection expand with time. As the volume of injected CO_2 increases, the CO_2 plumes from each injection well commingle in some of the layers. Once injection stops, the CO_2 footprint migration slows considerably. The combined effects of relative permeability, capillary pressure, CO_2 dissolving in brine, and limited structural dip ultimately arrest the extent of the CO_2 plume migration drift updip to the north-northwest. Figure 2-51 illustrates the cross-sectional view of the time-dependent CO_2 plume.

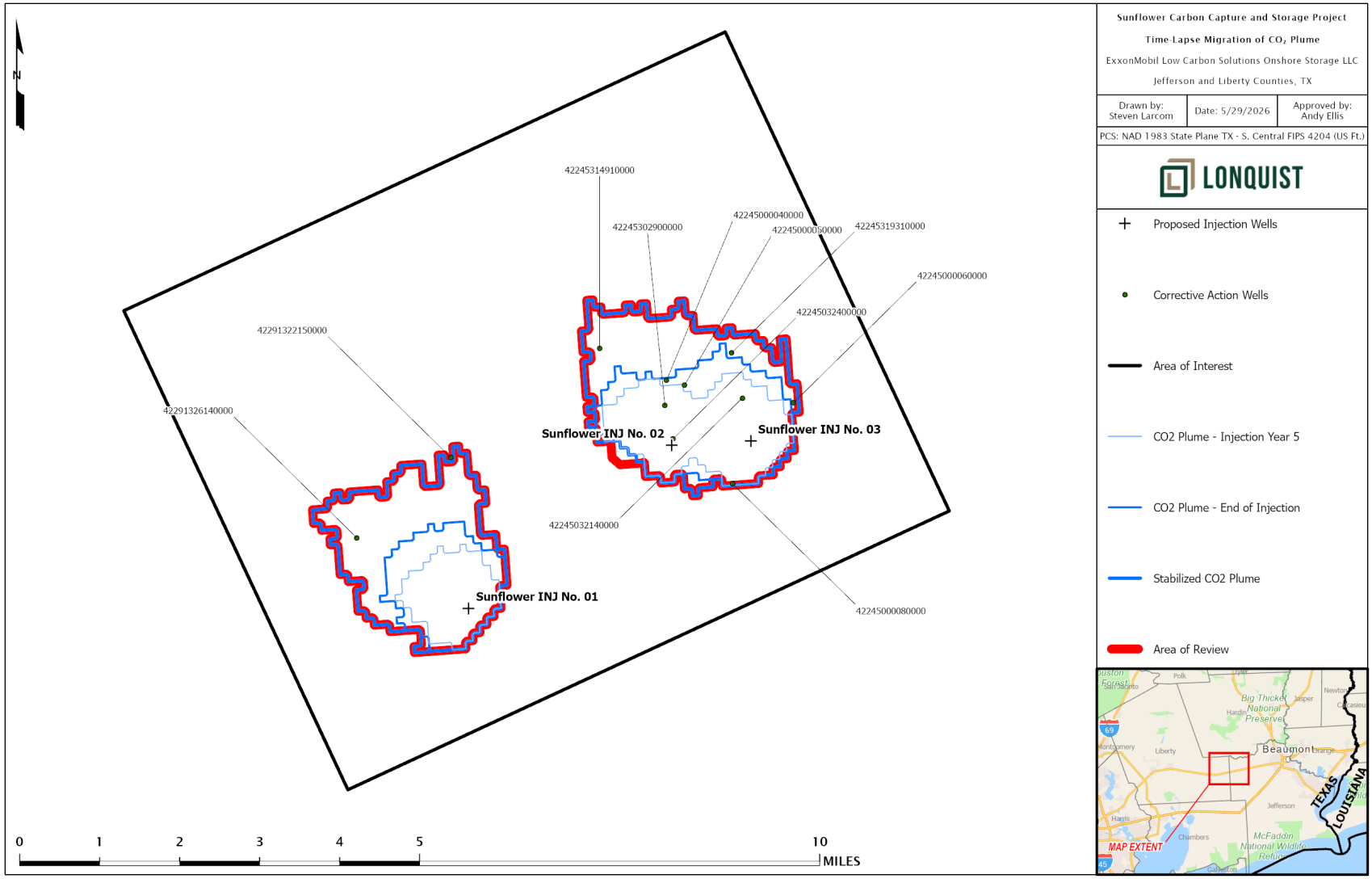


Figure 2-50 – Time-Lapse Migration of CO2 Plume

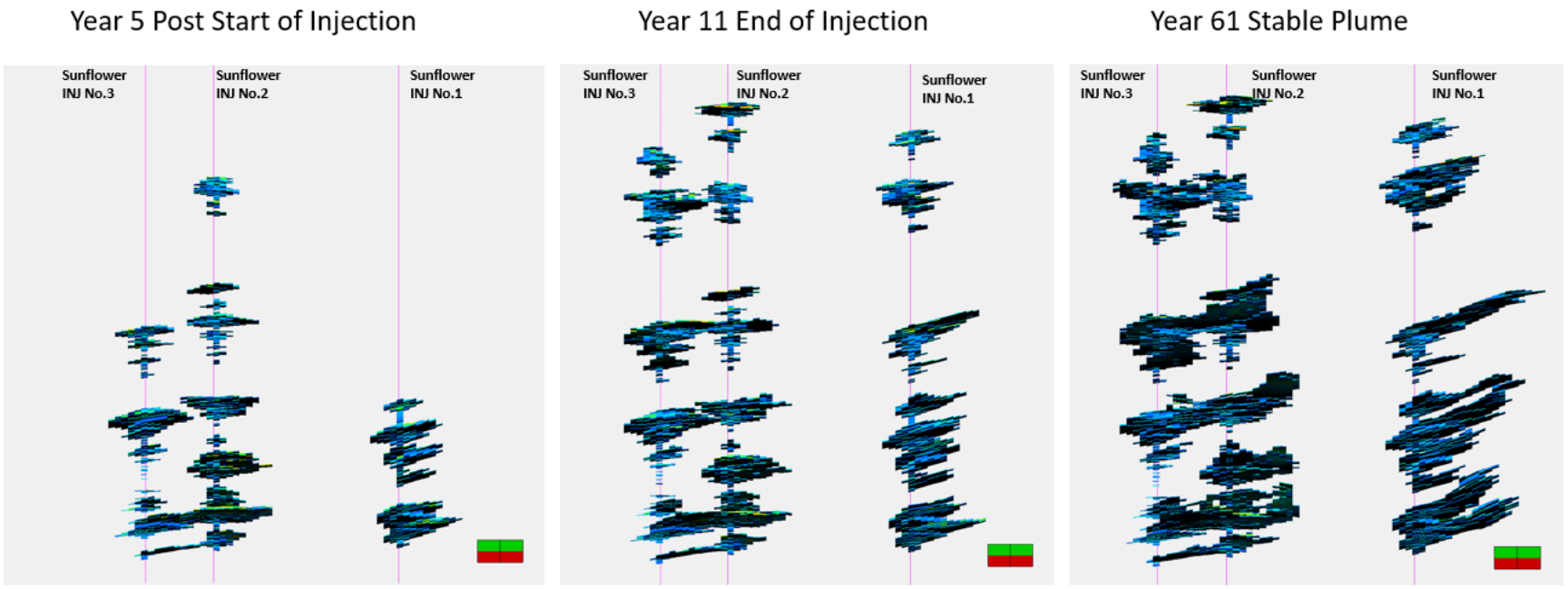


Figure 2-51 – Time-Lapse Migration of CO_2 Plume Cross Section View – Looking South

The rate of plume size growth is expected to diminish rapidly following the cessation of injection. The plume is expected to reach its maximum size approximately 50 years after injection ends—when the plume is considered stable.

2.7.3 Delineation of the Critical Pressure Front

In accordance with 16 TAC **§5.203(d)**, the pressure AOR was delineated by the critical pressure front created by the injection of CO_2 into the injection intervals. Critical pressure, referred to as pressure front in 16 TAC **§5.102(47)**, is the increase in reservoir pressure that has the potential to create a crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical pressure front defined by this pressure contour.

2.7.3.1 Critical Pressure Calculations

The methodology for determining critical pressure was sourced from Nicot (2009), which is referenced in the EPA guidance for calculations based on displacing fluid initially present in the borehole. Nicot assumes that the injection reservoir is in hydrostatic equilibrium, neither under- nor over-pressured, and that a direct path between the injection zone and lowermost USDW exists. This hypothetical vertical pathway could be an insufficiently plugged and abandoned wellbore or some other subsurface feature.

For the purposes of critical pressure calculations, a USDW map within the area of interest (AOI) was used. The USDW map is featured and discussed in *Section 1 – Site Characterization*. The critical pressure was calculated with input parameters including reservoir depth for each grid cell, USDW depth, wellbore fluid, and reservoir salinity. Injection-interval perforations ranging from depths of -4,254 feet to -7,756 feet MD. Based on the site-specific fluid samples from the stratigraphic test well, the total dissolved solids (TDS) of the brine were observed to range from 104,000 ppm to 110,000 ppm, for simplicity and to be conservative a uniform salinity of 100,000 ppm was assumed in the target injection zone Fleming 3 to Frio 3 (specific gravity of 1.052 to 1.056). The fluid within the USDW was assumed to be freshwater of 10,000 ppm salinity, with a fluid pressure gradient of 0.434 psi/ft. Inputs for an example calculation (Fleming Sand 3 interval in Sunflower Project Injection Well No. 2's shallowest completion) are provided in Table 2-21.

Table 2-21 – Input Parameter Values for Critical Pressure Calculation for Sunflower Project Injection Well No. 2; Fleming Sand 3

Input Parameter	Symbol	Value	Density Gradient (psi/ft)
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

The coefficient (λ) is first calculated in Equation 4 using the initial pressure gradients and depths for the base of the USDW and top of the injection zone:

(Eq. 4) $$\lambda = \frac{G_{if} - G_{uf}}{D_i - D_u}$$

[redacted]

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

(Eq. 5) $$\xi = \frac{G_{ii} - G_{ui}}{D_i - D_u}$$

[redacted]

Finally, critical pressure rise (ΔP_c) is calculated using Equation 6. The inputs include the coefficients (λ, ξ) calculated in Equations 4 and 5, and the depths for the base of the USDW (D_u) and the top of the injection zone (D_i):

(Eq. 6) $$\Delta P_c = (D_i - D_u)\left[\frac{\lambda - \xi}{2}(D_i - D_u) + G_{uf} - G_{ui}\right]$$

[redacted]

The resulting critical pressure rise for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by approximately 65 psi, without risk of endangerment to the lowermost USDW. The calculated critical pressure rise at the top of each geologic interval for the injection wells is included in Table 2-22.

Table 2-22 – Calculated Critical Pressure Rise for the Sunflower Project Injection Intervals

Interval	Critical Pressure Rise (psi)		
	Sunflower INJ No. 1	Sunflower INJ No. 2	Sunflower INJ No. 3
Fleming Sand 3	66	65	76
Frio Sand 1	111	105	117
Frio Sand 2	129	130	136
Frio Sand 3	152	149	152

2.7.3.2 Pressure Front Delineation

The critical pressure front, illustrated in Figure 2-52, represents the maximum critical pressure front over the complete operating timeframe, based on critical pressure calculations detailed in the prior section. Critical pressure rise was only observed around Sunflower INJ No. 02 during the Frio 1 injection interval due to the lower net sand value in that specific interval. Critical pressure was never reached in Sunflower INJ No. 01 or No. 03 or in the other intervals in Sunflower INJ No. 02 during other injection intervals, as can be seen in Figure 2-52.

2.7.4 Final AOR

The maximum areal extents of both the CO_2 plume and the critical pressure front were used to delineate the AOR at any time interval or depth following the definition of AOR in 16 TAC **§5.102(5)**. Figure 2-53 illustrates the maximum extent of the stabilized CO_2 plume, 50 years post end of injection. The critical pressure front, illustrated in Figure 2-52, represents the maximum areal cone of influence and combines results from the six completion stages for each of the three injection wells. Superimposing the maximum CO_2 plume and critical pressure boundaries, Figure 2-53 provides the AOR boundary for the project.

The Sunflower Project targets both the Frio Formation and the Fleming Formation within the single injection zone. Both the Frio and Fleming Formations are laterally extensive and exhibit internal pressure communication over the entire project area. Although the model produces two separate AOR polygons, injection into either the Frio or Fleming Formation within one AOR results in a measurable pressure response in the other AOR, even though this response does not reach critical pressure levels between them. Figure 2-54 illustrates pressure build-up (ΔP) across the two AORs during concurrent injection from all three wells in Frio 2 formation, while Figure 2-55 presents spatial distribution of the average pressure build-up (ΔP) over the same period. The continuity of pressure contours observed across both AORs demonstrates a shared pressure regime, consistent with a single laterally connected and hydraulically communicating reservoir. We expect vertical communication within the Fleming and Frio reservoirs but not between them.

Figure 2-56 represents the maximum pressure build up for each injection zone. The pressure response indicates that injection-driven pressure propagates across the full extent of both AORs, with no evidence of compartmentalization or independent pressure regimes across all zones.

16 TAC 5.102(5) defines area of review as the outermost extent of the CO_2 plume overlayed with the pressure front. Utilizing this definition results in two distinct Areas of Review; however, they represent components of a single project and an integrated injection strategy that must be evaluated concurrently. The two AORs, together with the necessary rights and appurtenances for facility operation, form the geologic storage facility as defined by 16 TAC **§5.102(29)** and outlined in Figure 1 in *Section 0 – Application Narrative*.

In accordance with TAC §5.203(d)(1)(A)(i), Figure 2-57 represents the average pressure-front (isobar) maps for each injection interval (Fleming 3, Frio 1, Frio 2, and Frio 3) at the three required evaluation periods: (1) five years after initiation of injection, (2) the end of the injection period, and (3) pressure-front stabilization. At 50 years after cessation of injection, the modeled pressure increase throughout the area of review is less than 5 psi.

Please reference Figure 2-45 detailing the planned injection strategy for each injection well. The corresponding ΔP maps (Figure 2-56) demonstrate that the maximum pressure buildup occurs in the vicinity of the active injection wells within their respective injection zones, with pressure dissipating radially away from the wellbores. In each ΔP map, lateral pressure communication is observed between the two AORs

Finally, a 2D map of simulated CO_2 plume areal extent at site closure (50 years post-injection) for Frio 1, Frio 2, Frio 3, and Fleming 3 overlaid on a single map (Figure 2-58), and a combined 2D map delineating the final AOR based on maximum extent of CO_2 plumes and critical pressure thresholds is provided in Figure 2-53.

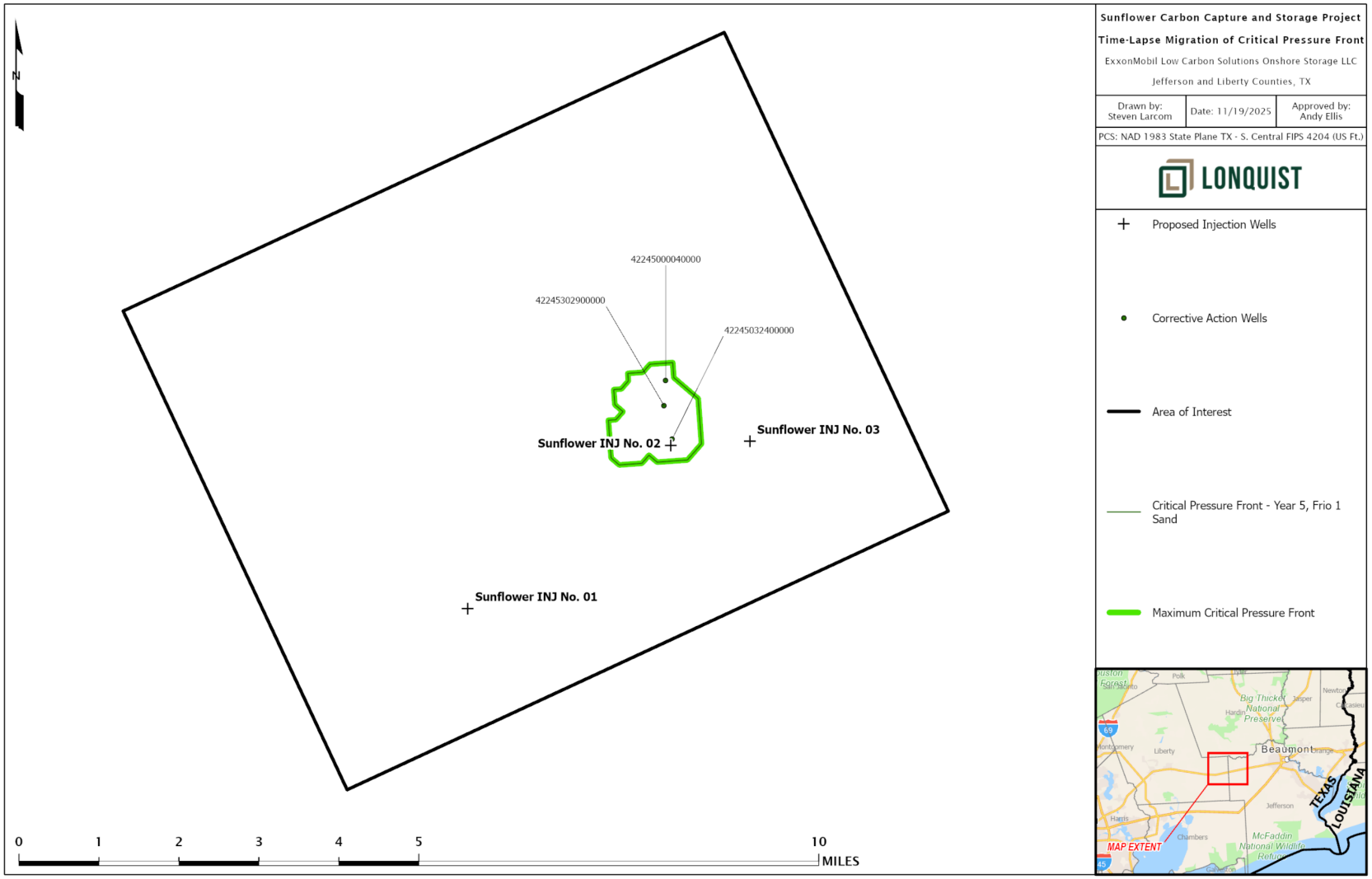


Figure 2-52 – Maximum Critical Pressure Front

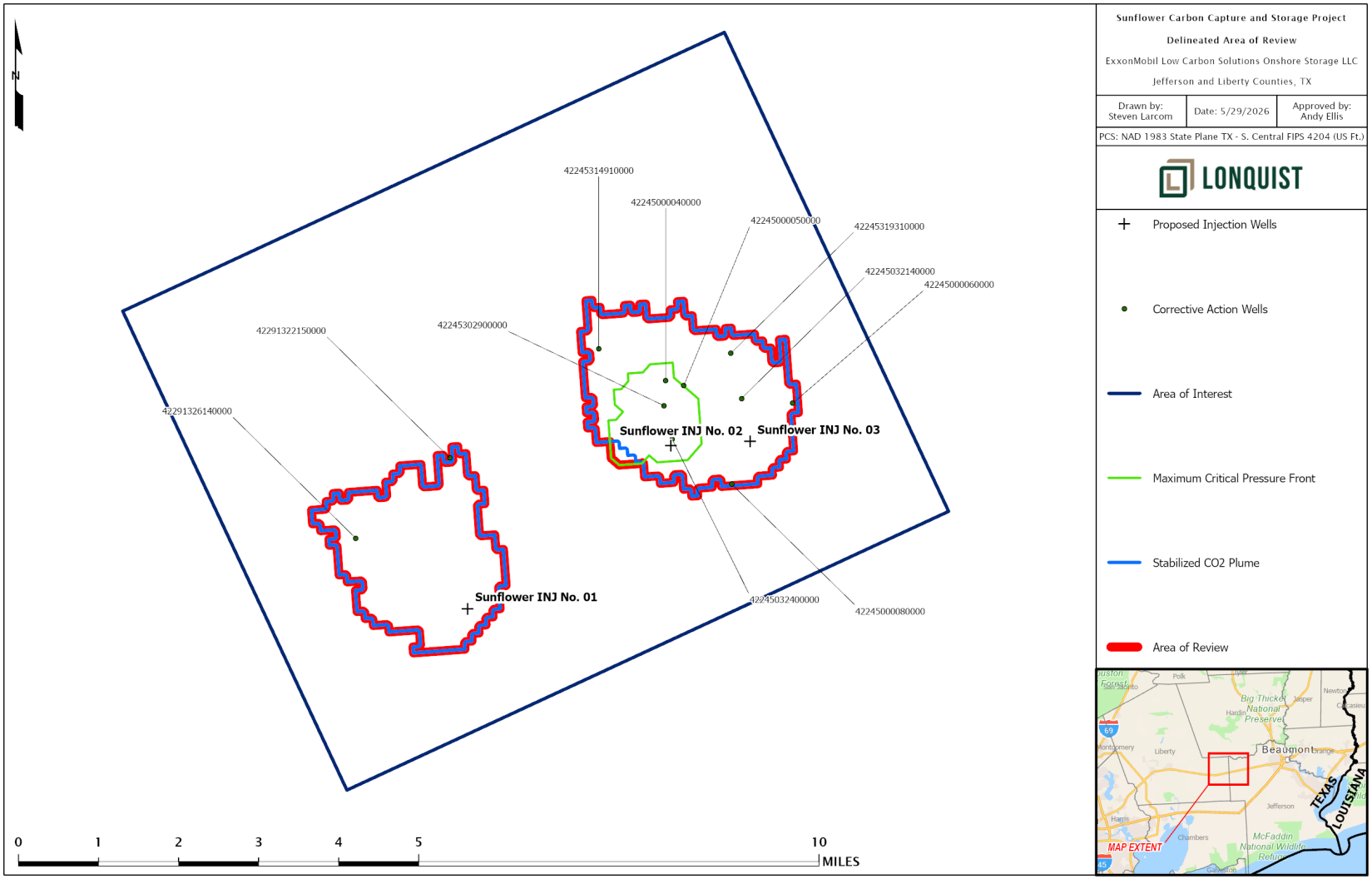


Figure 2-53 – Delineated Area of Review

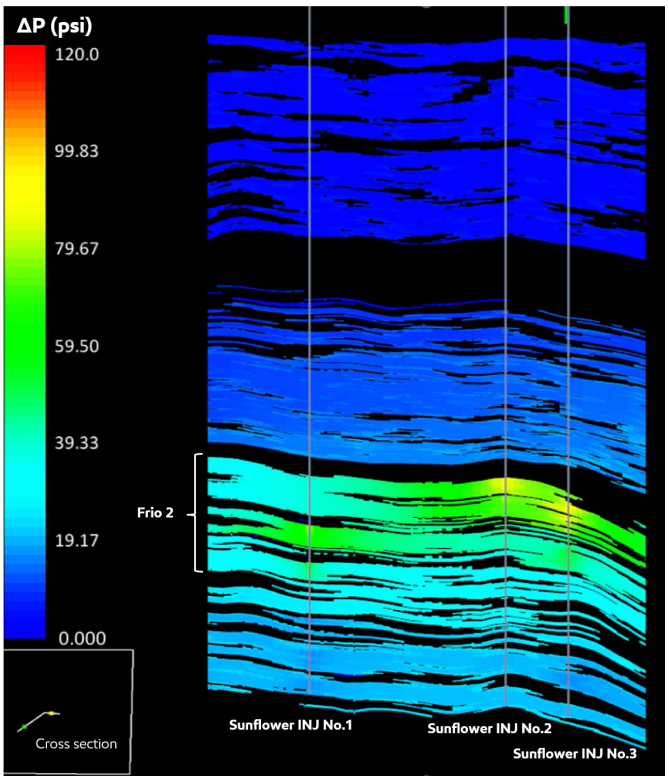


Figure 2-54 - ΔP Cross Section in Frio 2 at End of Year 3

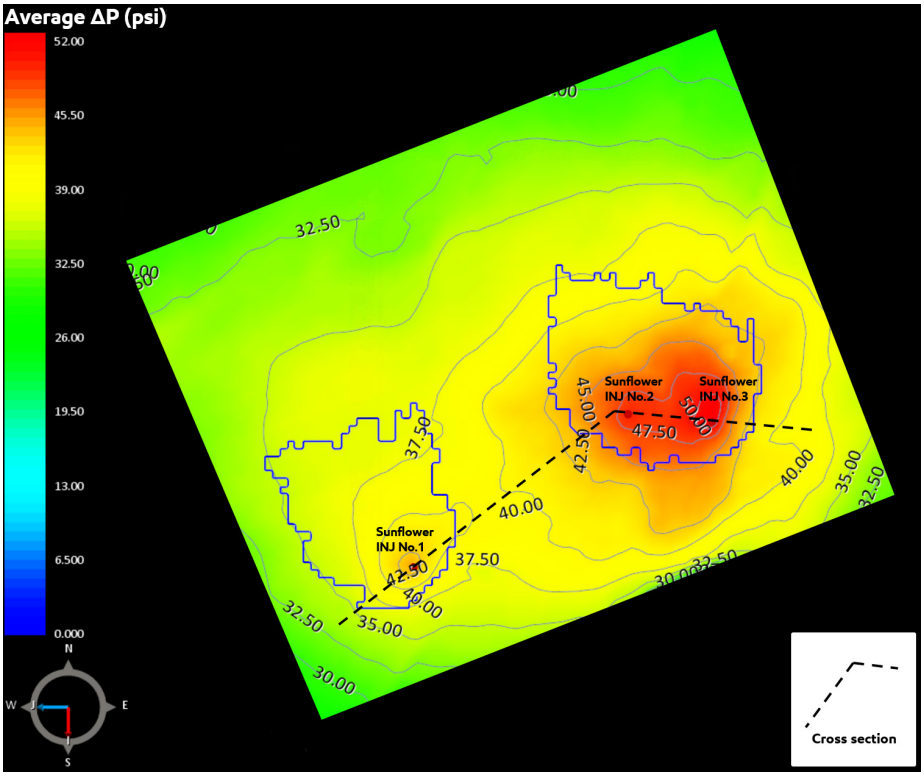


Figure 2-55 - Average ΔP Map in Frio 2 at End of Year 3

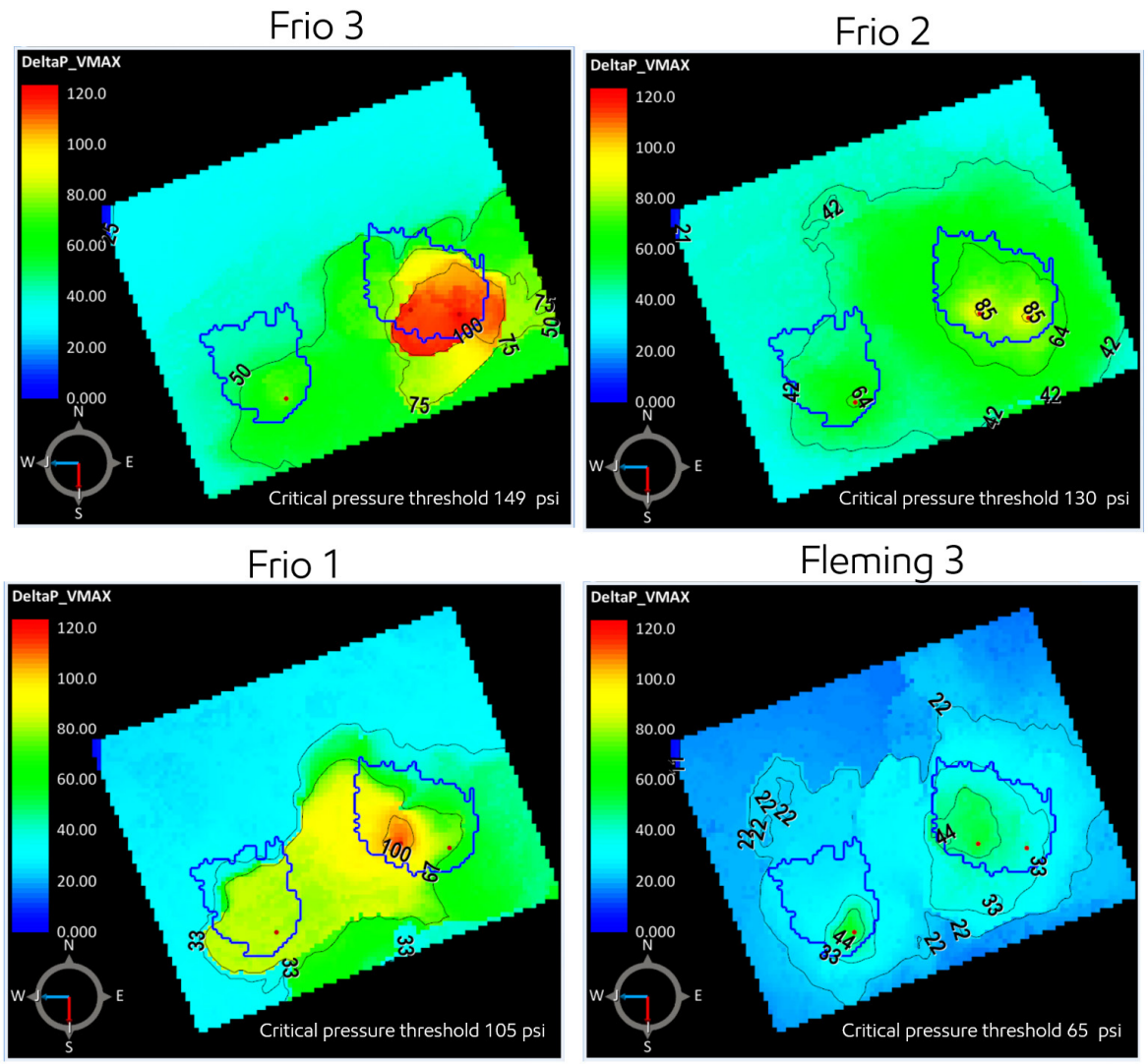


Figure 2-56 – Maximum ΔP Map per Injection Formation

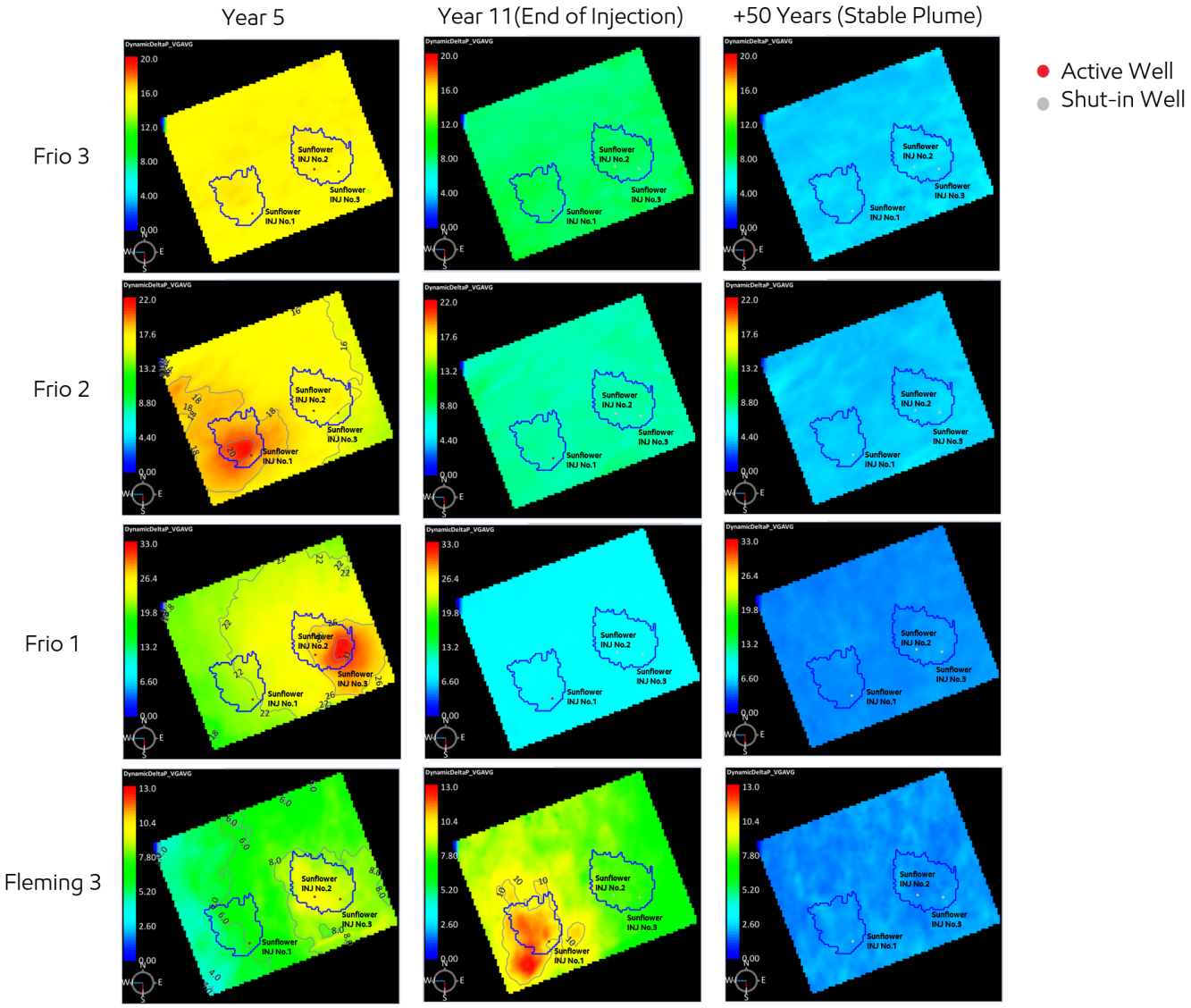


Figure 2-57 – Average ΔP Map per Injection Formation

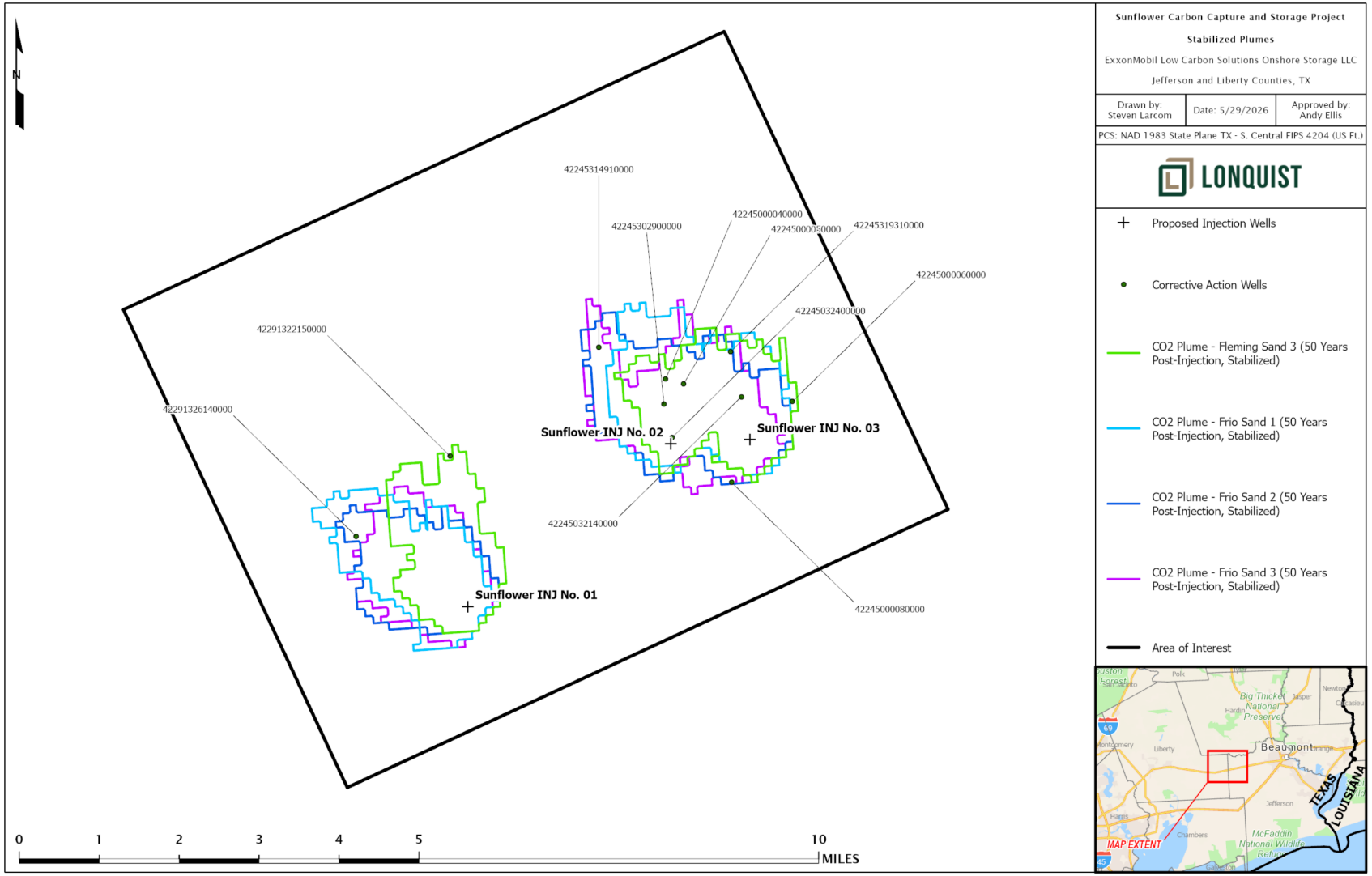


Figure 2-58 – Stabilized CO_2 Plume Per Injection Formation

2.7.5 Sensitivity Analysis

ExxonMobil conducts parametric sensitivity analyses on key geologic and simulation inputs to evaluate their relative influence on CO_2 migration and pressure behavior. Parameter ranges are derived from locally calibrated reservoir datasets and are tested independently across simulation runs to isolate the effect of each variable. Injection profiles (injection rate and duration) remain fixed and represent reasonable operational assumptions for the modeled scenario. Interactions among variables and operational dependencies are not incorporated. Results from this analysis provide insight into relative parameter significance but should not be interpreted as direct guidance for operational adjustments.

For the Sunflower site, sensitivity modeling results indicate that permeability, trapped-gas saturation (Sgt), gas relative permeability (krg), rock compressibility, and connected reservoir extent (i.e., saline aquifer support) are the most influential parameters controlling simulated CO_2 plume evolution and pressure response. Table 2-23 lists the range of parameters used for sensitivity analysis. Figures 2-59 & 2-60 present tornado diagrams summarizing the relative impact and parameter ranges associated with these key variables. Additional parameters—including reservoir temperature, formation water salinity, fracture pressure, irreducible water saturation (S_{wir}), fault transmissibility, and lithofacies fraction—were evaluated but demonstrated limited influence on model outcomes.

A probabilistic storage volume assessment was also completed to estimate the range of CO_2 mass that the Sunflower Project could accommodate within the defined project area. Site-specific parameter distributions (Table 2-24), along with known or assumed geologic dependencies (e.g., permeability–porosity covariance), were incorporated into the ArianeLogiX platform (Ariane, prospect assessment software; https://ariane-logix.com/) to generate a probabilistic distribution of potential storage capacity. Figure 2-61 presents both the tornado chart and the resulting probabilistic curve for total CO_2 mass.

Across all evaluated variables, storage efficiency (SE) is the largest contributor to uncertainty in the probabilistic assessment. SE represents the fraction of available pore volume within the injection interval that is ultimately occupied by CO_2. The SE range applied in this study (P90 = 0.8%, P50 = 1.54%, P10 = 2.4%) was informed by dynamic simulation results and reflects the combined performance effects observed in the sensitivity analysis. This range is conservative relative to published values for formation scale SE estimates, which range from approximately 1.66% to 5.13% between the 10th and 90th percentiles (e.g., Wang et al., 2024; Bachu, 2015). Because our assessment aggregates multiple injection stages, the resulting SE values are expected to align more closely with formation scale estimates rather than “site specific” SE values, which tend to be higher (approximately 4–17%).

The Class VI permit application reference case represents the best estimate of each parameter and typically falls near the P50 outcome of the resulting CO_2 mass distribution. This reference case reflects the pre- development volume estimate and will be refined over time as reservoir

management incorporates monitoring data, observed injection performance, and operational considerations.

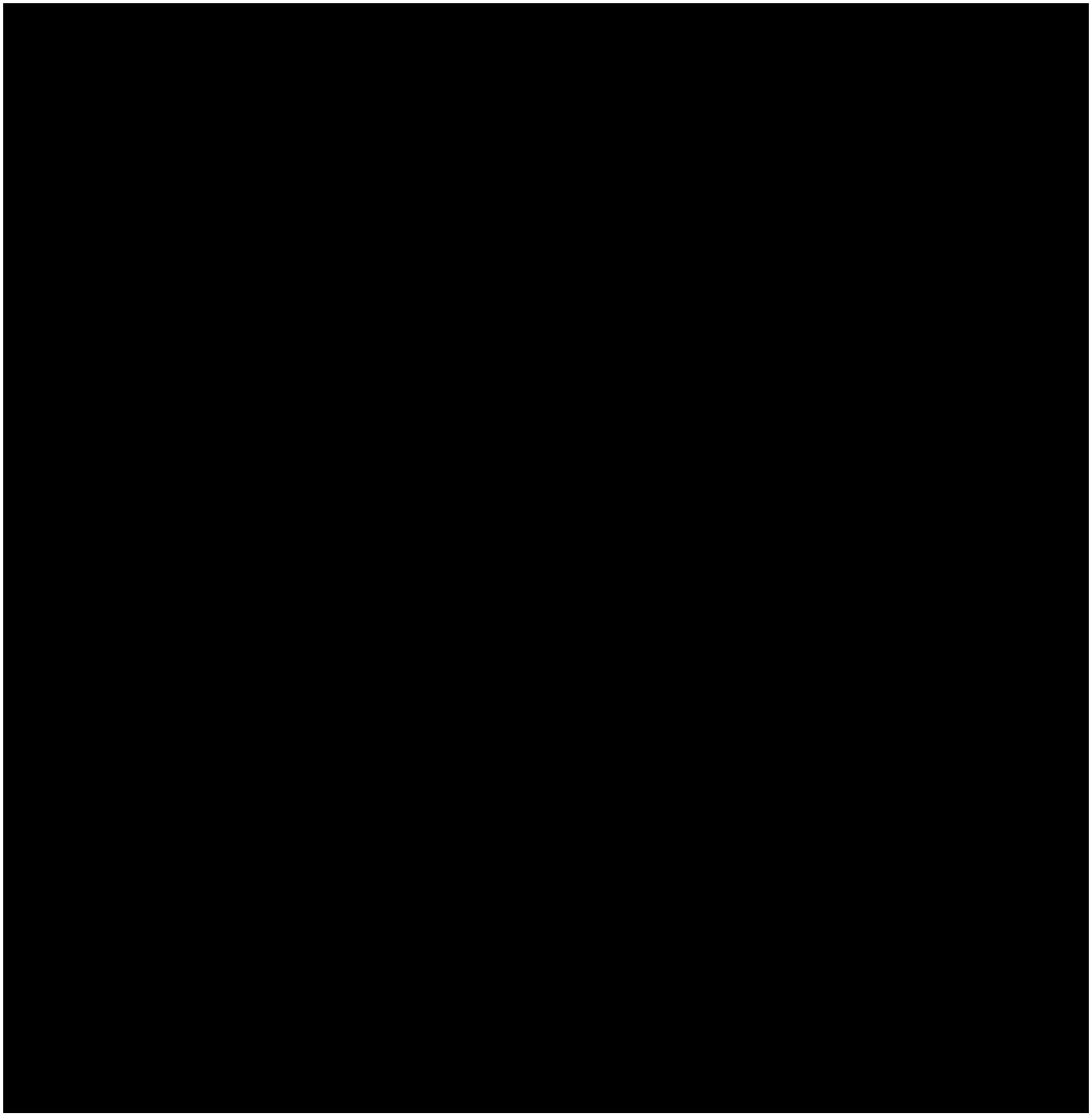
Subsurface modeling inherently carries uncertainty until dynamic data is incorporated. The monitoring program will enable enhanced fluid movement prediction through the life of the project. Monitoring data will be used to update expected outcomes and adapt operations to ensure compliance with permit constraints and AOR. Field data will be used to improve reservoir understanding, and to refine future iterations of the geologic model and simulations necessary for reservoir performance and AOR evaluation updates vs original forecasts.











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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Sunflower Carbon Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 3: August 2026

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.1 Area of Review and Corrective Action Plan

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson and Liberty Counties, Texas, to sequester approximately 25.3 million metric tons (MMT) of CO_2 over 11 years. This Area of Review (AOR) and Corrective Action Plan was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5.

ExxonMobil is pursuing individual Class VI permits for three injection wells consistent with 16 TAC **§5.203**. Given the proximity of the proposed injection wells for the Sunflower Project, ExxonMobil plans to obtain approval from the Underground Injection Control (UIC) Program director (UIC Director) to delineate the AOR and prepare the Corrective Action Plan to represent the collective effects of the three injection wells within the project AOR. Although the effects were evaluated in the collective, the required maps showing the delineated AOR and the Corrective Action Plan for artificial penetrations are submitted separately for each well so that they may be incorporated into each injection well's Class VI permit.

3.2 Objectives

A comprehensive modeling and evaluation effort was undertaken to accomplish the following objectives, consistent with the requirements of 16 TAC **§5.203(d)(1)**:

- Predict the extent of the CO_2 plume and pressure front, which form the basis for the AOR, using computational modeling, and identify all wells that require corrective action (16 TAC **§5.203(d)(1)(A)(i)**).
- Provide a plan to perform the required corrective action on artificial penetrations in the AOR (16 TAC **§5.203(d)(1)(C)**) that could threaten the underground source of drinking water (USDW).
- Support the development of effective monitoring strategies for the Testing and Monitoring Plan by identifying the locations where groundwater quality or pressure monitoring should be performed.
- Help direct emergency response planning by identifying potential vulnerable areas within or near the AOR that could require consideration when implementing an emergency response.
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AOR (16 TAC **§5.205(b)(3)**).
- Provide a guide for periodic AOR reevaluations to inform site management and monitoring over the life cycle of the Sunflower Project (16 TAC **§5.206(g)**).
- Retain modeling inputs and data used to support AOR reevaluations for 10 years (16 TAC **§5.206(g)(5)**).

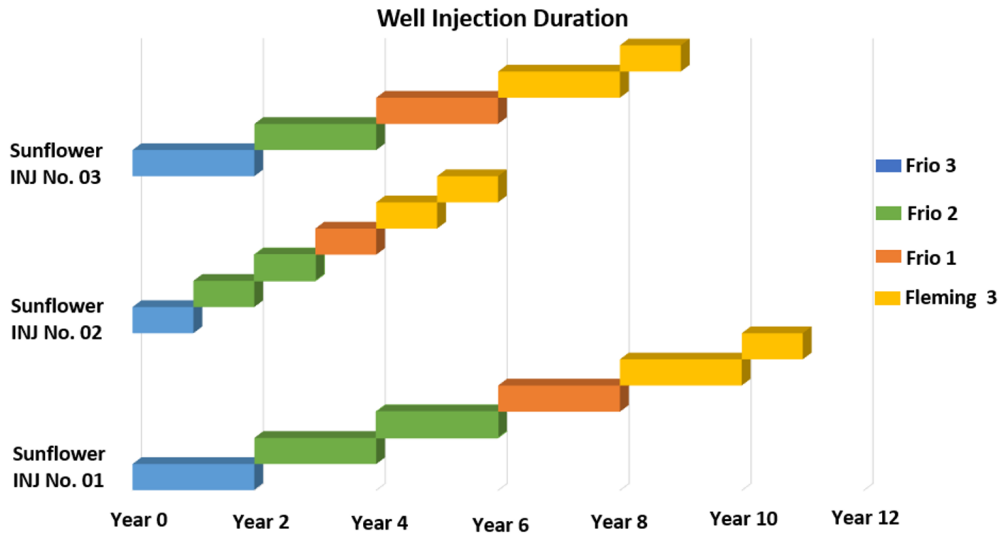
3.3 AOR Delineation Based on Model Results

The following subsections summarize information discussed further in *Section 2.7* (on model results) to provide context for the Corrective Action Plan and the AOR reevaluation plan that follow. More detailed information regarding geologic and dynamic model inputs and workflows are presented in *Section 2 – Plume Model.*

3.3.1 Extent of CO_2 Plume

In accordance with 16 TAC **§5.203(d)**, areal grid block size in the model was selected to optimize model runtimes, limit grid distortion effects, and allow for sufficiently accurate contouring of the plume extent. The operational and geologic input parameters were used in the Intersect model to generate projections of plume and pressure migration vs. time. Each well was initially completed and then recompleted into incrementally shallower portions of the injection intervals per the schedule presented in Figure 3-1.

Figure 3-2 presents the time-dependent, maximum areal extent of the CO_2 plume projected to be present in any of the injection zone layers at 5 years from the start of injection, at the end of injection, and at the stabilization of the plume. The CO_2 saturation and the areal extent of the plumes generated by CO_2 injection expand with time. As the volume of injected CO_2 increases, the CO_2 plumes from each injection well commingle in some of the layers. Once injection stops, the CO_2 footprint migration slows considerably. The combined effects of relative permeability, capillary pressure, CO_2 dissolving in brine, and limited structural dip ultimately arrest the extent of the CO_2 plume migration drift updip to the north-northwest. Figure 3-3 illustrates the cross-sectional view of the time-dependent CO_2 plume.



Stage	Injection Formation	Maximum Injection Rate Constraint (MMTPA)			Total Per Zone (MMT)
		Sunflower INJ No. 01	Sunflower INJ No. 02	Sunflower INJ No. 03	
1	Frio 3	1.2	1.0	0.8	5.0
2	Frio 2 Lower	1.0	1.2	1.2 *	7.8
3	Frio 2 Upper	0.5	1.2		
4	Frio 1	1.0	1.0	1.0	5.0
5	Fleming 3 Lower	1.0	1.0	1.0	7.5
6	Fleming 3 Upper	1.0	1.0	0.5	
Total Per Well (MMT)		10.4	6.4	8.5	**Site Total (25.3)**

* For Sunflower INJ No.3 stages 2 & 3 are combined.

Propietary Business Information

Figure 3-1 – Summary of Injection Intervals and Durations for Each Injection Well

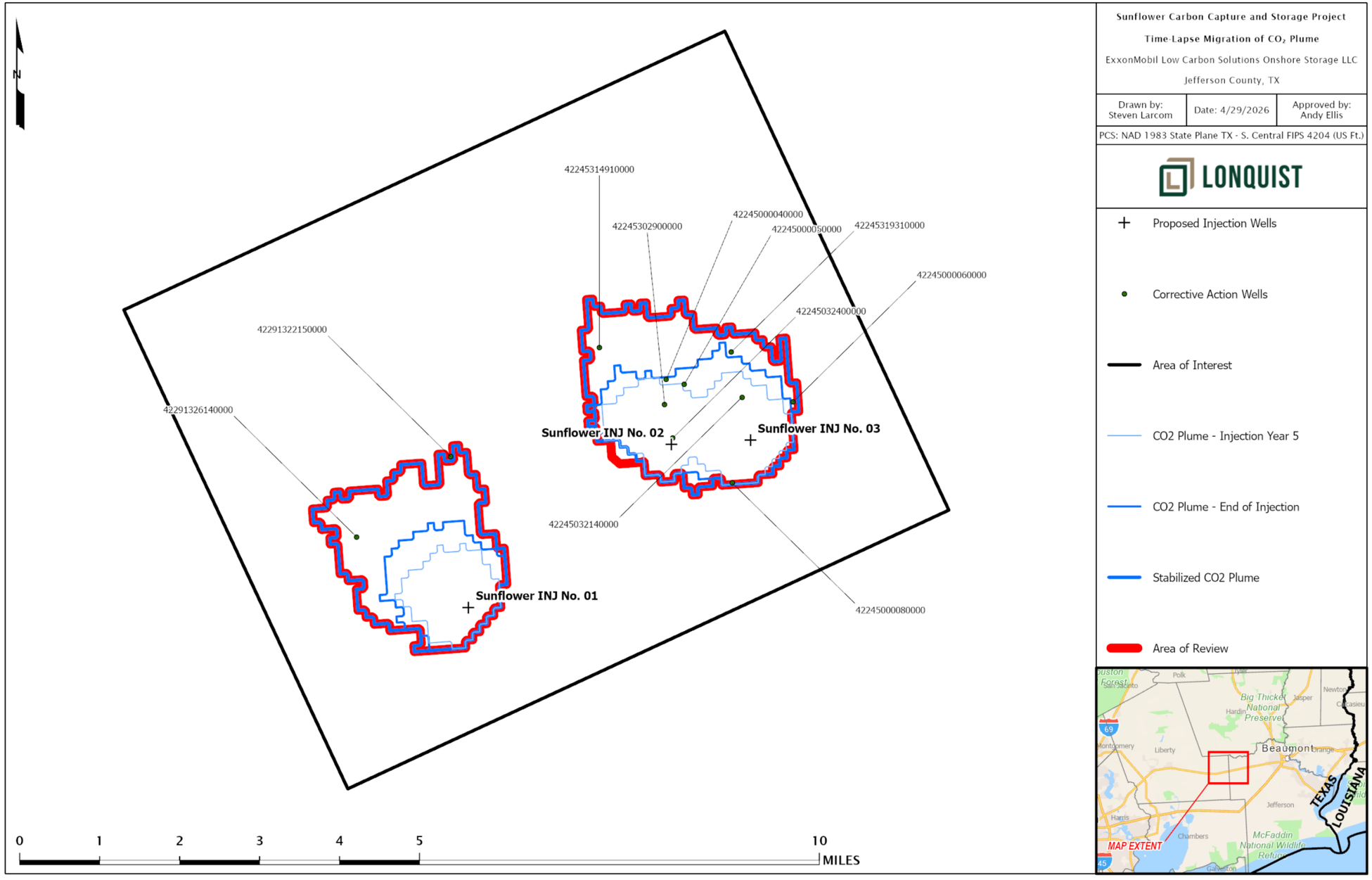


Figure 3-2 – Time-Lapse Migration of CO_2 Plume

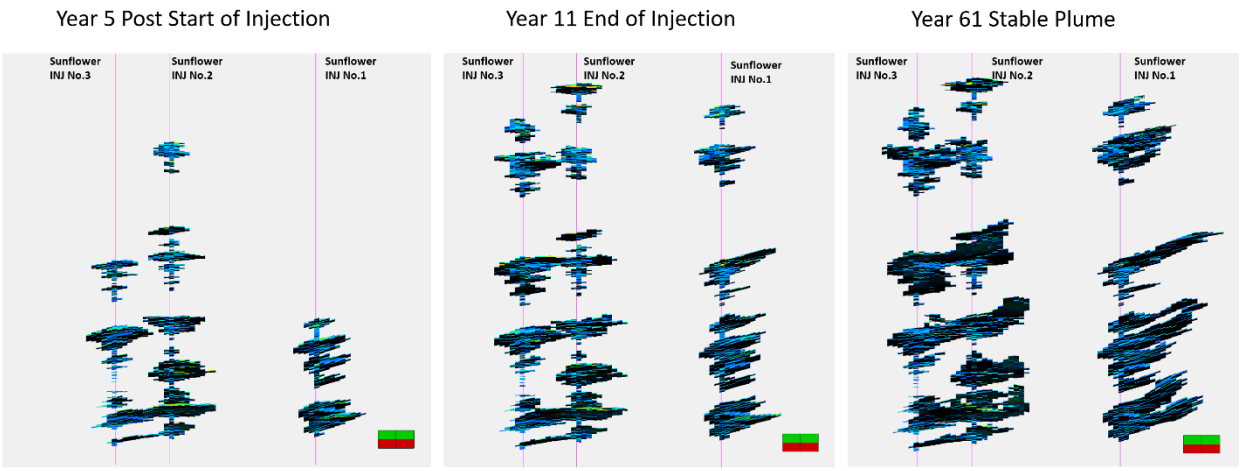


Figure 3-3 – Time-Lapse Migration of CO_2 Plume, Cross Section View Looking South

The rate of plume size growth is expected to diminish rapidly following the cessation of injection. The plume is expected to reach its maximum size approximately 50 years after injection ends—when the plume is considered stable.

3.3.2 Delineation of the Critical Pressure Front

In accordance with 16 TAC **§5.203(d)**, the pressure AOR was delineated by the critical pressure front created by the injection of CO_2 into the injection intervals. Critical pressure is the increase in reservoir pressure that has a potential to create a crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical pressure front defined by this pressure contour as detailed in *Section 2.7.3 – Plume Model*. The critical pressure front is shown in in Figure 3-4.

3.3.3 Final AOR

The maximum areal extents of both the CO_2 plume and the critical pressure front were used to delineate the AOR at any time interval or depth. The larger extent of either CO_2 saturation or critical pressure rise was used to define the AOR boundary. Figure 3-2 illustrates the maximum extent of the stabilized CO_2 plume. The critical pressure front, illustrated in Figure 3-5, represents the maximum areal cone of influence and combines results from the six completion intervals for each of the three injection wells. Superimposing the maximum CO_2 plume and critical pressure boundaries, Figure 3-5 provides the AOR boundary for the project along with the 11 artificial penetrations through the upper confining zone (UCZ) that require corrective action.

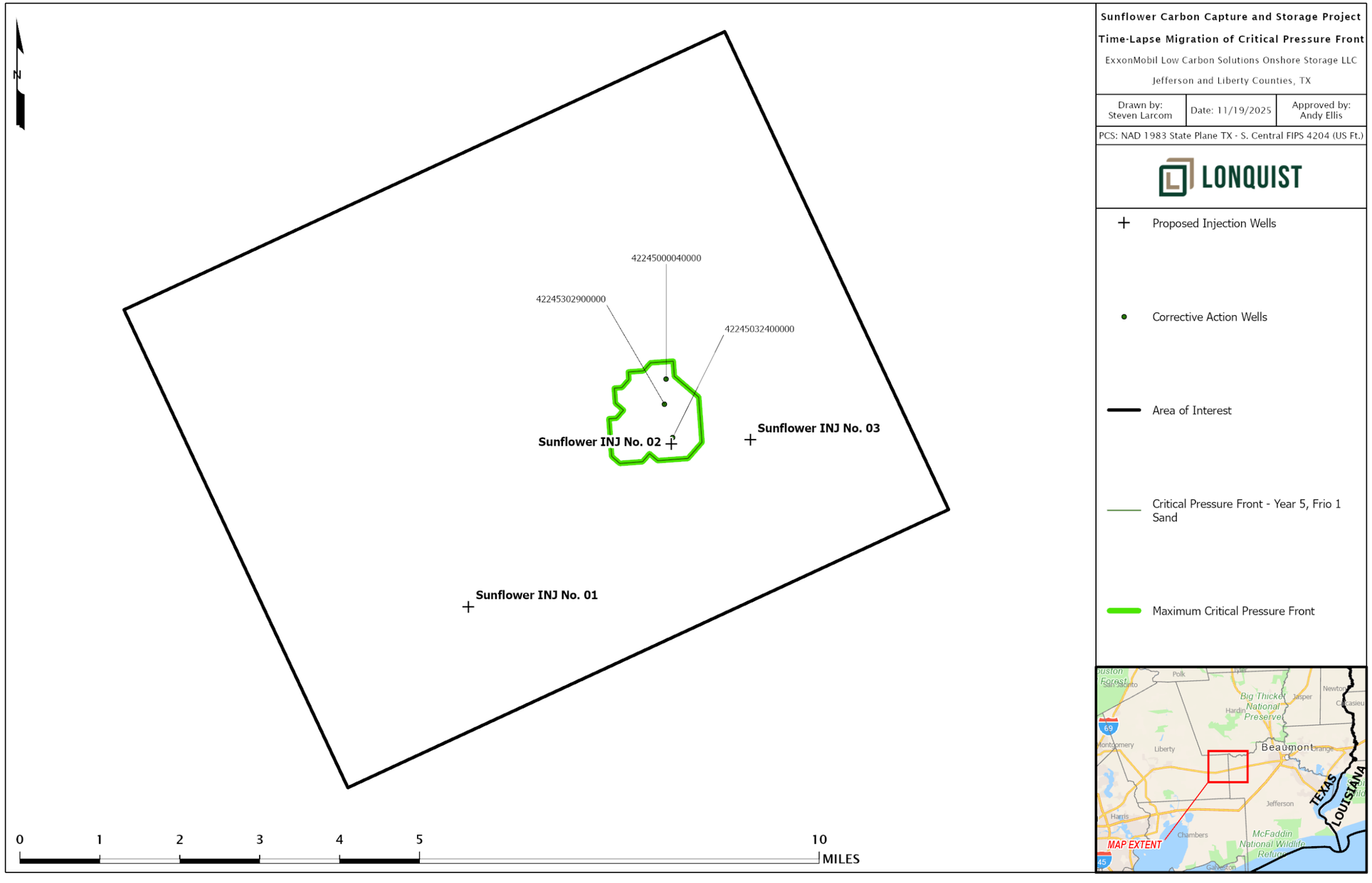


Figure 3-4 – Time-Lapse Migration of Critical Pressure Front

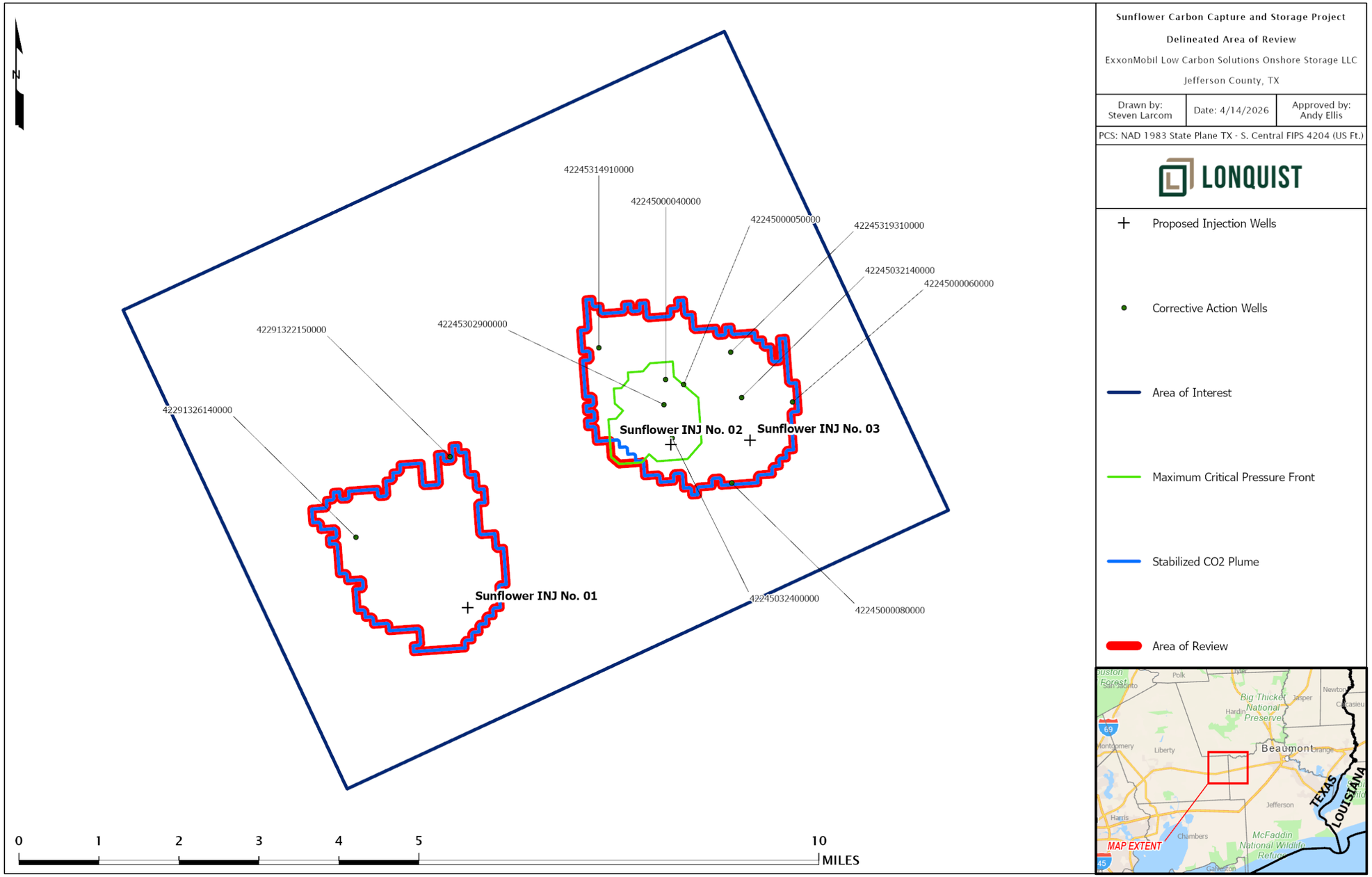


Figure 3-5 – Delineated Area of Review

3.4 Stages of Model Development

The stages of development for the CO_2 plume and pressure front model started with pre-operational phase data and industry standards to predict the AOR boundary. The geomodel and reservoir model rely on these data and on industry-standard correlations for the assignments of properties based on site-specific conditions derived from analysis of stratigraphic test well data. Physical rock-property distributions assigned to the model based on geostatistics have been analyzed and are consistent with all available data, including that of the stratigraphic test well.

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

3.5 Corrective Action Plan and Schedule

Consistent with 16 TAC **§5.203(d)**, the primary objective of this Corrective Action Plan is to identify the potential risk for loss of CO_2 or brine containment through artificial penetrations of the UCZ, and to specify corrective actions that would be taken to restore the integrity of the UCZ, if needed. ExxonMobil undertook a thorough investigation of artificial penetrations within and immediately adjacent to the AOR. Public and private databases were searched, and a total of 27 stratigraphic test wells, legacy oil and gas wells (legacy wells), and water wells were identified within the AOR. *Appendix C-2* shows the 16 water wells within the AOR.

Eleven artificial penetrations were found to penetrate the UCZ as shown in Figure 3-5, based on an analysis of the available data. All 11 of these artificial penetrations warrant corrective action planning and scheduling based on conservative assumptions regarding the potential for impact by injection. Following the requirements outlined in 16 TAC **§5.203(d)(1)(B)** and **§5.203(d)(1)(C)**), each artificial penetration within the AOR that may penetrate the UCZ was evaluated either for the quality of casing and cementing, in the case of existing wells—or for the quality of plugging and abandonment (P&A), in the case of abandoned wells.

This section provides for each well a rigorous corrective action process that begins with additional well-assessment activity and ends with establishing incremental barriers to remedy the potential for CO_2 or brine crossflow between the injection zones and the USDW. A USDW map within the AOI was used for setting the USDW cement plugs. The USDW map is featured and discussed in *Section 1 – Site Characterization*.

3.5.1 Data Acquisition and Evaluation of Artificial Penetration Information

In accordance with 16 TAC **§5.203(b)** and **§5.203(d)(1)(B**), a search was conducted to identify and assess the occurrence of artificial penetrations within the AOR. Additionally, a comprehensive

search of publicly available data sets was also performed to search for state- or EPA-approved subsurface cleanup sites, including Superfund/Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) sites, hazardous waste/Resource Conservation and Recovery Act (RCRA) sites, brownfields, and leaking underground storage tanks—as well as springs, mines, and quarries within the AOR. No such sites were found to exist within the Sunflower Project AOR. ExxonMobil also searched for other pertinent features including roads and structures intended for human occupancy which are shown in *Appendix C-5*. Pipelines that are located within the AOR are shown in Appendix G-2.

The following data sources were reviewed to identify the aforementioned sites within the AOR:

- Railroad Commission of Texas (TRRC) Geographical Information System (GIS) Database
- Texas Water Development Board
- Texas Commission on Environmental Quality UIC central file room database
- Third-party oil-and-gas record databases including Enverus Drilling Info, IHS Energy Portal, Tobin Data, EMSDB, HART, and Enerdeq
- EPA EnviroAtlas
- National Mine Map Repository

A tabulation of identified artificial penetrations within the AOR was created using a combination of the above data and is summarized in Table 3-1. Available records for the identified artificial penetrations are included in *Appendix C*.

Based on the artificial penetrations identified in the above databases, the following additional analysis was or will be conducted to assess the accuracy of well presence, location, and condition:

- A physical record request was made to the TRRC, and the available documents were reviewed.
- An aeromagnetic survey that fully includes the AOR was conducted in late 2025.
- In-person reconnaissance surveys will be conducted once surface access is secured.