Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage, LLC

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Prepared by

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CERTIFICATION

CERTIFIED BY:

I, [redacted], certify under penalty of law that this document and all attachments were prepared under my direction or supervision by 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 collecting the data, the information presented is, to the best of my knowledge and belief, true, accurate, and complete. I know there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

[redacted]

ExxonMobil Low Carbon Solutions Onshore Storage

ACRONYMS AND ABBREVIATIONS

Note: All terms are written as used in the text.

40 CFR	Title 40, U.S. Code of Federal Regulations
ACS	American Community Survey
AMPM	Association for Materials Protection and Performance
AOI	area of interest
AOR	area of review
ASTM	American Society for Testing and Materials
AZMI	above-zone monitoring interval
bbl	barrel(s)
BEG	Bureau of Economic Geology
BGL	below ground level
BHP	bottomhole pressure
BOE	barrels of oil equivalent
BTC	buttress-thread and coupled
BUQW	base of usable quality water
CBG	Census Block Group
CBL	cement bond log
CCS	carbon capture and storage
CEJST	Climate and Economic Justice Screening Tool
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CEQ	Council on Environmental Quality
CGM	Community Grievance Mechanism
CIL	casing inspection log
CMP	common mid-point
COC	chain-of-custody
CP	centipoise

CRA	corrosion-resistant alloy
CSIW	Component Solubility in Water
CT	Census tract
DHPT	downhole pressure temperature
DICE	Drilling Insight and Casing Estimator
DID	discharge ionization detector
DSA	double-studded adapter
DTC	compressional sonic
DTS	shear sonic slowness
EEHC	Exxon Equity Holding Company
EJ	environmental justice
EJScreen	Environmental Justice Screening and Mapping Tool
EMC	Exxon Mobil Corporation
EOR	enhanced oil recovery
EOS	equation of state
ERR	emergency and remedial response
ERRP	Emergency and Remedial Response Plan
ESD	Emergency Services District
F-C	Frio and Catahoula
FIT	formation integrity test
FITR	Fourier transform infrared
g/cc	grams per cubic centimeter
g/cm^3	grams per cubic meter
GAU	Groundwater Advisory Unit
GC	gas chromatography
GPa	gigapascals
GR	gamma ray
GS	geologic sequestration
GSDT	Geologic Sequestration Data Tool
GWB	Geochemist’s Workbench

HAZMAT	hazardous material
HAZWOPER	Hazardous Waste Operations
HNBR	hydrogenated nitrile rubber
Hz	hertz
ICS	Incident Command System
ID	inner diameter
IPaC	Information for Planning and Consultation
IRA	Inflation Reduction Act
ISBT	International Society of Beverage Technologists
ISD	Independent School District
IWG	Interagency Working Group
KB	kelly bushing
kg/m^3	kilograms per cubic meter
kips	thousand pounds
lb/ft^3	pounds per cubic foot
lb/gal	pounds per gallon
LCZ	lower confining zone
mD	millidarcy
MD	measured depth
MFS	maximum flooding surface
mg/L	milligrams per liter
MICP	mercury injection capillary pressure
MIT	mechanical integrity test
MMcf	million cubic feet
MMpsi	million psi
MMT	million metric tons
MMTPA	million metric tons per annum
MMV	monitoring measurement and verification
MPS	multipoint simulation
m/s	meters per second

Mscf/stb	million standard cubic feet per stock tank barrel
mV	millivolts
MW	mud weight
NACE	National Association of Corrosion Engineers
NAD	North American Datum (e.g., “of 1983”—NAD 83)
NADF	non-aqueous drilling fluid
NEIC	National Earthquake Information Center
NEPA	National Environmental Policy Act
NMR	nuclear magnetic resonance
NPHI	neutron porosity
NTG	net to gross
OBM	oil-based mud
OA	oxygen activation
OD	outer diameter
ohm-m	ohm-meters
P&A	plugging and abandonment
PHIE	calculated effective porosity
PHIT	total porosity
PISC	post-injection site care
PM	particulate matter
ppf	pounds per foot
ppg	pounds per gallon
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
P/T	pressure/temperature
PVT	pressure, volume, and temperature
RAPID	Reservoirs Applied Petrophysical Integrated Data
RCRA	Resource Conservation and Recovery Act
RHOB	bulk density

RMP	Risk Management Plan
RSWC	rotary sidewall core
SEP	Stakeholder Engagement Plan
SF	safety factor
SGR	shale gouge ratio
SIC	Standard Industrial Classification
SP	spontaneous potential
SRT	step-rate test
T&E	threatened and endangered
TAC	Texas Administrative Code
TCEQ	Texas Center on Environmental Quality
TD	total depth
TDS	total dissolved solids
TEC	tubing encapsulated conductor
TEEX	Texas A&M Engineering Extension Service
TRRC	Railroad Commission of Texas
TRL	Technology Readiness Level
TST	transgressive systems tract
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWDB	Texas Water Development Board
UCCZ	upper composite confining zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
µs/ft	microseconds per foot
VDL	variable density log
VSH	shale volume
WHP	wellhead pressure
XRD	X-ray diffraction

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REQUIREMENTS MATRIX

40 CFR - Subpart H - Criteria and Standards Applicable to Class VI Wells

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82 - Required Class VI permit information						
§146.82		This section sets forth the information which must be considered by the Director in authorizing Class VI wells. For converted Class I, Class II, or Class V experimental wells, certain maps, cross-sections, tabulations of wells within the area of review and other data may be included in the application by reference provided they are current, readily available to the Director, and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Regional Administrator.				
§146.82(a)		Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to § 146.91(e), and the Director shall consider the following:				
§146.82(a)(1)	Required class VI permit Information	Information required in § 144.31(e)(1) through (6) of this chapter;	§5.203 (a)(2)	General	General	
§146.82(a)(2)	Required class VI permit Information	A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	§5.203 (b)	Surface Map Information	Surface map and information. Only information of public record is required to be included on this map.	1.3, Appendix A
			§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;	3.3.1, Appendix C
			§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	1.3, Appendix A
			§5.203 (b)(2)(C)	Surface Map Information	other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.	1.3, Appendix C
			§5.203 (b)(3)	Surface Map Information	The applicant must identify on the map any known or suspected faults expressed at the surface.	1.10.2, Appendix B
§146.82(a)(3)	Required class VI permit Information	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	§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:	
§146.82(a)(3)(i)	Required class VI permit Information	Maps and cross sections of the area of review;				Appendix B
§146.82(a)(3)(ii)	Required class VI permit Information	The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	§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;	1.10.3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(a)(3)(iii)	Required class VI permit Information	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	§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
§146.82(a)(3)(iv)	Required class VI permit Information	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	§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
§146.82(a)(3)(v)	Required class VI permit Information	Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	§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
§146.82(a)(3)(vi)	Required class VI permit Information	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.				1.2, 1.5, 1.8, Appendix B
§146.82(a)(4)	Required class VI permit Information	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	§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.	3.5.1, Appendix C
§146.82(a)(5)	Required class VI permit Information	Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	§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;	1.8
§146.82(a)(6)	Required class VI permit Information	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	§5.203 (c)(2)(G)	Geologic, geochemical, and hydrologic information	Baseline geochemical data on subsurface formations, including all formations containing USDWs in the AOR;	1.8
§146.82(a)(7)	Required class VI permit Information	Proposed operating data for the proposed geologic sequestration site:	§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:	4.8

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(a)(7)(i)	Required class VI permit Information	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	§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;	2.1, 4.8.2
§146.82(a)(7)(ii)	Required class VI permit Information	Average and maximum injection pressure;	§5.203 (i)(1)(B)	Operating Information	The average and maximum surface injection pressure;	4.8.2
§146.82(a)(7)(iii)	Required class VI permit Information	The source(s) of the carbon dioxide stream; and	§5.203 (i)(1)(C)	Operating Information	The sources of the carbon dioxide stream and the volume of carbon dioxide from each source; and	Intro 2
§146.82(a)(7)(iv)	Required class VI permit Information	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	§5.203 (i)(1)(D)	Operating Information	An analysis of the chemical and physical characteristics of the carbon dioxide stream prior to injection.	2.1, 2.6.5, 4.3.1, 4.4
§146.82(a)(8)	Required class VI permit Information	Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;	§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	4.7
§146.82(a)(9)	Required class VI permit Information	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	§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	N/A 4.8.4
§146.82(a)(10)	Required class VI permit Information	Proposed procedure to outline steps necessary to conduct injection operation;	§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) of this title, and that outlines the steps necessary to conduct injection operation The applicant must include the following proposed operating data in the plan:	4.8
§146.82(a)(11)	Required class VI permit Information	Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	§5.203 (e)(2)(K)	Injection well construction	Schematic drawings of the surface and subsurface construction details.	Appendix D
§146.82(a)(12)	Required class VI permit Information	Injection well construction procedures that meet the requirements of § 146.86;	§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.	4.6.1, Appendix D
§146.82(a)(13)	Required class VI permit Information	Proposed area of review and corrective action plan that meets the requirements under § 146.84;	§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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(a)(14)	Required class VI permit Information	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	§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 8
			§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 8
§146.82(a)(15)	Required class VI permit Information	Proposed testing and monitoring plan required by § 146.90;				Section 5
§146.82(a)(16)	Required class VI permit Information	Proposed injection well plugging plan required by § 146.92(b);	§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
§146.82(a)(17)	Required class VI permit Information	Proposed post-injection site care and site closure plan required by § 146.93(a);	§5.206 (k)(1)	Permit Standards	Post-injection storage facility care and closure plan.	Section 7
§146.82(a)(18)	Required class VI permit Information	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);				
§146.82(a)(19)	Required class VI permit Information	Proposed emergency and remedial response plan required by § 146.94(a);	§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
§146.82(a)(20)	Required class VI permit Information	A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and				Intro N/A
§146.82(a)(21)	Required class VI permit Information	Any other information requested by the Director.				
§146.82(b)	Required class VI permit Information	The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.				
§146.82(c)	Required class VI permit Information	Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:				
§146.82(c)(1)	Required class VI permit Information	The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;				
§146.82(c)(2)	Required class VI permit Information	Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section;				
			§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:	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(c)(3)	Required class VI permit Information	Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;	§5.203 (g)(1)	Compatibility determination	the materials to be used to construct the well;	4.3
			§5.203 (g)(2)	Compatibility determination	fluids in the injection zone; and	4.3
			§5.203 (g)(3)	Compatibility determination	minerals in both the injection and the confining zone.	2.4.4
§146.82(c)(4)	Required class VI permit Information	The results of the formation testing program required at paragraph (a)(8) of this section;				
§146.82(c)(5)	Required class VI permit Information	Final injection well construction procedures that meet the requirements of § 146.86;				
§146.82(c)(6)	Required class VI permit Information	The status of corrective action on wells in the area of review;				
§146.82(c)(7)	Required class VI permit Information	All available logging and testing program data on the well required by § 146.87;				
§146.82(c)(8)	Required class VI permit Information	A demonstration of mechanical integrity pursuant to § 146.89;				
§146.82(c)(9)	Required class VI permit Information	Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and				
§146.82(c)(10)	Required class VI permit Information	Any other information requested by the Director.				
§146.82(d)	Required class VI permit Information		§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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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
§146.83						
§146.83(a)	Minimum Criteria for siting	Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	§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:	
§146.83(a)(1)	Minimum Criteria for siting	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	§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
§146.83(a)(2)	Minimum Criteria for siting	Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	§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;	1.11
§146.83(b)	Minimum Criteria for siting	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.				
§146.84	Area of review and corrective action		§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.	
§146.84(a)	Area of review and corrective action	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	§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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.84(b)	Area of review and corrective action	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	§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
§146.84(b)(1)	Area of review and corrective action	The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	§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
§146.84(b)(2)	Area of review and corrective action	A description of:	§5.203 (d)(2)(B)	AOR and corrective action	For AOR, a description of:	
§146.84(b)(2)(i)	Area of review and corrective action	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	§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.
§146.84(b)(2)(ii)	Area of review and corrective action	The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	§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
§146.84(b)(2)(iii)	Area of review 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	§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
§146.84(b)(2)(iv)	Area of review and corrective action	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§5.203 (d)(2)(C)	AOR and corrective action	a corrective action plan that describes:	
			§5.203 (d)(2)(C)(i)	AOR and corrective action	how the corrective action will be conducted;	3.5.2
			§5.203 (d)(2)(C)(ii)	AOR and corrective action	how corrective action will be adjusted if there are changes in the AOR;	3.5.2
			§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
§146.84(c)	Area of review and corrective action	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.84(c)(1)	Area of review and corrective action	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§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:	
			§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:	
§146.84(c)(1)(i)	Area of review and corrective action	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§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	2.6.3-2.6.6
			§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, 2.6.7
§146.84(c)(1)(ii)	Area of review and corrective action	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§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
§146.84(c)(1)(iii)	Area of review and corrective action	Consider potential migration through faults, fractures, and artificial penetrations.	§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.	
§146.84(c)(2)	Required class VI permit Information	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	§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 or excavated, location, depth, and 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.	3.5.1, Appendix C

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.84(c)(3)	Area of review and corrective action	Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	§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.	3.5.1
§146.84(d)	Area of review and corrective action	Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.				3.5.2
§146.84(e)	Area of review and corrective action	At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	§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
§146.84(e)(1)	Area of review and corrective action	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	§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
§146.84(e)(2)	Area of review and corrective action	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	§5.206 (g)(2)	AOR and corrective action	Identify all wells in the reevaluated area of review that require corrective action;	3.6.2
§146.84(e)(3)	Area of review and corrective action	Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	§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
§146.84(e)(4)	Area of review and corrective action	Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review 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 § 144.39 or § 144.41 of this chapter, as appropriate.	§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	
§146.84(f)	Financial Responsibility	The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	§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
§146.84(g)	Area of review and corrective action	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	§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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§5.205 (b)(2)	Fees, financial responsibility, and financial assurance	In determining whether the person is financially responsible, the director must rely on:	
			§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	
			§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	
			§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.	
			§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.	
			§5.205 (c)	Financial assurance	Financial assurance.	
			§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.	
			§5.205 (c)(2)	Fees, financial responsibility, and financial assurance	Geologic storage facility.	
			§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)(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.	
			§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.	
			§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:	
			§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	
			§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§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.	
			§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.	
			§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.	
			§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.	
			§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.	
			§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:	
			§5.205 (c)(2)(D)(iii)(III)(-a-)		the director deems the facility abandoned;	
			§5.205 (c)(2)(D)(iii)(III)(-b-)		the permit is terminated or revoked or a new permit is denied;	
			§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;	
			§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	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.205 (c)(2)(D)(iii)(III)(-e-)		the amount due is paid.	
			§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	
			§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;	
			§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;	
			§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.	
			§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§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.	
			§5.205 (c)(2)(H)(i)	Fees, financial responsibility, and financial assurance	The owner or operator must maintain financial responsibility until:	
			§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	
			§5.205 (c)(2)(H)(i)(II)	Fees, financial responsibility, and financial assurance	the director issues the certificate of closure.	
			§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:	
			§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	
			§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.	
			§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.	
			§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.	
			§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.	
			§5.205 (D)	Fees, financial responsibility, and financial assurance	Notice of adverse financial conditions	
			§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.	
			§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
§146.85	Financial Responsibility					
§146.85(a)	Financial Responsibility	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:				
§146.85(a)(1)	Financial Responsibility	The financial responsibility instrument(s) used must be from the following list of qualifying instruments:				
§146.85(a)(1)(i)		Trust Funds.				
§146.85(a)(1)(ii)		Surety Bonds.				
§146.85(a)(1)(iii)		Letter of Credit.				
§146.85(a)(1)(iv)		Insurance				
§146.85(a)(1)(v)		Self Insurance (i.e., Financial Test and Corporate Guarantee).				9.3
§146.85(a)(1)(vi)		Escrow Account				
§146.85(a)(1)(vii)		Any other instrument(s) satisfactory to the Director.				
§146.85(a)(2)		The qualifying instrument(s) must be sufficient to cover the cost of:	§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.	9.4
§146.85(a)(2)(i)		Corrective action (that meets the requirements of § 146.84);				
§146.85(a)(2)(ii)		Injection well plugging (that meets the requirements of § 146.92);				
§146.85(a)(2)(iii)		Post injection site care and site closure (that meets the requirements of § 146.93); and				
§146.85(a)(2)(iv)		Emergency and remedial response (that meets the requirements of § 146.94).				
§146.85(a)(3)		The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.				9.4
§146.85(a)(4)		The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.				
§146.85(a)(4)(i)		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.				
§146.85(a)(4)(i)(A)		Cancellation - for purposes of this part, an owner or operator must provide that their financial mechanism 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 for 120 days after receipt of 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.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(4)(i)(B)		Renewal - for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or 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.				
§146.85(a)(4)(i)(C)		Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.				
§146.85(a)(5)		The qualifying financial responsibility instrument(s) must be approved by the Director.				
§146.85(a)(5)(i)		The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).				
§146.85(a)(5)(ii)		The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.				9.3
§146.85(a)(5)(iii)		The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.				
§146.85(a)(6)		The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.				
§146.85(a)(6)(i)		In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(6)(ii)		When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.				
§146.85(a)(6)(iii)		An owner or operator using certain types of third-party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.				
§146.85(a)(6)(iv)		An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.				
§146.85(a)(6)(v)		An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than −0.1; and a net profit (revenues minus expenses) greater than 0.				9.3
§146.85(a)(6)(vi)		An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.				
§146.85(a)(6)(vii)		An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(b)		The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.				
§146.85(b)(1)		The owner or operator must maintain financial responsibility and resources until:				
§146.85(b)(1)(i)		The Director receives and approves the completed post-injection site care and site closure plan; and				9.7
§146.85(b)(1)(ii)		The Director approves site closure.				9.7
§146.85(b)(2)		The owner or operator may be released from a financial instrument in the following circumstances:				
§146.85(b)(2)(i)		The owner or operator has completed the phase of the geologic sequestration 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 GS project, if required; or				
§146.85(b)(2)(ii)		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.				
§146.85(c)		The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.				9.4
§146.85(c)(1)		The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.				9.4
§146.85(c)(2)		During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).				9.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(c)(3)		The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration 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 area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.				
§146.85(c)(4)		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 owner or operator has received written approval from the Director.				
§146.85(d)		The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.				
§146.85(d)(1)		In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.				
§146.85(d)(2)		A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(d)(3)		An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.				
§146.85(e)	Financial Responsibility	The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94).				
§146.85(f)	Financial Responsibility	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.				
§146.86	Injection well construction requirements		§5.203 (e)	Injection well construction	Injection well construction	
§146.86(a)	Injection well construction requirements	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	§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.	
			§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:	
§146.86(a)(1)	Injection well construction requirements	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	§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
§146.86(a)(2)	Injection well construction requirements	Permit the use of appropriate testing devices and workover tools; and	§5.203 (e)(1)(A)(ii)	Injection well construction	Allow the use of appropriate testing devices and workover tools; and	4.1
§146.86(a)(3)	Injection well construction requirements	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	§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
§146.86(b)	Injection well construction requirements	Casing and cementing of Class VI wells.	§5.203 (e)(1)(B)	Injection well construction	Casing and Cementing of anthropogenic CO2 injection wells	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.86(b)(1)	Injection well construction requirements	Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	§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.	4.3, 4.4
			§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:	
§146.86(b)(1)(i)	Injection well construction requirements	Depth to the injection zone(s);	§5.203 (e)(2)(A)	Injection well construction	Depth to the injection zone(s);	Appendix D
§146.86(b)(1)(ii)	Injection well construction requirements	Injection pressure, external pressure, internal pressure, and axial loading;				4.4
§146.86(b)(1)(iii)	Injection well construction requirements	Hole size;	§5.203 (e)(2)(B)	Injection well construction	Hole size	4.4
§146.86(b)(1)(iv)	Injection well construction requirements	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	§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);	4.4
§146.86(b)(1)(v)	Injection well construction requirements	Corrosiveness of the carbon dioxide stream and formation fluids;	§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;	4.3
§146.86(b)(1)(vi)	Injection well construction requirements	Down-hole temperatures;	§5.203 (e)(2)(G)	Injection well construction	Down-hole temperatures and pressures	4.7
§146.86(b)(1)(vii)	Injection well construction requirements	Lithology of injection and confining zone(s);	§5.203 (e)(2)(H)	Injection well construction	Lithology of injection and confining zone(s)	4.7
§146.86(b)(1)(viii)	Injection well construction requirements	Type or grade of cement and cement additives; and	§5.203 (e)(2)(I)	Injection well construction	Type or grade of cement and cement additives; and	4.6, Appendix D
§146.86(b)(1)(ix)	Injection well construction requirements	Quantity, chemical composition, and temperature of the carbon dioxide stream.	§5.203 (e)(2)(J)	Injection well construction	Quantity, chemical composition, and temperature of the carbon dioxide stream.	2.1, 2.6.5, 4.3.1, 4.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	4.4
§146.86(b)(2)	Injection well construction requirements	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	§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	4.4.2, Appendix D
§146.86(b)(3)	Injection well construction requirements	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.	§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	4.4.3
§146.86(b)(4)	Injection well construction requirements	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.	§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.	
§146.86(b)(5)	Injection well construction requirements	Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	§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.	4.7.2
§146.86(c)		Tubing and packer.	§5.203 (e)(1)(C)	Injection well construction	Special equipment.	4.7, Appendix D
§146.86(c)(1)	Injection well construction requirements	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.				4.5
§146.86(c)(2)	Injection well construction requirements	All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	§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.	4.4.3, Appendix D
			§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.	4.5.4
§146.86(c)(3)	Injection well construction requirements	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:				
§146.86(c)(3)(i)	Injection well construction requirements	Depth of setting;				4.5.1

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.86(c)(3)(ii)	Injection well construction requirements	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;				2.4.1, 2.6.5, 4.3.1, 4.7.3
§146.86(c)(3)(iii)	Injection well construction requirements	Maximum proposed injection pressure;				2.7.1, 4.8.2
§146.86(c)(3)(iv)	Injection well construction requirements	Maximum proposed annular pressure;				4.8.3
§146.86(c)(3)(v)	Injection well construction requirements	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	§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;	2.7.1,4.8.2
			§5.203 (e)(2)(E)	Injection well construction	type of packer and packer setting depth	4.5.1, 4.5.3
§146.86(c)(3)(vi)	Injection well construction requirements	Size of tubing and casing; and				4.4.3, 4.5.1
§146.86(c)(3)(vii)	Injection well construction requirements	Tubing tensile, burst, and collapse strengths.				4.5.1
§146.87		Logging, sampling, and testing prior to injection well operation				
§146.87(a)	Logging, sampling, and testing prior to injection well operation	During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	§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.	
			§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.	4.7
			§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.	4.7.2
§146.87(a)(1)	Logging, sampling, and testing prior to injection well operation	Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be 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; and	§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.87(a)(2)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the surface casing:				
§146.87(a)(2)(i)	Logging, sampling, and testing prior to injection well operation	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§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.	4.7.2
§146.87(a)(2)(ii)	Logging, sampling, and testing prior to injection well operation	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	§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.	4.7.2
§146.87(a)(3)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the long string casing:	§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.	
§146.87(a)(3)(i)	Logging, sampling, and testing prior to injection well operation	Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and				4.7.2
§146.87(a)(3)(ii)	Logging, sampling, and testing prior to injection well operation	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	§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.	4.7.2
			§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.	
			§5.203 (h)(1)(F)	Mechanical integrity testing	An operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
§146.87(a)(4)	Logging, sampling, and testing prior to injection well operation	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	§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
§146.87(a)(4)(i)	Logging, sampling, and testing prior to injection well operation	A pressure test with liquid or gas;	§5.203 (h)(2)(A)	Mechanical integrity testing	A pressure test with liquid or gas;	5.4.2
§146.87(a)(4)(ii)	Logging, sampling, and testing prior to injection well operation	A tracer survey such as oxygen-activation logging;	§5.203 (h)(2)(B)	Mechanical integrity testing	A tracer survey such as oxygen-activation logging;	5.4.2
§146.87(a)(4)(iii)	Logging, sampling, and testing prior to injection well operation	A temperature or noise log;	§5.203 (h)(2)(C)	Mechanical integrity testing	A temperature or noise log;	
§146.87(a)(4)(iv)	Logging, sampling, and testing prior to injection well operation	A casing inspection log; and	§5.203 (h)(2)(D)	Mechanical integrity testing	A casing inspection log; and	5.5.2.1

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§146.87(a)(5)	Logging, sampling, and testing prior to injection well operation	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	§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.	
§146.87(b)	Logging, sampling, and testing prior to injection well operation	The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	§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.	4.7.1, 4.7.3
§146.87(c)	Logging, sampling, and testing prior to injection well operation	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	§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.	4.7.3
§146.87(d)	Logging, sampling, and testing prior to injection well operation	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	§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.	
§146.87(d)(1)	Logging, sampling, and testing prior to injection well operation	Fracture pressure;	§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, 2.6.7.1, 4.8.2
§146.87(d)(2)	Logging, sampling, and testing prior to injection well operation	Other physical and chemical characteristics of the injection and confining zone(s); and				1.3, 1.4, 4.7
§146.87(d)(3)	Logging, sampling, and testing prior to injection well operation	Physical and chemical characteristics of the formation fluids in the injection zone(s).				1.7, 4.7
§146.87(e)	Logging, sampling, and testing prior to injection well operation	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):				
§146.87(e)(1)	Logging, sampling, and testing prior to injection well operation	A pressure fall-off test; and,	§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.	4.7.5
§146.87(e)(2)		A pump test; or				

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		Injectivity tests.				4.7.5
§146.87(f)	Logging, sampling, and testing prior to injection well operations	The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	§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.	4.7
§146.88		Injection well operating requirements				
			§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;	
			§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	
§146.88(a)	Injection well operating requirements	Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection 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. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	§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, 4.8.2, 4.8.4
			§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, 2.6.7.1, 4.8.2
§146.88(b)	Injection well construction requirements	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	§5.206 (d)(2)(A)	Operating a geologic storage facility	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	**4.8.2**
§146.88(c)	Injection well construction requirements	The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive 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.	§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.	4.5.3, 4.6.1
§146.88(d)	Injection well operating requirements	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.	§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.	**4.9**

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.88(d)	Injection well operating requirements	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.	§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.	4.9
§146.88(e)	Injection well operating requirements	The owner or operator must install and use:	§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.	
§146.88(e)(1)	Injection well operating requirements	Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	§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.	4.1, 5.5.1
§146.88(e)(2)	Injection well operating requirements	Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and				4.9, 5.5.1, 8.5.1
§146.88(e)(3)	Injection well operating requirements	Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.				
§146.88(f)	Injection well operating requirements	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 of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:	§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	4.9, 8.5.1
§146.88(f)(1)	Injection well operating requirements	Immediately cease injection;	§5.206 (d)(2)(F)(ii)(I)	Operating a geologic storage facility	Immediately cease injection;	4.9, 8.5.1
§146.88(f)(2)	Injection well operating requirements	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;	§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	4.9, 8.5.1
§146.88(f)(3)	Injection well operating requirements	Notify the Director within 24 hours;	§5.206 (d)(2)(F)(ii)(III)	Operating a geologic storage facility	Notify the Director within 24 hours	8.5.1
§146.88(f)(4)	Injection well operating requirements	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	§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	8.5.1
§146.88(f)(5)	Injection well operating requirements	Notify the Director when injection can be expected to resume.	§5.206 (d)(2)(F)(ii)(V)	Operating a geologic storage facility	Notify the Director when injection can be expected to resume	8.5.1
			§5.203 (h)	Mechanical integrity testing	Mechanical integrity testing.	

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§146.89	Mechanical Integrity	Mechanical Integrity	§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.	
			§5.206 (f)	Mechanical integrity	Mechanical Integrity	
§146.89(a)	Mechanical Integrity	A Class VI well has mechanical integrity if:				
§146.89(a)(1)	Mechanical Integrity	There is no significant leak in the casing, tubing, or packer; and				
§146.89(a)(2)	Mechanical Integrity	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.				
			§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
§146.89(b)	Mechanical Integrity	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	§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.	5.5.1.2
§146.89(c)	Mechanical Integrity	At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	§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).	5.3
§146.89(c)(1)	Mechanical Integrity	An approved tracer survey such as an oxygen-activation log; or				
§146.89(c)(2)	Mechanical Integrity	A temperature or noise log.				
§146.89(d)	Mechanical Integrity	If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.				
§146.89(e)	Mechanical Integrity	The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.				

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§146.89(f)	Mechanical Integrity	In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.				
§146.89(g)	Mechanical Integrity	The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	§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.	
§146.90	Testing and monitoring requirements	The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	§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:	
§146.90(a)	Testing and monitoring requirements	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	§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;	5.3
§146.90(b)	Testing and monitoring requirements	Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	§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	4.1, 5.5.1
§146.90(c)	Testing and monitoring requirements	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 § 146.86(b), by:	§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

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§146.90(c)(1)	Testing and monitoring requirements	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	§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	5.5.2.2
§146.90(c)(2)	Testing and monitoring requirements	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	§5.203 (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	
§146.90(c)(3)	Testing and monitoring requirements	Using an alternative method approved by the Director;	§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;	
§146.90(d)	Testing and monitoring requirements	Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	§5.203 (j)(2)(D)	Plan for monitoring, sampling, and testing after initiation of operation	Monitoring of geochemical and geophysical changes, including:	
			§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;	5.3
			§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;	5.3
			§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
§146.90(d)(1)	Testing and monitoring requirements	The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and				5.4.1
§146.90(d)(2)	Testing and monitoring requirements	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).	§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
§146.90(e)		A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	§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;	5.3
§146.90(f)	Testing and monitoring requirements	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;	§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

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§146.90(g)	Testing and monitoring requirements	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	§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;	
§146.90(g)(1)		Direct methods in the injection zone(s); and,				5.4
§146.90(g)(2)	Testing and monitoring requirements	Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	§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;	5.4
§146.90(h)		The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.				5.4, 5.5.3
§146.90(h)(1)		Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;				5.5.3
§146.90(h)(2)		The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter;				5.5.3
§146.90(h)(3)		If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;				
§146.90(i)	Testing and monitoring requirements	Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	§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.	
			§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	

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§146.90(j)	Testing and monitoring requirements	The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:				5.3
§146.90(j)(1)		Within one year of an area of review reevaluation;				5.3
§146.90(j)(2)		Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or	§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.	5.3
§146.90(j)(3)		When required by the Director.				
§146.90(k)	Testing and monitoring requirements	A quality assurance and surveillance plan for all testing and monitoring requirements.	§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.	5.4.3.3
§146.91	Reporting requirements	The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	§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:	
			§5.207 (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.	
			§5.207 (a)(2)(D)	Reporting and Record-Keeping	Annual reports. The operator must submit an annual report detailing:	
			§5.207 (a)(2)(D)(i)	Reporting and Record-Keeping	corrective action performed;	
			§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);	
			§5.207 (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;	

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			§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;	
			§5.207 (a)(2)(D)(v)	Reporting and Record-Keeping	tons of CO2 injected; and	
			§5.207 (a)(2)(D)(vi)	Reporting and Record-Keeping	other information as required by the permit.	
			§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.	
			§5.207 (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:	
			§5.207 (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	
			§5.207 (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.	
			§5.207 (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.	
§146.91(a)	Reporting requirements	**Semi-annual reports containing:**	§5.207 (a)(2)(C)	Reporting and Record-Keeping	**Semi-annual reports containing:**	5.2
§146.91(a)(1)	Reporting requirements	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	§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
§146.91(a)(2)	Reporting requirements	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	§5.207 (a)(2)(C)(i)	Reporting and Record-Keeping	a summary of well head pressure monitoring;	**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
§146.91(a)(3)	Reporting requirements	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	§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
§146.91(a)(4)	Reporting requirements	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	§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
§146.91(a)(5)	Reporting requirements	The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	§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
§146.91(a)(6)	Reporting requirements	Monthly annulus fluid volume added; and	§5.207 (a)(2)(C)(iv)	Reporting and Record-Keeping	monthly annulus fluid volume added;	5.2

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§146.91(a)(7)	Reporting requirements	The results of monitoring prescribed under § 146.90.	§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).	5.3, 5.4
§146.91(b)	Reporting requirements	**Report, within 30 days, the results of:**	§5.207 (a)(2)(B)	Reporting and Record-Keeping	**Report, within 30 days, the results of:**	5.2
§146.91(b)(1)	Reporting requirements	Periodic tests of mechanical integrity;	§5.207 (a)(2)(B)(i)	Reporting and Record-Keeping	the results of periodic tests for mechanical integrity;	5.2
§146.91(b)(2)	Reporting requirements	Any well workover; and,	§5.207 (a)(2)(B)(iii)	Reporting and Record-Keeping	a description of any well workover.	5.2
§146.91(b)(3)	Reporting requirements	Any other test of the injection well conducted by the permittee if required by the Director.	§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	5.2
§146.91(c)	Reporting requirements	**Report, within 24 hours:**	§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.	
			§5.207 (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.	5.2
			§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;	
§146.91(c)(1)	Reporting requirements	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	§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;	5.2
§146.91(c)(2)	Reporting requirements	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	§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;	5.2
§146.91(c)(3)	Reporting requirements	Any triggering of a shut-off system (i.e., down-hole or at the surface);	§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	5.2
§146.91(c)(4)	Reporting requirements	Any failure to maintain mechanical integrity; or.	§5.207 (a)(2)(A)(v)	Reporting and Record-Keeping	any failure to maintain mechanical integrity.	5.2
§146.91(c)(5)	Reporting requirements	Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.				
§146.91(d)	Reporting requirements	Owners or operators must notify the Director in writing 30 days in advance of				5.2

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§146.91(d)(1)	Reporting requirements	Any planned well workover;	§5.206 (i)	Commission witnessing of testing and logging.	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.	5.2
§146.91(d)(2)	Reporting requirements	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and				5.2
§146.91(d)(3)	Reporting requirements	Any other planned test of the injection well conducted by the permittee.				5.2
			§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**
§146.91(e)	Reporting requirements	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	§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.	
			§5.207 (c)	Reporting and Record-Keeping	Signatories to reports.	
			§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:	
			§5.207 (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;	
			§5.207 (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	
			§5.207 (c)(1)(C)	Reporting and Record-Keeping	the written authorization is submitted to the director.	
			§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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."	
§146.91(f)	Reporting requirements		§5.207 (e)	Reporting and Record-Keeping	Record retention.	
§146.91(f)(1)	Reporting requirements	All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	§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
§146.91(f)(2)	Reporting requirements	Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.	§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
			§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.	
§146.91(f)(3)	Reporting requirements	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	§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
§146.91(f)(4)	Reporting requirements	Well plugging reports, post-injection site care data, including, if appropriate, 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 at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.	§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.91(f)(5)	Reporting requirements	The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	§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.	
§146.92	Injection Well Plugging	Injection well plugging	§5.203 (k)	Well Plugging Plan	Injection well plugging	
§146.92(a)	Injection Well Plugging	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	§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
§146.92(b)	Injection Well Plugging	Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	§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:	
			§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
§146.92(b)(1)	Injection Well Plugging	Appropriate tests or measures for determining bottomhole reservoir pressure;	§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.3.3
§146.92(b)(2)	Injection Well Plugging	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	§5.203 (k)(2)(C)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.3.4
§146.92(b)(3)	Injection Well Plugging	The type and number of plugs to be used;	§5.203 (k)(1)(A)	Well Plugging Plan	The type and number of plugs to be used;	6.4.2.3
§146.92(b)(4)	Injection Well Plugging	The placement of each plug, including the elevation of the top and bottom of each plug;	§5.203 (k)(1)(B)	Well Plugging Plan	The placement of each plug, including the elevation of the top and bottom of each plug;	6.4.2.3
§146.92(b)(5)	Injection Well Plugging	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	§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	6.4.2.3
			§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;	6.4.2.3
§146.92(b)(6)	Injection Well Plugging	The method of placement of the plugs.	§5.203 (k)(1)(D)	Well Plugging Plan	The method of placement of the plugs.	6.4.2.3

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§146.92(c)	Injection Well Plugging	Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§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
§146.92(d)	Injection Well Plugging	Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	§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
§146.93	Post-injection and site closure	Post-injection site care and site closure	§5.203 (m)	Post-injection storage facility care and closure plan	The applicant must submit a post-injection storage facility care and closure plan.	
§146.93(a)	Post-injection and site closure	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.				Section 7
§146.93(a)(1)	Post-injection and site closure	The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.				
§146.93(a)(2)	Post-injection and site closure	The post-injection site care and site closure plan must include the following information:				
§146.93(a)(2)(i)	Post-injection and site closure	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	§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);	7.3
§146.93(a)(2)(ii)	Post-injection and site closure	The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(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
§146.93(a)(2)(iii)	Post-injection and site closure	A description of post-injection monitoring location, methods, and proposed frequency;	§5.203 (m)(4)	Post-injection storage facility care and closure plan	A description of post-injection monitoring location, methods, and proposed frequency;	7.4, 7.5
§146.93(a)(2)(iv)	Post-injection and site closure	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	§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
§146.93(a)(2)(v)	Post-injection and site closure	The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	§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;	7.5

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§146.93(a)(3)	Post-injection and site closure	Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. 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 at § 144.39 or § 144.41 of this chapter, as appropriate.				7.5.1
§146.93(a)(4)	Post-injection and site closure	At any time during the life of the geologic sequestration project, the owner or 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.	§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
§146.93(b)	Post-injection and site closure	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	§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.	7.5.3
§146.93(b)(1)		Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.				7.5
§146.93(b)(2)		If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.				7.6

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§146.93(b)(3)	Post-injection and site closure	Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, 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.	§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
§146.93(b)(4)	Post-injection and site closure	If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.				
§146.93(c)	Post-injection and site closure	Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.				7.5
			§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
§146.93(c)(1)	Post-injection and site closure	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	§5.203 (m)(7)	Post-injection storage facility care and closure plan	consideration and documentation of:	
§146.93(c)(1)(i)	Post-injection and site closure	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	§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;	
§146.93(c)(1)(ii)	Post-injection and site closure	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;	§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;	
§146.93(c)(1)(iii)	Post-injection and site closure	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	§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;	
§146.93(c)(1)(iv)	Post-injection and site closure	A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	§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;	
§146.93(c)(1)(v)	Post-injection and site closure	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	§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;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.93(c)(1)(vi)	Post-injection and site closure	The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section;	§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;	
§146.93(c)(1)(vii)	Post-injection and site closure	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., carbon dioxide, formation fluids) movement;	§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;	
§146.93(c)(1)(viii)	Post-injection and site closure	The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	§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;	
§146.93(c)(1)(ix)	Post-injection and site closure	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	§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;	
§146.93(c)(1)(x)	Post-injection and site closure	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	§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	
§146.93(c)(1)(xi)	Post-injection and site closure	Any additional site-specific factors required by the Director.	§5.203 (m)(7)(K)	Post-injection storage facility care and closure plan	any additional site-specific factors required by the director; and	
§146.93(c)(2)	Post-injection and site closure	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	§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:	
§146.93(c)(2)(i)	Post-injection and site closure	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	§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;	
§146.93(c)(2)(ii)	Post-injection and site closure	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	§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;	
§146.93(c)(2)(iii)	Post-injection and site closure	Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	§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;	
§146.93(c)(2)(iv)	Post-injection and site closure	Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	§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;	
§146.93(c)(2)(v)	Post-injection and site closure	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;	§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;	
§146.93(c)(2)(vi)	Post-injection and site closure	An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	§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;	

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§146.93(c)(2)(vii)	Post-injection and site closure	An approved quality assurance and quality control plan must address all aspects of the demonstration; and	§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	
§146.93(c)(2)(viii)	Post-injection and site closure	Any additional criteria required by the Director.	§5.203 (m)(8)(H)	Post-injection storage facility care and closure plan	any additional criteria required by the director.	
§146.93(d)	Post-injection and site 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.	§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
§146.93(e)	Post-injection and site closure	After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	§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.	7.7.2
§146.93(f)	Post-injection and site closure	The owner or 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:	§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
§146.93(f)(1)	Post-injection and site closure	Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or 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 owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;	§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
§146.93(f)(2)	Post-injection and site closure	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	§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	
§146.93(f)(3)	Post-injection and site closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	§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.	

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§146.93(g)	Post-injection and site closure	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	§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
§146.93(g)(1)	Post-injection and site closure	The fact that land has been used to sequester carbon dioxide;	§5.206 (l)(2)	Deed notation	The fact that land has been used to sequester carbon dioxide;	7.7.4
§146.93(g)(2)	Post-injection and site closure	The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and	§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
§146.93(g)(3)	Post-injection and site closure	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	§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.	
			§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.	
			§5.206 (m)(2)		The permittee shall retain records as follows:	
			§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.	
			§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

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			§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	
			§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
§146.93(h)	Post-injection and site closure	The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	§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
§146.94	Emergency and remedial response	Emergency and remedial response	§5.206 (h)	Emergency, mitigation, and remedial response	Emergency mitigation, and remedial response	
§146.94(a)	Emergency and remedial response	As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§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;	
			§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;	8.5
			§5.203 (l)(3)	Emergency and remedial response plan	Includes a safety plan that includes:	8.3
			§5.203 (l)(3)(A)	Emergency and remedial response plan	emergency response procedures;	8.5
			§5.203 (l)(3)(B)	Emergency and remedial response plan	provisions to provide security against unauthorized activity;	8.3
			§5.203 (l)(3)(C)	Emergency and remedial response plan	CO2 release detection and prevention measures;	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,	8.6

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			§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
			§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
§146.94(b)	Emergency and remedial response	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	§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:	8.2
§146.94(b)(1)	Emergency and remedial response	Immediately cease injection;	§5.206 (h)(3)(A)(i)	Emergency and remedial response plan	immediately cease injection;	8.2
§146.94(b)(2)	Emergency and remedial response	Take all steps reasonably necessary to identify and characterize any release;	§5.206 (h)(3)(A)(ii)	Emergency and remedial response plan	take all steps reasonably necessary to identify and characterize any release;	8.2
§146.94(b)(3)	Emergency and remedial response	Notify the Director within 24 hours; and	§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	8.2
§146.94(b)(4)	Emergency and remedial response	Implement the emergency and remedial response plan approved by the Director.	§5.206 (h)(3)(A)(iv)	Emergency and remedial response plan	implement the approved emergency and remedial response plan.	8.2
			§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.	
§146.94(c)	Emergency and remedial response	The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	§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.	
§146.94(d)	Emergency and remedial response	The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:				8.8
§146.94(d)(1)	Emergency and remedial response	Within one year of an area of review reevaluation;				8.8
§146.94(d)(2)	Emergency and remedial response	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	§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.	8.8
§146.94(d)(3)	Emergency and remedial response	When required by the Director.				

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			§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.**	
			§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:	
			§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.	
			§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.	
			§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.	
			§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."	
			§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.	
			§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.	
			§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;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§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.	
			§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.	
			§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.	4.7.5
			§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.	
			§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
			§5.206 (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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§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.	
			§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:	
			§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);	
			§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;	
			§5.206 (b)(3)	Permit Standards	the injection of anthropogenic CO2 will not endanger or injure human health and safety;	
			§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;	
			§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;	
			§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;	
			§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;	Cover sheets
			§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);	
			§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	
			§5.206 (b)(13)	Permit Standards	the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.	Section 8

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			§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
			§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.	
			§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.	
			§5.206 (d)(1)(A)	Permit Standards	Operating plan. The operator must maintain and comply with the approved operating plan.	
			§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:	
			§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;	
			§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;	
			§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;	
			§5.206 (d)(1)(B)(iv)		the results of the formation testing program required by §5.203(f) of this title;	
			§5.206 (d)(1)(B)(v)		final injection well construction procedures that meet the requirements of §5.203(e) of this title;	
			§5.206 (d)(1)(B)(vi)		the status of corrective action on wells in the AOR;	
			§5.206 (d)(1)(B)(vii)		all available logging and testing program data on the well required by §5.203(f) of this title;	
			§5.206 (d)(1)(B)(viii)		a demonstration of mechanical integrity pursuant to §5.203(h) of this title;	
			§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	

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			§5.206 (d)(1)(B)(x)		any other information requested by the director.	
			§5.206 (d)(2)	Permit Standards	Operating criteria.	
			§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.	5.3, 5.5.1
			§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.	4.8.2
			§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 (e)	Permit Standards	Monitoring, sampling, and testing requirements.	
			§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.	
			§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;	
			§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;	5.5.1
			§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).	5.2
			§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.	
			§5.206 (e)(5)		The operator shall comply with the following monitoring and record retention requirements.	
			§5.206 (e)(5)(A)		Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.	
			§5.206 (e)(5)(B)		The permittee shall retain records of all monitoring information, including the following:	

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			§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	
			§5.206 (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.	
			§5.206 (e)(5)(C)		Records of monitoring information shall include:	
			§5.206 (e)(5)(C)(i)		the date, exact place, and time of sampling or measurements;	
			§5.206 (e)(5)(C)(ii)		the individuals who performed the sampling or measurements;	
			§5.206 (e)(5)(C)(iii)		the dates analyses were performed;	
			§5.206 (e)(5)(C)(iv)		the individuals who performed the analyses;	
			§5.206 (e)(5)(C)(v)		the analytical techniques or methods used; and	
			§5.206 (e)(5)(C)(vi)		the results of such analyses.	
			§5.206 (e)(5)(D)		Operators of Class VI wells shall retain records as specified in this subchapter.	
			§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.	
			§5.206 (f)(3)	Permit Standards	The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
			§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.	
			§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.	
			§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.	
			§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.	
			§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.	
			§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.	

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			§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);	
			§5.206 (k)(3)(B)	Permit Standards	that there is no leakage of either CO2 or displaced formation fluids that will endanger USDWs;	
			§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;	
			§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	
			§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.	
			§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.	
			§5.206 (o)	Permit Standards	Other permit terms and conditions.	
			§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.	
			§5.206 (o)(2)	Permit Standards	Other conditions. The following conditions shall also be included in any permit issued under this subchapter.	
			§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.	
			§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.	
			§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.	
			§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§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.	
			§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.	
			§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.	
			§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:	
			§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;	
			§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;	
			§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	
			§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.	
			§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:	
			§5.203 (e)(1)(B)(vii)(I)		as-built schematics and construction procedures to demonstrate that repermitting is appropriate;	
			§5.203 (e)(1)(B)(vii)(II)		recent or newly conducted well-log information and mechanical integrity test results;	
			§5.203 (e)(1)(B)(vii)(III)		a demonstration that any needed remedial actions have been performed;	
			§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;	
			§5.203 (e)(1)(B)(vii)(V)		a demonstration that cement placement and materials are appropriate for CO2 injection for geologic storage;	
			§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	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§5.203 (n)(2)		In determining whether the applicant is financially responsible, the director must rely on the following:	
			§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	
			§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	
			§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.	
			§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.	
			§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.	
			§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.	
			§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.	
			§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.	
			§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.	
			§5.206 (o)(2)(L)	Permit Standards	Signatory requirement. All applications, reports, or information shall be signed and certified.	
			§5.206 (o)(2)(M)	Permit Standards	Reporting requirements.	
			§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	
			§5.206 (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.	
			§5.206 (o)(2)(M)(iv)	Permit Standards	Monitoring reports. Monitoring results shall be reported at the intervals specified elsewhere in this permit.	
			§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.	
			§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:	
			§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	
			§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.	
			§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.	
			§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:	

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			§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	
			§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.	
			§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.	
			§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.	

TAC 3.13 Regulations

16 TAC Chapter 5	TAC Category	Description
§3.13 (a)(4)(A)	Casing and Cementing	All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a As in effect on 11/21/2022. casing evaluation tool may be employed. Casing meeting the performance standards set forth in API Specification 5CT: Specification for Casing and Tubing (or a Commission-approved equivalent standard) shall be used through the protection depth.
§3.13 (a)(4)(B)	Casing and Cementing	The base cement shall meet the standards set forth in API Specification 10A: Specification for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification for Portland Cement (or a Commission-approved equivalent standard).
§3.13 (a)(4)(C)	Casing and Cementing	Casing shall be cemented across and above all formations permitted for injection under §3.9 of this title (relating to Disposal Wells) at the time the well is completed, or cemented immediately above all formations permitted for injection under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) at the time the well is completed, in a well within one-quarter mile of the proposed well location, as follows:
§3.13 (a)(4)(C)(i)	Casing and Cementing	if the top of cement is determined through calculation, at least 600 feet (measured depth) above the permitted formations;

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (a)(4)(C)(ii)	Casing and Cementing	if the top of cement is determined through the performance of a temperature survey conducted immediately after cementing, 250 feet (measured depth) above the permitted formations;				
§3.13 (a)(4)(C)(iii)	Casing and Cementing	if the top of cement is determined through the performance of a cement evaluation log, 100 feet (measured depth) above the permitted formations;				
§3.13 (a)(4)(C)(iv)	Casing and Cementing	at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or				
§3.13 (a)(4)(C)(v)	Casing and Cementing	as otherwise approved by the district director.				
§3.13 (a)(4)(D)	Casing and Cementing	Casing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids, as follows:				
§3.13 (a)(4)(D)(i)	Casing and Cementing	if the top of cement is determined through calculation, across and extending at least 600 feet (measured depth) above the zones;				
§3.13 (a)(4)(D)(ii)	Casing and Cementing	if the top of cement is determined through the performance of a temperature survey, across and extending 250 feet (measured depth) above the zones;				
§3.13 (a)(4)(D)(iii)	Casing and Cementing	if the top of cement is determined through the performance of a cement evaluation log, across and extending 100 feet (measured depth) above the zones;\				
§3.13 (a)(4)(D)(iv)	Casing and Cementing	across and extending at least 200 feet into the previous casing shoe (or to the surface if the shoe is less than 200 feet from the surface); or				
§3.13 (a)(4)(D)(v)	Casing and Cementing	as otherwise approved by the district director.				
§3.13 (a)(4)(E)	Casing and Cementing	Where necessary, the cement slurry shall be designed to control annular gas migration consistent with, or equivalent to, the standards in API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction.				
§3.13 (b)	Casing and cementing requirements for land wells and bay wells.	Casing and cementing requirements for land wells and bay wells.				
§3.13 (b)(1)	Casing and cementing requirements for land wells and bay wells.	Surface casing requirements for land wells and bay wells.				
§3.13 (b)(1)(A)	Casing and cementing requirements for land wells and bay wells.	Any proposal to set surface casing to a depth of 3,500 feet or greater shall require prior approval of the appropriate district director. A request for such approval shall be in writing and shall specify how the operator plans to maintain well control during drilling, and ensure successful circulation and adequate bonding of cement, and, if necessary, prevent upward migration of deeper formation fluids into protected water. The district director may grant approvals on an area basis.				
§3.13 (b)(1)(B)	Casing and cementing requirements for land wells and bay wells.	Amount required.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (b)(1)(B)(i)	Casing and cementing requirements for land wells and bay wells.	An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Groundwater Advisory Unit of the Oil and Gas Division. Unless surface casing requirements are specified in field rules approved prior to the effective date of this rule, before drilling any well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the district director. The district director may grant such approval on an area basis.				
§3.13 (b)(1)(B)(ii)	Casing and cementing requirements for land wells and bay wells.	Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.				
§3.13 (b)(1)(C)	Casing and cementing requirements for land wells and bay wells.	Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or the operator's representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.				
§3.13 (b)(1)(D)	Casing and cementing requirements for land wells and bay wells.	Cement quality.				
§3.13 (b)(1)(D)(i)	Casing and cementing requirements for land wells and bay wells.	Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.				
§3.13 (b)(1)(D)(ii)	Casing and cementing requirements for land wells and bay wells.	An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (b)(1)(D)(iii)	Casing and cementing requirements for land wells and bay wells.	In addition to the minimum compressive strength of the cement, the free water content shall be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. In no event shall the free water separation average more than two milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements, inside the zone of critical cement, or more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement.				
§3.13 (b)(1)(D)(iv)	Casing and cementing requirements for land wells and bay wells.	The Commission may require a better quality of cement mixture to be used in any well or any area if conditions indicate that a better quality of cement is necessary to prevent pollution, isolate productive zones, potential flow zones, or zones with corrosive formation fluids or prevent a safety issue in the well.				
§3.13 (b)(1)(E)	Casing and cementing requirements for land wells and bay wells.	Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures in, or equipment and procedures equivalent to those in, API RP 10B-2, Recommended Practice for Testing Well Cements. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.				
§3.13 (b)(1)(E)(i)	Casing and cementing requirements for land wells and bay wells.	For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.				
§3.13 (b)(1)(E)(ii)	Casing and cementing requirements for land wells and bay wells.	For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (b)(1)(F)	Casing and cementing requirements for land wells and bay wells.	Cementing report. Within 30 days of completion of the well, or within 90 days of cessation of drilling operations, whichever is earlier, a cementing report must be filed with the Commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the Commission. The operator of the well or the operator's duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the Commission.				
§3.13 (b)(1)(G)	Casing and cementing requirements for land wells and bay wells.	Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet specifications in, or equivalent to, API spec 10D Specifications for Bow-Spring Casing Centralizers; API Spec 10 TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations; and API RP 10D-2, Recommended Practice				
§3.13 (b)(1)(I)	Casing and cementing requirements for land wells and bay wells.	Mechanical integrity test of surface casing after drillout				
§3.13 (b)(1)(I)(i)	Casing and cementing requirements for land wells and bay wells.	If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the operator shall verify the integrity of the surface casing by using a casing evaluation tool or conducting a mechanical integrity test or equivalent Commission-approved casing evaluation method, unless otherwise approved by the district director.				
§3.13 (b)(1)(I)(ii)	Casing and cementing requirements for land wells and bay wells.	If a mechanical integrity test is conducted, the appropriate district office shall be notified at least eight hours before the test is conducted to give the district office an opportunity to witness the test. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation of an acceptable pressure test. The appropriate district office shall be notified within 24 hours after a failed test. Completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan, and successfully re-tests the surface casing.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (b)(2)		Intermediate casing requirements for land wells and bay wells.				
§3.13 (b)(2) (A)		Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe. If any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented;				
§3.13 (b)(2) (A)(i)		if the top of cement is determined through calculation, from the shoe up to a point at least 600 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;				
§3.13 (b)(2) (A)(ii)		if the top of cement is determined through performance of a temperature survey, from the shoe up to a point at least 250 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;				
§3.13 (b)(2) (A)(iil)		if the top of cement is determined through performance of a cement evaluation log, from the shoe up to a point at least 100 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluid; or				
§3.13 (b)(2) (A)(iv)		to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or				
§3.13 (b)(2) (A)(v)		as otherwise approved by the district director				
§3.13 (b)(2) (B)		Top of cement. The calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title (relating to Log and Completion or Plugging Report).				
§3.13 (b)(2) (C)		Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone, and/or zone with corrosive formation fluids make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively isolate and seal the zones to prevent fluid migration to or from such strata within the wellbore.				
§3.13 (b)(3)		Production casing requirements for land wells and bay wells.				
§3.13 (b)(3)(A)		Centralizers. In deviated and horizontal holes, the operator shall provide centralization as necessary to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (b)(3)(B)		Cementing method. The production string of casing shall be cemented by the pump and plug method, or another method approved by the Commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive zone, potential flow zone and/or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such zones by one of the methods specified for intermediate casing in paragraph (2) of this subsection. A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating casing pressure tests. In the event that the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone and/or zone with corrosive formation fluids make cementing, as required above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such zones, and prevent fluid migration to or from such zones within the wellbore. Uncemented casing is allowable within a producing reservoir provided the production casing is cemented in such a manner to effectively isolate and seal off that zone from all other productive zones in the wellbore as required by §3.7 of this title (relating to Strata To Be Sealed Off).				
§3.13 (b)(3)(C)		Reporting of top of cement. Calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title.				
§3.13 (b)(3)(D)		Isolation of gas/oil contact zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.				
§3.13 (b)(4)		Tubing requirements for land wells and bay wells.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (b)(4)(A)		Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet (vertical depth) above the top of the producing interval nor more than 50 feet (vertical depth) above the top of the liner, if a liner is used, or 100 feet (vertical depth) above the kickoff point in a deviated or horizontal well. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding, 1,000 feet (vertical depth) above the top of the perforated or open-hole interval actually open for production into the wellbore.				
§3.13 (c)		Casing, cementing, drilling, and completion requirements for offshore wells.				
§3.13 (c)(1)		Casing. An offshore well shall be cased with at least three strings of pipe, in addition to such drive pipe as the operator may desire, which shall be set in accordance with the following program.				
§3.13 (c)(1)(A)		Conductor casing. A string of new pipe, or reconditioned pipe with substantially the same characteristics as new pipe, shall be set and cemented at a depth of not less than 300 feet TVD (true vertical depth) nor more than 800 feet TVD below the mud line. Sufficient cement shall be used to fill the annular space back of the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations.				
§3.13 (c)(1)(B)		Surface casing. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi) or reconditioned pipe that has been tested to an equal pressure. Sufficient cement shall be used to fill the annular space behind the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Surface casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations. In all cases, surface casing shall be set prior to drilling below 3,500 feet TVD. Minimum depths for surface casing are as follows.				
§3.13 (c)(1)(B)(i)		Surface Casing Depth table (See Table)				
§3.13 (c)(1)(B)(ii)		Surface Casing test.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (c)(1)(B)(ii)(I)		Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling plug or initiating tests. Casing shall be tested by pump pressure to at least 1,000 psi. If, at the end of 30 minutes, the pressure shows a drop of 100 psi or more, the casing shall be condemned until the leak is corrected. A pressure test demonstrating a drop of less than 100 psi after 30 minutes constitutes confirmation that the condition has been corrected.				
§3.13 (c)(1)(B)(ii)(II)		After drillout, if the surface casing is exposed to more than 360 rotating hours, the operator shall verify the integrity of the casing using a casing evaluation tool, a mechanical integrity test, or an equivalent Commissionapproved alternate casing evaluation methodology, unless otherwise approved by the district director.				
§3.13 (c)(1)(B)(ii)(III)		If a mechanical integrity test of the surface casing is conducted, the appropriate district office shall be notified a minimum of eight (8) hours before the test is conducted. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a minimum test pressure of 0.5 psi per foot multiplied by the true vertical depth of the surface casing up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% drop in pressure after 30 minutes constitutes confirmation of an acceptable pressure test. The operator shall notify the appropriate district office within 24 hours of a failed test. Operations may not re-commence until the district director approves a remediation plan and the operator implements the approved plan, and the operator successfully re-tests the surface casing.				
§3.13 (c)(1)(C)		Production casing or oil string.				
§3.13 (c)(1)(C)(i)		The production casing or oil string shall be new or reconditioned pipe with a mill test of at least 2,000 psi that has been tested to an equal pressure.				
§3.13 (c)(1)(C)(ii)		After cementing, the production casing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner.				
§3.13 (c)(1)(C)(iii)		Cementing of the production casing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to isolate any productive zones, potential flow zones, or zones with corrosive formation fluids and to a depth that isolates abnormal pressure from normal pressure (0.465 psi per vertical foot of gradient). A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§3.13 (c)(2)		Operators shall comply with the well control requirements of subsection (a)(6) of this section.				
§3.13 (d)		Exceptions or alternate programs. The director may administratively grant an exception or approve an alternate casing/tubing program required by this section provided that the alternate casing/tubing program will achieve the intent of the rule as described in subsection (a)(				
§3.13 (d)(1)		The request for an exception or alternate casing/tubing program shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).				
§3.13 (d)(2)		An administrative exception for tubing shall not exceed a period of 180 days. A request for an exception for tubing beyond 180 days shall require a Commission order.				

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 0 – Application Narrative

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

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 County, Texas

[redacted]

*NAD 83 – North American Datum of 1983

Project Contact: [redacted]

Project Owner: ExxonMobil Low Carbon Solutions Onshore Storage

Ownership Status: Limited Liability Company

Entity Status: Public

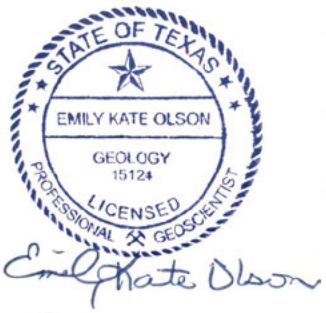
Standard Industrial Classification (SIC) Codes: 4953 – Refuse Systems (nonhazardous waste disposal sites)

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

CERTIFICATION OF PROFESSIONAL GEOLOGIST:

Sections of permit applications that represent geologic work shall be sealed, signed, and dated by a licensed professional geologist.

The geologic interpretations, cross sections, maps, 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 (SEAL)

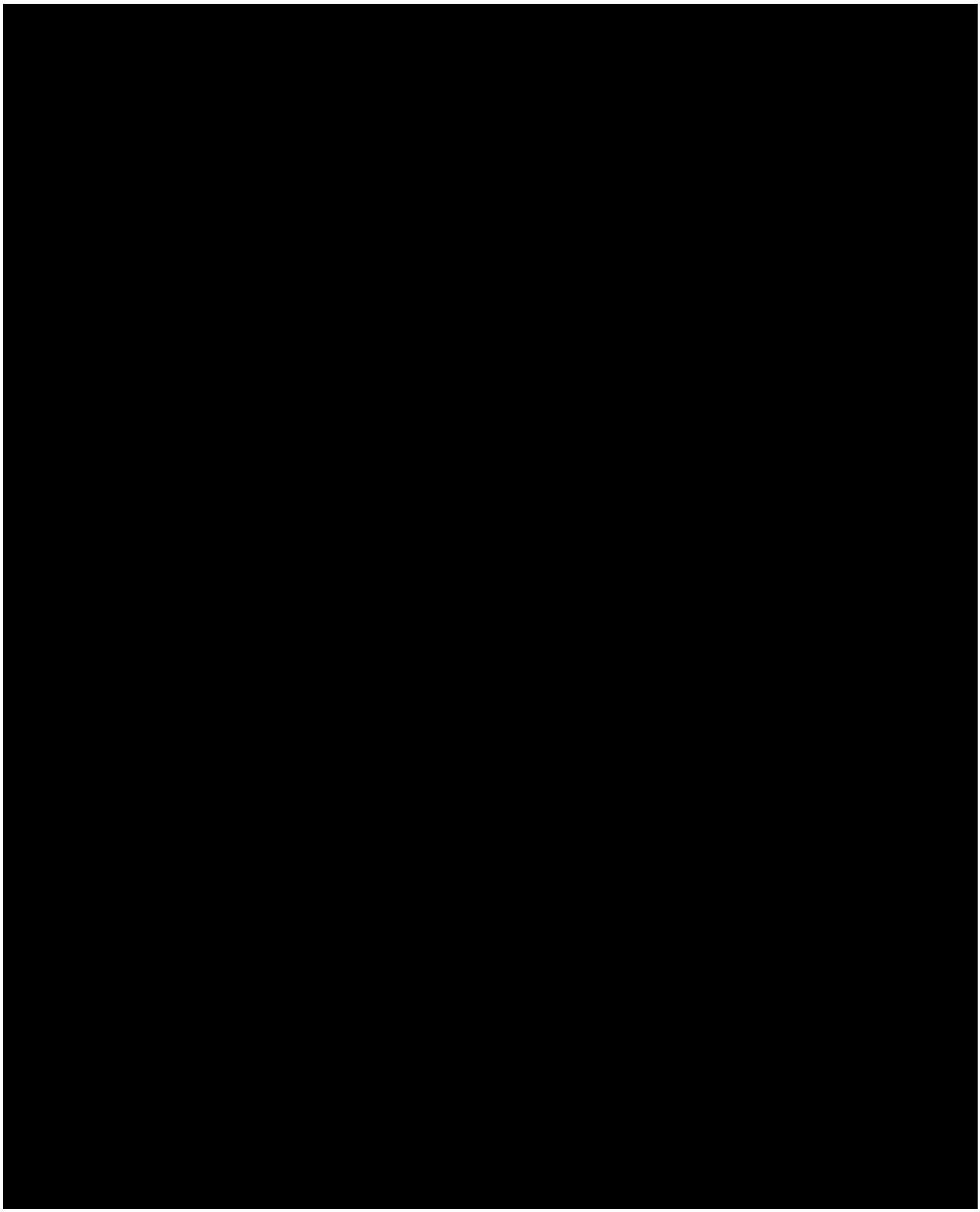
Signature of Professional Geologist

12.12.2024

Date Signed

1. Additional Permits

Table 1 – Additional Required Permits



2. Project Background

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is proposing to construct and operate four carbon sequestration wells in Jefferson County in southeastern Texas. The goal of the Sunflower Carbon Capture and Storage (CCS) Project (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 emitting sources of CO_2 and existing CO_2 pipelines. [redacted]

The application thoroughly describes and characterizes the geology of the planned well locations, evaluates the formation 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.

This application has been developed to meet all of the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR), **§146.82** through **§146.95**. Once issued, the permit will be updated every 5 years thereafter for the active injection life of the wells, per 40 CFR **§144.36(a)**. Figure 1 displays the Sunflower Project.

[redacted]

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. ExxonMobil also drilled a stratigraphic appraisal well nearby in November 2023 [redacted] 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 zone details, and the area of review (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 40 C.F.R. **§ 146.83**, the information provided in these sections demonstrates the suitability of the [redacted] formations at the Sunflower Project site for CO2 injection and sequestration. The injection zone is composed of thick, porous, and permeable sandstones that will support the proposed injection operations [redacted]

4. Plume Model

A compositional model delineated the AOR for the Sunflower Project consistent with the requirements of 40 CF.R. **§ 146.84©**. 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 [redacted] 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.

[redacted]

[redacted] the project aims to maximize storage capacity while preventing movement of fluid into and demonstrating non-endangerment of the USDW. After injection operations cease, the reservoir model shows pressure will stabilize near to 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 details the methodology behind the determination of the AOR and subsequent assessment of all of the artificial penetrations in the AOR. 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. [redacted] 40 C.F.R. **§ 146.82(a)(4).** 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 four CO_2 injection wells in Jefferson County, Texas. The wells are to be constructed in compliance with the Class VI Underground Injection Control (UIC) injection-well construction requirements of 40 CFR **§146.86**. 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 performance during the life of the Sunflower 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 40 C.F.R. § 146.68(b)-(c), 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- Well Construction Plan and Operating Conditions.*

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 provided under contract from industrial sources.

7. Testing and Monitoring

Section 5 – Testing and Monitoring Plan describes how ExxonMobil will monitor the Sunflower Project pursuant to 40 CFR **§146.90**. 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 fall-off testing, and plume tracking. Details of each of these testing and monitoring activities is 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 USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone 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 wells pursuant to 40 CFR **§146.92**. *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 40 CFR **§146.93**. 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 Director. ExxonMobil may not cease post-injection monitoring until a demonstration of non-endangerment of the USDW has been approved by the UIC Program Director (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 40 CFR **§146.94**. 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 wells, 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 40 CFR **§146.85**, ExxonMobil will maintain financial responsibility throughout all phases of the Sunflower Project, as detailed in *Section 9 – Financial Assurance*. The instruments 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.

12. Environmental Justice

ExxonMobil uses a multi-stage process to assess environmental justice (EJ) and stakeholder considerations in the Sunflower Project area as well as a surrounding area—defined from the edge of the AOR (as shown in *Section 10 – Environmental Justice*). This process begins with an initial screening using the EPA's EJScreen tool. A secondary screening is undertaken using additional EJ indicators, including the Climate and Economic Justice Screening Tool (CEJST), the EPA's Inflation Reduction Act (IRA) tool, and the U.S. Department of Energy's (DOE) Disadvantaged Communities Reporter tool. These initial screening stages are built upon through local analysis and engagement, which may include environmental assessments, initial stakeholder engagements, and ground-truthing.

A Stakeholder Engagement Plan (SEP) and community benefits considerations are created from data collected in these stages. The engagement process is iterative and designed to incorporate findings and feedback from communities to refine and enhance overall engagement. Insights from stakeholder engagements, grievance mechanism inputs, and community activities are integrated as collected. These studies are updated as needed. [redacted]

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 1 – Site Characterization

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

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 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(3)** and Texas Administrative Code (TAC), Part 1 Title 16 Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the project in Jefferson County, Texas, [redacted] 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 40 CFR **§146.82**:

- Provide maps and cross sections of the area of review (AOR) (40 CFR **§146.82(a)(3)(i)** and **§146.82(a)(2)**).
- 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 (40 CFR **§146.82(a)(3)(iii)**).
- Provide geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area (40 CFR **§146.82(a)(3)(vi)**).
- 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 (40 CFR **§146.82(a)(3)(ii)**).
- Discuss the available geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) (40 CFR **§146.82(a)(3)(iv)**).
- 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) (40 CFR **§146.82(a)(5)**).

- Summarize the available baseline geochemical data on subsurface formations, including the USDWs in the AOR (40 CFR **§146.82(a)(6)**).
- 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 (40 CFR **§146.82(a)(3)(v)**).

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*.

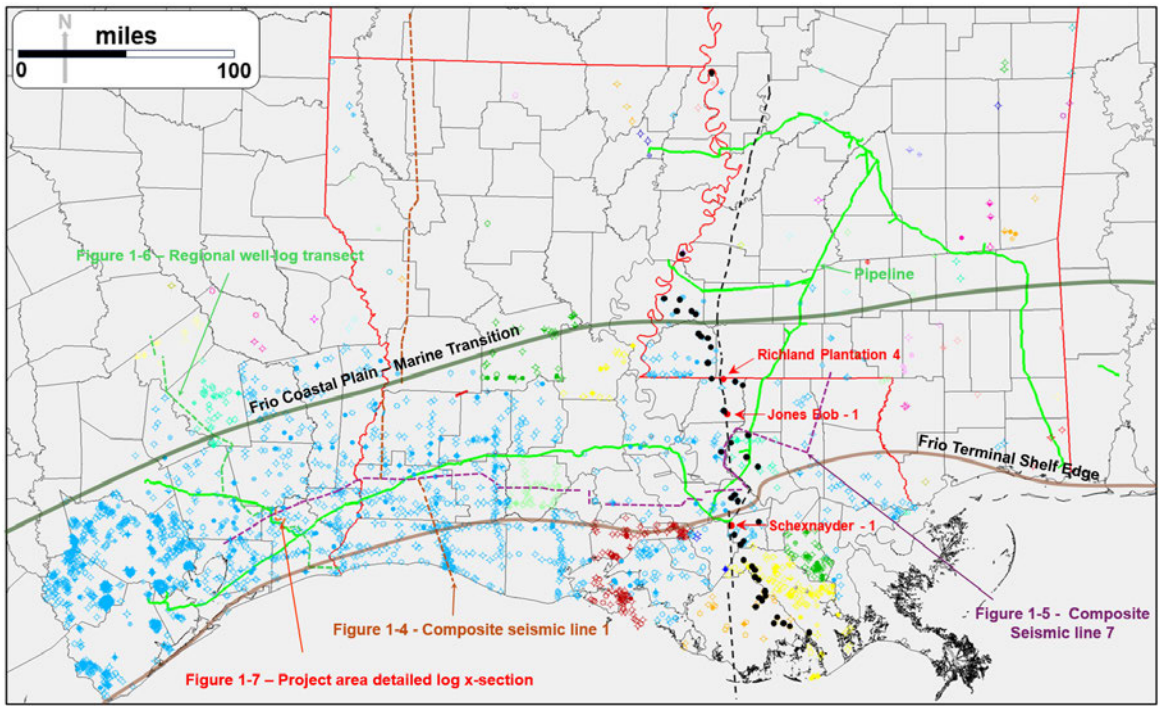


Figure 1-1 – Base map for the Gulf of Mexico. Wells used in the regional analysis are depicted as circles. Dashed lines represent seismic sections and well-log sections shown in Figures 1-4 through 1-7. (Figure 1-3 presents the basin margin and limits of the study area.) Initial coastal plain to marine 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).

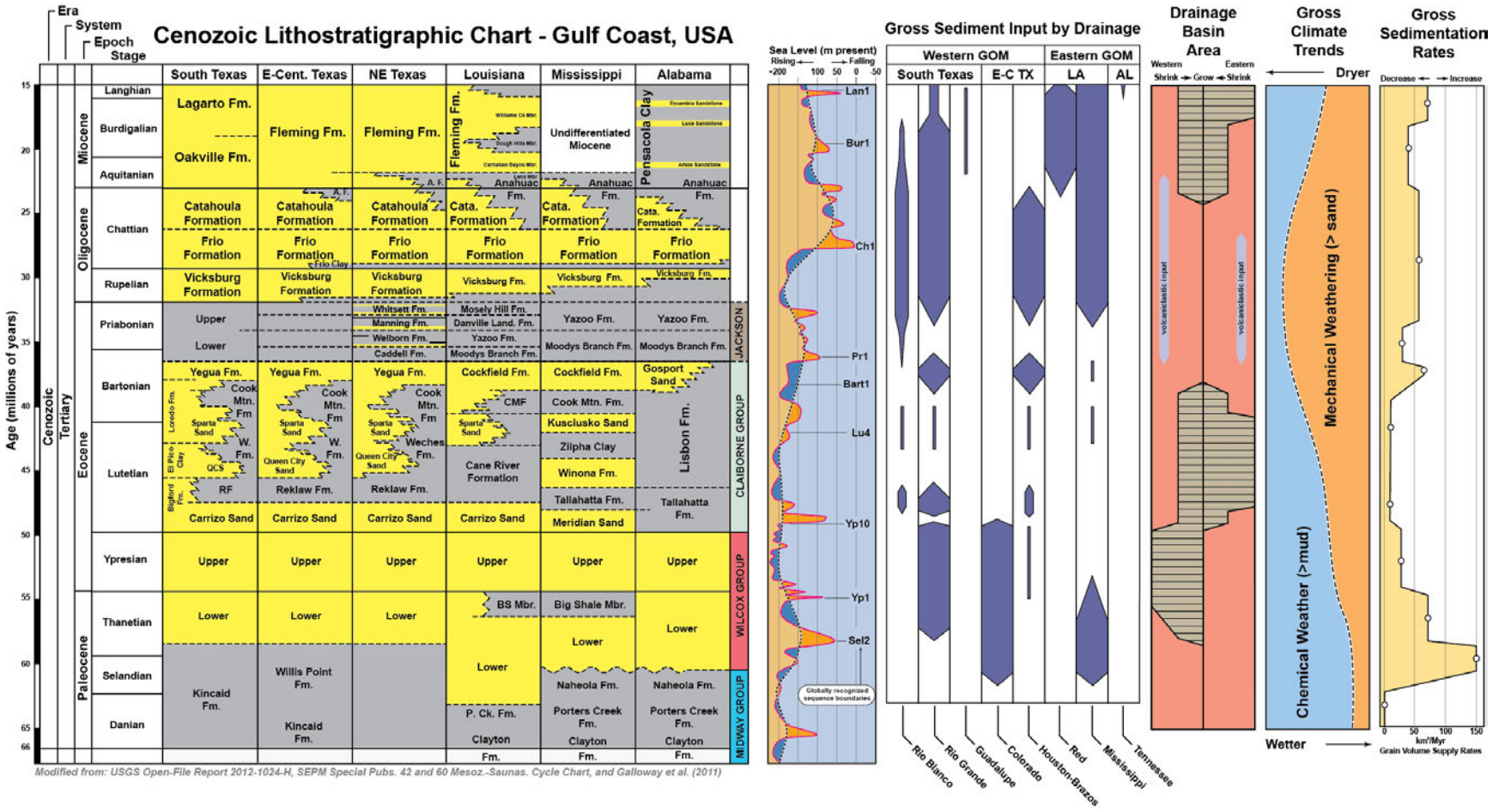


Figure 1-2 – Lithostratigraphic correlation chart for the northern portion of the Gulf of Mexico Basin (left).
Yellow formations represent more sandy intervals and gray formations represent more muddy intervals. A comparison of stratigraphic forcing mechanisms, relative to the development of formations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

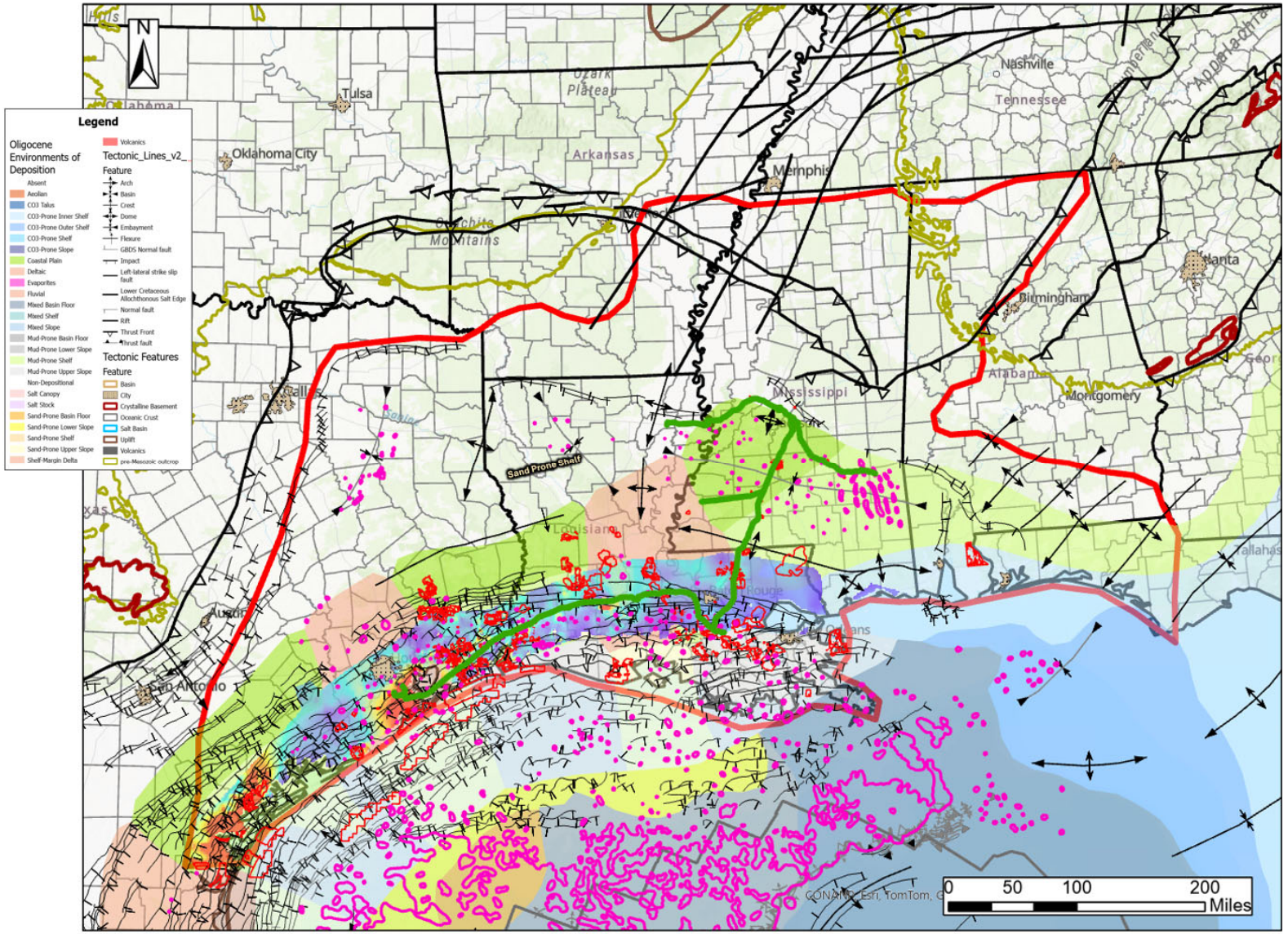


Figure 1-3 – Regional play element map for the Oligocene (Frio and Catahoula formations). Modified from Galloway et al (2011).



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 1-4 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.

[redacted]



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. [redacted]

[redacted] 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 [redacted] 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).

[redacted] 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).



[redacted] 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 [redacted] is thought to be linked to the development of the Pioche-Marysville Igneous Belt of western Utah and eastern Navada. Explosive volcanic events in this area occurred just prior to and during delivery of sediments to the Houston-Brazos Delta [redacted] (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 [redacted] 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 [redacted] Figure 1-2 illustrated the observed stratal architecture [redacted] in the eastern Texas and western Louisiana sectors of the Gulf of Mexico basi [redacted] seal units.

[redacted]





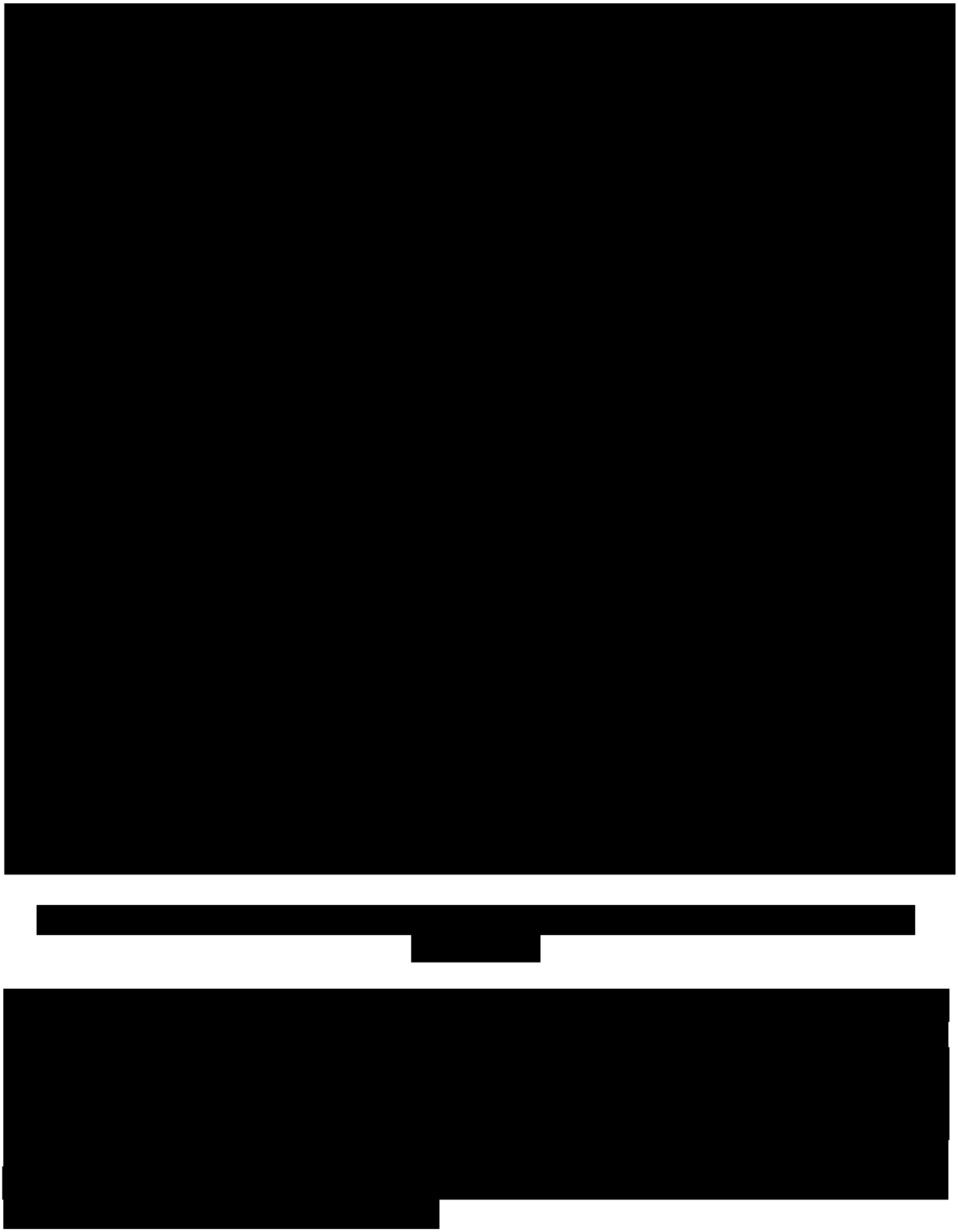




1.3 Site Geology

[redacted] Reservoir characteristics and geological properties of the injection and confining intervals 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. [redacted] Structure depth maps and isochores for key major intervals are contained in [redacted] A seismic cross section through the proposed Sunflower CCS Project Injection Wells No. 02, No. 03, and No. 04 is shown in Figure 1-9.





[redacted]

[redacted]

*MD – measured depth





1.3.1 Injection Zone

The injection zone is composed of sediments deposited [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] illustrated the alternating sands, siltstones, and shales of the [redacted] The [redacted] have been divided based on correlation of regionally mappable shale zones that act as internal baffles and barriers. [redacted]

[redacted]

[redacted]

[redacted]

1.3.2 Upper Composite Confining Zone

The upper composite confining zone (UCCZ) occurs immediately above the [redacted]

[redacted]



[redacted]

[redacted]

Based on data collected at the offset stratigraphic appraisal well, the UCCZ is composed of high-quality, clay-rich mudstones. Mercury injection capillary pressure (MICP) analyses performed on samples from [redacted] Thin section photographs for the UCCZ are shown in Figure 1-17. Typical Miocene-age mudstones from the UCCZ can be described as bioturbated, with silt-sized quartz and feldspar grains embedded in a clay-rich matrix with dispersed framboidal and pore-filling pyrite cements. Other grain types frequently observed include micaceous minerals, glauconite, and fossil fragments. Organic matter is also common.



The UCCZ 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

A review of Figure 1-18 indicates that different pressure regimes are present within the overlying sands, and the injection intervals of the

[redacted]

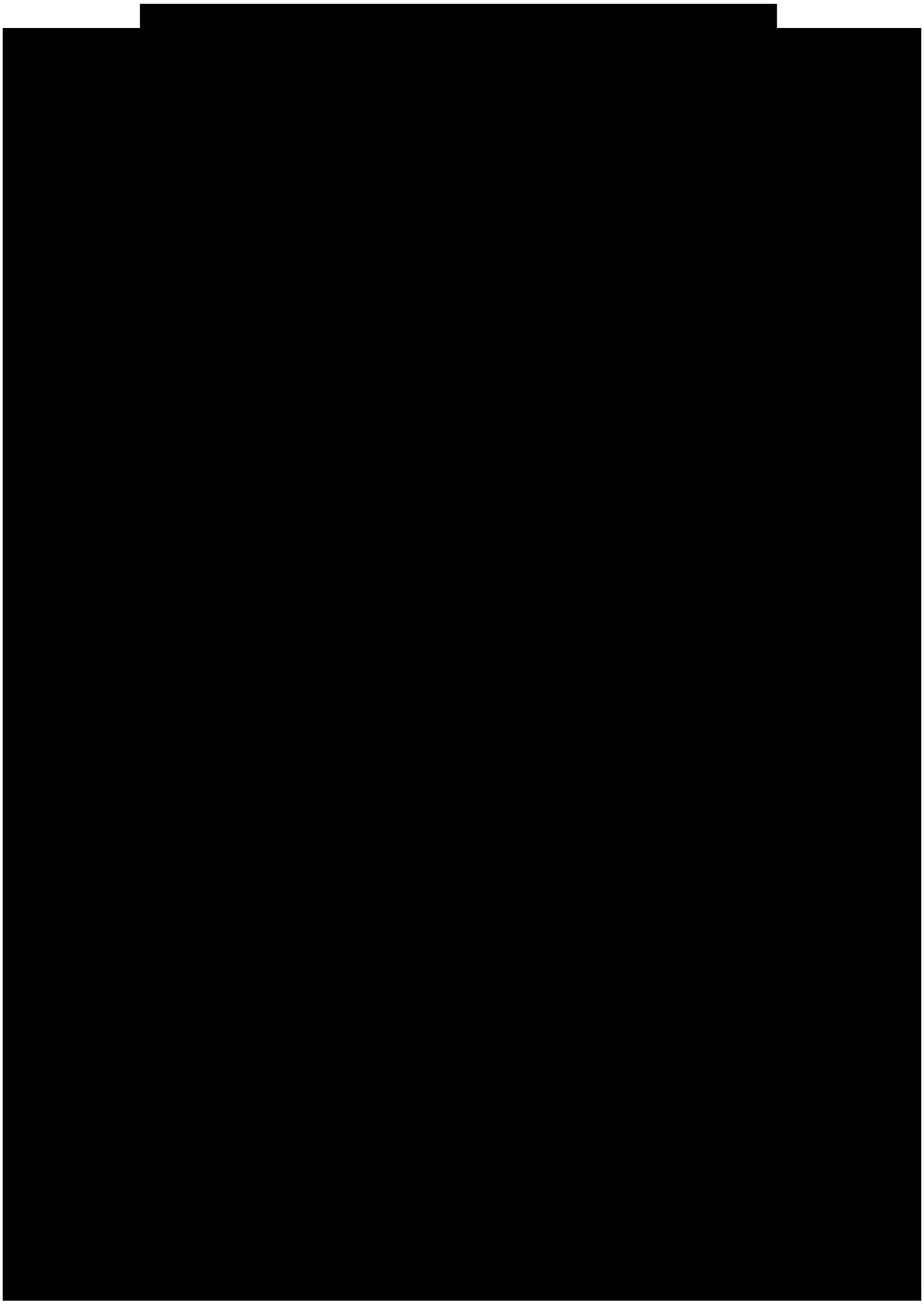
1.3.3 Lower Confining Zone

[redacted] displayed data [redacted]—the lower confining zone (LCZ). Few wells in the Sunflower Project area were drilled into and beneath this section as it underlies most hydrocarbon production. As shown on the log cross sections, thick and pervasive shales exist below [redacted] and extend thousands of feet below the base of the injection zone. [redacted] A "Base LCZ" was mapped approximately 700 ft below the LCZ top, although the shales extend much deeper in available logs (Figures 1-10 and 1-11).

1.4 Porosity

1.4.1 Well Data

Petrophysical evaluations were performed on 52 wells to estimate shale volume (VSH) and total porosity (PHIT) from wireline logs across the [redacted] For the 52 wells evaluated, all wells had either a spontaneous potential (SP) or gamma ray (GR) log to estimate shale volume. Of these 52 wells, 17 had either a compressional sonic (DTC) and/or bulk density (RHOB) log to estimate total porosity across the formations of interest. Table 1-2 lists the wells and log data, including neutron porosity (NPHI), available for analysis. Those wells with log data available only over deeper intervals [redacted] are annotated as "(deep)."



1.4.2 Log Quality Control

[redacted] These data were leveraged for quality control and for evaluation of key wells with porosity logs. However, since many legacy wells were affected by poor borehole conditions, additional steps were required to ensure consistent petrophysical properties between the wells. These steps are discussed in greater detail in the following section.

1.4.3 Methodology

1.4.3.1 Shale Volume (VSH)

Shale volume was primarily determined from the SP log. The SP logs were baselined in thick shales to read zero millivolts (mV), and clean sand values were interpreted for each well based on the magnitude of the SP deflection. Shale volume was then calculated from the SP log as follows in Equation 1:

(Eq. 1)

$$VSH_SP = \left\lfloor \frac{SP_{log} - SP_{clean}}{SP_{shale} - SP_{clean}} \right\rfloor$$

In the absence of an available SP log, the GR log was used to calculate shale volume. Similar to the SP approach, the GR logs were bulk-shifted to read approximately 100 GAPI in shales, and clean sand values were interpreted for each well. Shale volume was then calculated from the GR log as follows in Equation 2:

(Eq. 2)

$$VSH_GR = \left\lfloor \frac{GR_{log} - GR_{clean}}{GR_{shale} - GR_{clean}} \right\rfloor$$

1.4.3.2 Total Porosity

Compressional sonic was the most common porosity log available. To compute total porosity, the method proposed by Raymer et al. (1980) was used. This method is particularly well-suited for high-porosity, unconsolidated sands typical of the Gulf Coast region. Additionally, a "Shale Reduced" option was selected to correct the high apparent porosities related to increasing shale content (i.e., due to an increase in measured slowness). Total porosity from sonic logs was calculated as follows in Equation 3:

(Eq. 3)

$$DT_{SR} = \text{maximum}\left[DT_{ma}, \left(\frac{DT_{log} - V_{sh} * DT_{sh}}{1 - V_{sh}}\right)\right]$$

$$\emptyset_S = \left[C * \left(\frac{DT_{SR} - DT_{ma}}{DT_{SR}}\right) * (1 - V_{sh})\right] + (V_{sh} * \emptyset_{sh})$$

where DT_{SR} is the shale-reduced slowness, DT_{sh} is the measured shale slowness from sonic logs, Φ_S is the sonic-derived total porosity, and Φ_{sh} is shale porosity (assumed or known a priori). Table 1-3 provides the parameters used for calculating sonic-derived porosity.

Table 1-3 – Parameters for Calculating Sonic-Derived Porosity

Parameter	Value or Function
Compaction Factor, *C*	[redacted]
Matrix Slowness, DT_{ma}	55.5 us/ft (default for sandstones)
Shale Slowness, DT_{sh}	10 ^ (2.205 - 0.0000285 * DEPTH + 0.000000001 * DEPTH^2)
Shale Porosity, $\emptyset_{sh}$	0.15

*us/ft – microseconds per foot

Bulk density logs were used to estimate total porosity in six additional wells. In general, estimating porosity from bulk density logs is more straightforward since any increase in shale content typically results in a higher measured bulk density (or lower apparent porosity). However, as noted previously, many legacy wells were affected by borehole washouts, which adversely impacts the bulk density measurement. Consequently, a similar approach using shale volume was implemented where density-derived porosity was calculated as follows in Equation 4:

(Eq. 4)

$$\emptyset_D = (1 - V_{sh}) * \left(\frac{\rho_{ma} - \rho_{log}}{\rho_{ma} - \rho_f}\right) + V_{sh} * \theta_{sh}$$

where Φ_D is the density-derived total porosity, ρ_{ma} is the matrix density, and ρ_f is the fluid density. Table 1-4 provides the parameters used for calculating density-derived porosity.

Table 1-4 – Parameters for Calculating Density-Derived Porosity

Parameter	Value
Matrix Density, ρ_{ma}	2.65 g/cc (default for sandstones)
Fluid Density, ρ_f	1 g/cc
Shale Porosity, ϕ_{sh}	0.15

*g/cc – grams per cubic centimeter

Figure 1-19 compares the resulting sonic- and density-derived porosities [redacted] The results are generally consistent between both methods.

[redacted]

(Eq. 5)

$$\emptyset_T = \frac{(\emptyset_D + \emptyset_{RES})}{2} \; or \; \emptyset_T = \frac{(\emptyset_S + \emptyset_{RES})}{2}$$

where ϕ_{RES} is the conductivity-derived porosity.

[redacted]

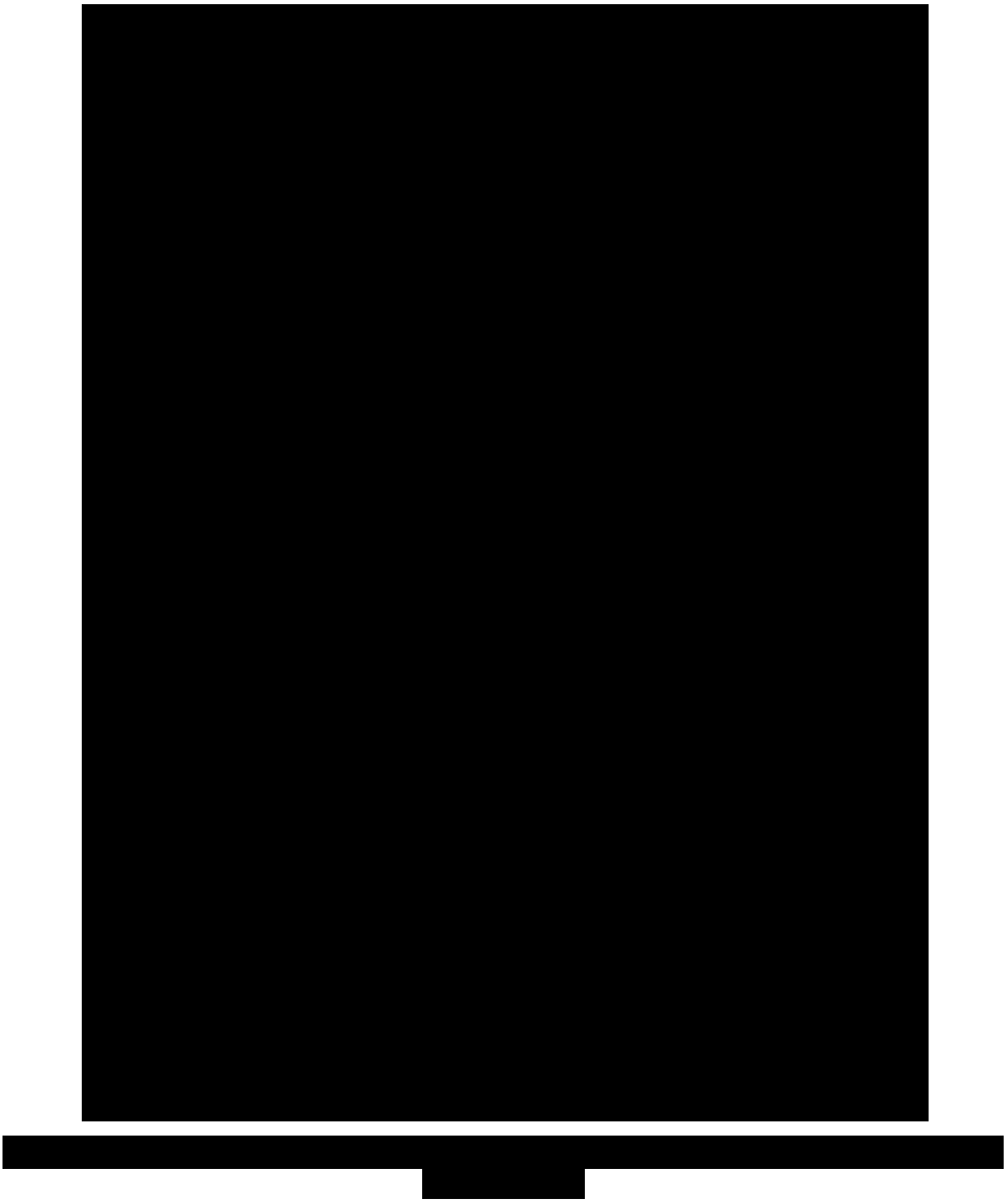
$$\emptyset_{RES} = -0.425 + 0.21 * LOG10(COND)$$

[redacted]

$$\emptyset_{RES} = -1.77 + 0.905 * LOG10(COND) - 0.091 * LOG10(COND)^2$$

[redacted]





[redacted]

1.5 Geologic Structure

[redacted]



[redacted]

[redacted]

1.5.1 Seismic Survey Data

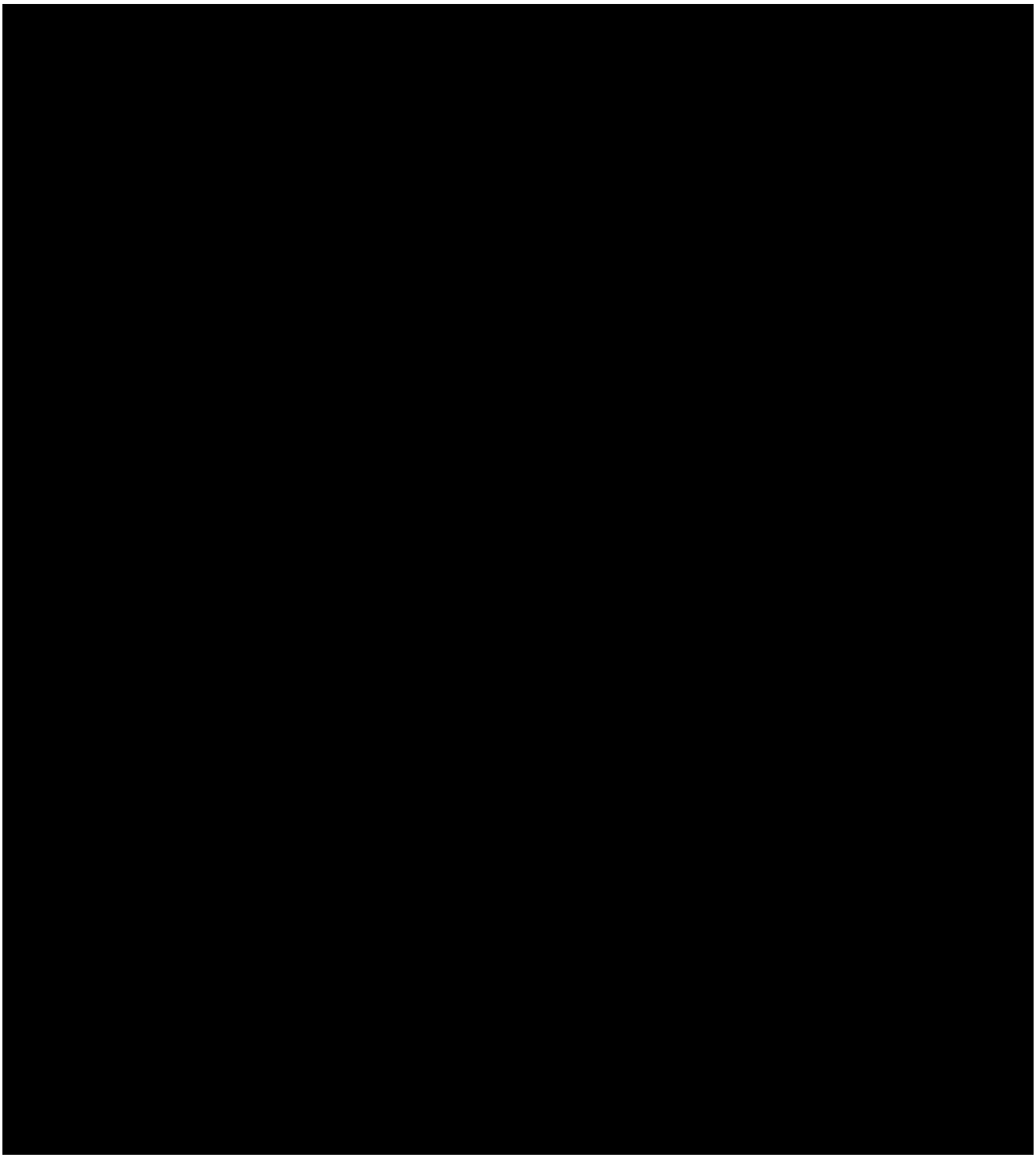
[redacted]

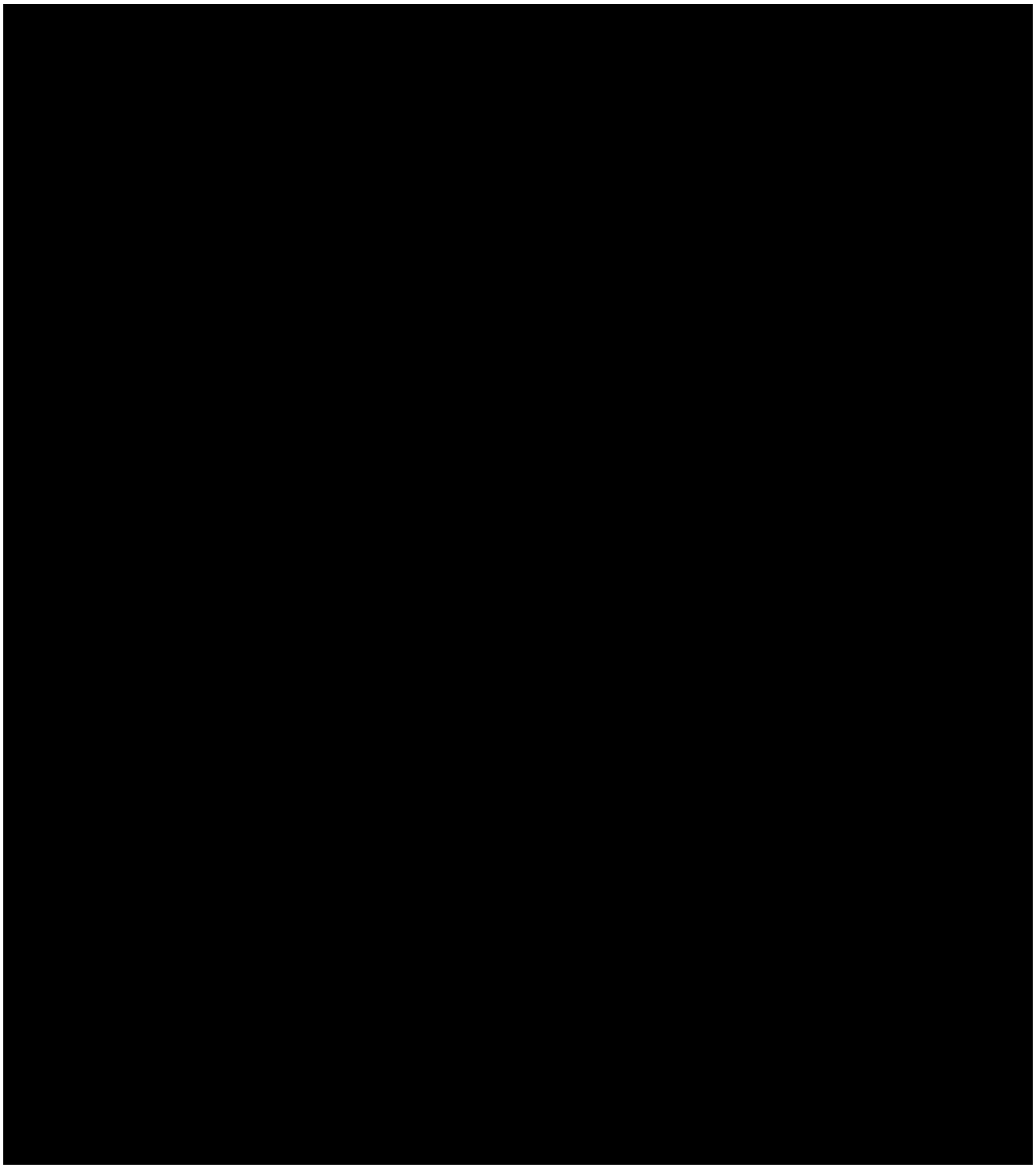
1.5.1.1 Velocity Control and Synthetic Seismogram

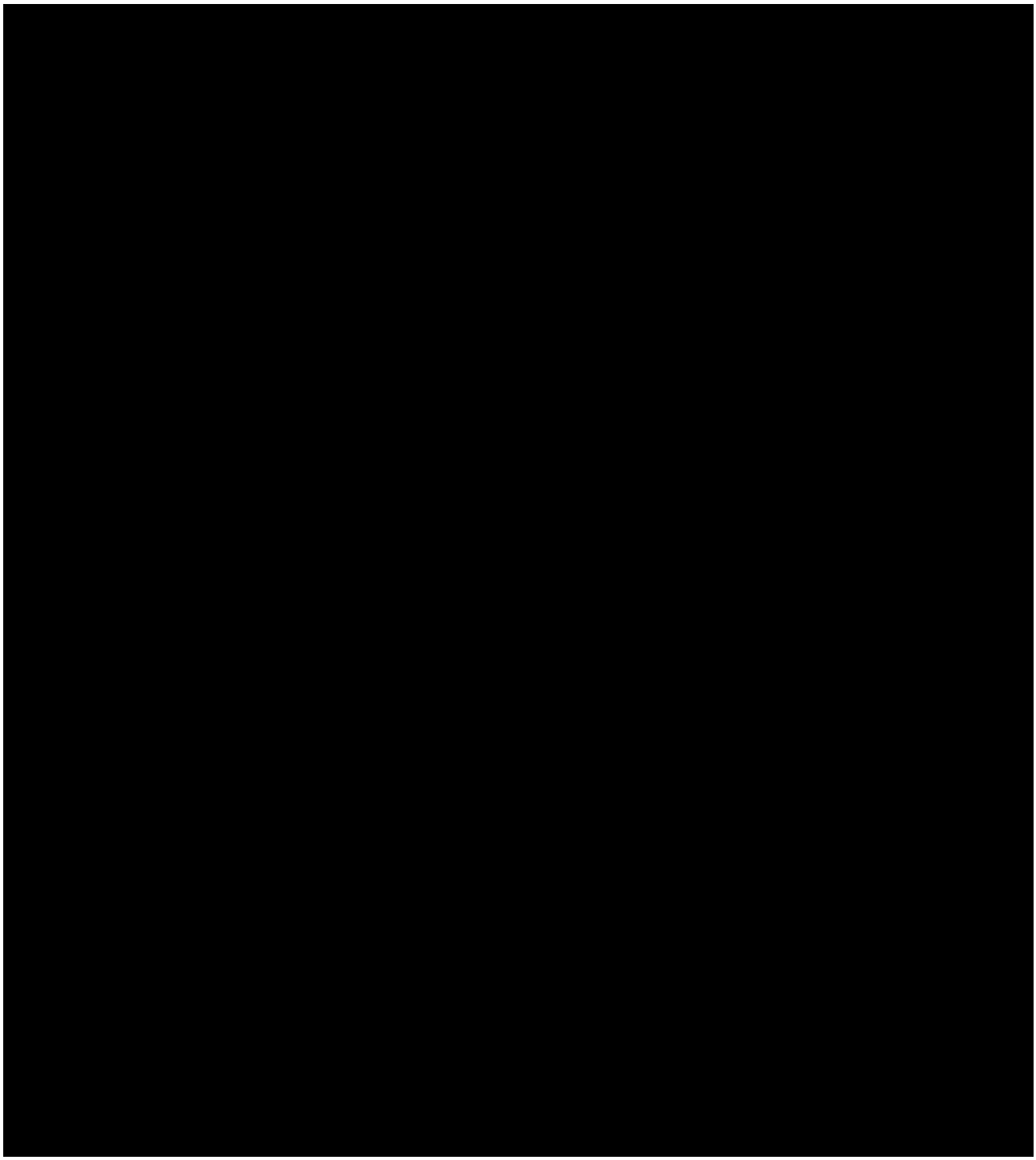
The wells that contained enough data to perform a well tie (i.e., tie the seismic survey to depth and allow the correlation of historical well logs to seismic data) were [redacted]

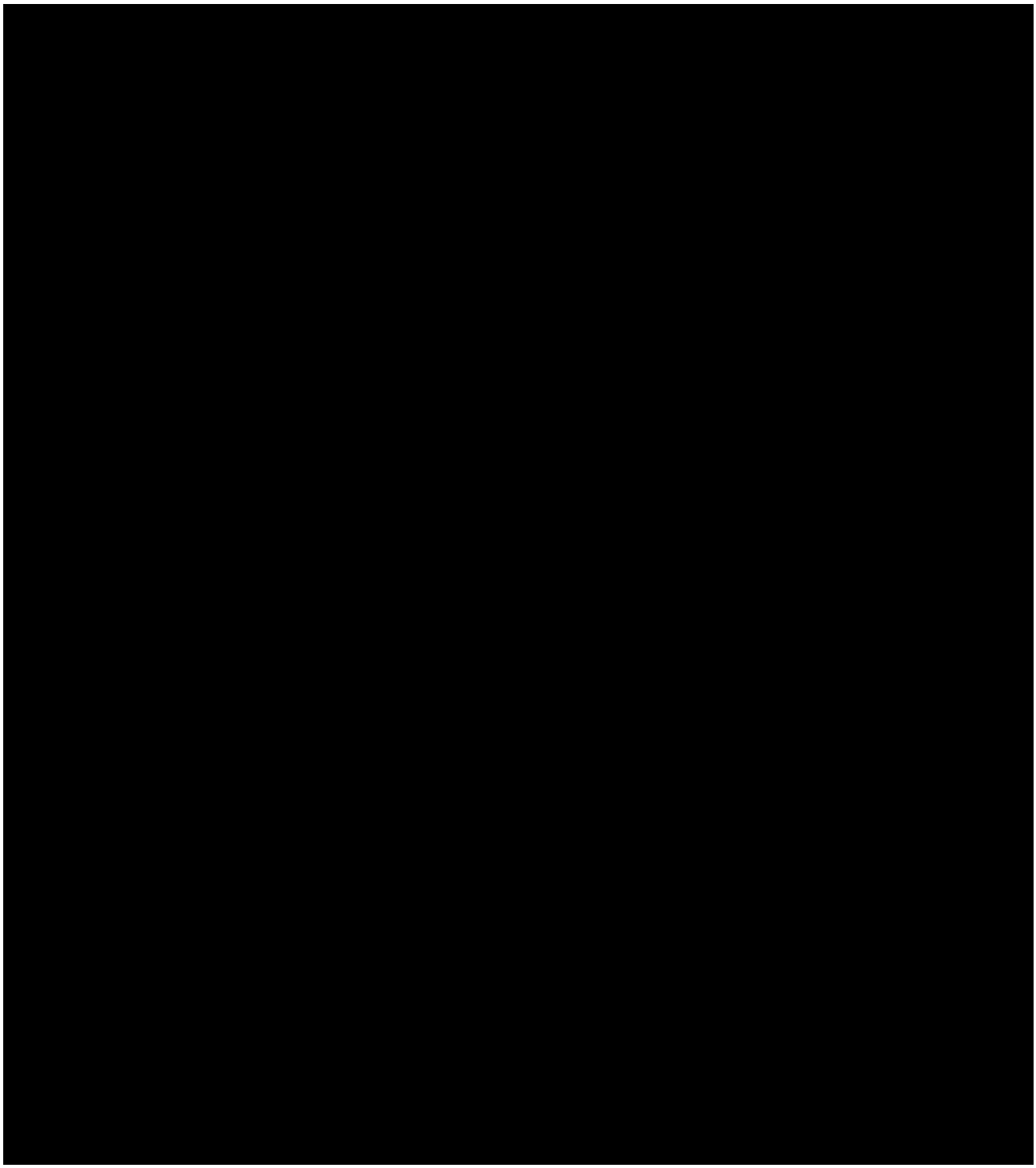
[redacted] A zero-phase Ricker wavelet with a peak frequency of 25 Hertz (Hz) was used to perform the ties. The results of the well ties are shown in Figures 1-25 through 1-28. Time-depth relationships were generated from the respective sonic logs, and all four wells offered good ties for the purposes of geologic characterization at the project site. High-quality well ties, as discussed in this section, yield a good conversion of the seismic data from time to depth, allowing for a quality comparison between well data and seismic data. In areas without well control, a regional velocity model was utilized, built from a network of regional 2D seismic data, which generally yielded decent time-depth conversion results, as blind-tested at the well locations.

[redacted]









1.5.2 Faults

[redacted]



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 is based on Yielding et al. (1997) (Figure 1-30), calculated using Equation 6, which utilizes the zone (lithology) thickness (h), clay fraction (Vshale, estimated from SP log (see *Section 1.4.3.1*)), and the fault displacement (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)

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

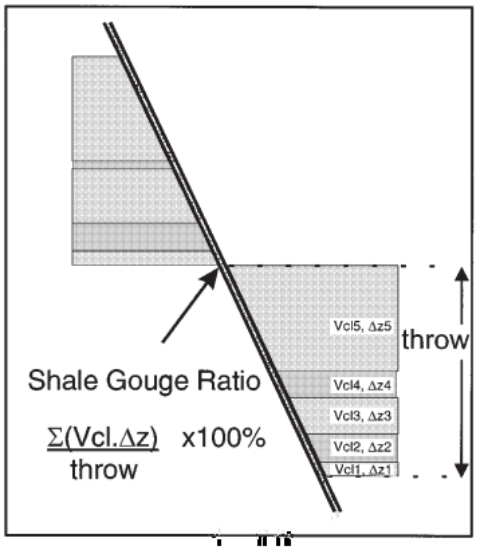


Figure 1-30 – Schematic of SGR Calculation from Yielding et al. (1997)

[redacted]











[redacted]

[redacted]

[redacted]

[redacted]

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 0.5, while published calibration expects the onset of seal development at SGR greater than 0.2.

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 mi 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 [redacted] 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. [redacted]
   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 [redacted] 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 [redacted] 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 [redacted] 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. [redacted]

1.6 Geomechanics

The information discussed in this section is from existing sources, such as publications and offset well data. Well data from [redacted] and log data from existing wells within the Sunflower Project region are 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 1-36. 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/



1.6.1.1 Vertical Stress

Vertical stress was characterized primarily using bulk density logs from offset wells. Figure 1-37 shows the four existing wells with bulk density logs near or in the project region, together with the density log of [redacted] 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 1-37, which gives an average gradient of 0.933 psi/ft.

[redacted]

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. [redacted] 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)

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

[redacted] Using the input values from Table 1-7, the resulting Poisson's ratio is equal to 0.401.

[redacted]

[redacted]

*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 [redacted] while parameter C is a constant for calibration (tectonic stress) with available data.

(Eq. 8)

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

Input parameters, shown in Table 1-8, were used for Equation 8 [redacted]

[redacted]

[redacted]

The resulting minimum horizontal stress using the values in Table 1-8 is equal to [redacted] Note that the calibration is performed with available formation integrity tests in offset wells [redacted]

The result of these calculations shows the average best estimate, within the relevant formations, of the minimum horizontal stress for the stratigraphic appraisal well to be [redacted] with depth-dependent variations along the well, shown in Figure 1-38. 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 1-9) were used in Equation 9 at a depth of 3,644 ft MD in [redacted] and gave a dynamic Young's modulus of [redacted]

[redacted]

*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 [redacted], 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 [redacted] 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 1-39. The average Young's moduli in the proposed injection zones are summarized in Table 1-10.



1.6.3 Fracture Gradient

1.6.3.1 Impact of Salt Dome

A radial finite element model was built to understand the impact on the stress profile and fracture pressure at the proposed injector locations, which are approximately 6.5 mi from the center of the dome.

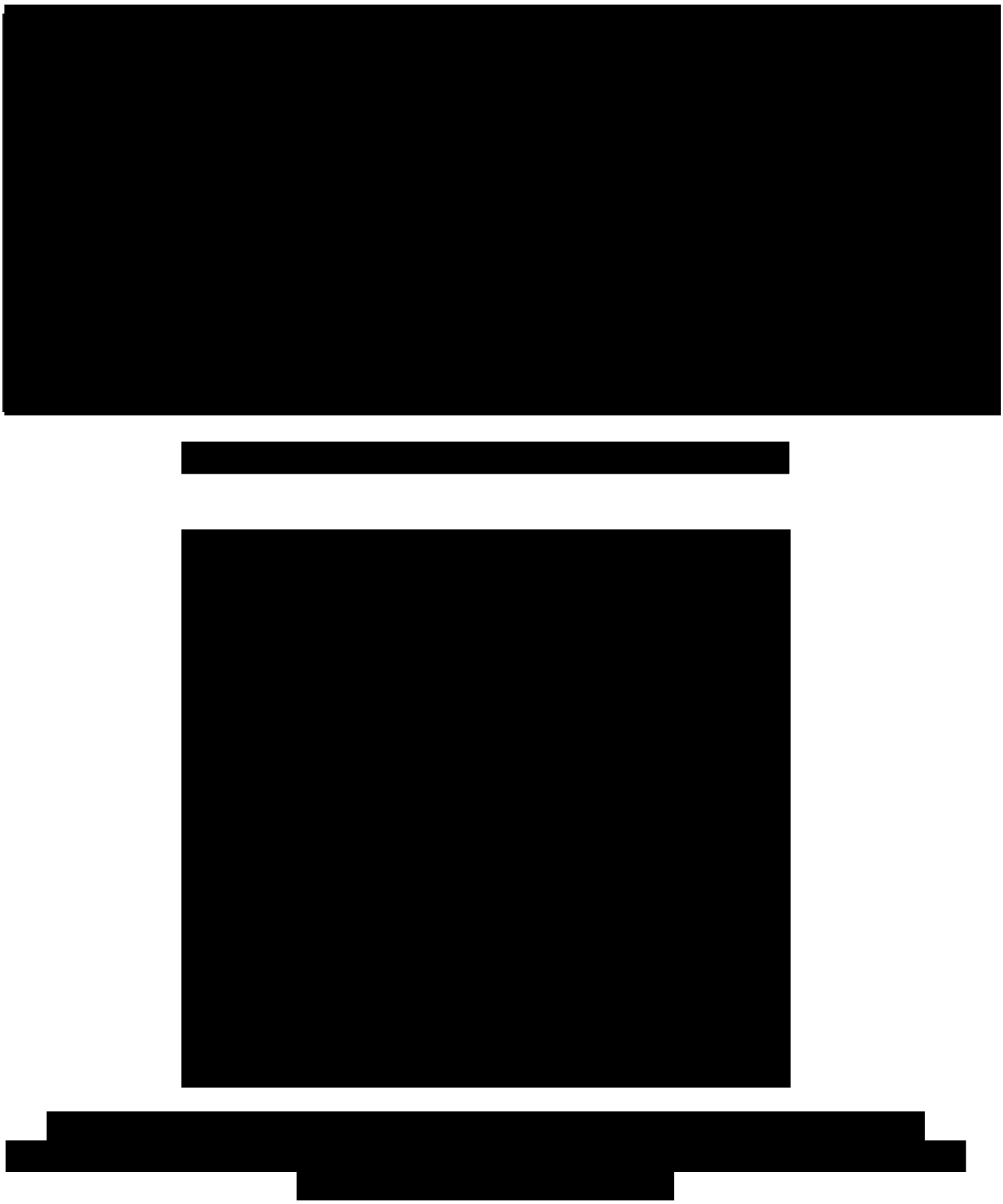


Figure 1-40 shows that the presence of the salt dome does have a noticeable effect on stress distribution in nearby rock volumes. However, that effect diminishes with increasing distance from the salt dome. At the proposed injection well locations, as shown in Figure 1-41, the salt dome has a very small effect on the stress state in [redacted] For conservatism, the stress

profiles from [redacted] (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 0.45 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) [redacted] 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 1-11.

[redacted]

[redacted]

1.6.3.3 Confining Zone

Similarly, fracture gradients in the confining zone can also be evaluated from Figure 1-41. The calculated average values are shown in Table 1-12.

[redacted]

[redacted]

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. Using the estimated fracture gradient in Table 1-11, the maximum bottomhole injection pressures for the injection wells, at the top of each injection interval, are shown in Table 1-13. Note that these estimates may be revised based on site data and updated well locations.



*TVDSS – true vertical depth subsea

1.7 Baseline Geochemistry

1.7.1 Assessment of Injection Interval and Confining Zone Geochemical Reactions

Baseline geochemical information on the subsurface formations in the AOR are provided based on preexisting data. Additionally, the evaluation of the injection-zone fluid geochemistry and mineralogy was conducted to assess 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 total dissolved solids (TDS) on these chemical reactions, the total change in mineral volume, and the pH of the brine phase.

Brine chemistry was taken from available regional data in Jefferson County and modeled in three TDS scenarios for [redacted] These three TDS scenarios represent a "Regional" case in which the TDS is derived from the regional TDS data, a "Moderately Elevated" case in which TDS is 50,000 milligrams per liter (mg/L) greater than the Regional scenario, and a "High" case in which the TDS is 100,000 mg/L greater than the Regional scenario. Each formation/scenario combination was modeled as a CO_2-saturated brine in contact with a separate CO_2-rich fluid phase, supplying continuous CO_2 to the brine phase. In all models for each formation at each TDS scenario, 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 the injectivity or storage capacity of the reservoirs—nor the integrity of the seal.

1.7.2 Summary of Available Geochemical Brine Data

The baseline geochemical data for fluids in the injection intervals were obtained from surrounding wells in Jefferson County, including [redacted] and seven wells in the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database (Blondes et al., 2023). 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*.

[redacted] There is uncertainty in the quality of the regional data due to the absence of duplicate and quality assurance samples. However, it is believed that the average chemical composition of these existing fluid samples modeled to be in equilibrium with the expected formation mineralogy is representative of the subsurface fluids

anticipated to be encountered in the AOR formations of interest. [redacted] shows the locations of the wells from which preexisting data was taken for the geochemical models.

[redacted]

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

Simple 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 the brine chemistry and the 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.

Model Input: Brine Chemistry

To obtain the Regional TDS scenario brine composition for each formation, the data for a given formation in *Appendix B-4* was averaged. [redacted]

For the Moderately Elevated and High TDS scenarios, the concentration of cations and Cl^- was scaled proportional to the increase in TDS from the Regional TDS scenario value, to the higher TDS scenario values. The brine chemistry was found to be somewhat incomplete relative to the representative mineralogical data discussed in the next section.

The fluid is in equilibrium with quartz and feldspars; however, the analysis of the brine did not provide the concentrations of Al^{3+} or $SiO_{2\,(aq)}$. To estimate these fluid components, the SpecE8 module from the GWB was used, setting $SiO_{2\,(aq)}$ and Al^{3+} concentrations to be controlled by the equilibrium solubility of quartz and albite, respectively, with the brine at the temperature of the formation. This equilibration step also slightly alters the initial brine chemistry and 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, estimated formation temperature, and pH.

Model Input: Formation Mineralogy

Four formations were modeled at the three TDS scenarios: [redacted] The representative primary mineralogy for each formation used in the geochemical models was averaged from [redacted] The averaged primary mineralogy used in the geochemical models is presented in *Appendix B-4*. [redacted]

The averaged primary mineralogies represent at least 97% of the [redacted] 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. [redacted] pyrite and marcasite were combined and represented as only pyrite. Albite was substituted for "plagioclase." The mixed, interlayered illite/smectite was subdivided into illite and smectite portions using the smectite abundance [redacted] 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 5,000-year model simulation period in the React module of the 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 year.

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 five models, including ankerite and dawsonite, which are carbonate minerals and store CO_2 in their chemical structure. The thermo.com.V8.R6+.tdat database (Wolery, 1992), modified to include thermodynamic data on ankerite, was used in all models. *Appendix B-4* also lists the relevant chemical formulae of the modeled minerals.

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 under three TDS scenarios. *Appendix B-4* presents the geochemical modeling results for each formation under the different TDS scenarios. The results are plotted as change vs. time for these relationships:

- Mineral weight percent change vs. elapsed time during the fixed CO_2 gas-fugacity portion of the model (time interval of 0.05–100 years) for the Regional TDS scenario (A), Moderately Elevated TDS scenario (B), and High TDS scenario (C) for a given formation

- The pH of the brine vs. time over both the variable and fixed CO_2 gas-fugacity portions of the model (time interval of 0–100 years) for the Regional TDS scenario (blue line), Moderately Elevated TDS scenario (orange line), and High TDS scenario (green line) for a given formation

- The total mineral volume change vs. time for both the variable and fixed CO_2 gas-fugacity portion of the model (time interval of 0–100 years) for the Regional TDS scenario (blue line), Moderately Elevated TDS scenario (orange line), and High TDS scenario (green line) for a given formation

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 change in volume percent (vol%) was less than 0.3.

- The presence of a significant quantity of calcite (6.8 weight percent or greater) in the primary mineralogy is predicted to buffer the pH of the system to a steady-state within approximately 10–15 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 TDS is not predicted to significantly influence the primary or secondary mineral assemblages within a given formation modeled.

- The TDS is predicted to influence the pH of the brine. This is expected as CO_2 solubility is controlled by the salinity of the fluid. However, this influence on the pH is minor in all formations modeled and is predicted to be on the order of approximately 0.2 pH units.

- The TDS is predicted to influence the total mineral volume change of the system. This is expected, as a higher TDS brine has more cations and anions necessary for mineral precipitation. [redacted] mineral precipitation in the High TDS scenario was predicted to increase the total mineral volume, exceeding the pre-injection volume by the end of the simulation. The total mineral volume of [redacted] are predicted to remain below the pre-injection volume.

  [redacted] In all cases, neither the maximum mineral-volume decrease nor the final mineral volume relative to the pre-injection volume is predicted to be significant, in all cases being less than 0.3 vol%.

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 the 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 except the High TDS scenarios. To account for the higher ionic strength fluids, the default ionic strength limitations were appropriately adjusted. 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; Zeral et al., 2006). However, even with these corrections, the uncertainty in the High TDS scenarios is expected to be up to 15% (Allen et al., 2005).

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 the 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.

Brine chemistry specific to [redacted] was estimated by averaging the brine chemistry of the two bounding layers [redacted] It is expected that the brine geochemistry for the overlaying and underlying formations are a reasonable basis for [redacted], especially considering that crossflow through [redacted] is not likely to be a factor based on its sealing properties.

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 [redacted] mineralogical data representative of the formations of interest. Test scenarios of an expected TDS value based on the regional brine chemistries (Regional scenario) and two higher TDS scenarios of 50,000 (Moderately Elevated scenario) and 100,000 mg/L (High scenario) above the expected TDS value, were used to assess the potential impact of TDS on mineral precipitation and dissolution. 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.

1.8 Hydrology

The following hydrologic review of Jefferson County 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 ([redacted]). No minor aquifers were reported to have freshwater potential near the project (Bruun et al., 2016). The Gulf Coast aquifer is present across Jefferson County and represents the primary source of fresh groundwater for municipal, industrial, and irrigation purposes. According to the TWDB, Jefferson County does not fall within any current Underground Conservation Districts (Davidson and Mace, 2006).



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 [redacted], 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 [redacted] 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 ft (Bruun et al., 2016).

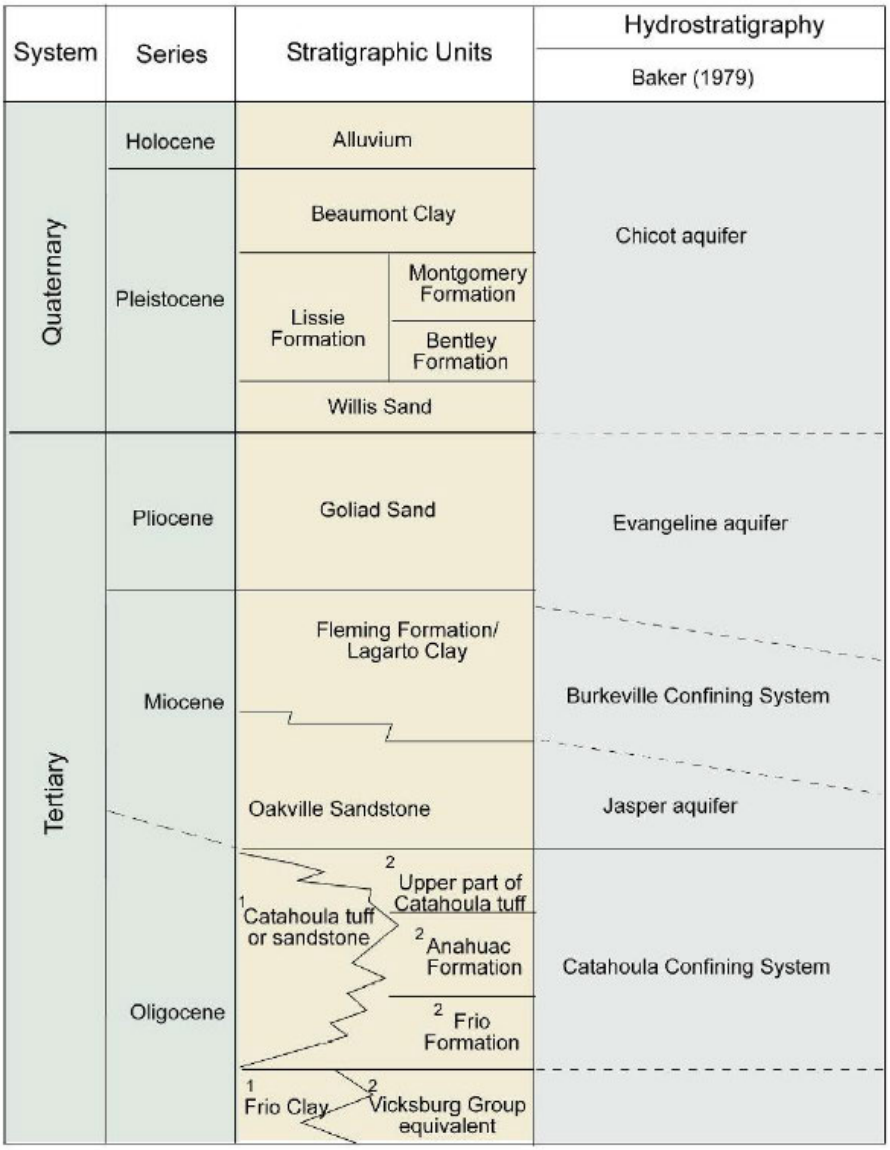


Figure 1-44 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury and Turco, 2006)



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

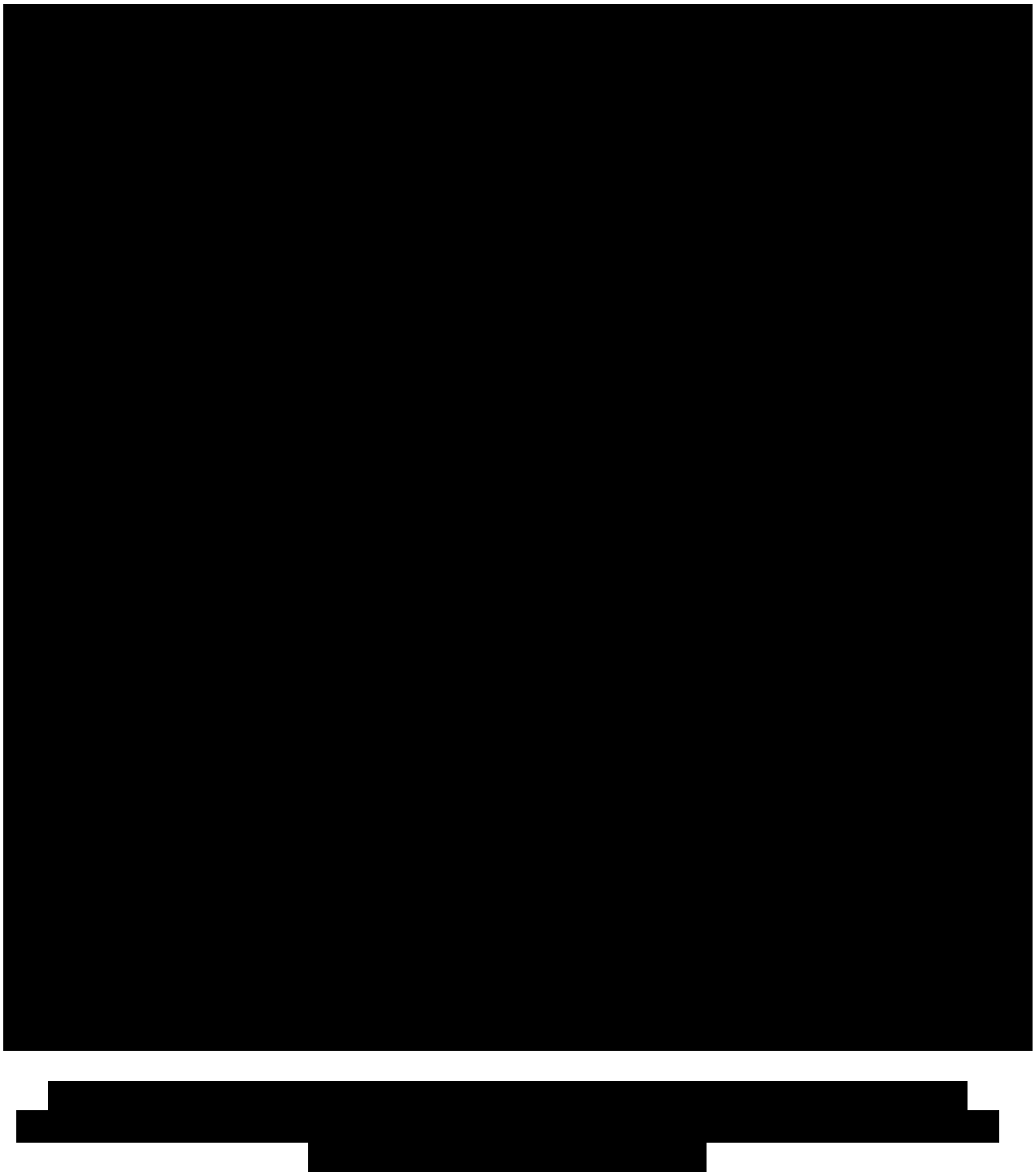
Groundwater moves within aquifers from areas of higher hydraulic head to areas of lower hydraulic head, and the flow direction is generally perpendicular to potentiometric surface contours. A potentiometric surface map of the Chicot aquifer published by the TWDB is provided in Figure 1-46 for reference. The map suggests that groundwater should flow south-southeast near the Sunflower Project, as indicated by the bold blue arrows.

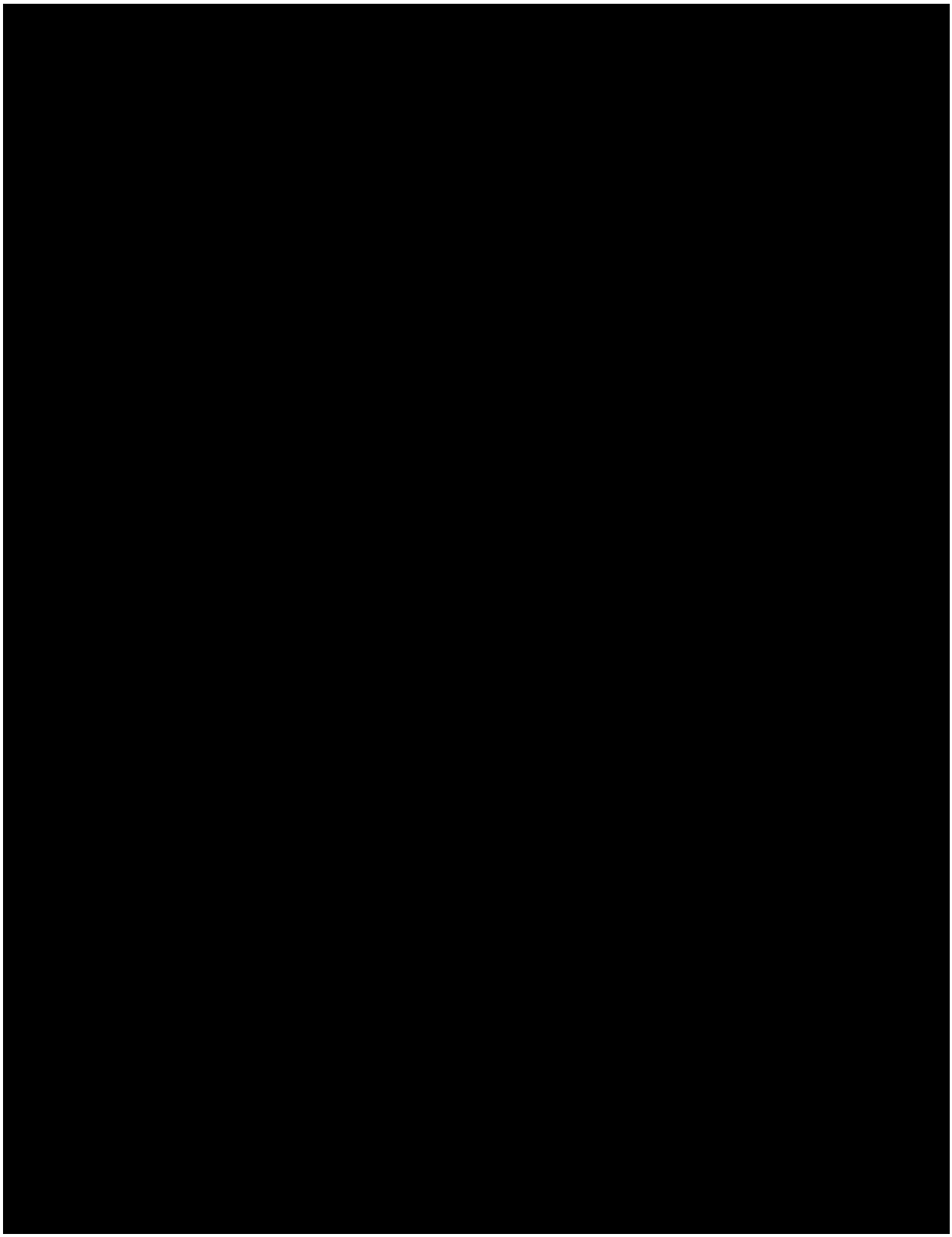
Water Quality

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 mg/L, as illustrated in Figure 1-47. According to the map, the TDS of the Gulf Coast aquifer are 1–3,000 mg/L in northwestern Jefferson County, 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).

[redacted]



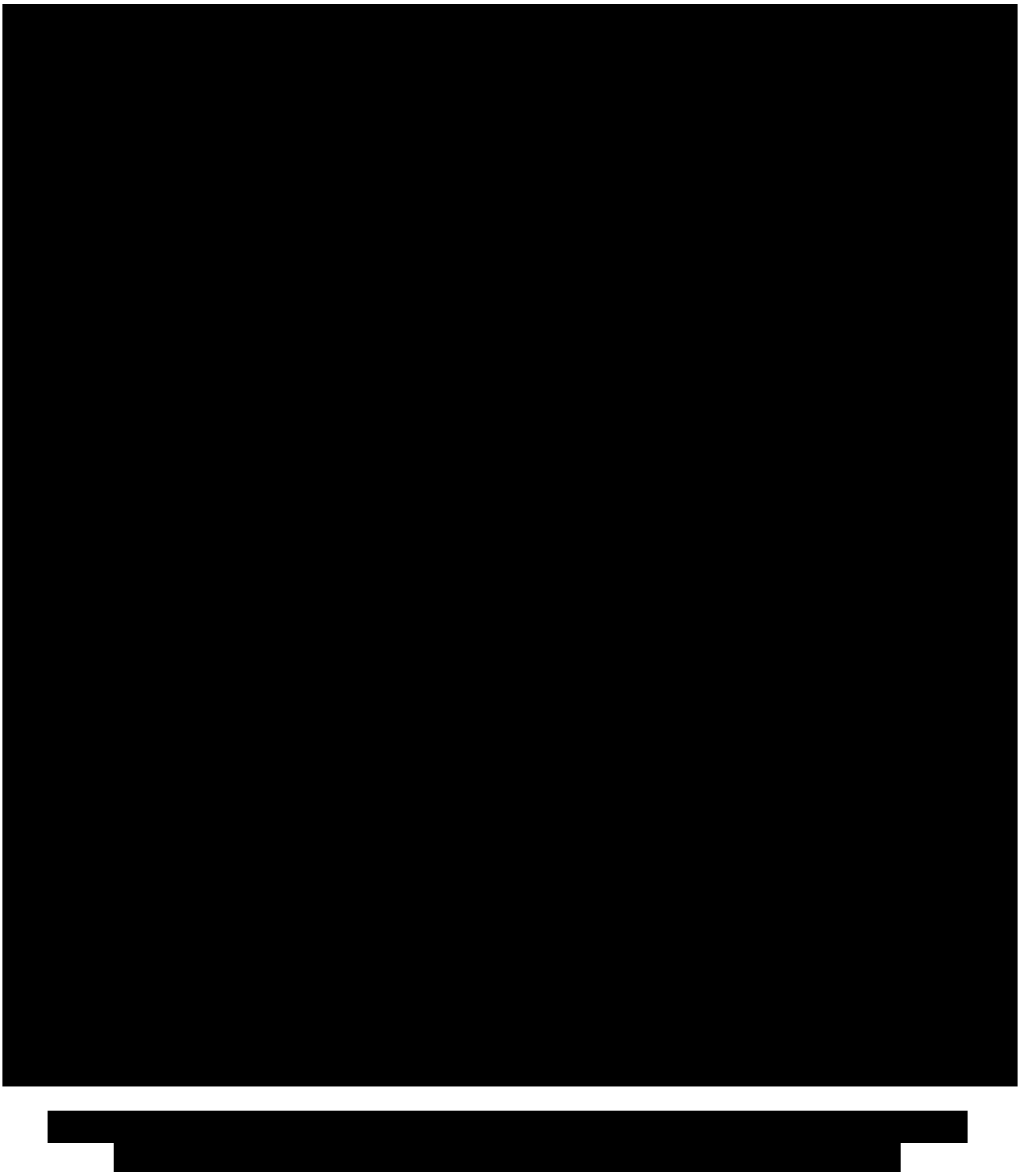


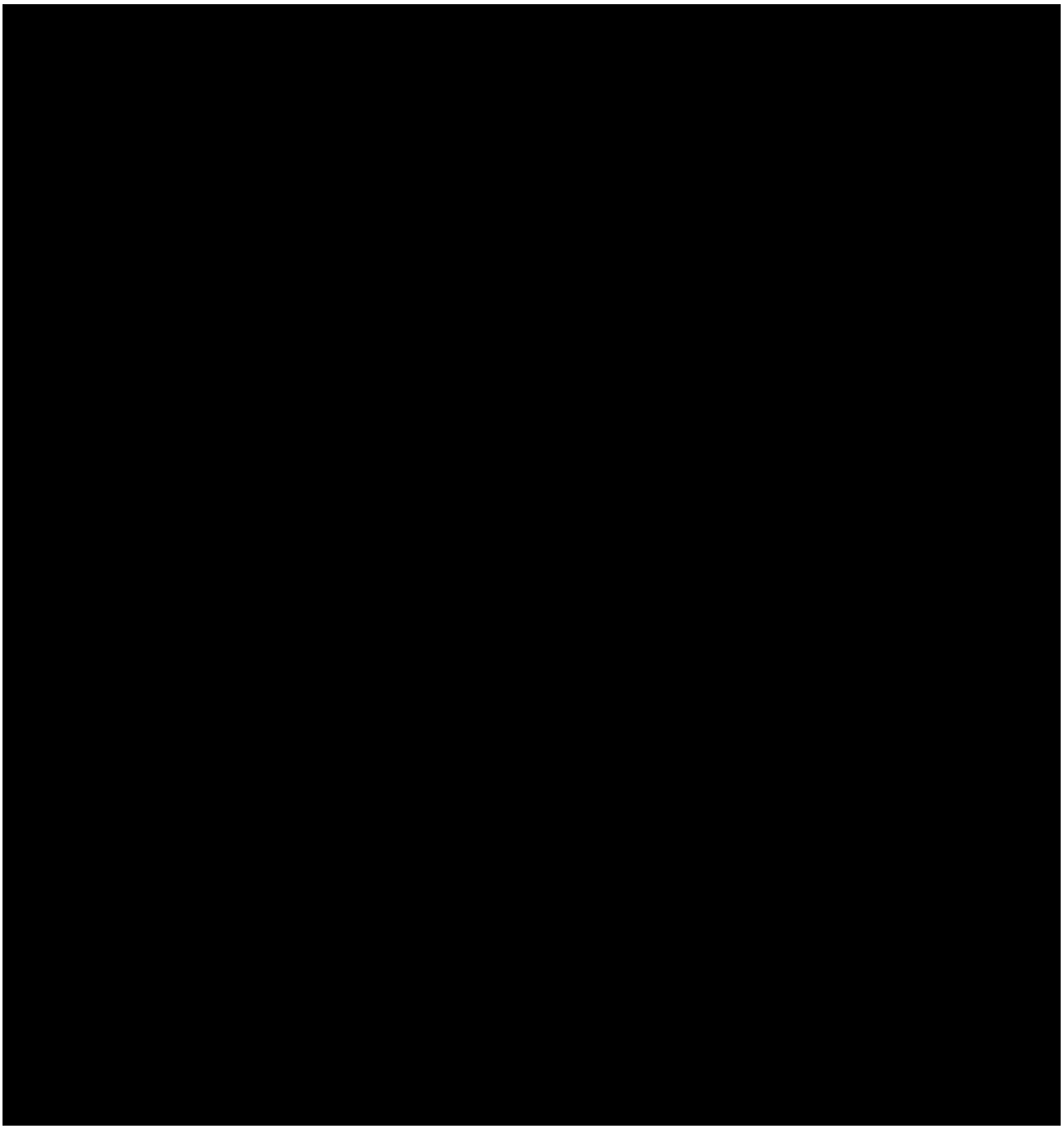
1.8.3 Base of USDW Determination

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 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 1-48 and 1-49, 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 1,000–1,500 ft, and the base of the USDW occurs between 1,500–1,750 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 1-50 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 1-44).

The Railroad Commission of Texas's (TRRC) Drilling Insight and Casing Estimator (DICE) identified the BUQW at a depth of 973 ft around the general location of the Sunflower Project, in general agreement with maps and discussions provided herein. [redacted]

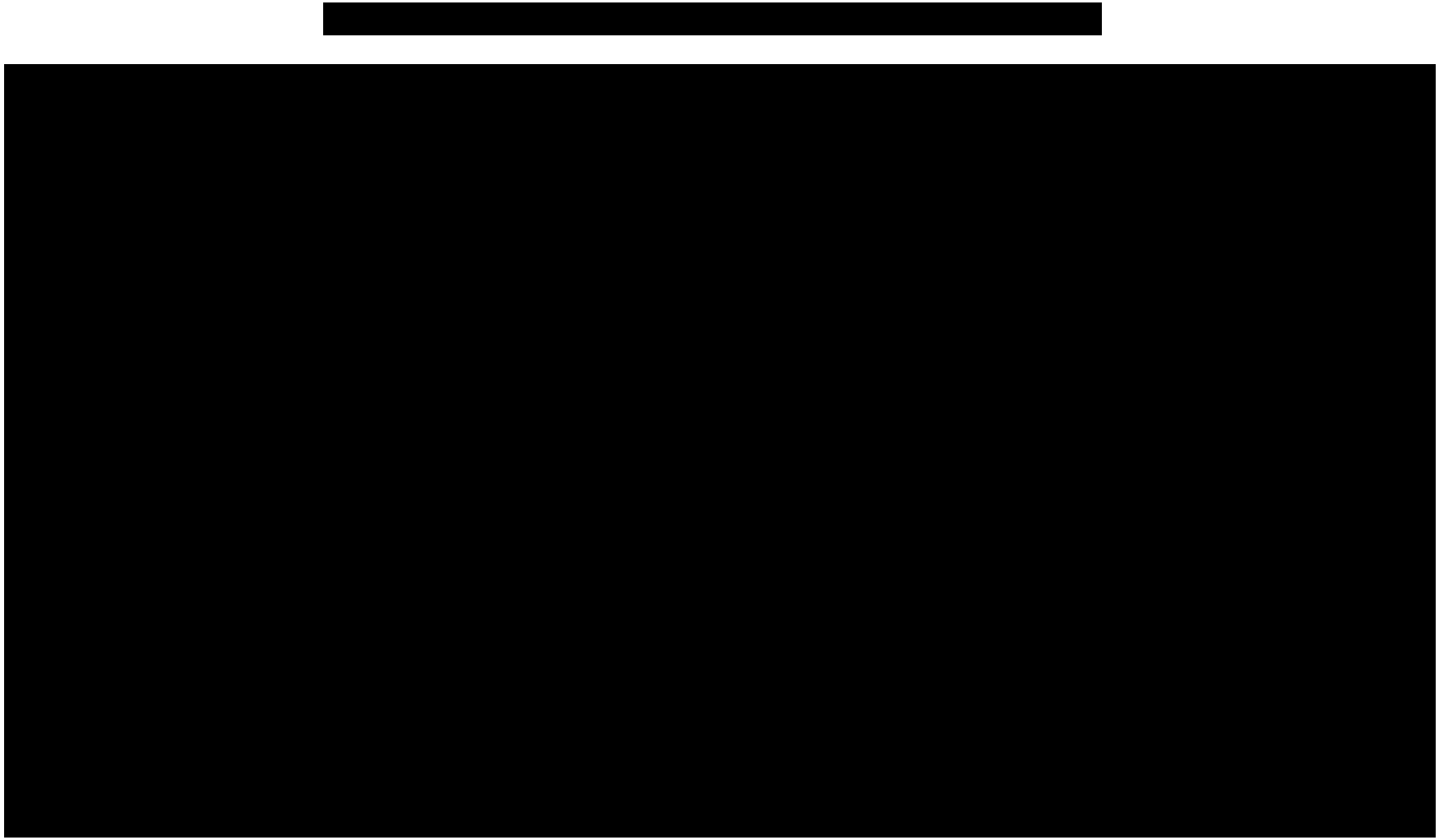






An assessment of the USDW depth was also performed using legacy wells in the Sunflower Project area. A total of 31 wells were investigated to estimate the USDW depth based on deep resistivity logs. Sands reading less than 2 ohm-meters (ohm-m) were interpreted to have a TDS value greater than 10,000 ppm. Table 1-14 summarizes the USDW depths based on the wells available. Figure 1-51 is a USDW depth contour map across the Sunflower Project area, with the AOR polygon shown in a red outline.

It is worth noting that two wells were omitted from the map due to either the vintage or quality of the logs available. [redacted] 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. [redacted] 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. [redacted]





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 November 8, 2024, 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,

[redacted]

[redacted]

[redacted]

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. [redacted]

[redacted] While these fields are within the 5-mi search radius, neither is intersected by the modeled extent of the injected CO_2.

[redacted]

[redacted]

[redacted] Historical production for wells within the AOR is also deeper than the gross injection interval, which makes this area well suited for the injection and sequestration of CO_2. Any wellbores within the AOR that are drilled through the injection interval are discussed in *Section 3 – Area of Review and Corrective Action Plan*.

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 128 mi 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 58 mi 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 93 mi from the project site. The closest earthquake 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 89 mi 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.

[redacted] 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. The estimates of the stresses included a vertical gradient of 0.93 psi/ft, a maximum horizontal stress gradient calculated using an Aphi range of 0.65–0.75 (Lundstern and Zoback, 2020), [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

[redacted], and a pore pressure gradient of 0.45 psi/ft. 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 [redacted] well, where the residual strength was calculated on the failure plane (37°) following shear failure. [redacted]

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. [redacted] 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 [redacted], indicating that the potential for induced seismic risk based on this methodology is low.

[redacted]







[redacted]

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. [redacted]

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 1-56 (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.

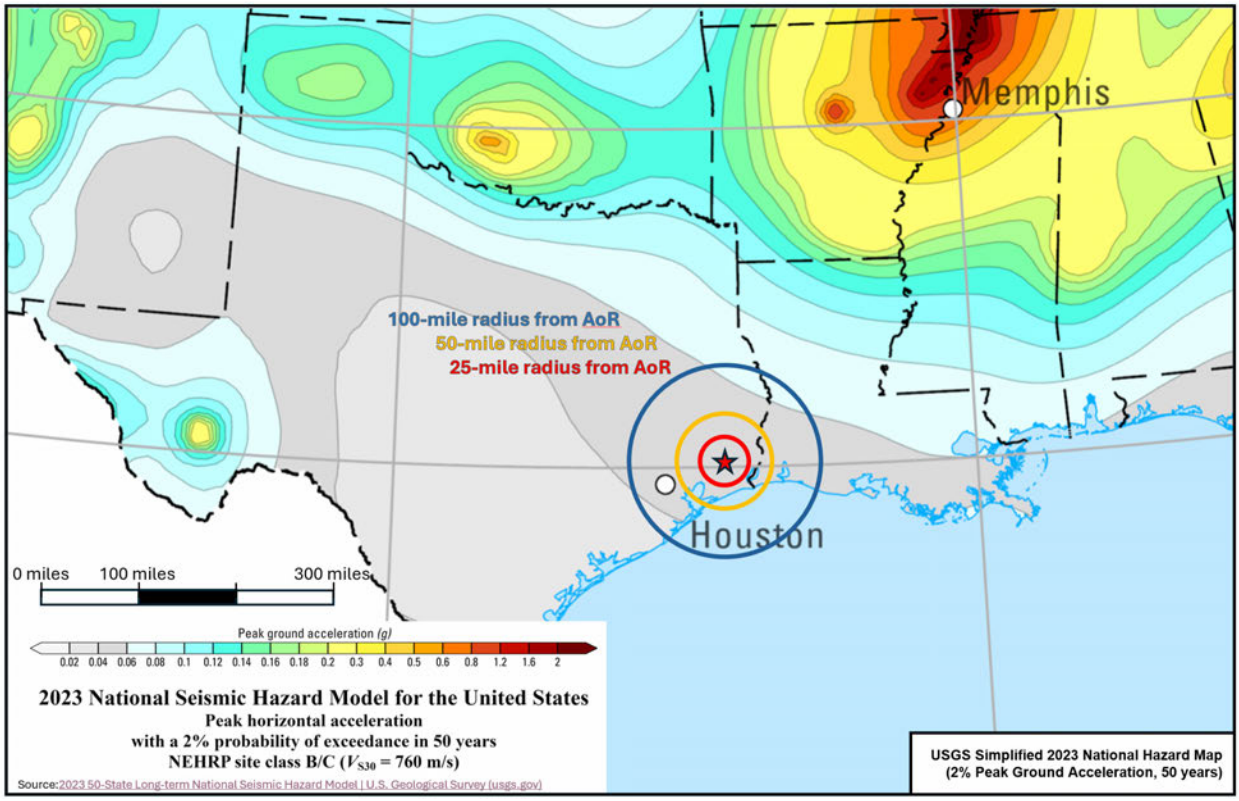


Figure 1-56 – National Seismic Hazard Model for the United States

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 an ideal location for carbon dioxide injection and storage operations. The upper composite confining zone is characterized by low porosity and permeability, modeled to impede upward migration of 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 and minimal faulting within the injection and confining zones of the AOI.
- Faults have been identified, characterized, and analyzed in the project area. [redacted] Shale gouge ratio was calculated for [redacted] and is determined to seal across the UCCZ, 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. The USDWs will not be affected by the Sunflower Project's operations.
- Proposed operations will not 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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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 2 – Plume Model

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 2 – PLUME MODEL

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2.1 Introduction

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2.2 Objectives

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2.3 Modeling and Simulation Framework

2.3.1 Software

2.3.1.1 Petrel™ Software Suite

Schlumberger's (SLB) Petrel Software suite (Ver. 2023.6) was chosen to create a detailed geologic model for the CCS site. 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, [redacted] Using Petrel, the porosity and permeability properties of the reservoirs were distributed using industry-standard geostatistical methods, incorporating all 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. 2022.8) 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 literatures.

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 of the reservoir properties. [redacted] 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 [redacted] 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 subsurface, such as faults, salt domes, or any other structural changes in the subsurface. This data enhanced the accuracy of the geologic model by providing a clearer understanding of the targeted stratigraphy. Core data was used to determine the porosity-permeability relationship in the Frio and Fleming injection formations. This data is discussed in greater detail in *Section 2.5*.

Additional data will be collected during the drilling of wells for the proposed carbon storage project. A detail 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.

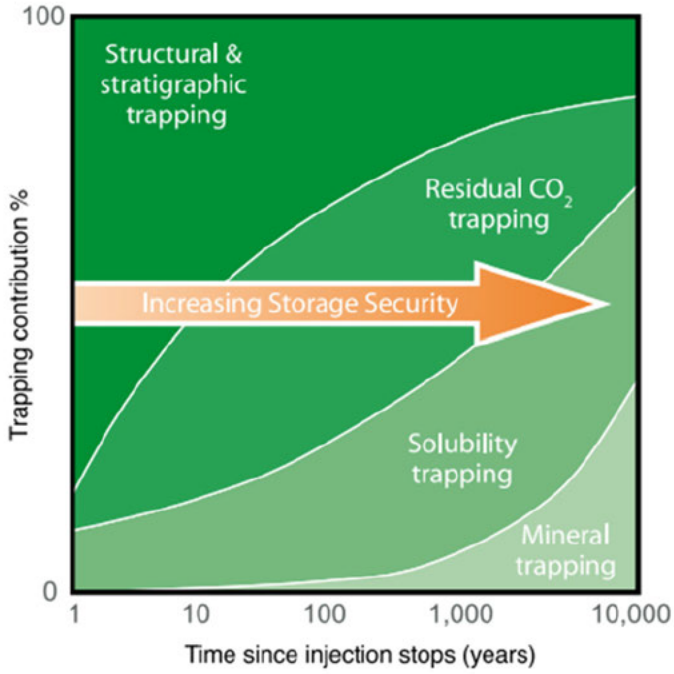


Figure 2-1 – CO_2 Storage Mechanisms (Metz et al., 2005)

2.4.1 Structural and Stratigraphic Trapping

Structural trapping is a physical form of trapping where injected CO_2 is immobilized by the presence of sealing faults and 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. [redacted]

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 trap 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 (2003, 2005, 2010) 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. The aqueous phase density and viscosity are also provided by the user in the solubility table. Salt is not modeled explicitly (in Intersect Ver. 2022.8); 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. These components interact with each other, resulting in CO_2 often being precipitated out as a new mineral. This new mineral is typically $Ca\text{-}CO_3$, 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.

[redacted]

[redacted]

[redacted]

[redacted]

2.5 3D Geologic Model

Characterization of the [redacted] 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 includes 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 exceeds the spatial limit of the AOR. [redacted]

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. [redacted]



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 stratigraphic layering method. [redacted]

[redacted]

[redacted]

2.5.3 Net and Non-Net Model

[redacted] available evaluations of the regional depositional environments were considered along with relevant well data, to help provide an accurate and representative sand distribution for the geologic model. 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 injection intervals laterally and vertically. The second step was

the modeling of different lithofacies [redacted] within the net regions defined in the first step.

[redacted] 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. [redacted]

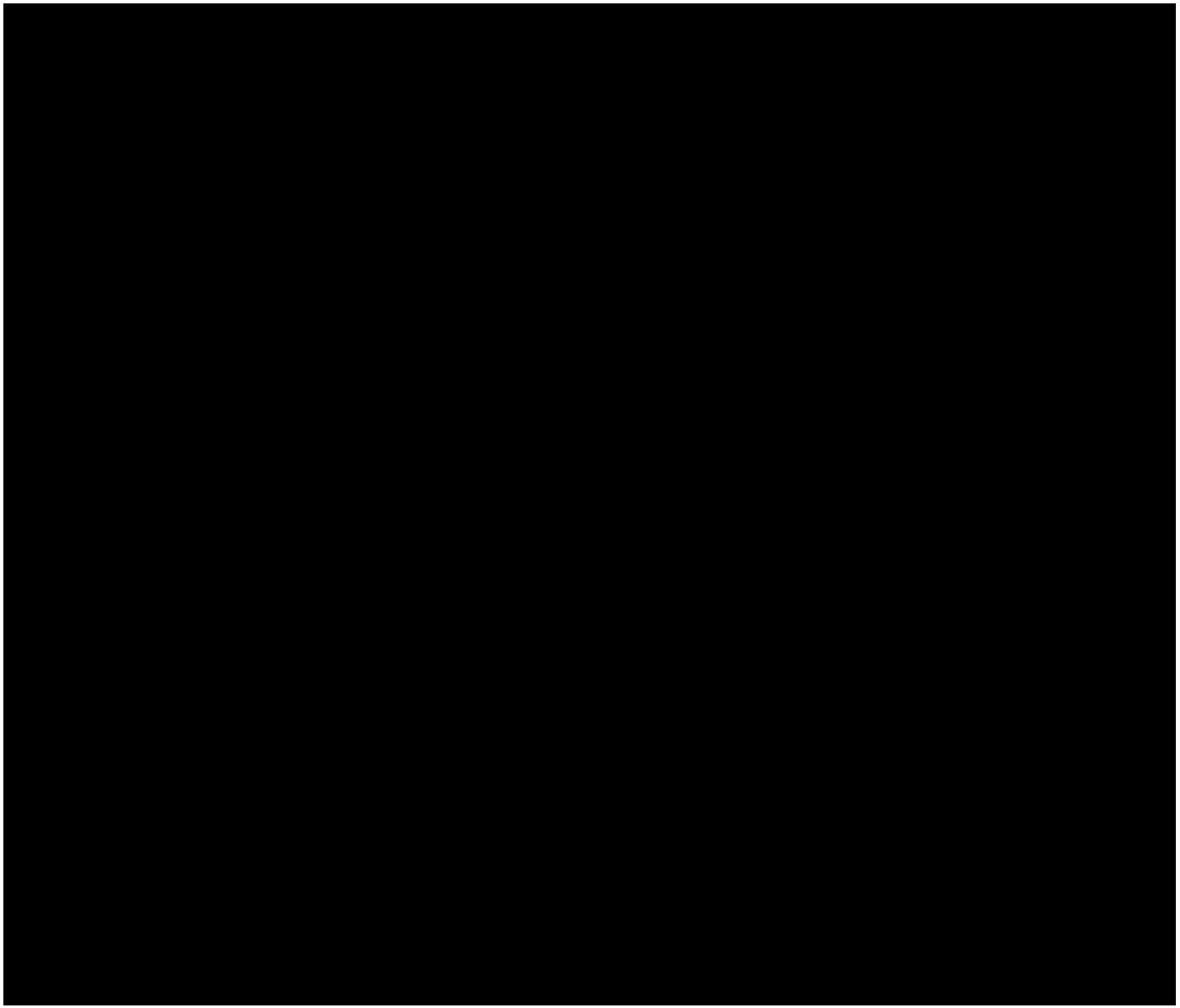


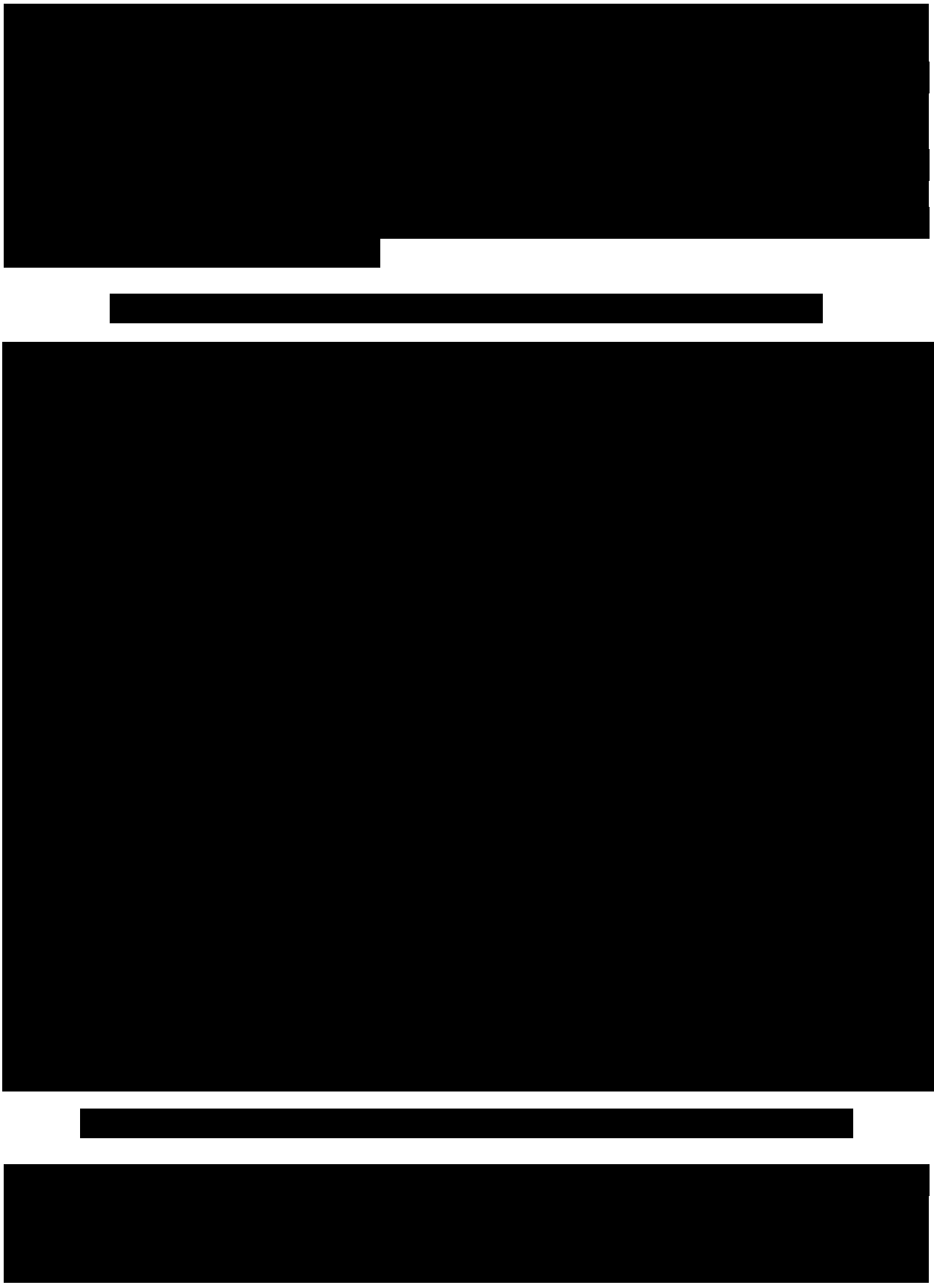
[redacted]





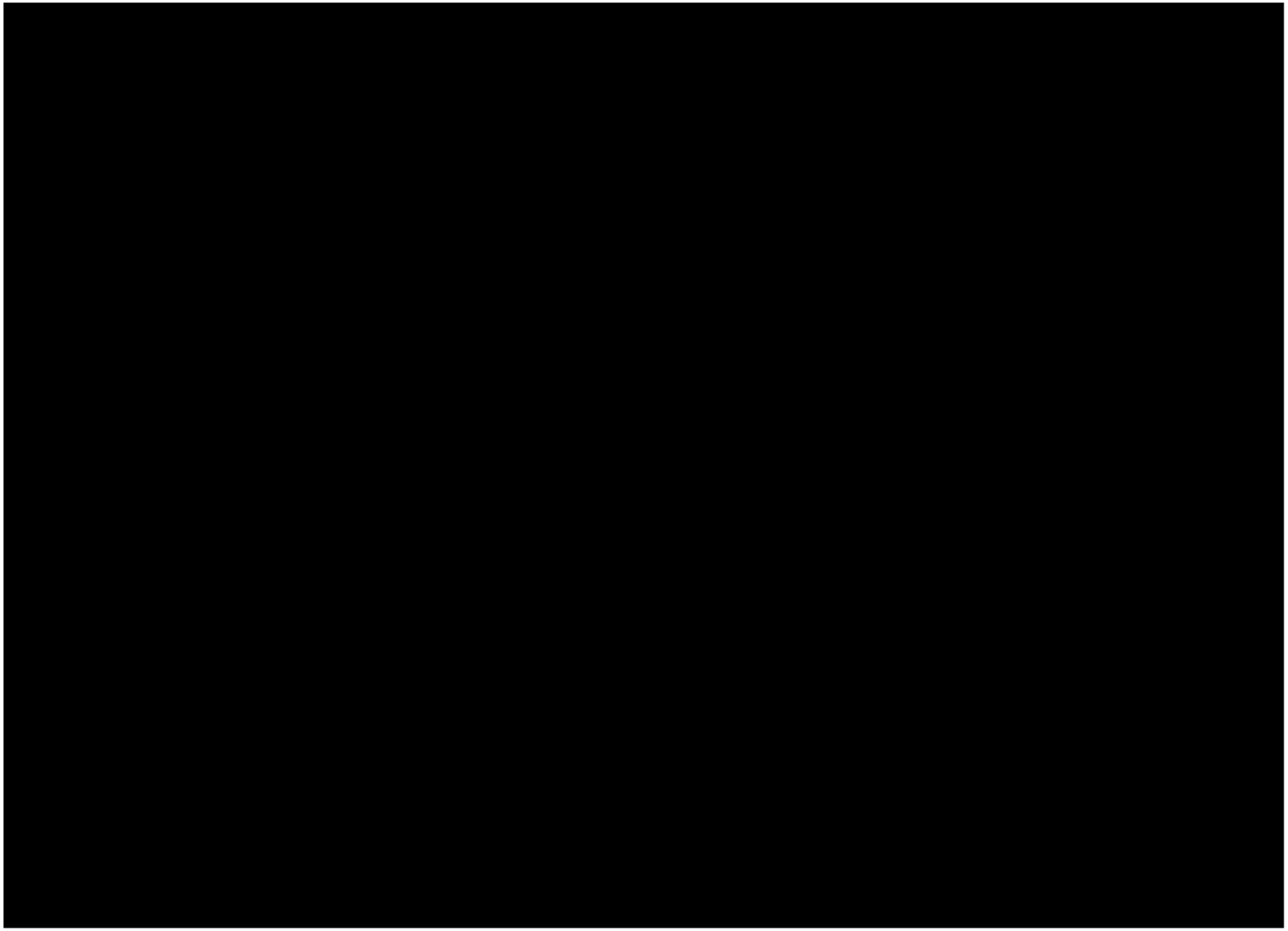
The interpreted net and non-net logs were upscaled to model resolution and then distributed within the 3D model [redacted] This modeling approach was adopted to adequately capture the reservoir heterogeneity while preserving the concept of fluvial channels and deltaic lobes within the fluvio-deltaic environment of deposition.



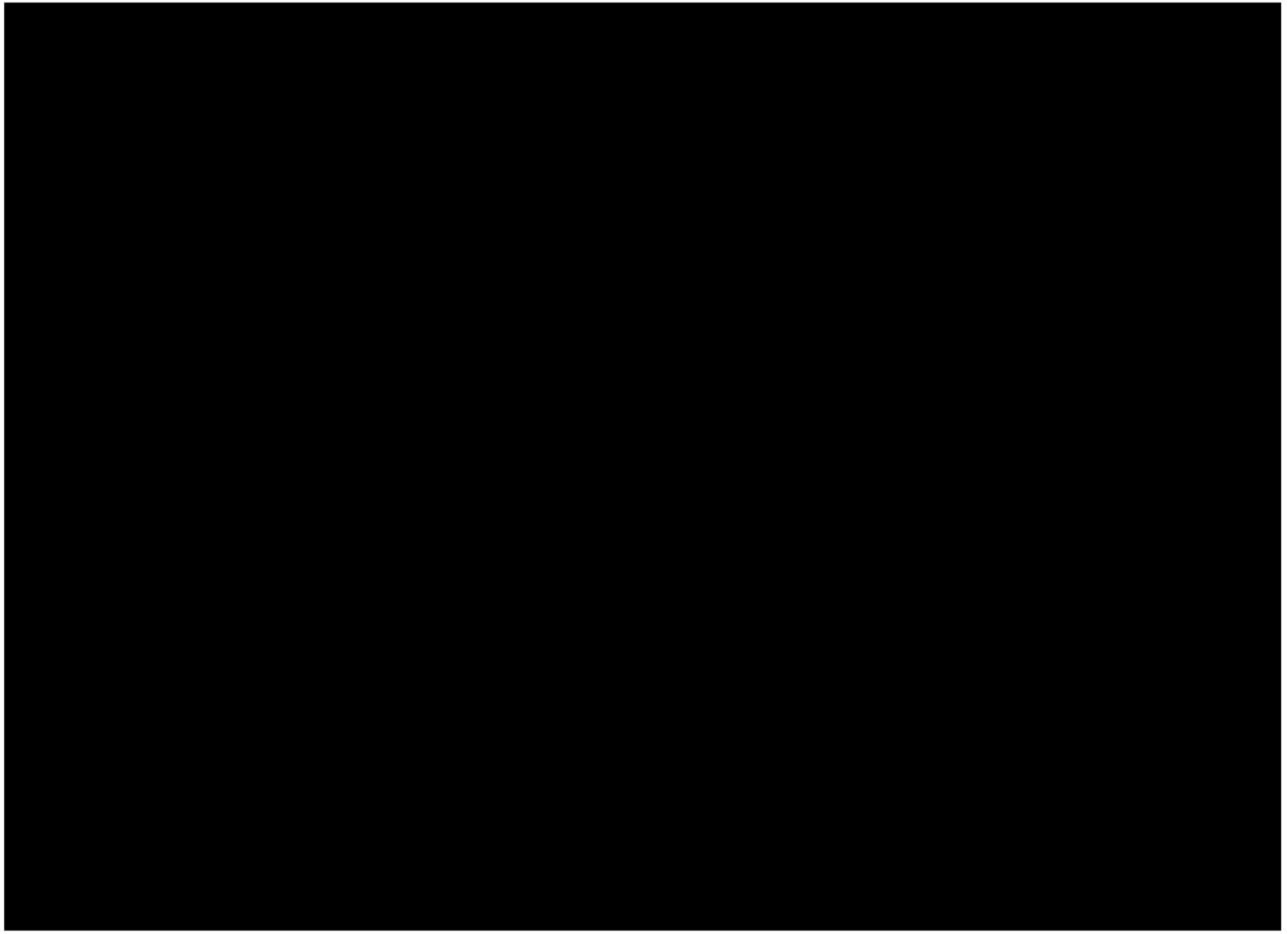


[redacted]

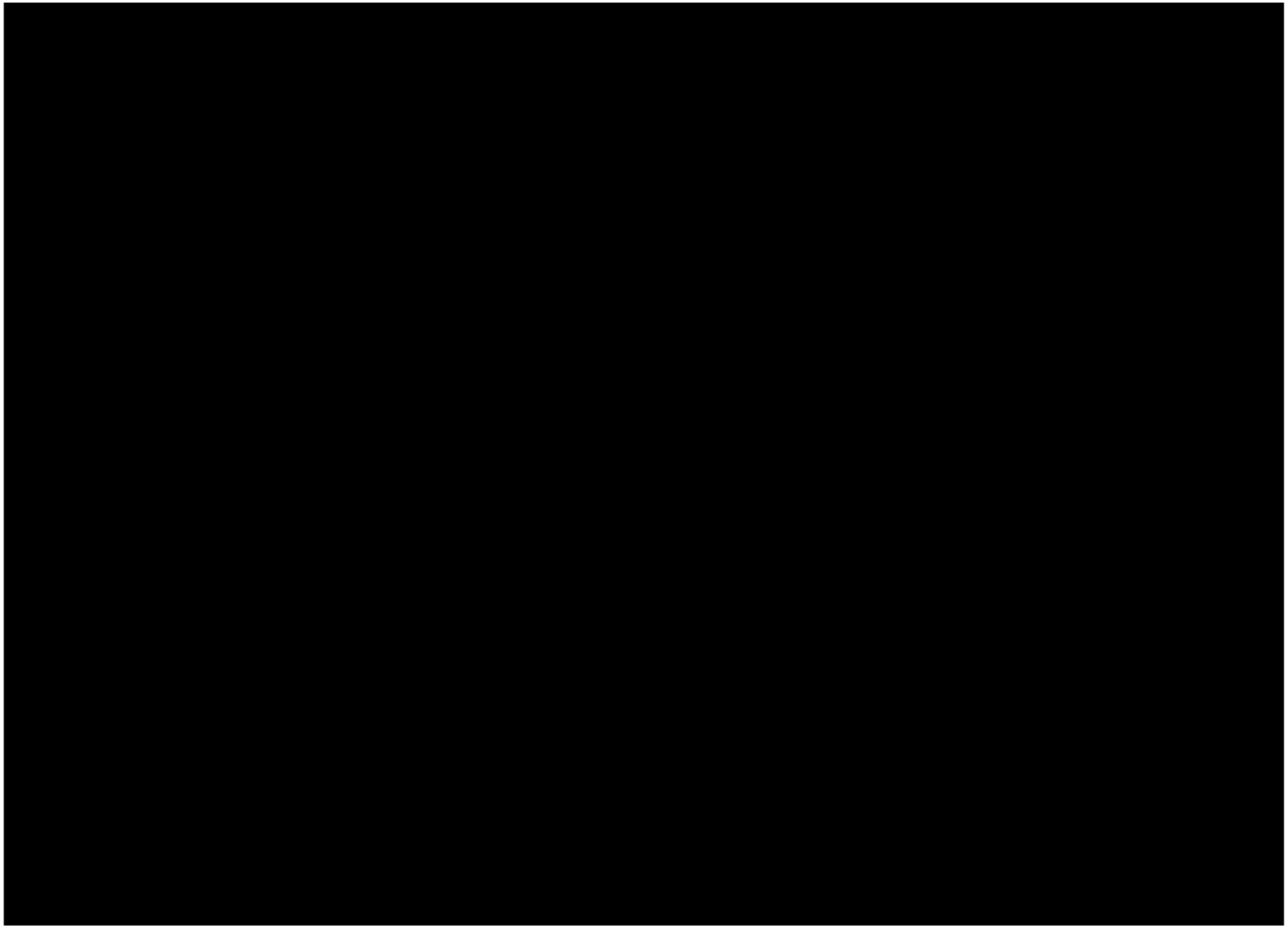




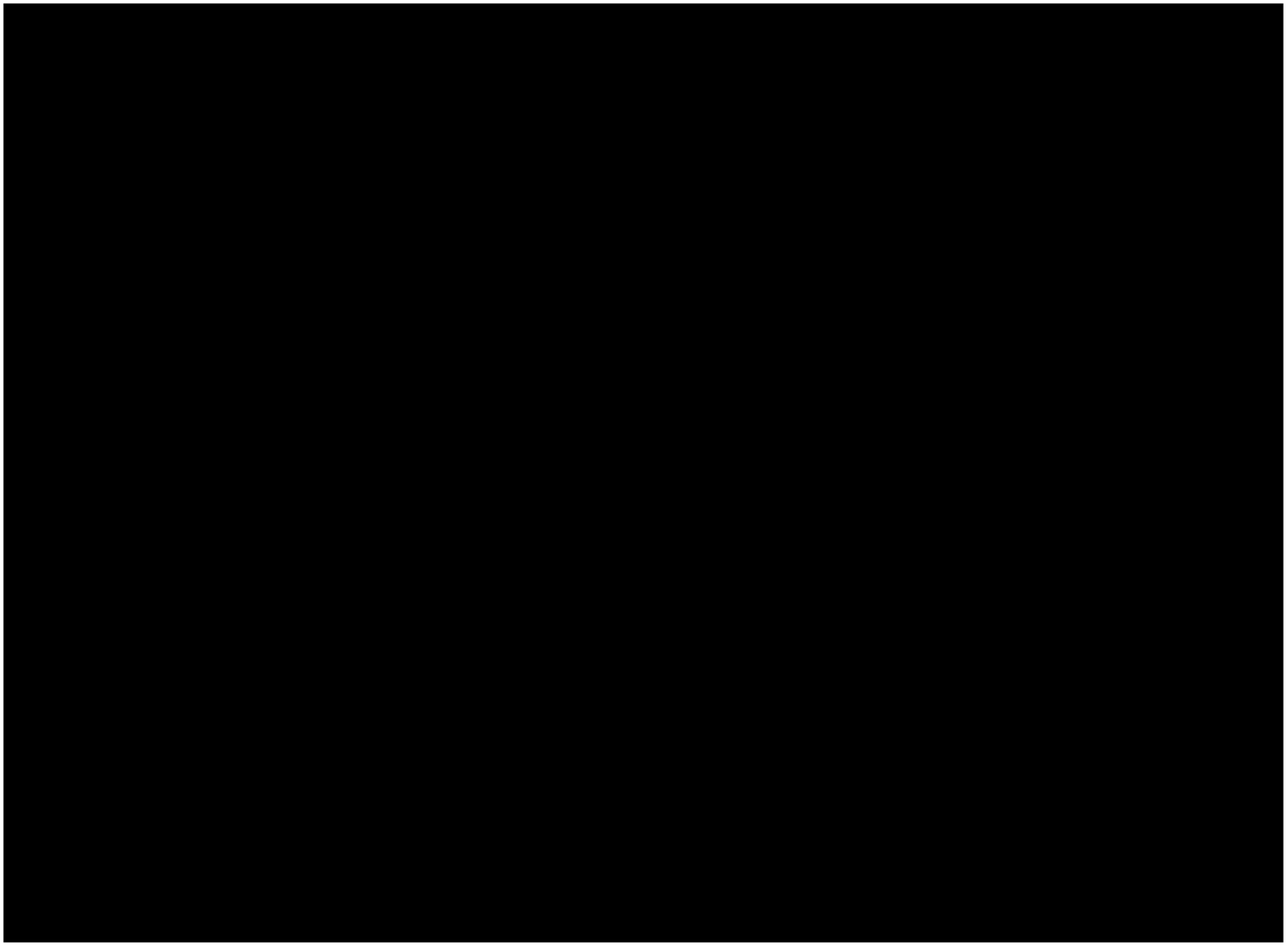






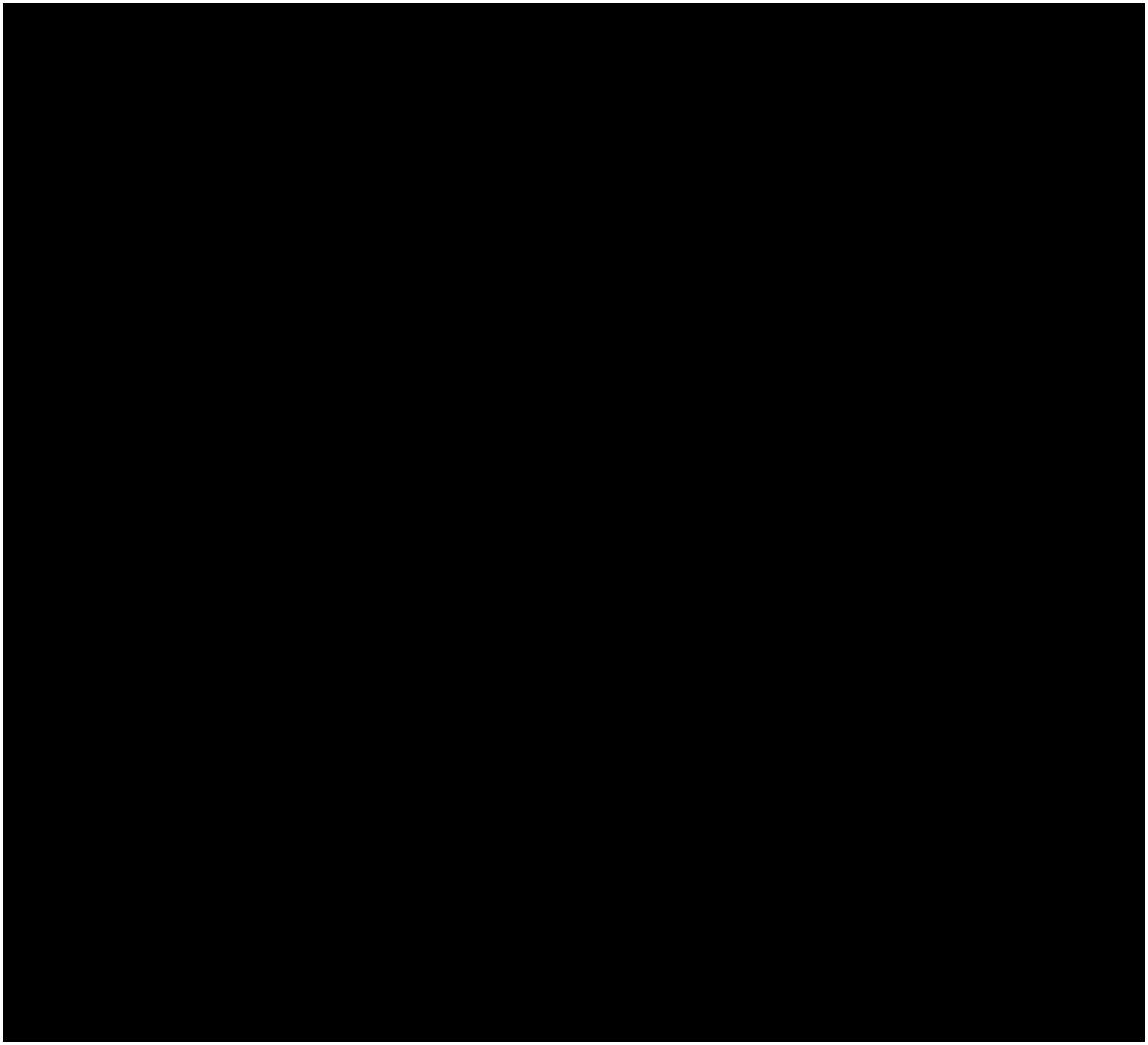






2.5.4 Lithofacies Model

[redacted]



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 truncated Gaussian simulation algorithm. The statistical parameters and trend maps 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. [redacted]

[redacted]



[redacted] The results show excellent correlation between the modeled facies and log assignment. The figures also illustrate the distribution of lithofacies away from the wells. [redacted] Both net and lithofacies on the figure were mapped based on the interpreted depositional environment for the [redacted] injection intervals.







[redacted]

[redacted]

2.5.5 Net-to-Gross Model

[redacted]

[redacted]

[redacted]

[redacted]



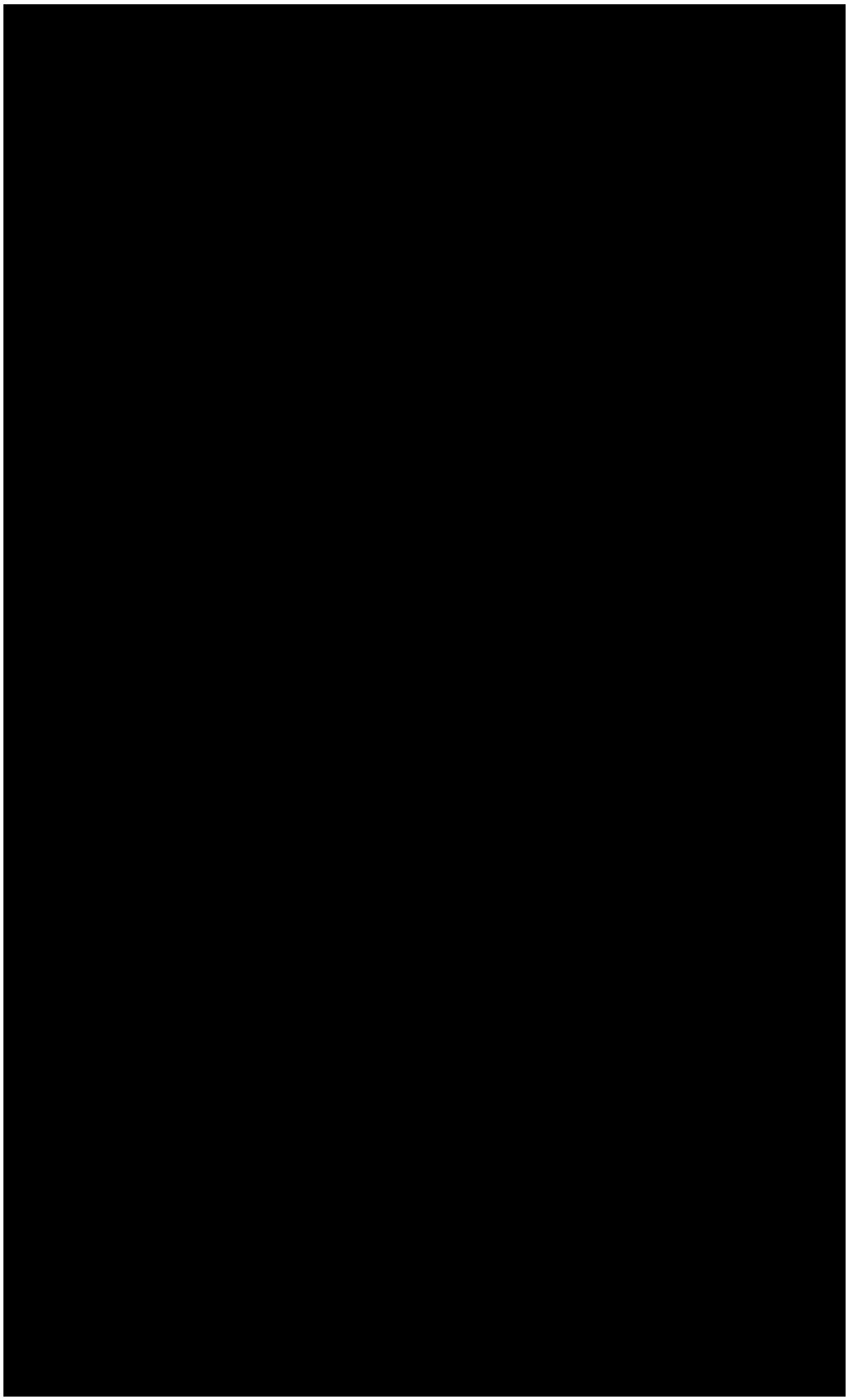


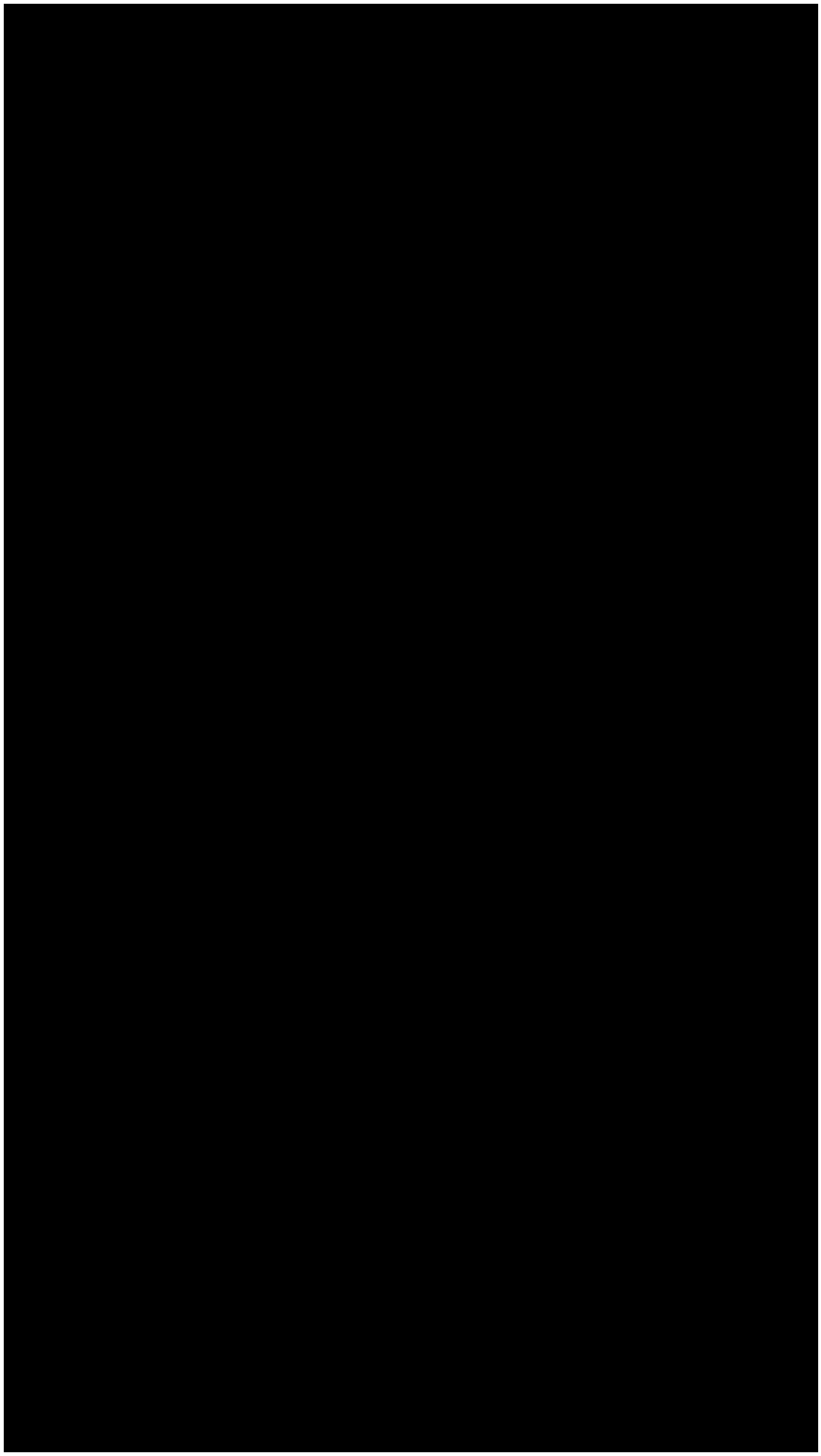


2.5.6 Porosity Model

Porosity logs from [redacted] within the geologic model boundary were upscaled to model resolution. Compressional sonic data are the most common porosity data source, but some bulk density data also informed porosity estimation. [redacted]

[redacted]





The estimated average total porosity and permeability of the net reservoirs within [redacted]

[redacted]

[redacted]

The porosity data were de-clustered to remove the sampling bias within the data in the 3D space. These de-clustered data were then used to define the porosity distribution (range) by facies. As part of the modeling process, total porosity logs were then upscaled, with a bias to the modeled facies. [redacted]

[redacted] The porosity model is built for each facies within the injection zone using a sequential Gaussian simulation algorithm, ensuring that the porosity distributions are being honored. Finally, this modeled total porosity volume is multiplied with the modeled NTG volume to derive the effective porosity volume.









2.5.7 Permeability Model

Permeability was modeled based on the results of stratigraphic appraisal well [redacted]

[redacted]







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 net thickness between wells in the injection zones, including the continuity of the net facies
- Vertical vs. horizonal permeability relationships adopted based on the log data
- Presence of intrazonal flow barriers, baffles, and pinchouts (permeability architecture)

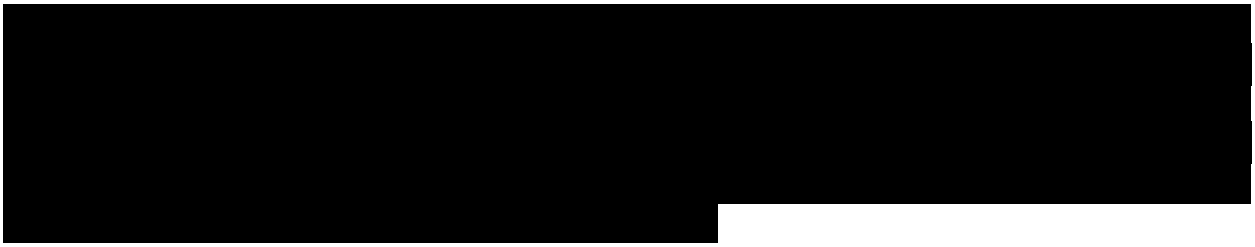
Based on the available data used in the geologic model, these uncertainties—though present—are not expected to have a significant impact on the model results and delineation of the AOR. The available geologic data are sufficient to characterize the overall depositional system and, in turn, key geologic features in the Sunflower 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 SLB 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



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 550 was applied uniformly along the four edges of the model domain. The effective aquifer volume in communication with the model is approximately 30 times greater than the modeled region pore volume. In addition, a transmissibility reduction of 1/550 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. A stratigraphic appraisal well was completed nearby and core samples were collected from the well 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 appraisal 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" (40 CFR **§146.83(a)(1)** [16 TAC **§5.206(b)(6)(A)**]). Both the UCCZ and Anahuac Shale are thick, continuous sealing intervals across the AOR and are sufficient to "contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone" (40 CFR **§146.83(a)(2)** [16 TAC **§5.206(b)(6)(B)**]).

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



[redacted]

2.6.3.1 Rock Compressibility

Based on the rock compressibility measurements for the sandstone samples collected at the stratigraphic appraisal well (Bead Farm Co. – 1), an average value of [redacted] Figure 2-37 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 appraisal well are demonstrated in Figure 2-38. These values are consistent with the literature-based ranges described in Figure 2-37.

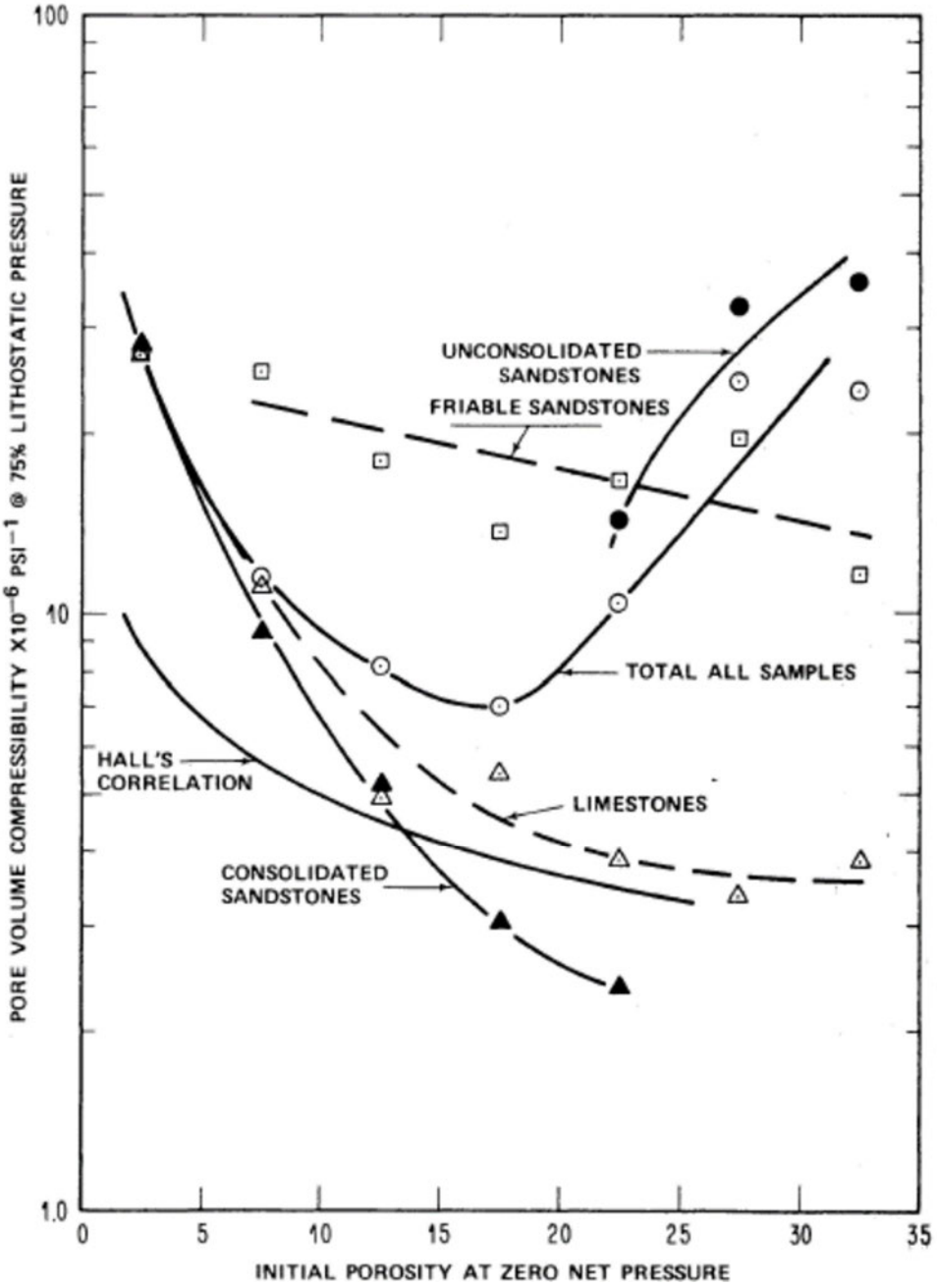


Figure 2-34 – Pore Volume Compressibility as a Function of Initial Porosity (Newman, 1973)

[redacted]

[redacted]

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 ([redacted]). 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. [redacted]

[redacted]

[redacted]

The irreducible water saturation was assumed to be in the range of 6% to 42% based on published values for various sand qualities in the available Gulf Coast regional data. [redacted] The geologic model's permeability property is based on absolute gas permeability, as shown in Figure 2-39 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 Brooks-Corey 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 l and estimated based on Burdine's theory:

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

In a gas-water system, the Brooks-Corey capillary pressure model (Eq. 3) indicates that the capillary pressure curves steepen as they approach the irreducible water saturation point. The five sets of capillary curves are plotted in Figure 2-40.

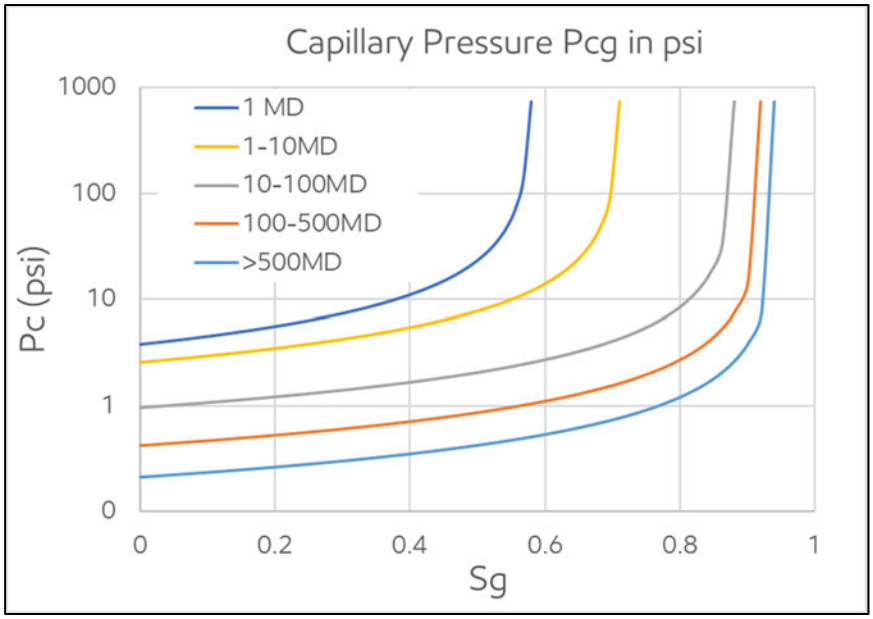


Figure 2-36 – Capillary Pressure Functions

2.6.3.4 Fluid Pressure

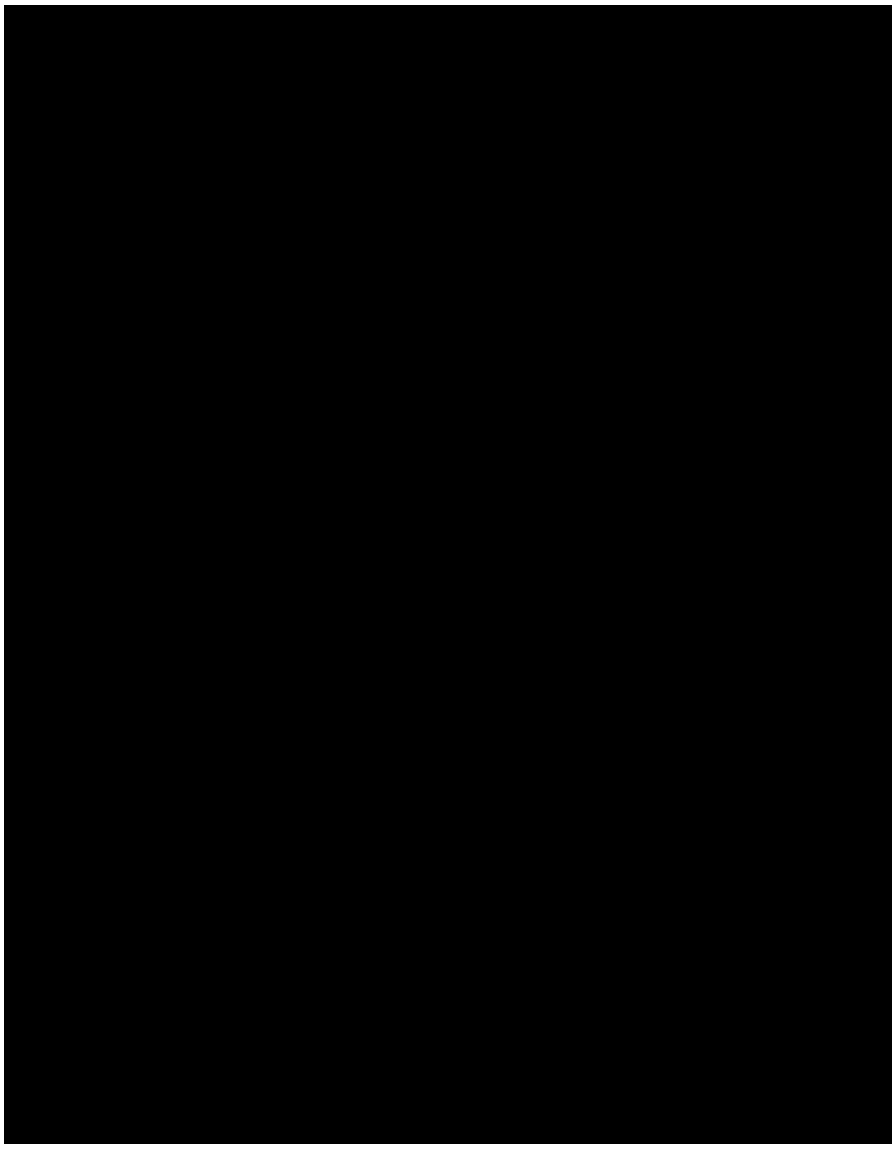
The average formation fluid pressure gradient was derived from 17 formation pressure data points acquired from the stratigraphic appraisal well. The pressure gradient value is 0.45 psi/ft and represented in Figure 2-41. This original reservoir pressure gradient was based on data points collected from 3,200–8,400 ft and was considered representative of sand intervals to be used for injection. The measured site-specific values are consistent with expected values obtained from available literature, which reported an average value of approximately 0.45 psi/ft (Kreitler, 1988).



*TVDSS – true vertical depth subsea
psia – pounds per square inch absolute

2.6.3.5 Temperature

Based on data collected from the stratigraphic appraisal well, the temperature gradient is [redacted] Mean surface temperature was assigned [redacted] yielding an original temperature of [redacted] in the reservoir model at a reference depth of [redacted] The original temperature was assigned to be consistent with this temperature and the temperature gradient throughout the model domain. The temperature gradient is presented in Figure 2-42.



2.6.3.6 Initial Saturation

A review of the available literature (Kreitler, 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 injection fluid stream will be a high-purity industrial source of CO_2. For this simulation, 100% CO_2 injection was assumed.

2.6.5 Fluid Composition

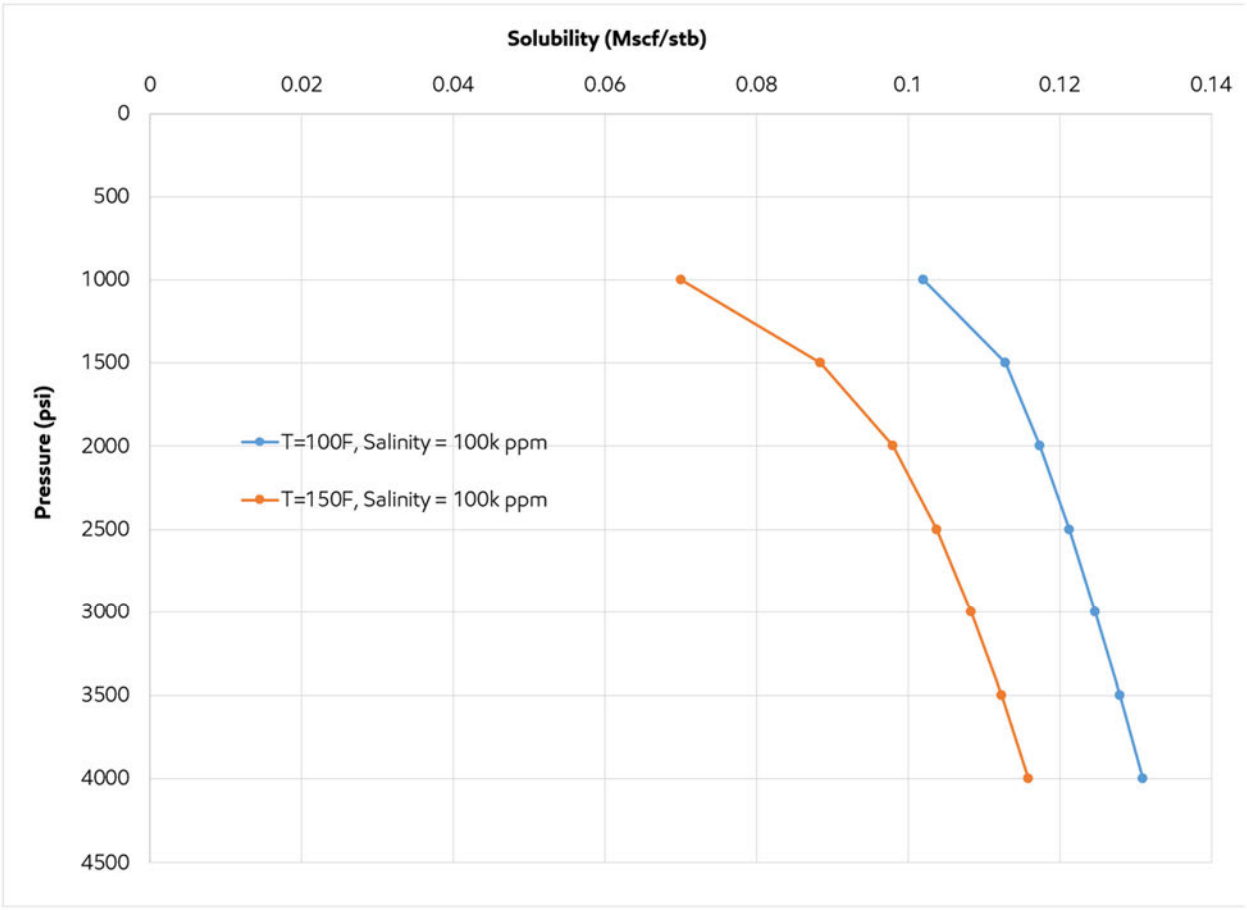
Fluid samples were collected from the nearby stratigraphic appraisal well and analyzed. The results of laboratory analyses for total salinity are summarized in Table 2-9. Based on this data, the simulation model was initialized with an average salinity of [redacted] at a reference depth of [redacted]. A detailed fluid analysis is presented in *Section 1.7* of *Section 1 – Site Characterization*.

[redacted]

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.

[redacted]



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

Figure 2-39 – 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. [redacted]

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 meter
cp – centipoise

Figures 2-44 and 2-45 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.

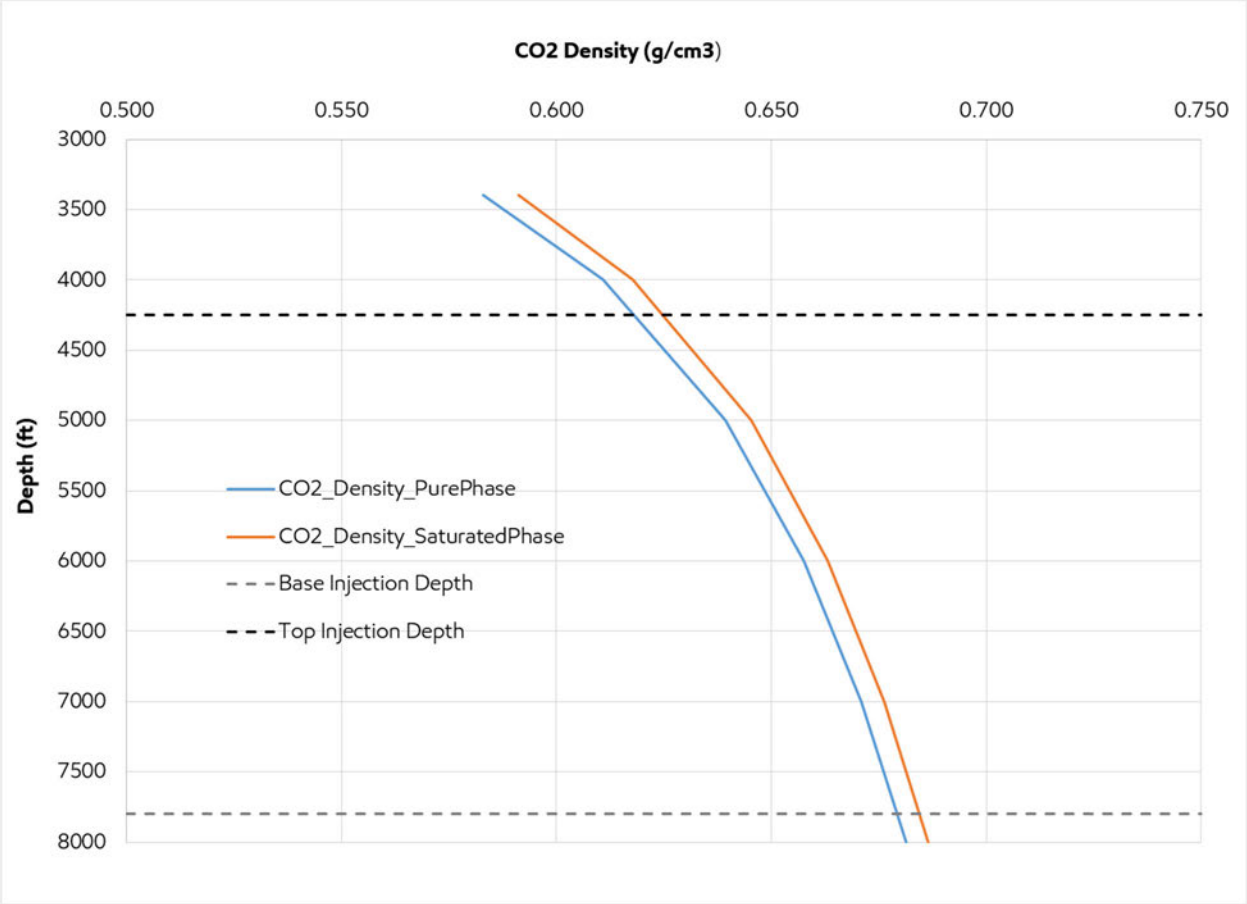


Figure 2-40 – Pure Phase and Saturated Phase CO_2 Density vs. Depth

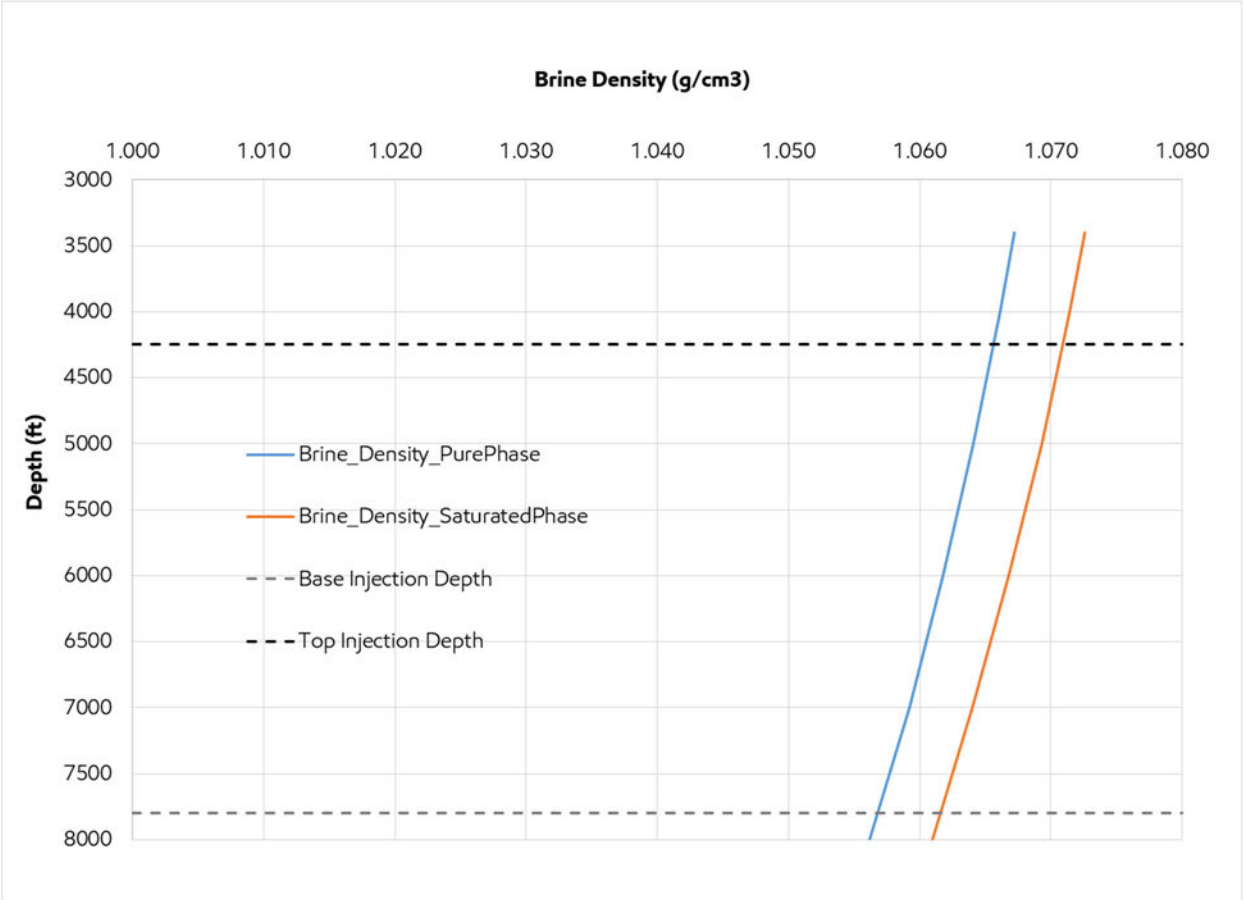


Figure 2-41 – Pure Phase and Saturated Phase Brine Density vs. Depth for Salinity = 100,000 ppm Case

2.6.5.4 Fluid Compressibility

[redacted]

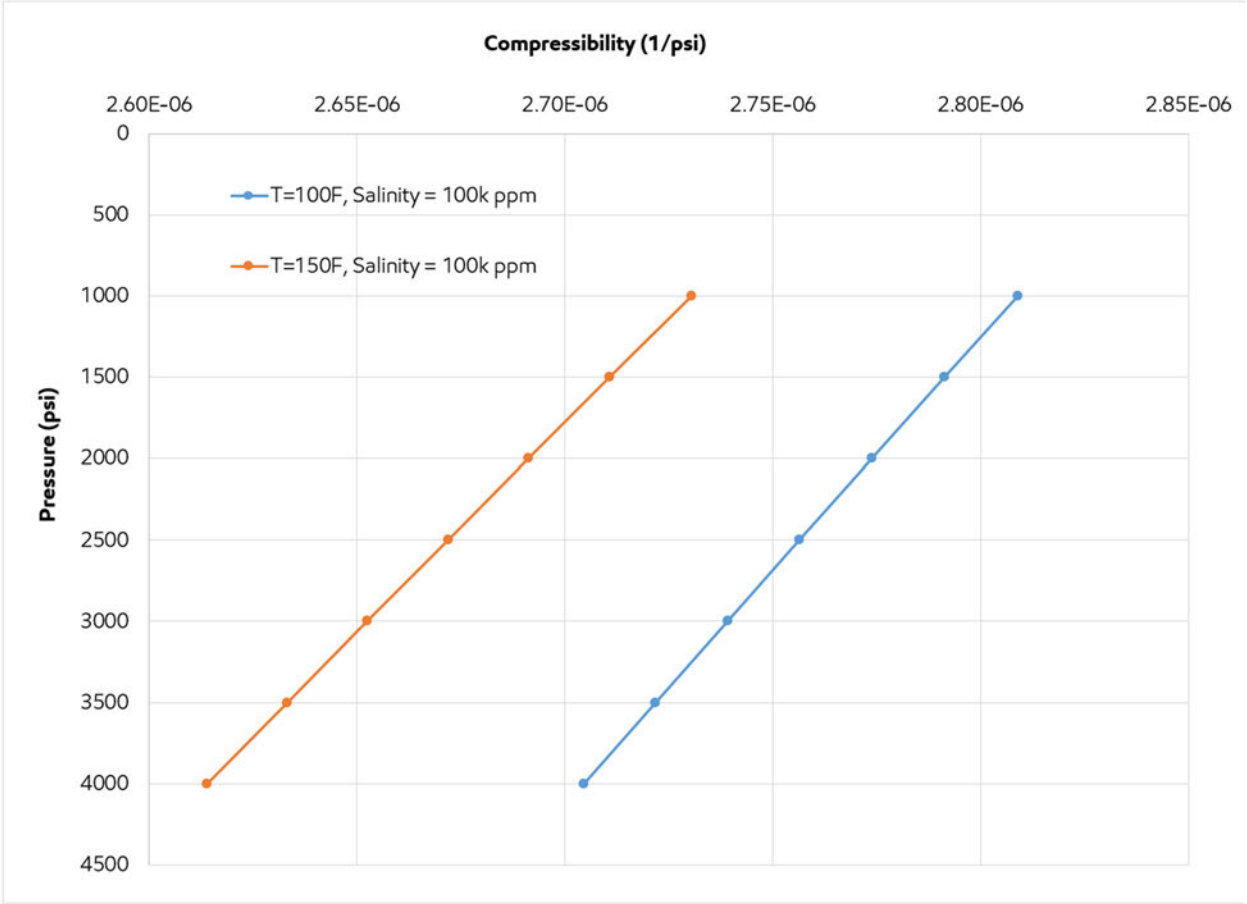


Figure 2- – Brine Compressibility at Different Pressures and Temperatures

2.6.6 Well Operating Parameters

2.6.7.1 Fracture Pressure and Fracture Gradient

As discussed in *Section 1.6* of *Section 1 – Site Characterization*, a log-based approach was utilized [redacted]

[redacted]

Table 2-12 – Maximum Modeled Bottomhole Injection Pressures



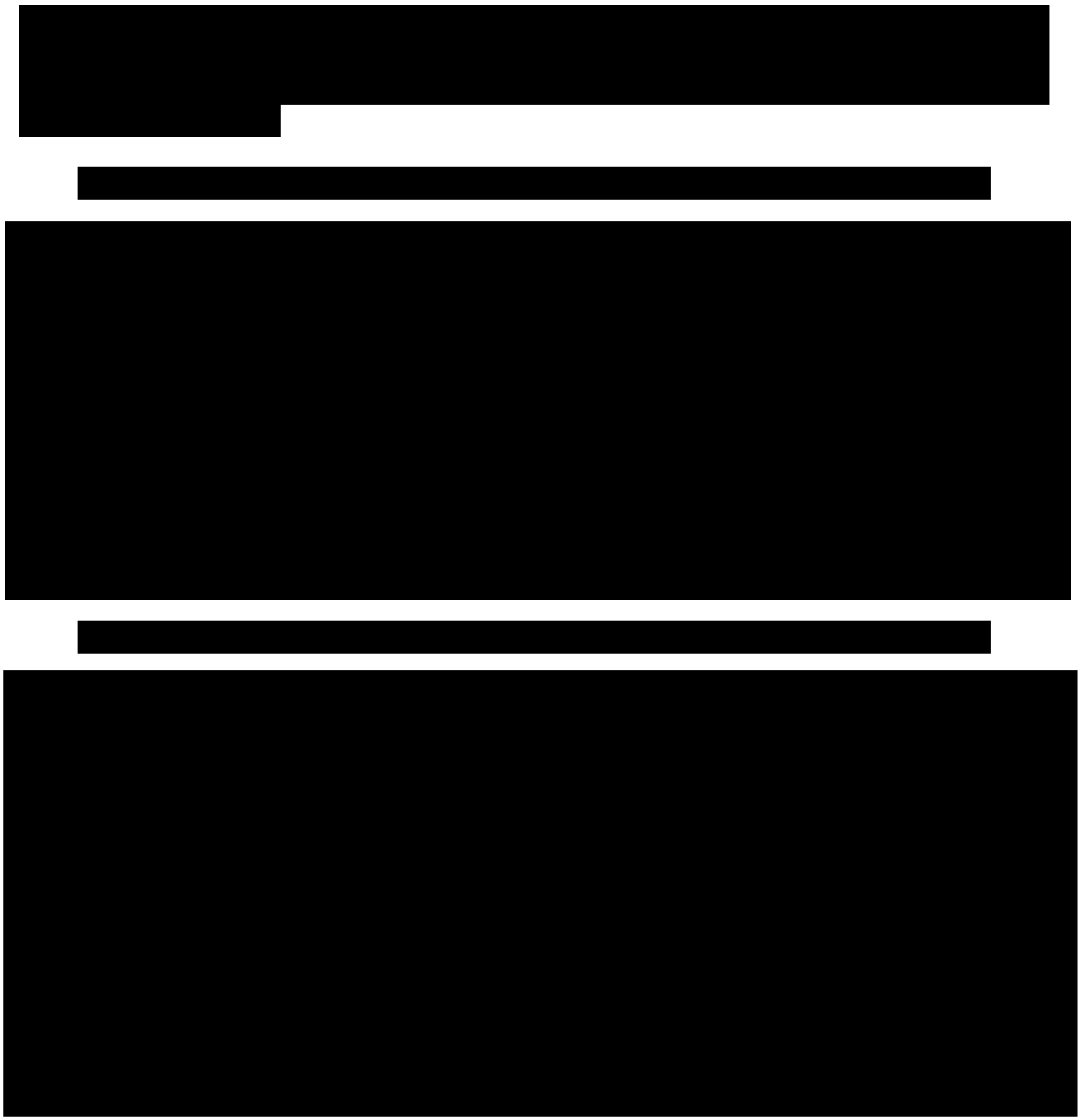
*BHP – bottomhole pressure

2.6.7.2 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.

[redacted]





[redacted]

[redacted]

[redacted]

2.7 Model Results

2.8.1 Active Injection Operations of Proposed CO_2 Injector

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 2-19 through 2-22 summarize the injection rate and pressure parameters corresponding to all stages in each well. Bottomhole pressures are reported at mid-sand face in each zone. The depths of these reporting intervals were listed in Tables 2-15 through 2-18.

[redacted]

Continuous injection rates, injection pressures, and associated pressure constraints for each well are illustrated in Figures 2-48 through 2-51. As shown, the operational bottomhole pressure remains well below the allowed maximum pressure, with at least a 600 psi margin in each zone.



[redacted]







The elevated pressure in the saline aquifer quickly dissipates once active-injection operations cease. Twelve years post-injection all injection wells are shut in; the reservoir pressure stabilizes close to initial conditions. Figure 2-52 represents the maximum pressure gradient throughout the life of the project. As shown, the pressure gradient never exceeds the constraint (90% of the fracture gradient) imposed on each well, to allow for the safe injection of supercritical CO_2.

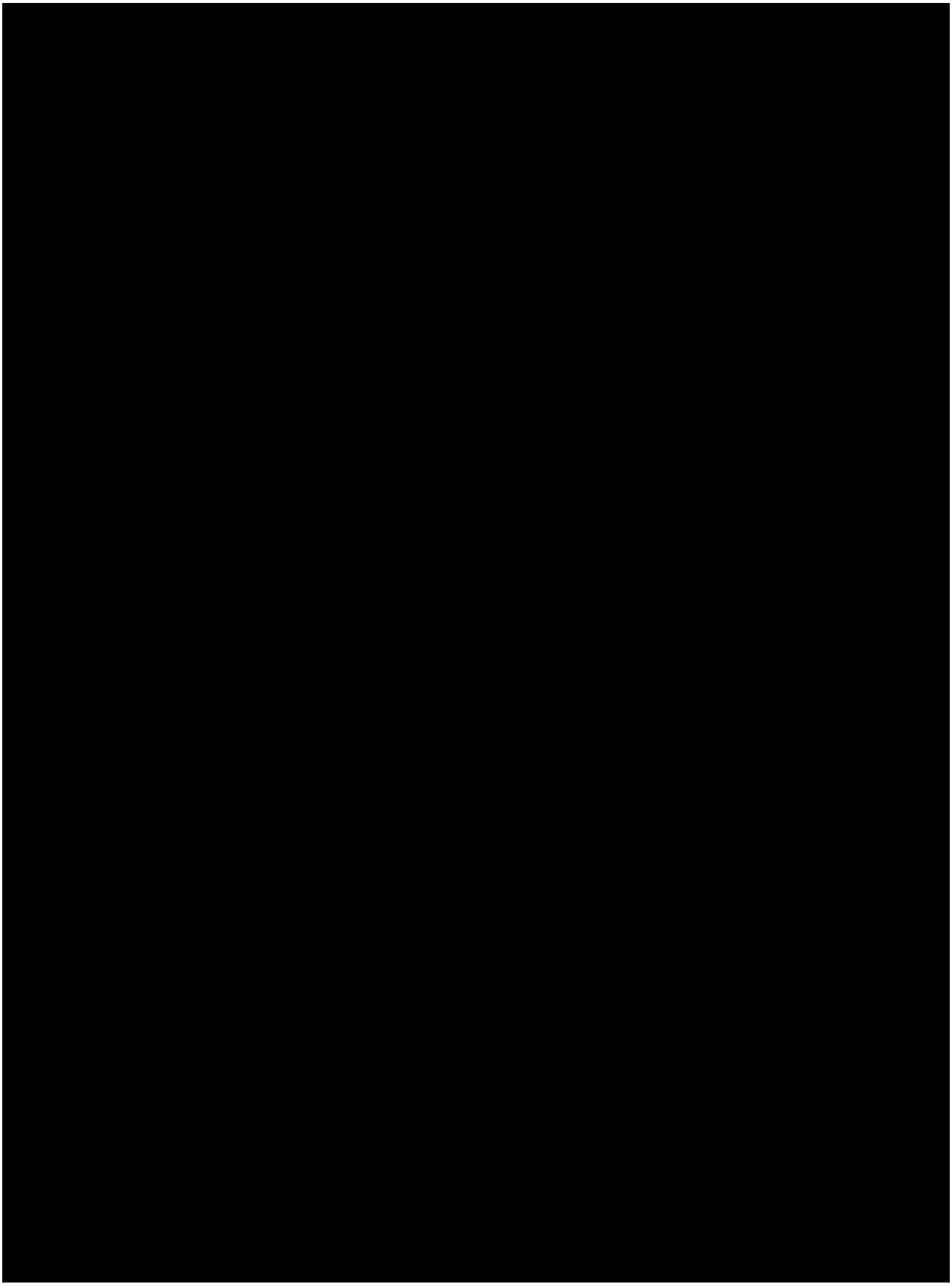


2.8.2 Extent of CO_2 Plume

In accordance with 40 CFR **§146.84** (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 2-47.

Figure 2-53 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 northwest. Figure 2-54 illustrates the cross-sectional view of the time-dependent CO_2 plume.





As shown in Figure 2-55, the rate of plume size growth is expected to diminish rapidly following the cessation of injection, [redacted]



[redacted]

2.8.3 Delineation of the Critical Pressure Front

In accordance with 40 CFR **§146.84** (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 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.

2.8.6.1 Critical Pressure Calculations

[redacted] 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.

[redacted] The critical pressure was calculated for each completion phase of each injection well, with the top of the effective injection-interval perforations ranging from depths [redacted] Based on the site-specific fluid samples from the stratigraphic appraisal well, the total dissolved solids (TDS) of the [redacted] The fluid within the USDW was assumed to be freshwater of 10,000 ppm salinity, with a fluid pressure gradient of [redacted] Inputs for an example calculation (Fleming Sand 1 interval in Sunflower CCS Project Injection Well No. 02's shallowest completion) are provided in Table 2-21.

[redacted]

















[redacted]
The critical pressure front, illustrated in Figure 2-56, represents the maximum areal cone of influence and combines results from the six completion intervals for each of the four injection wells.

2.8.7 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. [redacted] Superimposing the maximum CO_2 plume and critical pressure boundaries, Figure 2-57 provides the AOR boundary for the project.





2.9 References

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Intersect Technical Description, Reservoir Simulation, Compositional Fluid modeling.

Intersect Technical Description, Reservoir Simulation, Component solubility in the aqueous phase.

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 3 – Area of Review and Corrective Action Plan

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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- [redacted]
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- [redacted]
- [redacted]
- [redacted]

- [redacted]

The following subsections repeat information provided in Section 2.7 (Model Results) to provide context for the Corrective Action plan and AOR reevaluation plan that follow. More detailed information regarding geologic and dynamic model inputs and workflows can be found in Section 2 – Plume Model.

3.3.1 Extent of CO_2 Plume

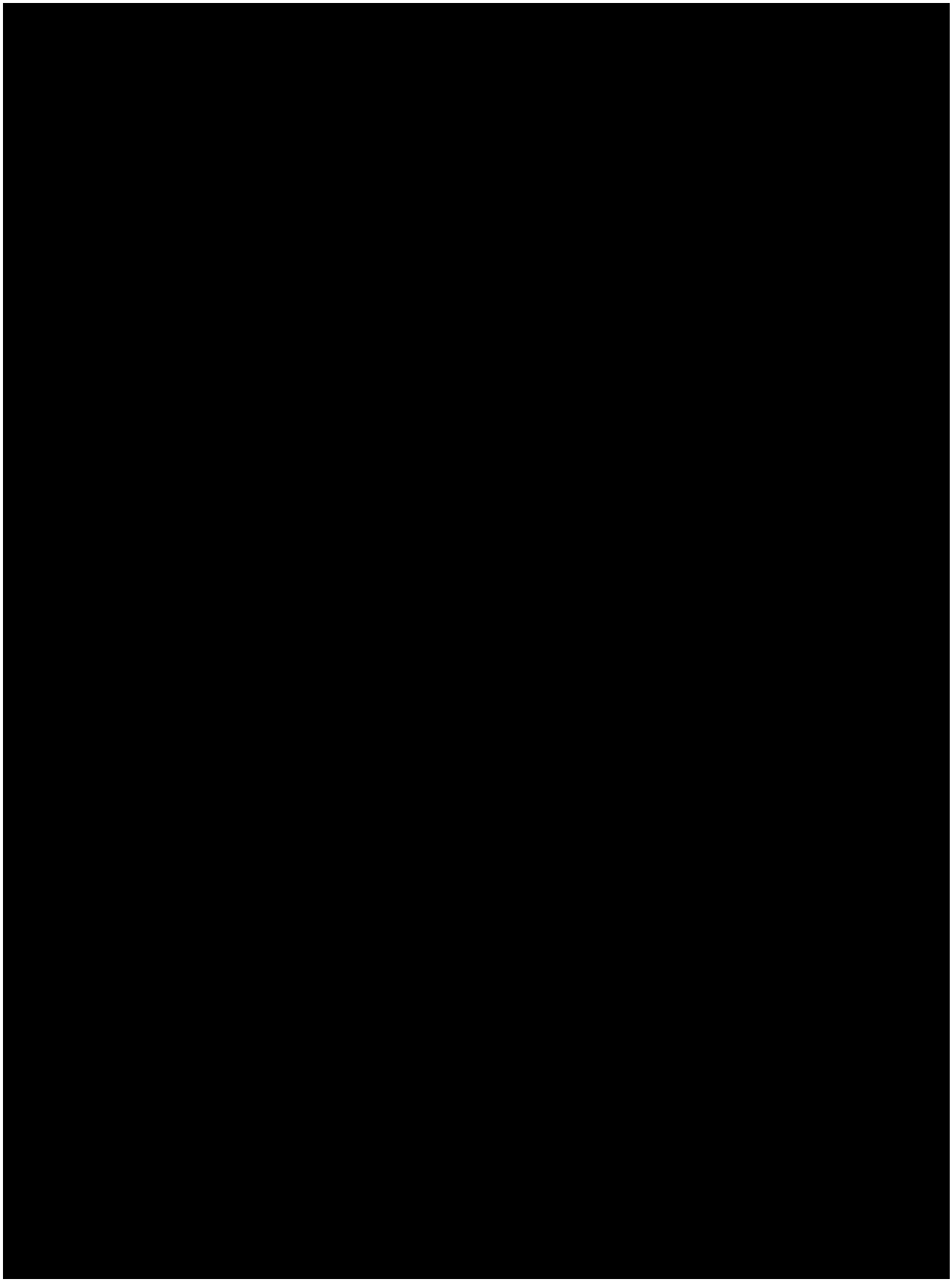
In accordance with 40 CFR **§146.84** (16 TAC **§5.203 (d)**), areal grid block size in the model was selected to optimize model runtimes, limit grid distortion effects, and allow for sufficiently accurate contouring of the plume extent. The operational and geologic input parameters were used in the 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 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 northwest. Figure 3-3 illustrates the cross-sectional view of the time-dependent CO_2 plume.



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As shown in Figure 3-4, the rate of plume size growth is expected to diminish rapidly following the cessation of injection, [redacted]

[redacted]

[redacted]

3.3.2 Delineation of the Critical Pressure Front

In accordance with 40 CFR **§146.84** (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.

3.3.2.1 Critical Pressure Calculations

[redacted] 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.

[redacted] The critical pressure was calculated for each completion phase of each injection well, with the top of the effective injection-interval perforations ranging from depths [redacted]

Based on the site-specific fluid samples from the stratigraphic appraisal well, the total dissolved solids (TDS) of the [redacted] The fluid within the USDW was assumed to be freshwater of 10,000 ppm salinity with a fluid pressure gradient of [redacted] Inputs for an example calculation ([redacted] interval in Sunflower CCS Project Injection Well No. 02's shallowest completion) are provided in Table 3-1.

[redacted]

[redacted]

3.3.2.2 Pressure Front Delineation

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 four injection wells.

3.3.2.3 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. [redacted] 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 four injection wells. Superimposing the maximum CO_2 plume and critical pressure boundaries, Figure 3-6 provides the AOR boundary for the project.

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[redacted]



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 appraisal well data. Physical rock-property distributions assigned to the model based on geostatistics have been analyzed and are consistent with all available data, including the stratigraphic appraisal 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 40 CFR **§146.84** (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 upper composite confining zone (UCCZ), and to specify corrective actions that would be taken to restore the integrity of the UCCZ, if needed. ExxonMobil undertook a thorough investigation of artificial penetrations within and immediately adjacent to the AOR. Public and private databases were searched, and a total of 30 stratigraphic appraisal wells, legacy oil and gas wells (legacy wells), and water wells were identified within the AOR as shown in Figure 3-6.

Twenty-two artificial penetrations were found to penetrate the UCCZ, based on an analysis of the available data. 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 40 CFR **§146.84(c)(2)** (16 TAC **§5.203(d)(1)(B)**), **§146.84(c)(3)** (16 TAC **§5.203(d)(1)(C)**), and **§146.84(d)** (16 TAC **§5.203(d)(1)(C)**), each artificial penetration within the AOR that may penetrate the UCCZ 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. For conservative purposes, the USDW depth of 2,000 ft measured depth (MD) was used for setting the USDW cement plugs.

3.5.1 Data Acquisition and Evaluation of Artificial Penetration Information

In accordance with 40 CFR **§146.82(a)(2)** (16 TAC **§5.203(b)**)**, §146.82(a)(4)** (16 TAC **§5.203(d)(1)(B)**), and **§146.84(c)(2)** (16 TAC **§5.203(d)(1)(B)**), a search was conducted to identify and assess the occurrence of artificial penetrations within the AOR. 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 springs, mines, and quarries within the AOR. No such sites were found to exist within the AOR.

The following data searches were conducted for the Sunflower Project to make a determination. Based on a data search utilizing the EPA EnviroAtlas, the Sunflower Project is free of any Superfund/CERCLA sites, hazardous waste/RCRA sites, and brownfields. The project area is free of any leaking underground storage tanks or subsurface cleanup sites based on data from the EPA's Underground Storage Tank Finder and Cleanups map. Additionally, the Sunflower Project is free of any mines or quarries according to the Office of Surface Mining Reclamation and Enforcement and the National Mine Map Repository.

The following data sources were reviewed to identify potential artificial penetrations within the AOR:

- The Railroad Commission of Texas (TRRC) GIS Database
- The 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

A tabulation of identified artificial penetrations within the AOR was created using a combination of the above data and is summarized in Table 3-3. 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 of the AOR will be conducted.
- In-person reconnaissance surveys will be conducted once surface access is secured.

[redacted]

[redacted]

[redacted]

[1] Readily available well identification numbers provided from public data sources up to October 8, 2024.

[redacted]

*Water well datum is BGL.
**Kelly bushing (KB) not available in historical records.
***NAD 83 – North American Datum of 1983

3.5.1.1 Physical Records Review

The records of artificial penetrations with the AOR were reviewed through digital copies on the TRRC online databases, Enverus Drilling Info, and IHS Energy Portal. These records are included in *Appendix C*.

3.5.1.2 Aeromagnetic Survey

Due to the age of well development in the area, additional data collection is required to improve the accuracy of well locations and details. Magnetic survey methods are planned to be conducted in 2024. Magnetic survey methods will be used to scan portions of the AOR for magnetic anomalies caused by subsurface features, which could include abandoned wellbores with iron or steel casing.

This section and its associated tabulation of artificial penetrations will be updated with aeromagnetic survey results once the surveys are executed. Legacy well locations will be updated and any additional artificial penetrations of the UCCZ will be added, and corrective actions required to remediate the UCCZ will be planned.

3.5.1.3 Review of Abandoned Well Plugging Records

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

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

Wells listed on lines 1 through 22 were identified as penetrating the UCCZ and subject to an assessment of plugging records and, potentially, to corrective action for deficiencies.

3.5.1.4 Summary of Artificial Penetrations Tabulation

Wells and boreholes that did not penetrate the UCCZ were determined to pose no hypothetical risk to function as a vertical conduit from the injection zone. For those artificial penetrations that were completed below the UCCZ, multiple sources of information were reviewed, and the relevant information was analyzed in detail (40 CFR **§146.84(c)(2)** [16 TAC **§5.203(d)(1)(B)**]). Table 3-3 presented a summary of the artificial penetrations of interest for developing the Corrective Action Plan. Schematics detailing UCCZ penetrating wells and their proposed corrective action plan are presented in *Appendix C*.

3.5.2 Corrective Action Plan for Artificial Penetrations

ExxonMobil developed a Corrective Action Plan for each artificial penetration that was identified to have the potential to act as a vertical conduit, because it was either not plugged or not plugged in a manner that, as required by 40 CFR **§146.84(c)** and **(d)** (16 TAC **§5.203(d)(1)**), mitigates the movement of CO_2 or other fluids that could potentially endanger USDWs. For the wells identified with plugging deficiencies, the basis for the corrective action strategy is to reenter and install cement barriers to mitigate migration potential.

3.5.2.1 Corrective Action Phasing

[redacted]

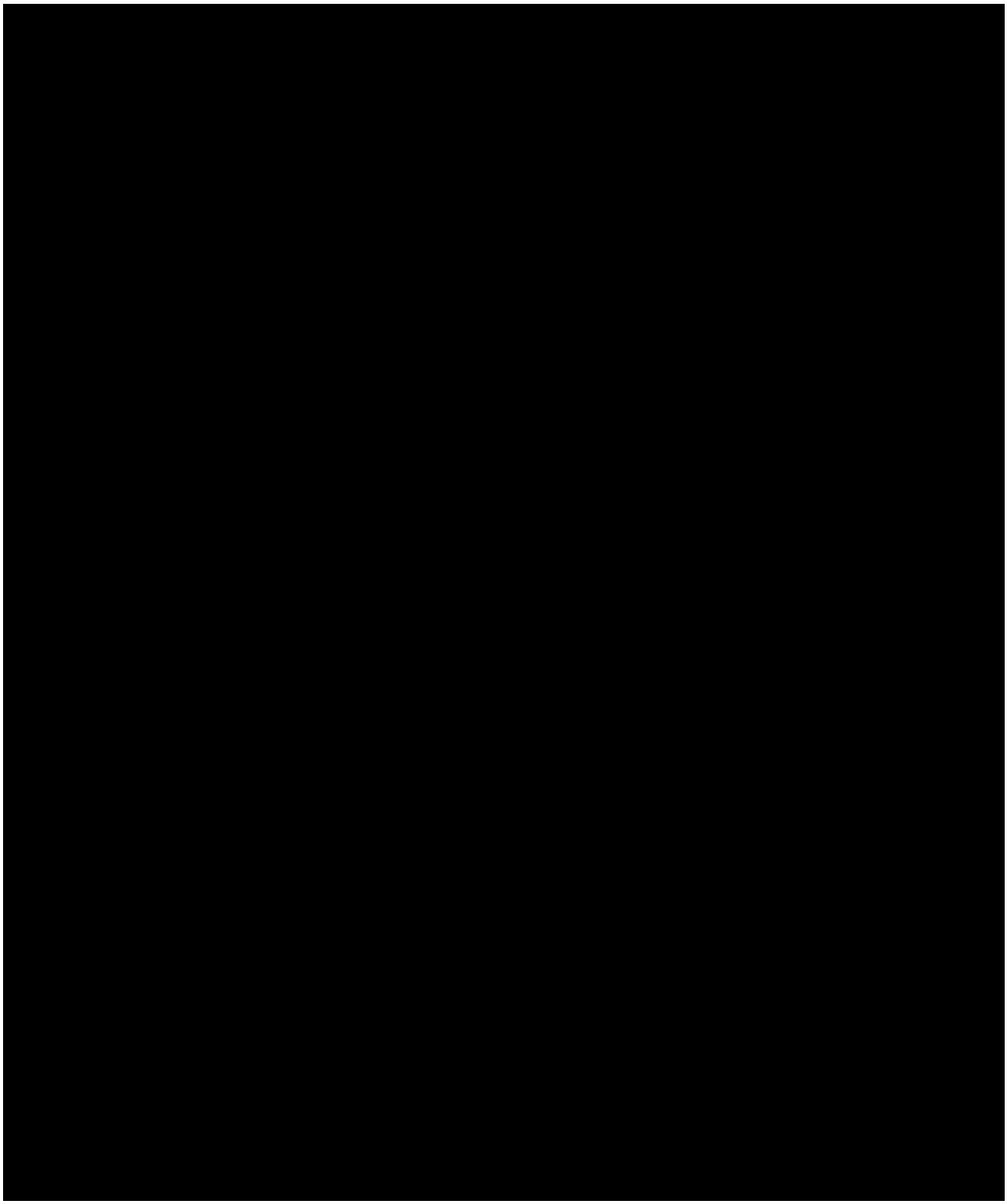
As described in *Section 5 – Testing and Monitoring Plan*, direct and indirect monitoring technologies will be used to track the CO_2 plume and pressure front. A planned reevaluation of the AOR will occur after 5 years of injection and at least at 5-year intervals throughout the life cycle of the Sunflower Project. If at any evaluation, the rate of the CO_2 plume or pressure front expansion is predicted to impact additional artificial penetrations that may be found, the Corrective Action Plan will be amended to include the necessary corrective action to address the potential for USDW endangerment, in accordance with 40 CFR **§146.84(b)(2)(i)–(iv)** (16 TAC **§5.203(d)(2)(B)** and **(C)**).

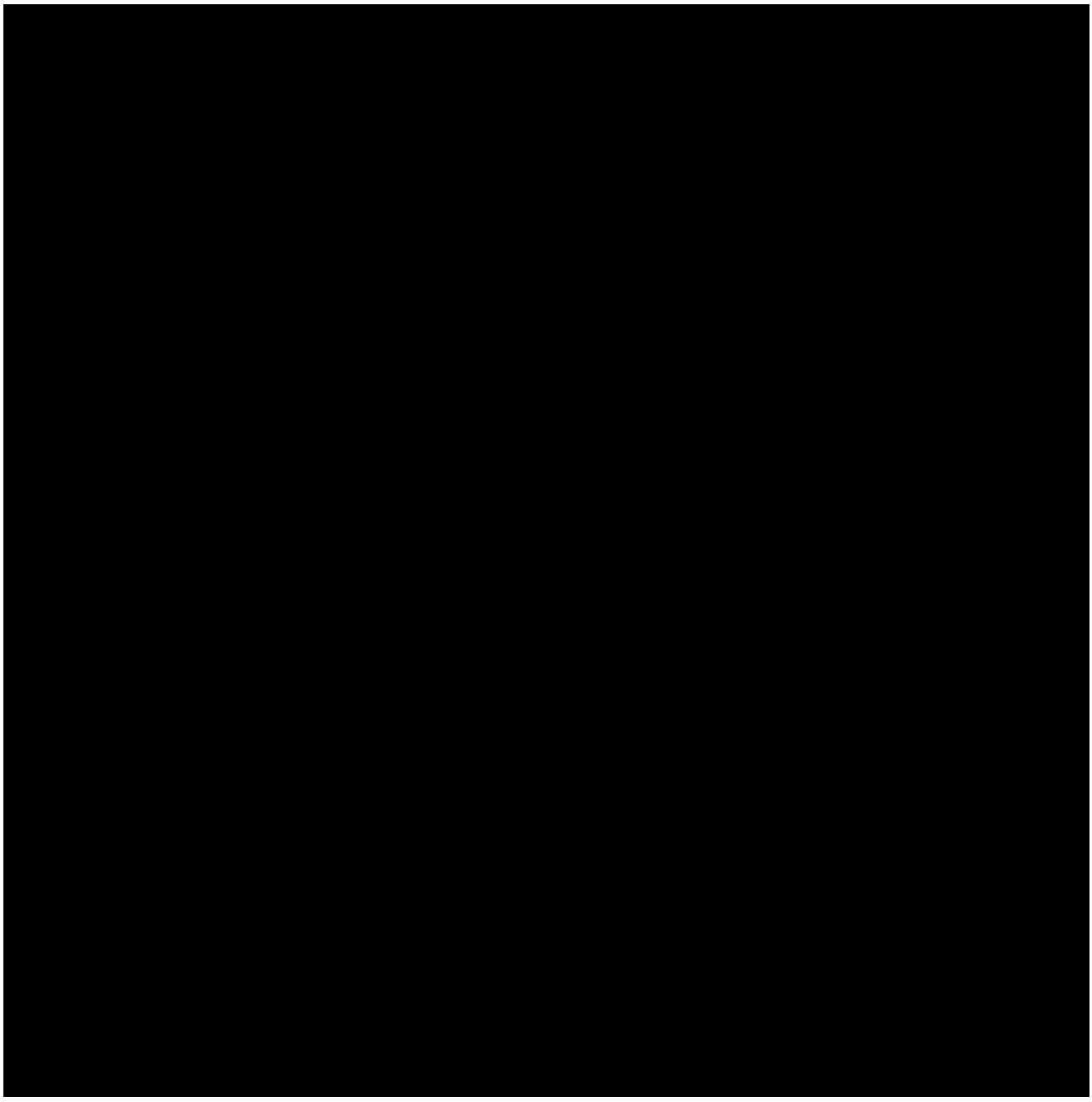
3.5.2.2 Analysis of Wells Identified for Corrective Action

Table 3-4 summarizes the available information concerning the borehole or well completion features and the P&A activities, as appropriate. ExxonMobil reviewed this information and determined the specific defects that require mitigation under 40 CFR **§146.84(c)** and **(d)** (16 TAC **§5.203(d)(1)**).

[redacted]

[redacted]





[redacted]

The planned actions are based on proposed plug deficiencies potentially present in the legacy wells based on the available records (displayed above, in Table 3-5). Each artificial penetration in the CO_2 plume will be reentered, and if sufficient barriers are not present, each well will have the appropriate barriers installed during the corrective action P&A field operations. The barriers will be established at the UCCZ, the surface casing shoe (where applicable), the base of usable quality water (BUQW), the base of the lowermost USDW, and the wellhead surface. The barrier at the UCCZ will be constructed of CO_2-compatible material consistent with 40 CFR **§146.84(d)** (16 TAC **§5.203(d)(1)(C)**).

A general approach for well reentry and corrective actions is summarized in the sections below.

A detailed summary of the corrective action sequence for each well is presented in Table 3-6—and in *Appendix C* as specific well schematics for each well to be reentered.

3.5.3.1 Preparing the Surface Location

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

If a sign or marker is present, the first step will be to confirm that the API number on the plat corresponds to the well where mobilization is taking place, to complete corrective action operations. After the P&A marker or exposed metal plate is removed, the necessary equipment will be rigged up on the well. The cement surface plug of the well will be drilled out and the hole reentered for corrective action.

ExxonMobil will follow required notification requirements prior to commencing remedial field activities that may take the form of workover or drilling operations. At least 5 days prior to commencement of well plugging operations, ExxonMobil will notify the TRRC via a request for approval of the proposed procedure for plugging the well, using Form W-3A. ExxonMobil will also notify the TRRC at least 4 hours prior to the start of plugging operations. Copies of the notifications and of field operational records provided to the state will simultaneously be provided to EPA Region 6.

[redacted]

[redacted]

[redacted]

3.5.3.3 Setting a Plug for the UCCZ

Each legacy well requiring corrective action will have a CO_2-compatible cement plug set at the base of the UCCZ. The cement will be designed to withstand the long-term exposure of temperature, pressure, and chemical environment. The barrier will be tested for estimated hardness and integrity after placement.

3.5.3.4 Setting Plugs at the Casing Shoe, Lowermost USDW, BUQW, and Surface

A cement plug will be set at the USDW, BUQW, and casing shoe (when present). The lowermost USDW will be plugged with a minimum 130-ft cement plug that will be set at the base of the lowermost USDW depth, starting from 50 ft beneath that depth and extending 80 ft above the target depth. In accordance with 6 TAC **§3.14(e)(1)(2)(3)**, the BUQW will be plugged with a minimum 130-ft cement plug set at the base of the BUQW, starting 50 ft beneath that depth and extending 80 ft above the target depth. The cement will be lab-tested prior to pumping, and pressure-tested or tagged at each relevant marker. A final 30-ft cement plug will be set at the surface before cutting the casings 5 ft beneath the surface.

[redacted]

3.5.3.6 Surface Restoration

The wellhead will be cut off at 5 ft BGL. A metal plate with the API number will be welded to the top of the casing. The area around the well will be backfilled above the casing stub to the surface. The site will then be restored to its previous conditions.

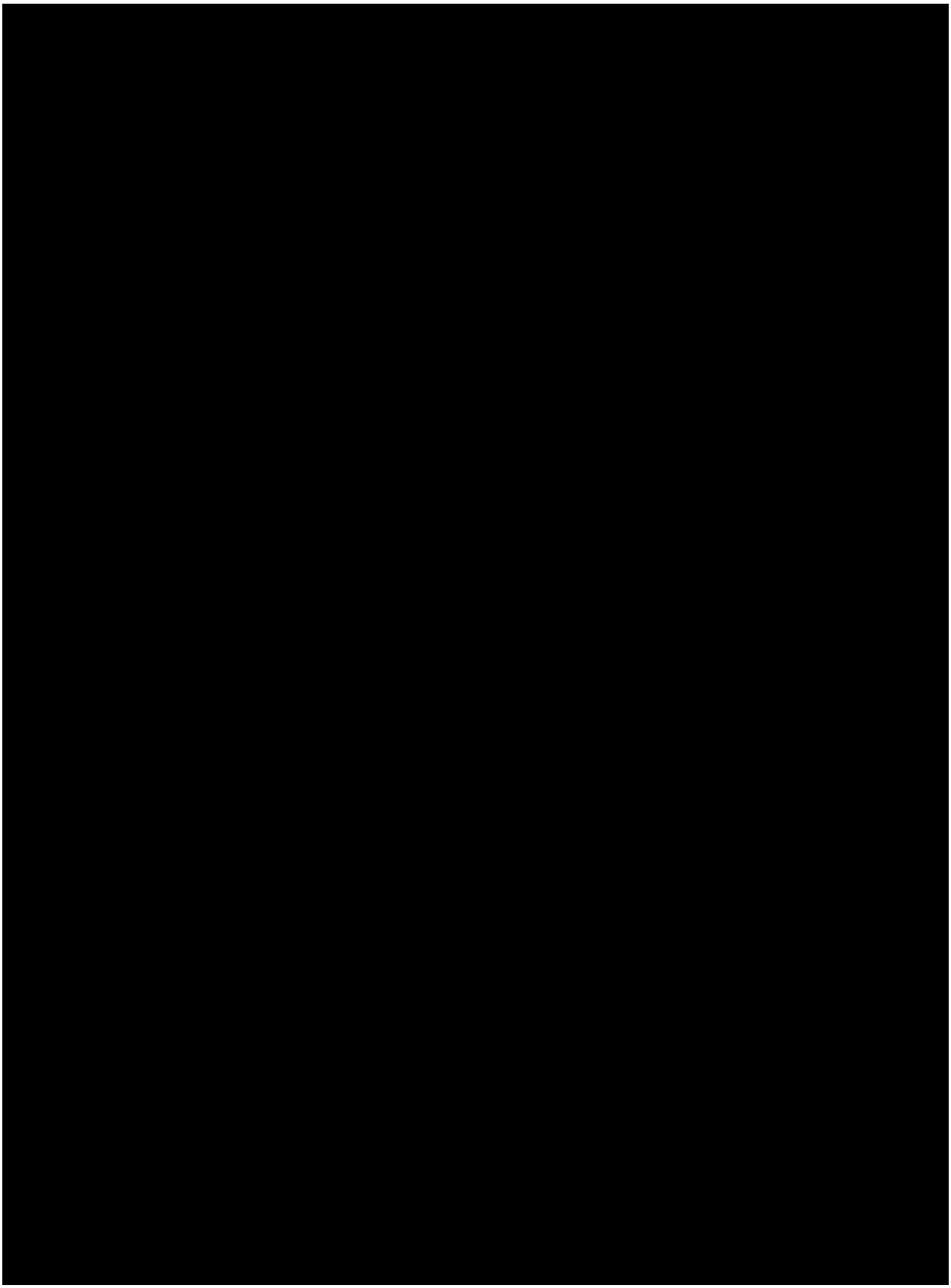
3.5.3.7 Reporting Completion of Corrective Action

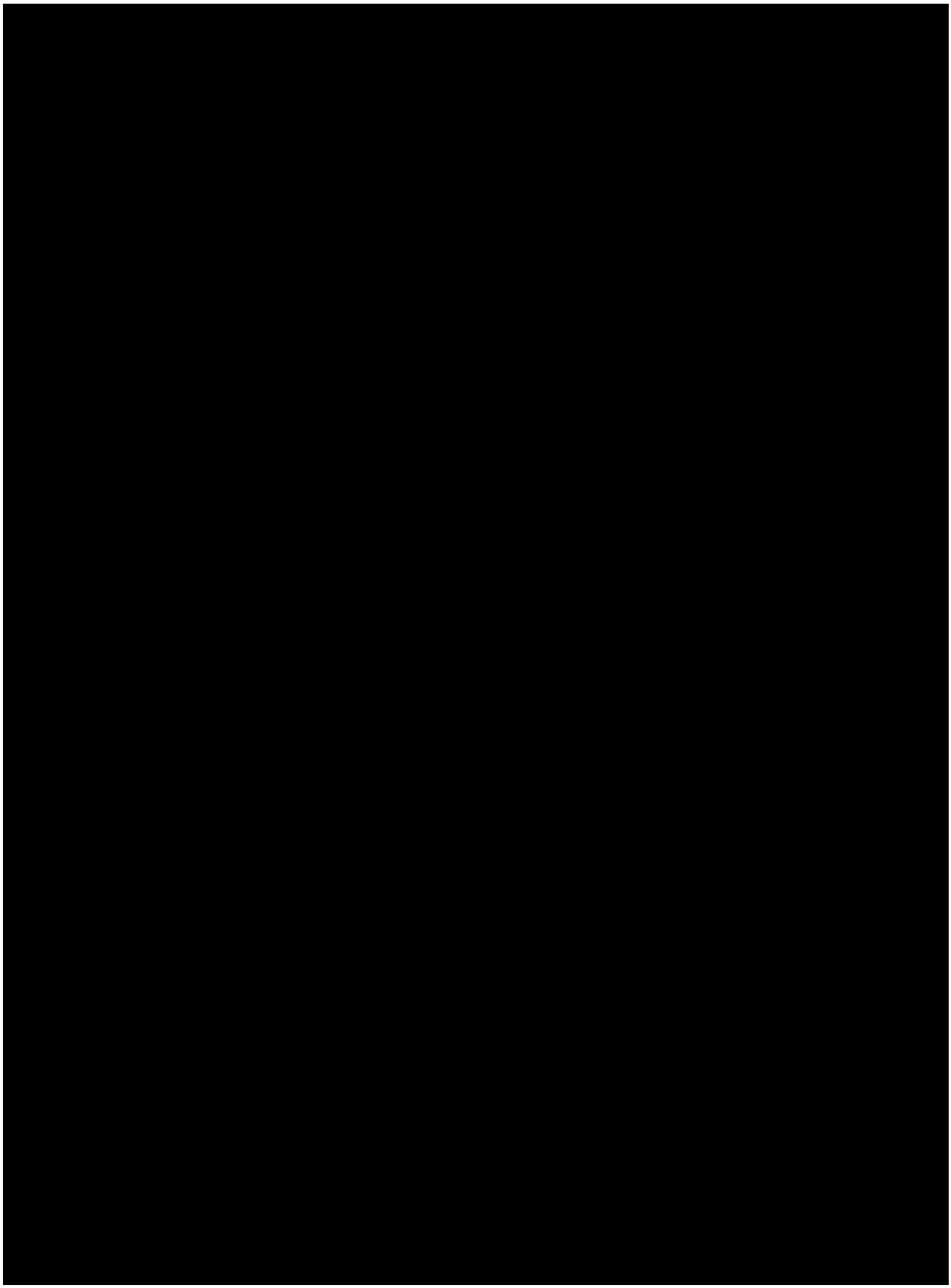
After completing the corrective actions and re-plugging a well, a W-3 plugging report will be submitted to the TRRC within 30 days of plugging, including the W-15 cementing report. Records of the corrective actions will be submitted to the UIC Director, with copies provided to EPA Region 6.

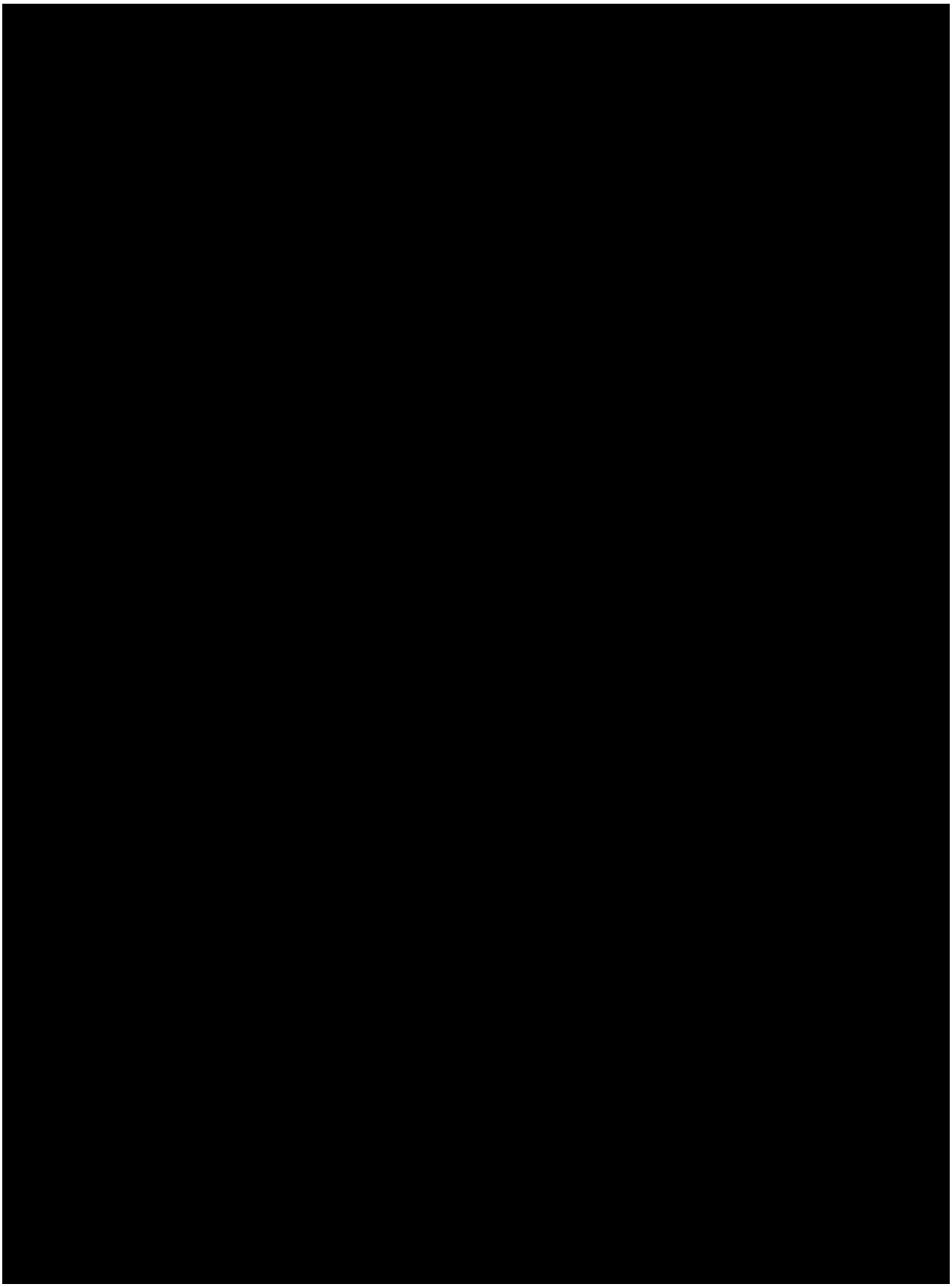
3.5.4 Site-Specific Review of Corrective Actions

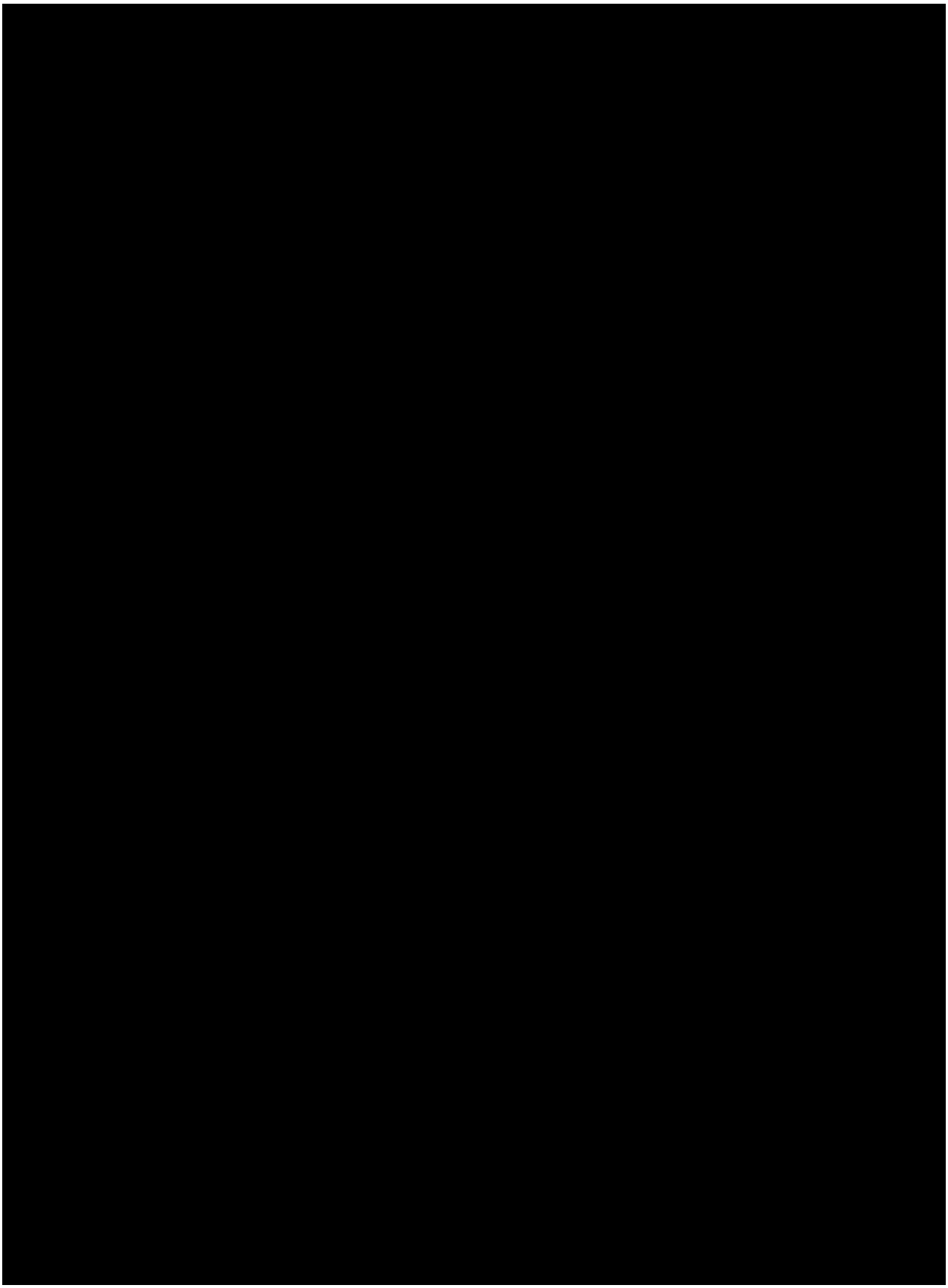
Table 3-6 provides the corrective action sequences for the 22 wells. For each legacy well that will be reentered for evaluation and re-plugging, *Appendices C-1* to *C-22* provide the well schematics that have been developed based on both the historical information and the completion of the associated proposed corrective actions.

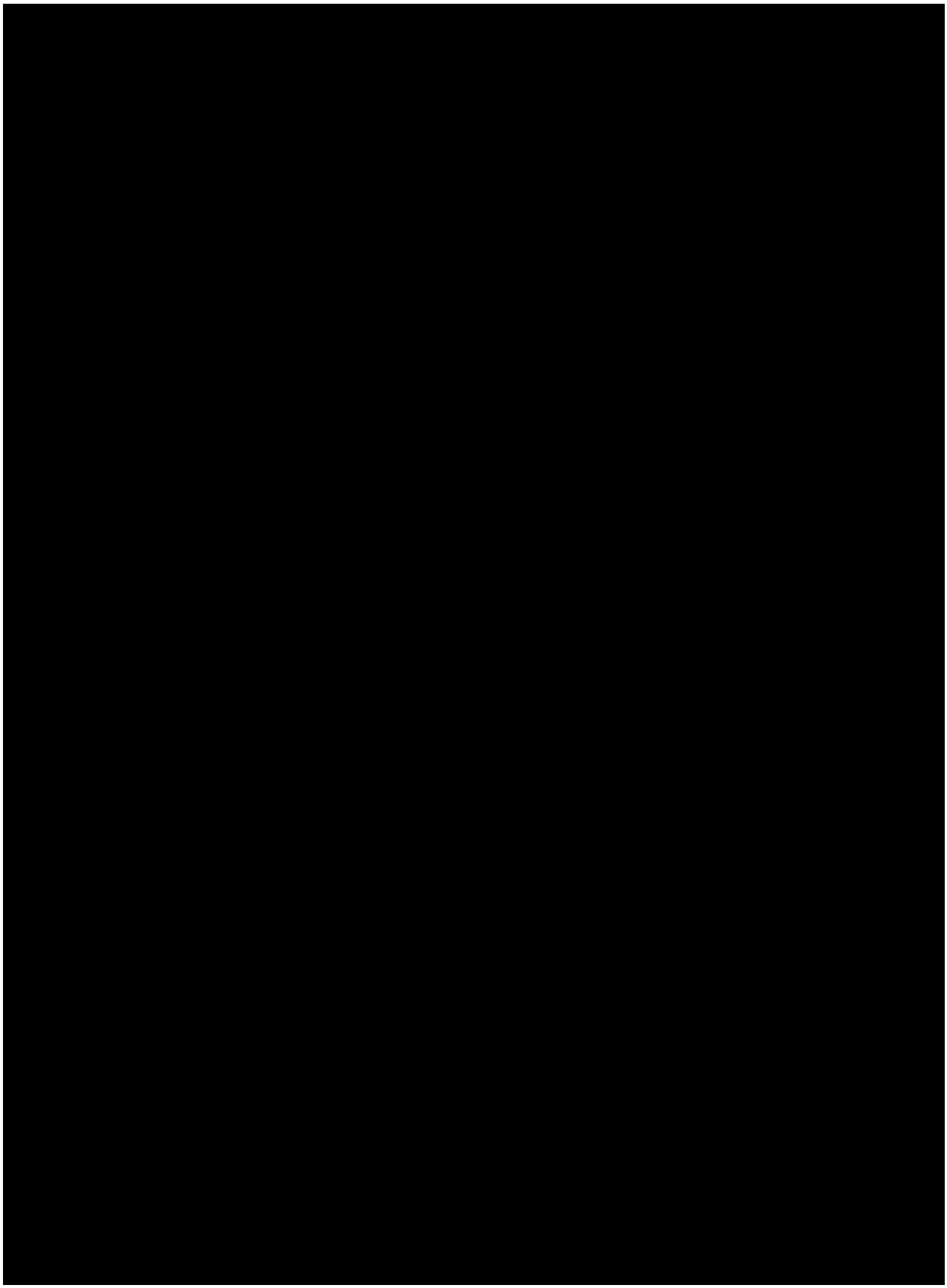












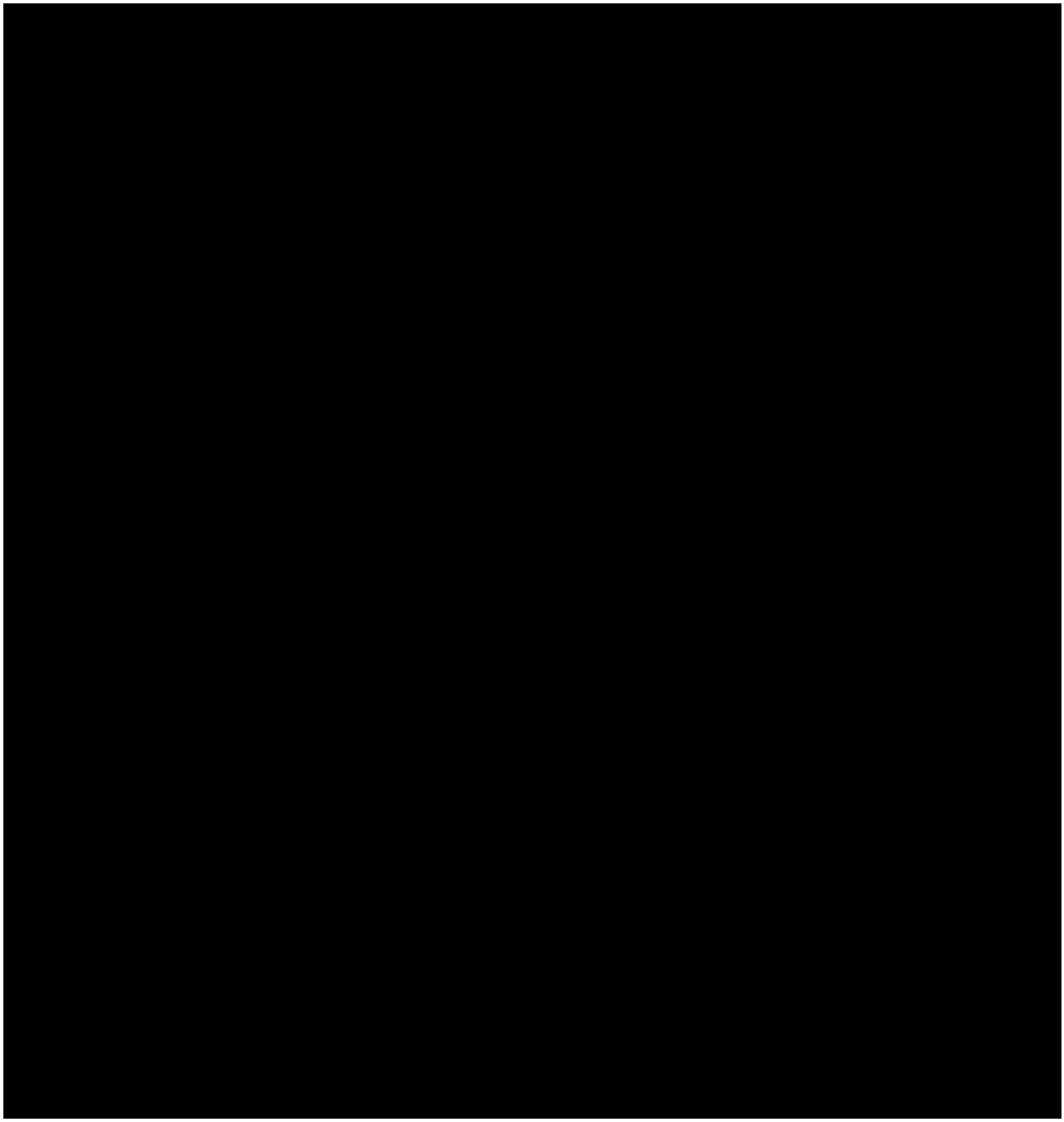


3.5.5 Plan for Site Access

In accordance with 40 CFR **§146.84(b)(2)(iv)** (16 TAC **§5.203(d)(2)(C)**) and 40 CFR **§146.84(d)** (16 TAC **§5.203(d)(1)(C)**), ExxonMobil is in the process of negotiating land access for each of the artificial penetrations identified for corrective action. Research to identify the well owners via regulatory databases has been completed. The process of securing necessary access rights (Table 3-7) will be completed in advance of the final submittal of this permit application to the UIC Director.

Discussions are underway with the owner and operators of record to enter into an access agreement to perform corrective actions. If appropriate and necessary, ExxonMobil will seek plugging orders from the TRRC in accordance with Subchapter C of Chapter 89 of the Texas Natural Resource Code to obtain access for corrective actions.

If the AOR reevaluation conducted at the minimum schedule of once every 5 years identifies the potential for corrective action requirements at additional wells, ExxonMobil will promptly begin review of the additional wells in accordance with the process described in this Corrective Action Plan. If site access issues are identified for wells identified for corrective action, ExxonMobil will notify the UIC Director.



[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

- [redacted]
- [redacted]
- [redacted]

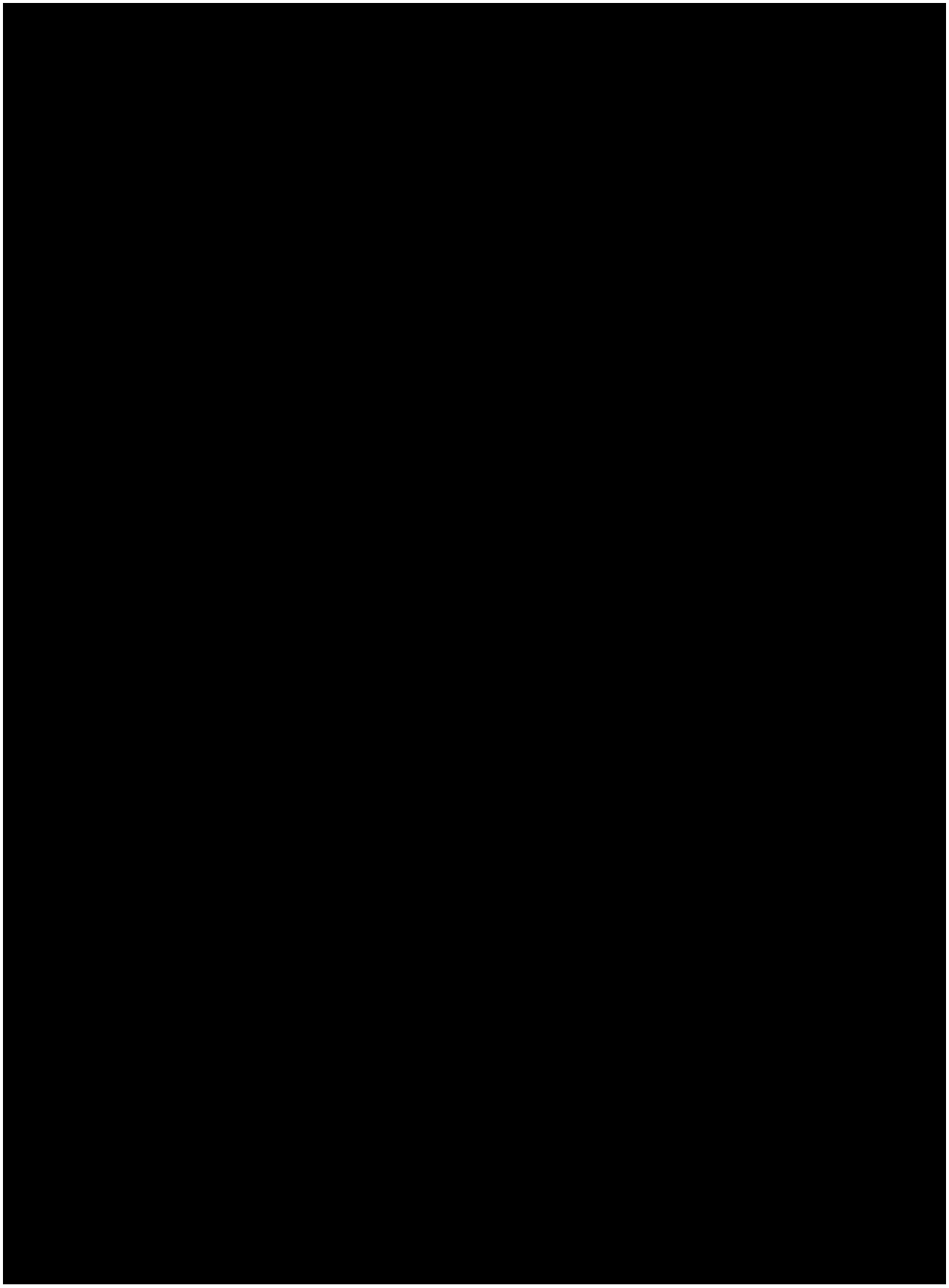
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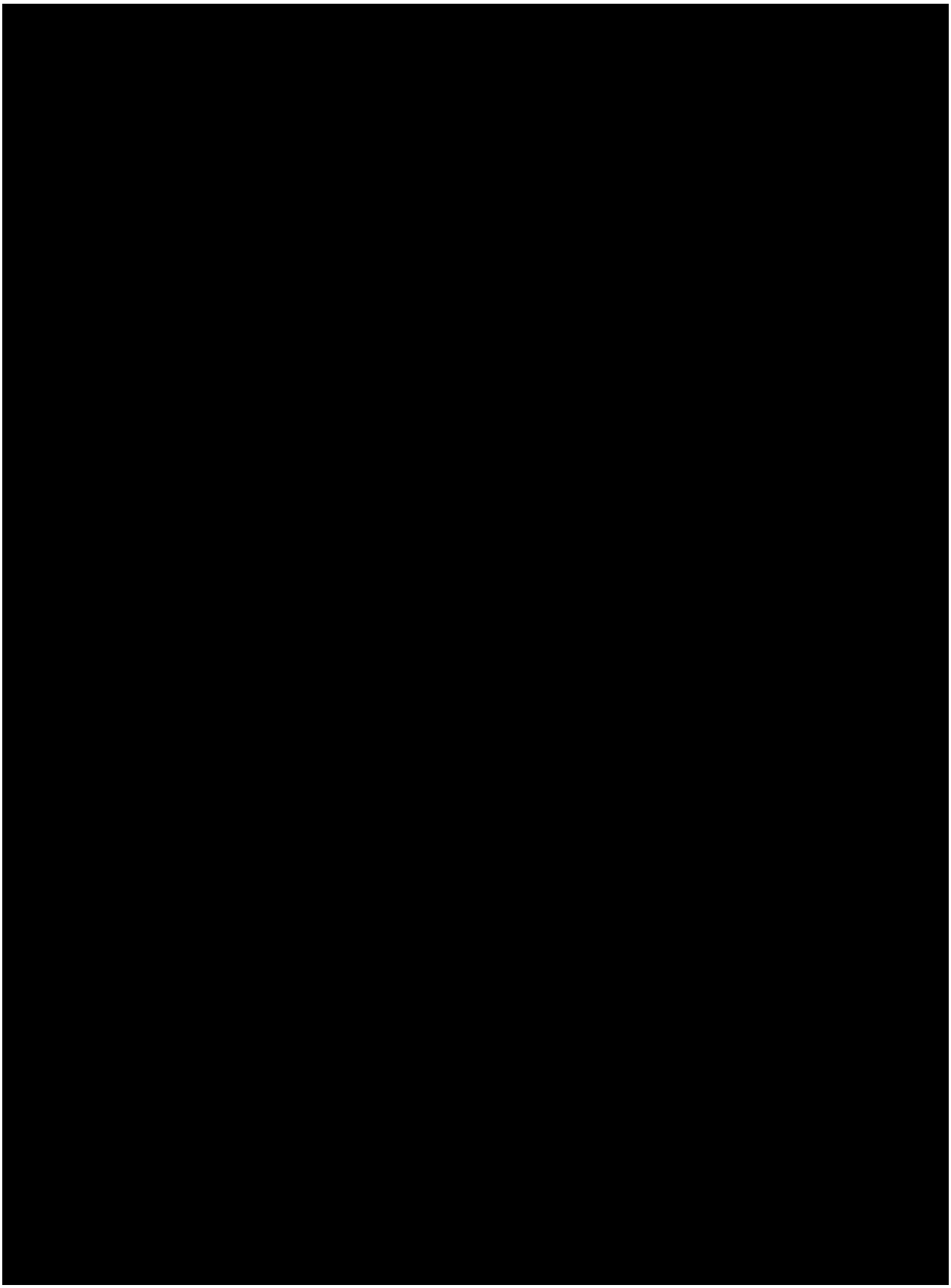
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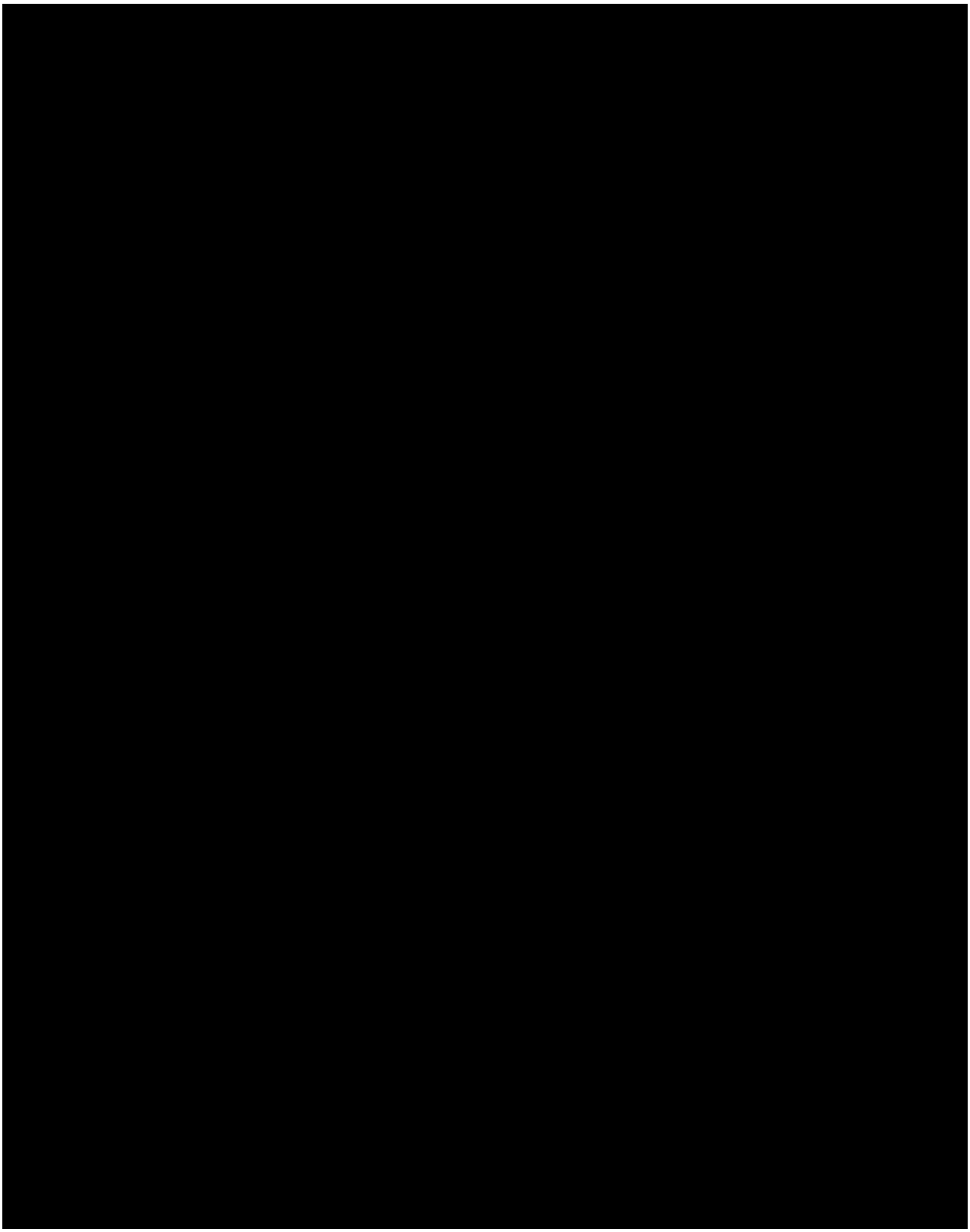
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[redacted]

[redacted]









[redacted]

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 4 – Well Construction Plan and Operating Conditions

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 4 – WELL CONSTRUCTION PLAN AND OPERATING CONDITIONS

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[redacted]

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4.1 Well Construction Plan and Operating Conditions

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson County, Texas, to sequester CO_2 using [redacted] injection wells, Sunflower CCS Project [redacted] This section contains information on the well construction and operating conditions in compliance with the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR), **§146.82** and **§146.86**, and Texas Administrative Code (TAC), Part 1, Title 16, Chapter 5A.

This section provides a narrative document with associated schematics and data summary tables that describe how ExxonMobil will construct the injection wells to meet the goals of 40 CFR **§146.86**—specifically, to do the following:

1. Prevent the movement of fluids into or between Underground Sources of Drinking Water (USDWs) or into unauthorized zones (40 CFR **§146.86(a)(1)**).
2. Permit the use of appropriate testing devices and workover tools (40 CFR **§146.86(a)(2)**).
3. Permit continuous monitoring of the annulus space between the injection tubing and long string casing (40 CFR **§146.86(a)(3)**).

The engineering design is based on the collection of as much site-specific data as possible, particularly from [redacted] This level of effort was undertaken to facilitate the permit writing process, between conducting the pre-construction activities required at 40 CFR **§146.82(a)** and the pre-operation phase activities required at 40 CFR **§146.82(c)**.

4.2 Objectives

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

- The injection well construction design, material specifications, and construction will be compatible with the composition of the CO_2 stream over the duration of the Sunflower Project to reduce the potential for endangerment of USDWs (40 CFR **§146.82(a)(11)** and **(12)**; **§146.86**).

- The injection wells will undergo logging and testing prior to operation, to assess injection well and formation performance and update the operating strategy as necessary before the injection of CO_2 (40 CFR **§146.82(a)(8)**; **§146.87**).

- The injection well operating strategy provides continuous injection and annulus monitoring systems for each injection well, to control injection pressure and trigger automatic shutoff devices, consistent with safe operating procedures (40 CFR **§146.82(a)(7)**, **(9)**, and **(10)**; **§146.88(e)**].

[redacted]

[redacted]

[redacted]

4.4 Well Design and Construction

The engineering design parameters for the [redacted] proposed injection wells are based on the planned injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid. [redacted] The casing and cement were designed to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be exposed (40 CFR **§146.86(b)(1)**).

Well design schematics are included in *Appendices D.1-1* to *D.1-8* (40 CFR **§146.82(a)(11)**).

4.4.1 Surface Conductor Pipe Design

The unconsolidated nature of the sediments in the upper subsurface soil requires the installation of a conductor pipe to establish and maintain borehole integrity. [redacted]

4.4.2 Surface Casing Design

The surface hole will be drilled to below the USDW (40 CFR **§146.86(b)(2)**) with a [redacted], with surface casing set at [redacted] for each of the injection wells. A string of [redacted] will be run and cemented to the surface, with the casing centered in the open hole with centralizers.

A summary of the surface casing design parameters is presented in Tables 4-2 through 4-5.

Table 4-2 – Summary of Design for Surface Casing Completion for the Sunflower Project Injection Wells

[redacted]

*OD – outer diameter
ID – inner diameter
lb/ft – pounds per foot
psi – pounds per square inch
kips – thousand pounds

Table 4-3 – Surface Casing Design Calculations for the Injection Wells



Table 4-4 – Surface Casing Cement-Volume Calculations for the Injection Wells



Table 4-5 – Summary of Design for Surface Casing Centralizers



4.4.3 Production Casing Design

The production hole will be drilled to below the surface casing with a [redacted].

- [redacted]
- [redacted]
- [redacted]

The engineering and design parameters for the production casing are summarized in Tables 4-6 and 4-7. These depths will be updated based on the final logging of the injection wells.

Table 4-6 – Production Casing Specifications



Table 4-7 – Production Casing Design Calculations



Tables 4-8 to 4-11 provide the production casing cement-volume calculations for each injection well.

Table 4-8 – Production Casing Cement-Volume Calculations for Injection Well No. 01



Table 4-9 – Production Casing Cement-Volume Calculations for Injection Well No. 02



[redacted]

Table 4-10 – Production Casing Cement-Volume Calculations for Injection Well No. 03

[redacted]

Table 4-11 – Production Casing Cement-Volume Calculations for Injection Well No. 04

[redacted]

Centralizer placement for the [redacted] is designed to promote a continuous, uniform column of cement throughout the production casing (40 CFR **§146.86(b)(3)**). The proposed placement of centralizers through the production casing is shown in Table 4-12.

Table 4-12 – Production Casing Centralizer Program

[redacted]

4.5 Completion Design and Equipment

The engineering design parameters for the [redacted] proposed injection wells are based on the planned injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid. [redacted] The tubing, packer, instrumentation, and wellhead equipment were selected to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be exposed (40 CFR **§146.86(c)(1)**).

Completion schematics are included in *Appendices D.1-1* to *D.1-8*.

4.5.1 Injection Tubing Design

The production tubing will be [redacted] with [redacted], installed with an injection packer. [redacted] A tubing design analysis was conducted that considered calculated pipe-friction losses, exit velocities, and compression requirements. Tables 4-13 and 4-14 provide the tubing design parameters and evaluation (40 CFR **§146.86(c)(1)**).

Table 4-13 – Tubing Specifications (40 CFR §146.86(c)(3)(vii))

[redacted]

Table 4-14 – Engineering Design Calculations for Tubing

[redacted]

4.5.3 Injection Packer Design

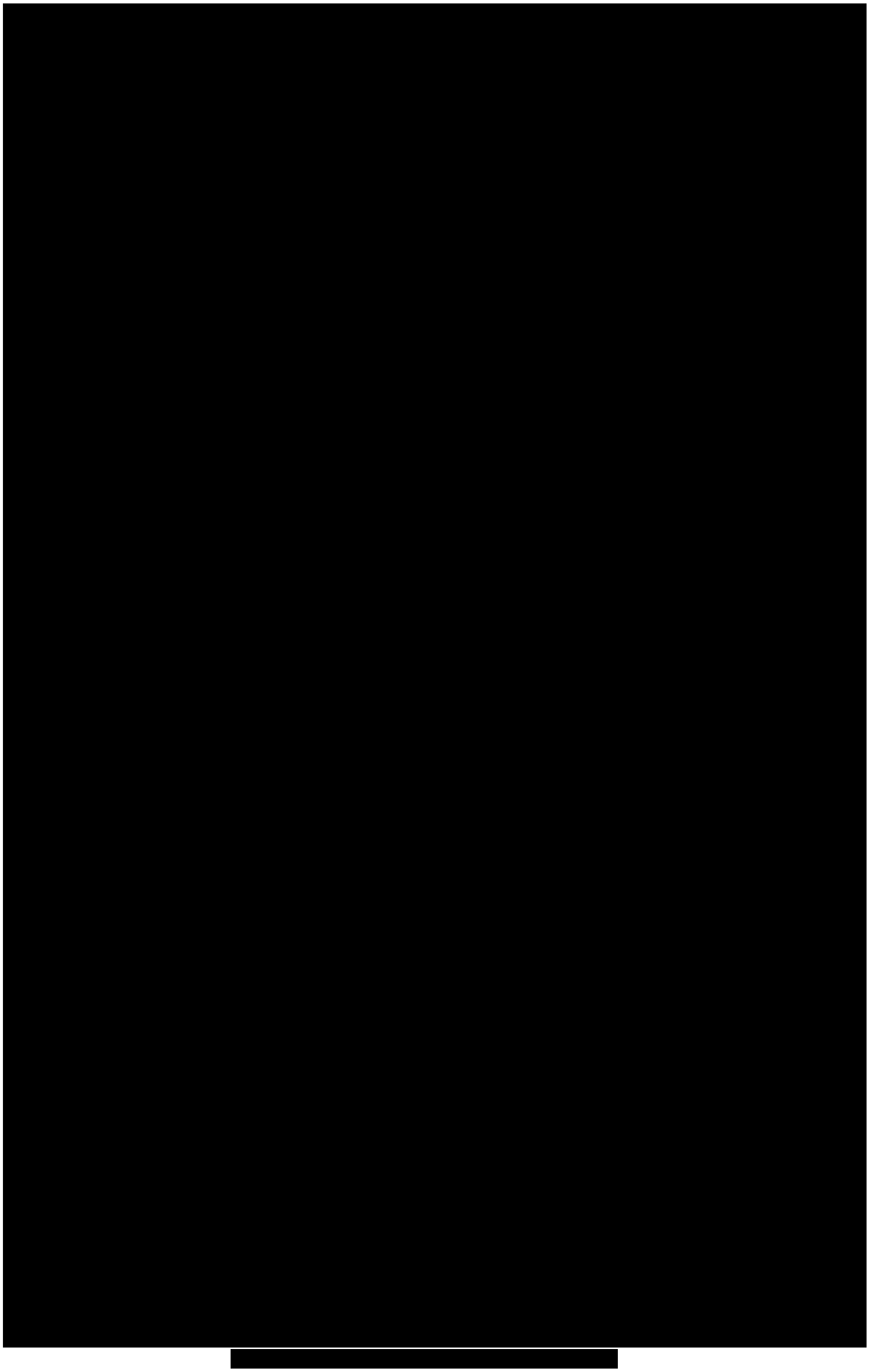
An injection packer will be installed with the [redacted] The [redacted] or a suitable equivalent. Differential pressure ratings of the packer will be selected to withstand all expected injection and shut-in load cases. Prior to setting the packer, the tubing annulus will be filled with a noncorrosive fluid.

4.5.4 Wellhead and Tree Equipment Design

The wellhead and tree are designed to manage working pressures and provide mechanical and pressure integrity for each injection well. The equipment will be manufactured to the requirements of API 6A. [redacted] The following is a detailed list of wellhead components:

- [redacted]

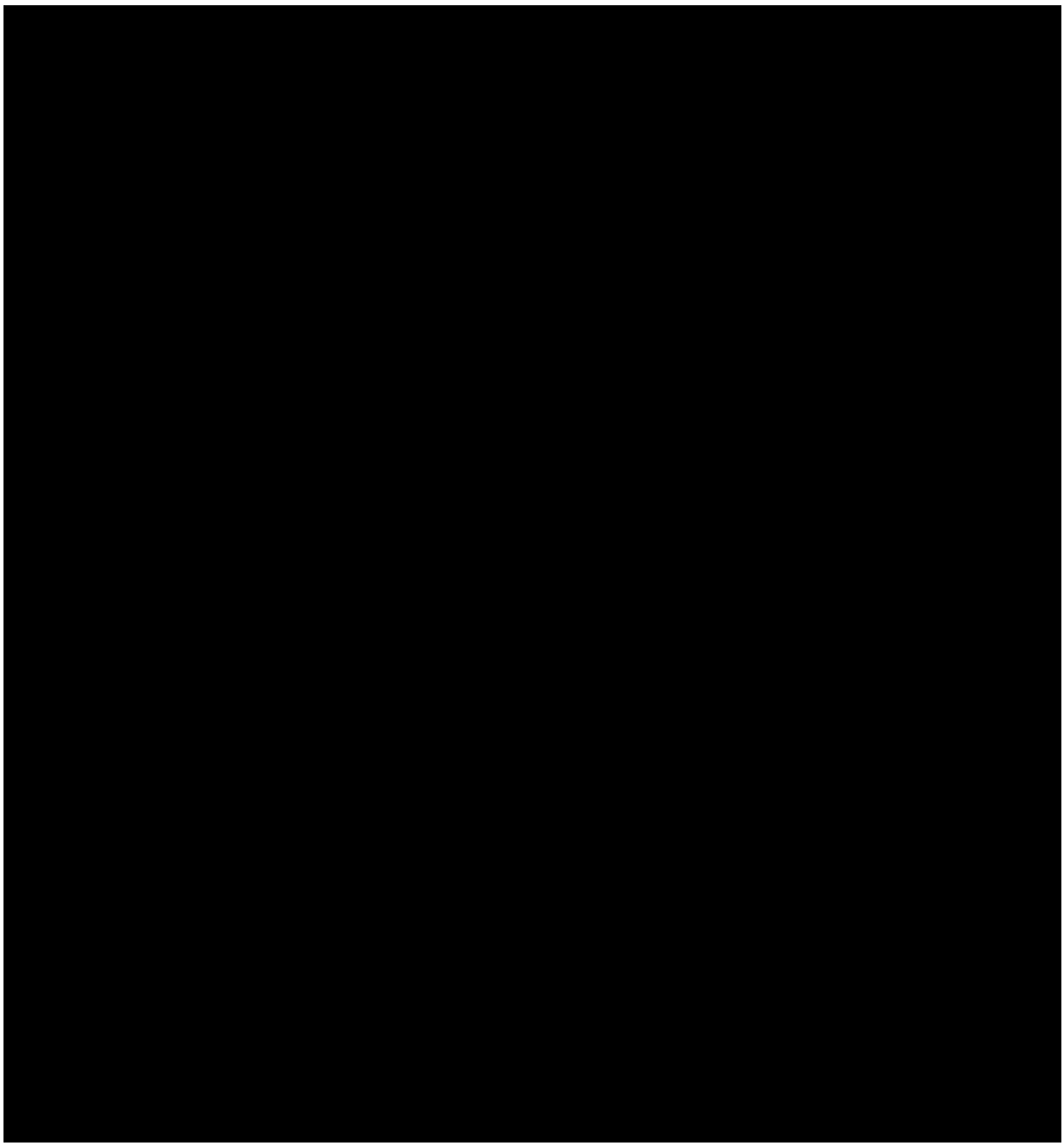
The wellhead will be configured as illustrated in Figure 4-1. Suitable equivalents for the specific manufacturers or equipment models indicated in the figure may be substituted as appropriate, based on vendors used and equipment availability.



4.6 Well Drilling and Completion Design

4.6.1 Drilling and Completion Procedure for the Injection Wells

The proposed design summary and procedure for the injection wells is described below. The tables presented here and *Appendix D* provide the well design and completion details for each injection well. The final completion depths and specifications listed in those tables and the *Appendix D* schematics may be modified based on actual formation depths and/or conditions encountered during drilling.



[redacted]

4.7 Pre-Operational Testing Plan

[redacted]

Additional core, well log, and injection test data will be taken in the construction of the proposed injection wells as outlined below.

4.7.1 Injection and Confining Zone Core Sampling

The following preliminary coring operations are planned during the construction of the injection wells. Table 4-15 details the potential core intervals and operations per formation interval.

[redacted]

4.7.2 Pre-Operation Logging Program

The following geophysical logs are planned for each proposed injection well. The openhole logging plan is detailed in Table 4-16. The cased-hole logging plan is detailed in Table 4-17.

Table 4-16 – Openhole Logging Plan for the Injection Wells

[redacted]



Table 4-17 – Cased-Hole Logging Plan for the Injection Wells



4.7.3 Injection Zone Characterization

ExxonMobil will collect characterization data for the permitted injection interval of the injection wells, including formation fluid temperature, pH, specific conductivity, and formation pressure (40 CFR **§146.87(c)**).

4.7.4 Fluid Characteristics and Downhole Conditions

During the construction of the injection wells, ExxonMobil will collect formation fluid samples in the injection interval and the formation above the UCCZ. Injection zone samples will be evaluated for the compatibility of the injectate with the formation fluids (40 CFR **§146.87(d)(3)**).

Samples collected above the UCCZ during the pre-operation phase will form the baseline data for comparison with water quality data representing the operating and post-operating phases of the Sunflower Project. The analysis plan for water samples collected in the injection zones and above the UCCZ formation is specified in Table 4-18.

Table 4-18 – Sampling and Analysis Plan for the UCCZ Water Sample

[redacted]

4.7.5 Injection and Confining Zone Formation Testing

Pressure transient well testing (e.g., a pressure falloff test) will be conducted in each of the injection wells as a part of completion activities (40 CFR **§146.87(e)(1)**). These tests are intended to confirm reservoir and operational parameters used in the permitting process and provide needed data on the geologic and hydrogeologic properties of subsurface formations. [redacted]

[redacted]

4.8 Injection Well Operating Strategy

4.8.1 Overview of Injection Well Perforation and Completion Strategy

Upon permit approval, injection will start based on the stages and injection schedules referenced below in Tables 4-19 through 4-22.

Table 4-19 – Injection Sequencing Strategy for Injection Well No. 01



Table 4-20 – Injection Sequencing Strategy for Injection Well No. 02



Table 4-21 – Injection Sequencing Strategy for Injection Well No. 03



Table 4-22 – Injection Sequencing Strategy for Injection Well No. 04

[redacted]

[redacted] The perforation depths provided in Tables 4-19 to 4-22 are based on the current geologic model described in *Section 1 – Site Characterization* and are subject to change based on as-drilled conditions.



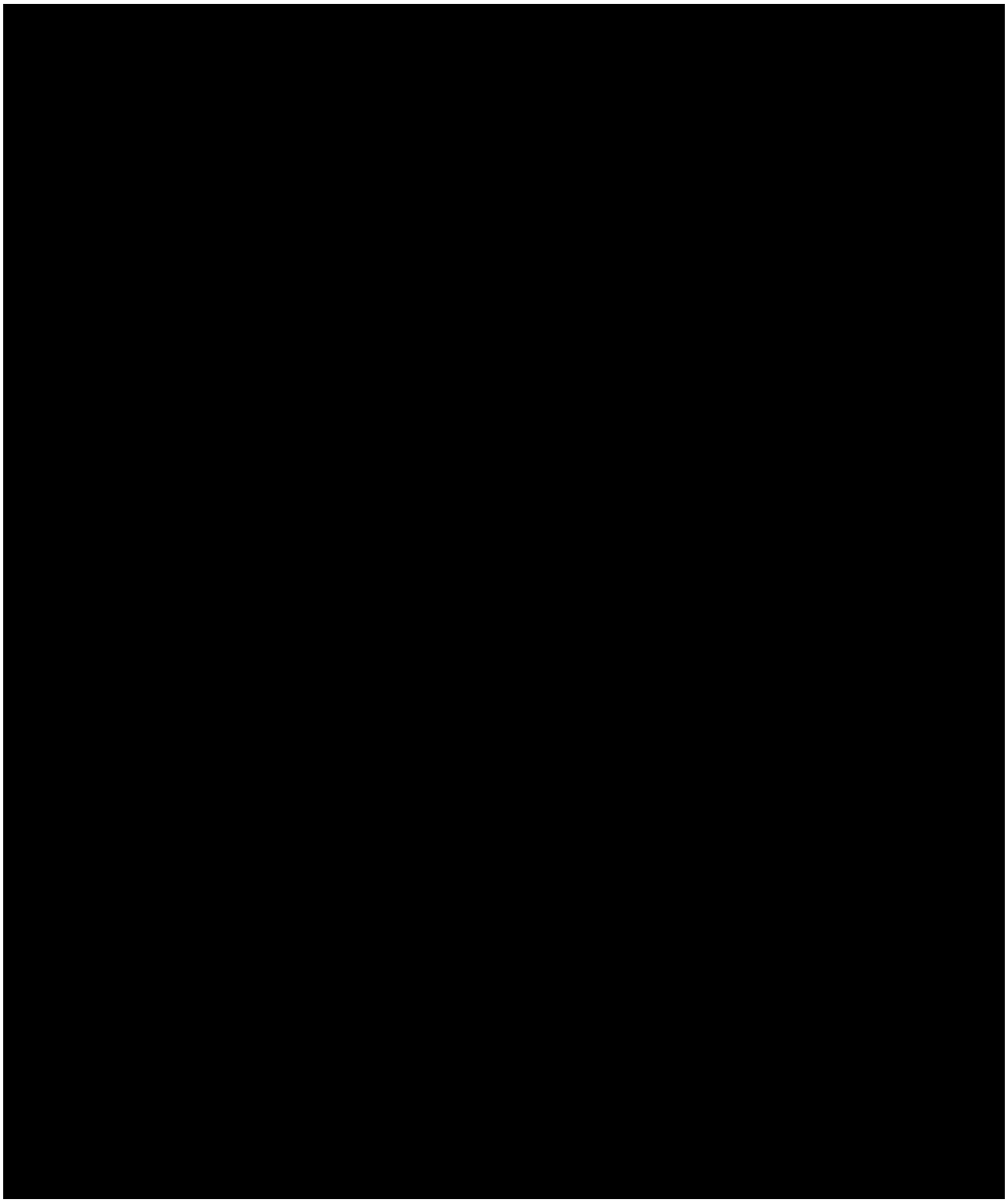
Figure 4-2 – Operational Completion Strategy for the Injection Wells

4.8.2 Injection Rate and Pressure

Table 4-23 provides the proposed operations for the injection wells, including injection rate and pressure by well. Both the maximum and average injection rates are predicted to result in reservoir

pressure rises that are below 90% of the critical fracture pressure, shown in Table 4-23. Both the injection rates and pressures are within the operating window of the injection wells.

Table 4-23 – Summary of Injection Parameters for the Injection Wells





*BHP – bottomhole pressure

4.8.3 Annulus Pressure

The annulus pressure will be adjusted to be more than the wellhead injection pressure, with a maximum allowable pressure of [redacted] (40 CFR **§146.88(c)**).

4.8.4 Well Stimulation Procedures

ExxonMobil is not proposing a stimulation program for the proposed injection wells. In accordance with 40 CFR **§146.91(d)(2)**, if a stimulation program is proposed, ExxonMobil will provide an advance notice of the proposed stimulation procedures to the Underground Injection Control (UIC) Program Director (UIC Director) in writing at least 30 days prior to implementation.

4.9 Operational Reporting Plan

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

- Evidence that the CO_2 plume or pressure front may endanger one or more USDWs
- The noncompliance situation as it relates to a permit condition
- Apparent malfunction of the injection system
- Triggering of a shutoff system or a loss of mechanical integrity
- A release of CO_2 to the atmosphere or biosphere

ExxonMobil will cease injection and take all steps reasonably necessary to determine whether there may have been a release of CO_2 to an unauthorized zone, in the event that there is a loss of mechanical integrity (40 CFR **§146.88(f)(2)**).

Appendix D – Well Construction Schematics and Procedures:



Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 5 – Testing and Monitoring Plan

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

Consistent with the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) developed a comprehensive Testing and Monitoring Plan for the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) using a risk-based approach. The data collection includes injectate monitoring; corrosion monitoring of the well tubulars, mechanical, and cement components; pressure falloff testing; seismic surveying; well logging; continuous monitoring of injection rate, pressure, and temperature; groundwater quality monitoring; and CO_2 plume and pressure front tracking. The data generated from implementation of the plan provides the basis to verify the confinement of the injectate in the permitted injection formations during the active injection phase of the project.

The post-injection phase of monitoring is provided in *Section 7 – Post-Injection Site Care (PISC) and Site Closure*, consistent with the structure of the Underground Injection Control (UIC) Class VI permit application for this project. In conjunction with careful site selection and area of review (AOR) delineation, this plan will be a critical component of the successful operation, PISC, and eventual closure of the Sunflower Project.

A key feature of the Testing and Monitoring Plan is that the location and frequency of monitoring and surveillance data acquisition and analysis are designed to align with the injection operation plan and the identified site-risk elements that impact and determine CO_2 plume and pressure front migration. This plan presents a data collection plan to confirm that the injection is consistent with the permit requirements. The plan also includes a phased/triggered approach for the incremental implementation of testing and monitoring technology, consistent with the EPA's presentation of phased/triggered monitoring in their 2013 *UIC Program Class VI Well Testing and Monitoring Guidance*.[1] Overall, the risk of Underground Source of Drinking Water (USDW) endangerment is mitigated (1) by balancing the increase in CO_2 plume and pressure front size and location with the collection and analysis of data to track migration in the subsurface; and (2) by implementing robust risk management processes to assess the potential for leaks through the upper composite confining zone (UCCZ) throughout the life of the project.

ExxonMobil intends for the review process for the Testing and Monitoring Plan and subsequent iterations to continue throughout the life of the Sunflower Project. An adaptive approach will be employed with respect to the monitoring frequency of select parameters, whereby the application of selected monitoring technologies may be decreased based on improved subsurface understanding and subsequent reduction of reservoir uncertainties. Monitoring results will be presented in semiannual reports, wherein data will be evaluated and any proposed monitoring frequency modification within the Testing and Monitoring plan justified. Baseline data will be collected prior to injection start-up, and time-lapse comparisons to the baseline data will be made during the operational period of the project. The adaptive approach will be applied

[1] UIC Program Class VI Well Testing and Monitoring Guidance, EPA 816-R-13-001 (March 2013). https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13001.pdf)

if the data collected during the injection period shows results within the expected CO_2 behavior range. An ongoing dialogue between ExxonMobil and the UIC Program Director (UIC Director) is envisioned, marked by tying the monitoring plan reviews and proposed modifications to the AOR reevaluation frequency. Consistent with the discussion of AOR reevaluation in *Section 3 – Area of Review and Corrective Action Plan*, a minimum frequency of 5 years is planned to reevaluate the AOR and Corrective Action Plan. More frequent evaluations of the AOR and updates to the Corrective Action Plan may also be triggered if other unexpected changes in testing and monitoring data are detected as discussed in Section 3, Table 3-8. Key to this is the efficient review process that is needed and contemplated, particularly where the AOR reevaluation confirms that the plan is appropriate as written.If ExxonMobil determines that monitoring data suggests potential corrective actions are needed and mitigation measures should be employed, then the Emergency and Remedial Response Plan (Section 8) will be implemented as appropriate.

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

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

5.2 Reporting Requirements

The Testing and Monitoring Plan was developed to achieve two reporting objectives:

- Provide the necessary data to verify predictions of CO_2 plume and pressure front movement (40 CFR **§146.90(g)**).
- Provide the basis for evaluating the model inputs, making necessary changes, and reevaluating the AOR (40 CFR **§146.90(j)**).

In compliance with 40 CFR **§146.91**, ExxonMobil will provide reports to the UIC Director in routine semiannual reports that document both the performance of the system and the CO_2 plume and pressure front tracking data. Relevant records pertaining to the Class VI testing and monitoring program will be submitted to the EPA. In addition, ExxonMobil will follow the prescribed notification requirements for deviation from permit conditions, in the event of an operational malfunction that may allow CO_2 or brine to migrate into or between USDWs, or for other evidence of USDW endangerment.

The semiannual reports will include the data collected during each reporting period and a list of notifications triggered during a semiannual period, if any. The following information is proposed for the routine performance reporting:

- Monthly average, maximum, and minimum values of injection pressure, flow rate and volume, and annular pressure
- Monthly volume and/or mass of the CO_2 stream injected over the reporting period, and the volume injected cumulatively over the life of the Sunflower Project
- Monthly annulus fluid volume added
- Results of CO_2 plume and pressure front tracking data analysis as described herein
- Any significant changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data that could impact plume migration or protection of USDWs
- A description of any event that triggered a shutoff device required according to **§146.88(e)**, and the response taken
- A description of any event that exceeded operating parameters for annulus pressure or injection pressure specified in the permit

The semiannual reports will be submitted 30 days after the completion of the quality control and quality review of the data for each reporting period. Table 5-1 describes the non-routine reporting triggers, contents, and schedule.

Table 5-1 – Summary of Triggering Events for Notification and Reporting Schedule

Triggering Event	Reporting Schedule
Planned well workover, stimulation activities, or other planned test of an injection well	Notification to the UIC Director, in writing, 30 days in advance of planned activity
Completion of well workover	30 days after completion of well workover
Any test of the injection well conducted, if required by the UIC Director	30 days after completion of any testing required by the UIC Director
Evidence of potential non-compliance with a permit condition, or potential malfunction of the injection system that may cause fluid migration into or between USDWs	Verbal notification – reported within 24 hours of verification of non-compliance or malfunction
Primary evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW	Verbal notification – reported within 24 hours of verification of endangerment
A failure to maintain mechanical integrity	Verbal notification – reported within 24 hours of verification of mechanical integrity test failure
A statistically significant change to the physical, chemical, and other relevant characteristics of the CO_2 stream from the composition described in the proposed operating plan	Written notification – reported within 72 hours of verification of composition change

Triggering Event	Reporting Schedule
An operational condition that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit	• Verbal notification – reported within 24 hours of verification of non-compliance with permit conditions • Written notification – reported within 72 hours of verification of non-compliance with permit conditions
A shutoff device that is activated anywhere in the injection well system	• Verbal notification – reported within 24 hours of event • Written notification – reported within 72 hours of event

ExxonMobil will provide all reports, submittals, and notifications to both the EPA and the Railroad Commission of Texas (TRRC) and retain records in accordance with 40 CFR **§146.91(f)** for a 10-year period after site closure. Additionally, injected-fluid data, including nature and composition, will also be retained for the 10-year period following site closure. Monitoring data will be retained for a minimum of 10 years post-collection, while well plugging reports, PISC data, and the site closure report will be retained for 10 years after site closure.

5.3 Testing Plan Review and Updates

In accordance with 40 CFR **§146.90(j)**, the Testing and Monitoring Plan will be reviewed and revised at a minimum of every 5 years to do one or more—or all—of the following:

- Identify Sunflower Project-specific factors that may warrant revision to the plan.
- Incorporate information and changes necessary to monitor an increase in risk to or endangerment of USDWs.
- Account for any deviations from permitted conditions that require plan modifications.

ExxonMobil will incorporate the collected monitoring data that characterize the project-specific factors and the changes needed, if any, to monitor both increased potential risk to the USDW and overall plan compliance with the UIC Director's requirements. Plan amendments will be submitted within 1 year of an AOR reevaluation, following significant facility changes (such as the development of offset monitoring wells or newly permitted injection wells within the AOR), or as the UIC Director requires.

Table 5-2 summarizes the various measurements discussed in the Testing and Monitoring Plan and the frequency of measurements for data collection and reporting purposes.

Table 5-2 – Testing and Monitoring Plan Measurements and Frequency

Equipment / Measurement	40 CFR Regulation	Objective	Frequency
Coriolis flow meter	§146.90b	Measure mass flow rate	

Equipment / Measurement	40 CFR Regulation	Objective	Frequency
Corrosion coupon	§146.90c	Measure corrosion levels on the types of metal used in the project	[redacted]
Injection stream sampling	§146.90a	Provide a more detailed analysis via periodic lab analysis of injection stream	
Central pad temperature gauge	§146.90a	Measure the temperature of the total injection stream at the pad before partitioning to injections	
Injection wellhead tubing gauge	§146.90a	Measure downstream of choke	Continuously
Injection wellhead annulus pressure gauge	§146.90b	Verify that the annulus pressure is maintained	[redacted]
Injection annulus pressure test	§146.89b	Verify the absence of a leak in the annulus	
Injection well downhole pressure and temperature gauge for active/open injection interval	§146.90b	Measure downhole pressure and temperature (injection mass-to-volume conversion, verifying that it is not exceeding maximum pressure)	
	§146.90f	Measure falloff of pressure immediately before abandoning injection stage and initiating injection in next stage above	
	§146.90g(1)	Direct measurement of downhole pressure open to active injection zone	
Time-lapse surface seismic survey	§146.90g(2)	Monitoring of CO_2 plume growth in the subsurface over time	

Equipment / Measurement	40 CFR Regulation	Objective	Frequency
[redacted]	§146.90e	Use temperature log to assess changes in the temperature profile due to migration of injected fluids	[redacted]
Injection well casing inspection log	§146.90e	Use through-tubing log to detect loss of metal mass in casing due to corrosion	
[redacted]			

5.4 Overall Strategy and Approach for Testing and Monitoring Plan

The Class VI Permit regulations (40CFR § 146.90) require various testing and monitoring activities to identify potential risks to, and the potential for endangerment of, USDWs during the injection

phase of the Sunflower Project. ExxonMobil consulted with the EPA, Region VI UIC Director, and TRRC in pre-application discussions to identify the testing and monitoring activities that were best suited for the project. The site features that affect the degree of risk and potential for endangerment of a USDW include the following:

[redacted]

Of these features, the key risk factor that is most critical for the design of this plan is the potential for [redacted] ExxonMobil completed a variety of technical tasks, discussed in *Section 3 – Area of Review and Corrective Action Plan*, to identify and evaluate the potential for [redacted] Other potential risks associated with the project were deemed to be of a lower probability and consequence.

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

[redacted]

Figure 5-1 presents a summary of the risk assessment process for the life cycle of the project.

[redacted]

As shown in Figure 5-1, the anticipated risk level is [redacted] The injection well locations and injection intervals were selected to provide separation from geologic features (e.g., faults) that could potentially contribute to CO_2 or brine crossflow between the injection zone and USDW. The maximum injection pressure will be maintained below the potential hydraulic fracturing or activation pressure of a natural fault, to mitigate the potential for CO_2/brine migration through one or more seals due to mechanical fracturing or migration of CO_2/brine along faults.

State-of-the-art construction and mechanical integrity testing will be employed to reduce the potential for the loss of external mechanical integrity, to prevent potential release of CO_2. The composition of the injectate stream will be managed and monitored so that unexpected reactions with the potential to impact containment are mitigated. Monitoring and predictive reservoir modeling are being used to limit the potential for CO_2 plume and pressure front migration, to encounter artificial penetrations that have the potential for CO_2 or brine crossflow from the injection intervals to the lowermost USDW.

The Class VI Permit testing and monitoring requirements (40 CFR § 146.90) address the potential risk scenarios identified by ExxonMobil as warranting monitoring and testing. Scenarios that were found to have elevated risk will be the subject of corrective action prior to operations. [redacted]

[redacted]

An array of data collection technologies was screened to identify the most reasonable and appropriate methods for the Testing and Monitoring Plan. The screening criteria included: (1) selection of appropriate direct and indirect mix of mature or commercially demonstrated monitoring technologies linked to identified risk scenarios; (2) cost benefit analysis of each technology to mitigate unexpected CO_2/brine migration potential; and (3) a mix between continuous and periodic technologies implementation schedules. ExxonMobil recognizes mature technologies based on their Technology Readiness Levels (TRLs), as defined by the International Energy Agency in their report *Energy Technology Perspectives, 2020; Special Report on Carbon Capture Utilisation and Storage.* This scheme is applicable to any technology, including those described in Table 5-3 for implementation in the Sunflower Project. As described in Figure 5-2, ExxonMobil considers mature technologies to be those with [redacted] and higher.

The selected mature monitoring technologies for the Sunflower Project are designed to track the CO_2 and pressure plume growth in each of the four injection intervals from bottom to top: Upper Frio (Oligocene) Sands 1, 2, and 3, and Fleming (Miocene) Sand 3 (Figure 5-3).



Table 5-3 provides a summary of mature technologies selected for tracking the CO_2 plume and pressure front. Consistent with the stated interests of the EPA, the Testing and Monitoring Plan is intended to be a flexible approach using appropriate technologies and techniques that are refined and adapted based on site-specific information over time. ExxonMobil will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to investigate large-scale applications and improve the performance of the testing and monitoring surveillance system.

ExxonMobil will communicate with the UIC Director on plans and the potential for modifications and updates to the Testing and Monitoring Plan in the case that emergent technologies are deemed ready for adoption. Through the combination of proven and emerging technology implementation, an efficient testing and monitoring strategy will be maintained for the Sunflower Project to ensure effective monitoring of CO_2 plume and pressure front migration paths in the subsurface, and to provide reliable data for risk management, mitigation strategies, and a potential reevaluation of the AOR model.

[redacted]



5.4.1 Use of Phased and/or Triggered Approach

The testing and monitoring plan for tracking the CO_2 plume and brine pressure front uses the phased and/or triggered approach to scale the testing and monitoring network location and cadence within the extent of the AOR and the site features that warrant monitoring as identified in the risk assessment evaluation. The goal of the approach is to provide the monitoring and surveillance data necessary to demonstrate that USDWs are protected from the potential migration of CO_2 or brine. The scaling aspect of the strategy is aligned with the multi-staged injection approach outline in *Section 2 – Plume Model*, that [redacted]

The initial monitoring network array is based [redacted] and what was deemed appropriate to track the CO_2 plume and brine pressure front growth during that time period. From that point, the AOR reevaluation process will be used to assess the adequacy of the testing and monitoring program to detect potential unexpected CO_2 or brine migration—should it occur—and make recommendations for changes and implementation of corrective measures, if necessary, to demonstrate the protection of USDWs.

[redacted]





5.4.2 Mechanical Integrity Testing

5.4.2.1 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 40 CFR **§146.89(b)**, ExxonMobil will assess the internal mechanical integrity of each injection well by performing annulus pressure tests after the well has been completed, prior to injection, and annually thereafter. During well construction and prior to the installation of the injection tubing and packer, the casing will also be pressure-tested to the maximum anticipated annulus-surface pressure to verify its integrity.

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

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times (40 CFR **§146.89(b)**). The tubing annulus pressure will be recorded and reported to the regulatory permitting authority in semiannual reports to demonstrate compliance with casing integrity requirements.

5.4.2.2 External Mechanical Integrity Testing

Following the requirements of 40 CFR **§146.89(c)**, ExxonMobil will use [redacted]

Procedures for Acquiring a Temperature Log:

- A temperature log with gamma ray and casing collar locator will be obtained prior to injection activities to establish baseline conditions and to identify any potential local temperature anomalies that may exist.
- Shut-in the well for minimum of 24 hours, targeting 36 hours of shut-in time, if possible, based on operational needs.
- Rig-up wireline company and perform temperature log from surface to total depth.
- Pull temperature tool out of hole. If anomalies are present, re-log well at least 8 hours after initial pass to re-establish sufficient conditions. If none are identified, rig-down wireline company.

Per EPA Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance, dated March 2013, any temperature logs will be evaluated by comparing the relative differences of the log to a baseline log. If the baseline log is comparable to the baseline log, it is considered a successful demonstration of mechanical integrity. If log data is inconclusive or anomalies are detected, additional logs such as an Oxygen Activation or Pulsed Neutron log may be run to further investigate MIT.

5.4.2.3 Reporting Results of MIT

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

5.4.3 Pressure Falloff Testing

Required pressure-transient falloff testing will be conducted [redacted] The objective of periodic testing is to monitor for any changes in the near-wellbore environment that may impact permeability and reservoir pressures during active injection. A report containing the pressure falloff data and interpretation of the reservoir pressure will be submitted to the EPA within 30 days of the conclusion of the test. Although test procedures or methods may be changed based on the request of the permittee and approval by the UIC Director, the following procedure is expected to be typical for such periodic monitoring.

5.4.3.1 Testing Method

The procedures to conduct a pressure falloff test are as follows:

- Record data regarding the test well injection at typical operating conditions (constant rate plus or minus 10%). Rate vs. time data will be recorded during the injection period. Cumulative injection volume will also be recorded. Continue the injection for a time equivalent to the projected duration of the falloff necessary to observe analyzable radial flow. Note that significant rate variations may require more complicated analysis techniques.
- Verify the operation of the permanent monitoring equipment or rig up downhole the memory pressure gauge and run in the well to a datum depth approved by the regulators.
- For pressure transient falloff, obtain the final stabilized injection rate and pressure for a minimum of [redacted]. Ensure that the injectate temperature has stabilized.
- Cease injection and monitor the pressure falloff. Continue monitoring pressure for a time sufficient to observe reservoir behavior. Wellbore pressure gradients will be obtained to establish the fluid gradient.
- Stop the test-data acquisition, rig down, and release the equipment.

5.4.3.2 Analytical Methods

Near-wellbore conditions, such as the prevailing flow regimes, well skin, reservoir properties, and boundary conditions will be assessed using standard pressure-transient diagnostic plotting and well test simulators, as required. This assessment will be accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions will be identified by comparing pressure falloff tests performed prior to initial injection with later tests. These well parameters resulting from falloff testing will be compared against those used in AOR determination and site

computational modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary.

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

5.4.3.3 Quality Assurance/Quality Control

The surface field equipment will undergo inspection and testing prior to operation. The pressure gauges will be calibrated prior to installation per manufacturer instructions. Documentation certifying proper calibration will also be enclosed with the test results.

5.4.4 Monitoring of CO_2 Stream

Consistent with 40 CFR **§146.90(a)**, ExxonMobil will install and use measurement devices to analyze the chemical composition of the injection stream, to assess the potential for interactions between CO_2 and other injectate components—and compatibility with the well-completion materials. Temperature and pressure will also be measured at the sample collection point.

5.4.4.1 Sampling Frequency

[redacted]

5.4.4.2 Sampling Methods

The quarterly measurements will be obtained by collecting representative samples of CO_2 at a sample port on the project's central pad, beyond the last stage of compression in the compression build or similar point. Sufficient mixing and residence time in the system will have occurred at this sampling point for the sample to be representative of the injected CO_2 stream. The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container.

The central pad is the connection point between the CO_2 pipeline and the sequestration field's distribution system.

Sampling activities will be conducted at the direction of site representatives, in accordance with the certified or accredited analytical laboratory procedures, and will meet the minimum current standard EPA procedures. A sample will be collected by depressurizing the liquid stream and sampling the CO_2 as a gas in either a Tedlar® bag, a Summa cannister, or a laboratory-approved alternate. The grab sample will be sent to an independent contract laboratory for analysis.

Each sample will be accompanied by a facility or contract laboratory chain-of-custody (COC) form that provides a record of sample handling—starting with sample acquisition—documenting the sample transfer process up to the laboratory analysis. Samples taken are to be logged in the field using the COC form. Sample transfer containers (e.g., coolers) will be sealed and delivered to the laboratory with a COC form, which will provide the following items recorded by the sampler:

- Sample ID including code or name, in addition to date and time
- Name of sample collector (include sampling company name if not site personnel)
- Sample collection method
- Sample collection date
- Sample collection point
- Sample presentation technique, as applicable
- Standard laboratory COC forms that document the times and dates of all personnel handling the sample, along with standard labels and container seals sufficient to distinguish between samples and prevent tampering, will be acceptable.
- The sample COC will be followed at all times during the sampling and subsequent analysis and will be used to document the handling and control necessary to identify and trace a sample from collection to final analytical results.

5.4.4.3 Analytical Plan

Table 5-4 presents the test parameters, analytical methods, and sample frequency for each test parameter.

[redacted]

5.5 Monitoring Programs

5.5.1 Continuous injection Stream Physical Monitoring

ExxonMobil will install and use continuous measurement devices to monitor the injection pressure, rate, and mass injected; the pressure on the annulus between the tubing and the production casing; and the temperature of the CO_2 stream, as required under 40 CFR **§146.88(e)(1)**, **§146.89(b)**, and **§146.90(b)**. Data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent, and it will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor the operating conditions, set alarms for alerting operations of malfunction, and establish safety protocols in case of abnormal conditions. Alarms will additionally be set for pressures outside of described tolerances (generally 90% of the fracture gradient and prescribed wellhead pressures), and changes in annular pressure and fluid.

Instrument calibration standards, precision, and tolerances will be determined based on manufacturer recommendations. The automated control system data will be visually monitored for anomalies on a regular basis. Average values will be compared to baseline and predicted values to determine if there are any significant deviations relevant to integrity or containment. The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the Sunflower Project will be stored in a database to support AOR reviews, quality assurance/quality control review programs, and routine reporting. Table 5-5 provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program. As may become necessary, paper records may be substituted for digital records at the discretion of the operator. Suitable equivalent devices may be used as technology availability and maintenance dictate.

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

Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface injection pressure	Wellhead pressure logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure gauges	Injection unit	5 seconds	5 minutes
Injection rate	Coriolis flow meter	Central pad piping	5 seconds	5 minutes
Injectate density	Coriolis flow meter	Central pad piping	5 seconds	5 minutes

Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Total mass injected	Coriolis flow meter	Central pad piping	5 seconds	5 minutes
Annular pressure	Pressure gauge	Wellhead	5 seconds	5 minutes
Annulus fluid volume	Pressure gauge	Annulus system tank	5 seconds	5 minutes
CO_2 stream temperature	Coriolis flow meter/wellhead pressure logger	Wellhead, injection well flowing	5 seconds	5 minutes

5.5.1.1 Continuous Monitoring of Injection Rate and Volume

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

A Coriolis flow meter will be used to measure the flow rate at the central pad and compute flow rates for each injection well. The meter directly measures the mass flow rate of the injected fluid. Analytical methods will be conducted at a periodic interval to determine the mass percentage concentration of CO_2 and carbon monoxide (CO). The mass percentage concentration of CO_2 and CO are multiplied by the total mass flow reading from the Coriolis flow meter to estimate the total mass of captured CO_2 and CO for a given period. The meter will be placed directly at the point of injection and calibrated to manufacturer specifications.

[redacted]

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

5.5.1.2 Continuous Monitoring of Injection Temperature and Pressure at the Injection Wells

ExxonMobil will perform continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with 40 CFR **§146.90(b)**. The injected CO_2 stream pressure will be continuously monitored in the CO_2 flowline near the wellhead interface. The annulus pressure will also be continuously recorded. The combined wellhead and downhole monitoring data will be used to continuously characterize the injection stream in detail.

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

5.5.1.3 Continuous Monitoring of Injection Temperature and Pressure in the Reservoir

Reservoir temperatures and pressures will be measured using a downhole gauge that will be installed in the tubing above the production packer. (*Section 4 – Well Construction Plan and Operating Conditions* contains the well diagrams.) The wellhead pressure logger will also continuously measure the temperature.

5.5.1.4 Continuous Monitoring of Annular Pressure and Volume (Tank Level)

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

5.5.1.5 Positive Annular Pressure

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

5.5.2 Corrosion Monitoring

To meet the requirements of 40 CFR **§ 146.90(c),** the tubing and casing materials will be monitored during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion, to demonstrate that the well components continue to meet the minimum standards for material strength and performance. Monitoring based on well-specific conditions that are encountered will be conducted at least once per year.

5.5.2.1 Monitoring Location and Frequency

Corrosion coupons will be placed in continuous contact with the CO_2 stream in a selected location deemed representative of the four proposed injection wells. The samples will be exposed to the process stream conditions immediately prior to injection, using a recycle loop or sample retriever. Exposure is to be representative of conditions at the top of the tubing. Initially, coupons will be tested quarterly. After establishing service life trends, coupon testing frequency may be reduced but will be conducted at a minimum of once per year.

Casing inspection logs (CILs) (e.g., ultrasonic imaging tool, electromagnetic, cement bond log, or caliper) will be conducted on the long string casing at a minimum frequency of once every 5 years at the time of permit renewal. [redacted]

5.5.2.2 Monitoring of Corrosion Coupon

Monitoring of well tubing and casing material corrosion will initially be conducted on a quarterly basis to evaluate the corrosion coupon monitoring system. After establishing service life trends, coupon testing frequency may be reduced but will be conducted at a minimum of once per year. A corrosion coupon station or rack will be provided as part of well-materials integrity monitoring. Any coupon in active use will be exposed to the stream composition to provide ongoing evaluation of material compatibility with the CO_2 stream. The results will be reported semiannually to the regulatory permitting authority, such as the UIC Director.

The coupons will be assessed for corrosion using American Society for Testing and Materials (ASTM) and Association for Materials Protection and Performance (AMPP) standards for evaluating corrosion tests (e.g., ASTM G1-03 (2017), Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens), or a suitable equivalent. When the coupons are removed, they will be inspected visually for signs of corrosion or pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period.

The initial baseline measurements of the coupons will follow the recommendations of AMPP National Association of Corrosion Engineers (NACE) SP0775-2023. Coupons will be prepared from the material used to construct the injection wells. A method of coupon preparation will be chosen that does not alter the properties of the metal. For example, grinding operations will be controlled to avoid high surface tensions/temperatures that could change the microstructure of the coupon. Coupons may be prepared by smooth grinding with 120-grit paper, by tumbling with loose grit, or by blasting with abrasive blasting material. A consistent finish may be obtained by blasting with glass beads. The abrasives will be free of metallic particles.

A permanent serial number will be etched or stamped on each coupon. ExxonMobil will machine or polish the edges of the coupon to remove cold-worked metal if the cold-worked edges adversely affect the data. ExxonMobil will dry the coupons, measure their length and width and thickness, and weigh them to within ± 0.5 milligrams (mg)—then record the mass, serial number, and exposed dimensions, calculate the surface area (including the edges), and record. The areas covered by the coupon holder and shielded areas of flush-mounted coupons will be excluded.

5.5.2.3 Cement Evaluation and Casing Inspection Logs

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

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

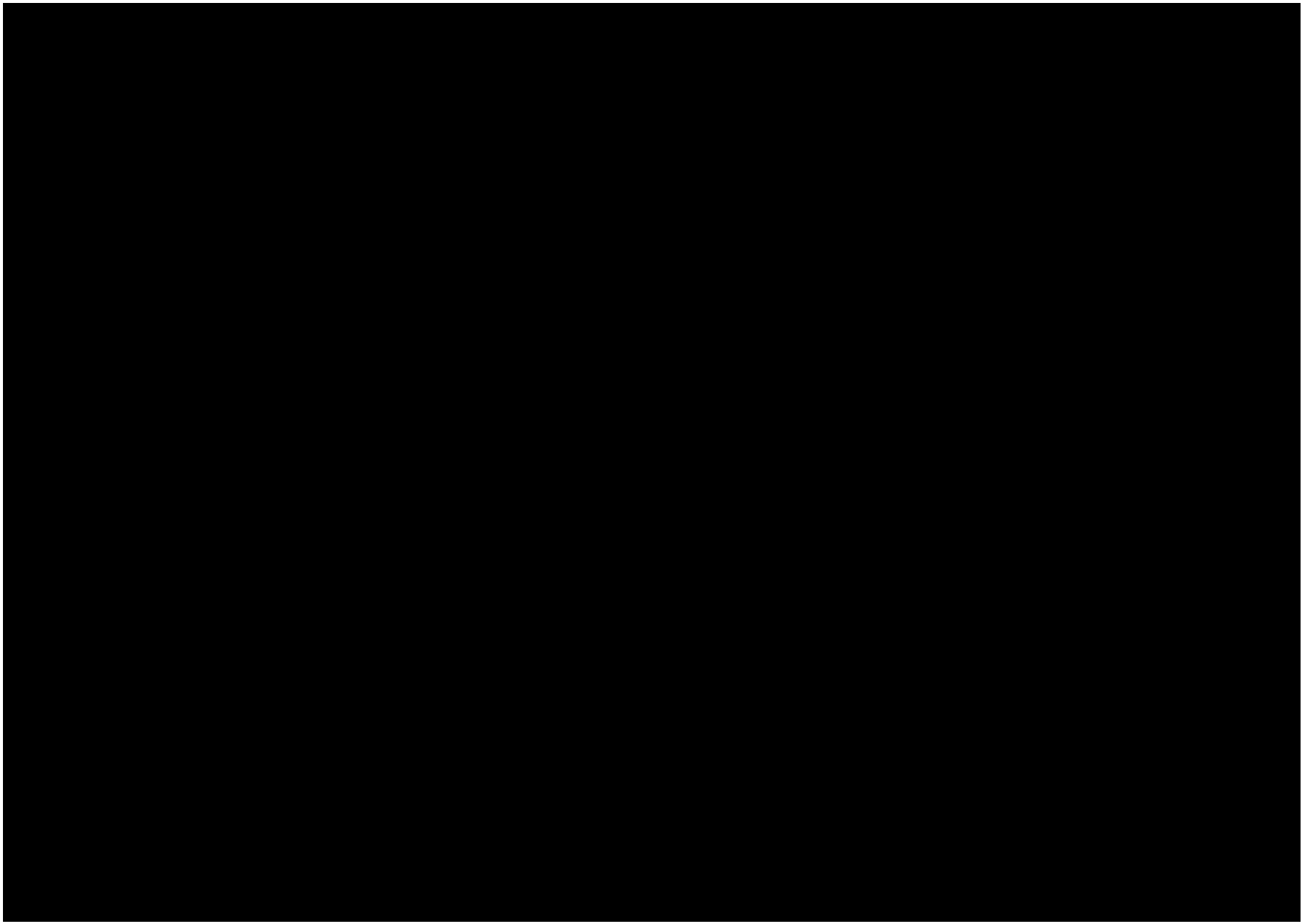
5.5.3 Groundwater/USDW Quality Monitoring

To meet the requirements of 40 CFR **§ 146.90(d)**, ExxonMobil will monitor groundwater quality and geochemical changes above the confining zone during the period of operation.

5.5.3.1 Phased and/or Triggered Monitoring

The phased and/or triggered monitoring strategy (Table 5-6) was adopted for the installation of potential additional USDW monitoring wells, soil-gas monitoring wells, and air monitoring locations. The phased approach was deemed reasonable and appropriate based on the schedule of CO_2 injection for four injection wells—and the degree of protectiveness evident based on the geologic site characterization and demonstrated by the plume modeling. This type of approach allows the site-specific testing and monitoring strategies to be tailored to changes in predicted performance and in response to potential increased risks to USDWs identified or detected during injection.







5.5.3.2 Design of the Monitoring Well Network

The monitoring well network includes the proposed monitoring wells that will be used to support compliance with the testing and monitoring requirements under the Class VI Rule (40CFR § 146.90). Combined with the monitoring of pressure buildup at each proposed injection well, the design of the monitoring well network was selected to provide a high degree of confidence in detecting vertical CO_2 migration through the confining zone, that may endanger the USDW. The relevant site data considered for the design of the monitoring well network included the phased injection depths, rate, and volume; the geology; and the presence of the legacy wells as required by 40 CFR **§146.90(d)(1)** and **(2)**.

5.5.3.3 USDW Monitoring Well Construction

To comply with 40 CFR **§146.90(d)**, a phased approach to USDW monitoring well installation is proposed. Initially, [redacted] will be completed at the locations shown on Figure 5-4. These locations were selected to provide a baseline of geochemical data in the vicinity of two of the injection wells and both in-zone monitoring wells.

The Chicot aquifer is the primary USDW aquifer within the AOR, and its relatively shallow water-bearing zones are a target for the completion of freshwater wells, typically at depths ranging from approximately 60–520 feet (ft) below ground level (BGL) in the AOR, as reported in *Appendix C-4* [redacted] *AOR and Corrective Action*. [redacted]

Potential vertical migration points were considered for the USDW monitoring wells, but the [redacted]

5.5.3.4 Summary of Water Well Data for the AOR

Table 5-7 provides a summary of the [redacted] The well construction details for additional USDW monitoring wells (if constructed) will be consistent with the construction details in Table 5-7.

A total of [redacted] freshwater wells were identified in and near the AOR as listed in *Appendix C-4* of *Section 3 – AOR and Corrective Action* from the Texas Water Development Board well registration list and the Submitted Drillers Report Database. *Appendix C-3* of *Section 3 – AOR and Corrective*

Action illustrates the location of the water wells, each of which is completed in the Chicot aquifer with a maximum depth of [redacted] For planning purposes, the extent of the CO_2 plume and pressure front relative to the water wells will be reviewed after sufficient data have been collected to assess whether additional USDW groundwater monitoring is needed for situations of potential USDW endangerment.

[redacted]

Groundwater samples will be collected using decontaminated submersible pumps equipped with new dedicated, disposable sampling tubing capable of producing representative groundwater samples to the surface with the least pumping effort. The fluid sampling parameters and frequencies for the in-zone and USDW monitoring wells are shown in Table 5-8. Additional USDW monitoring wells will be added to assess the potential for USDW endangerment, if necessary. The USDW monitoring wells will be completed to collect groundwater samples for the Chicot aquifer at depths from approximately [redacted]

5.5.3.5 Collection and Analysis of Groundwater Samples

Fluid samples will be taken periodically from the USDW monitoring wells and the [redacted] The USDW monitoring wells target the Chicot aquifer, which is the most used aquifer in the AOR for potable and non-potable purposes. [redacted]

Table 5-8 summarizes the parameters analyzed and the planned sampling frequency, which apply to the USDW and in-zone monitoring wells. Anomalous measurements will trigger resampling

and additional data analysis, including a more detailed evaluation of data using statistical comparisons approved by the EPA for detection monitoring programs. This analysis could also include geochemical modeling to compare the compositions of groundwater from before and during operations.

If warranted, other tests may be added to the evaluation if resampling and detailed analysis of the fluid samples do not satisfactorily rule out an undesired migration scenario.

[redacted]

Measurements are performed on gases collected from the fluid samples by depressurizing them to atmospheric conditions in a controlled laboratory environment.

ExxonMobil will test the fluid samples and maintain results for the parameters listed in Table 5-8. If results indicate the existence of impurities in the injection stream, the significance of these constituents relative to the protection of USDW will be assessed to determine if they should be included in the analysis of the water samples. Testing results will be stored in an electronic database.

Fluid chemistry data will be monitored for deviations from baseline, predicted, and average values. If a significant variance occurs, the numerical model will be reevaluated. Potential geochemical signs that fluid may be unexpectedly migrating from the injection interval may be detected upon observation of the following trends:

- Change in total dissolved solids (TDS)
- Change in signature of major cations and anions
- Increase in CO_2 concentration
- Decrease in pH
- Increase in concentration of injectate impurities
- Increase in concentration of leached constituents

5.5.3.6 Laboratory to Be Used/Chain of Custody Procedures

The analysis of the fluid samples will be transported to an accredited and state-approved laboratory. ExxonMobil will observe standard COC procedures and maintain records to allow full

reconstruction of the sampling procedure, storage, and transportation, including any problems encountered.

5.5.3.7 Quality Assurance and Surveillance Measures

ExxonMobil will collect replicate samples and sample blanks for quality assurance/quality control purposes. The samples will be used to validate test results, if needed

5.5.3.8 Plan for Guaranteeing Access to all Monitoring Locations

The placement of the well locations is optimized to be accessible from roads.

5.5.4 Upper Confining Interval/Above Zone Monitoring

5.5.4.1 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

*MD – measured depth

5.5.5 Plume and Critical Pressure Front Monitoring

[redacted]

5.5.5.1 Direct Monitoring

[redacted]

[redacted]

Any periods of shut-in for an injection well may be observed and treated as a falloff test by recording the shut-in wellhead pressure, bottomhole pressure, and temperature readings. This information, together with the continuous measurements obtained during regular operating conditions, will aid in updating the CO_2 plume reservoir models and plume growth forecasts.

5.5.5.2 Indirect Monitoring: Time-Lapse Seismic Surveying

[redacted]

[redacted]

[redacted]

[redacted]

The timing of [redacted] will occur when the following criteria have been met and the analysis of operational and testing data demonstrates compliance with the UIC Class VI permits—in the [redacted]

[redacted]

Should at any time the acquisition of indirect monitoring data suggest deviation from expected behavior for compliance with the permits, ExxonMobil will discuss the need with the UIC Director and take appropriate action.

[redacted]

[redacted] A significant amount of direct and indirect monitoring data will be available by this time and conclusions made regarding the predictive capabilities of the CO_2 plume and pressure front subsurface dynamic model for both the [redacted] ExxonMobil expects that the model will be a reliable predictor of the growth rate and extent of CO_2 saturation and pressure plumes. With the UIC Director's concurrence, [redacted]

If additional surface seismic surveys are necessary during the PISC period to improve the model's predictive capability or show CO_2 plume stability, ExxonMobil will communicate with the UIC Director on the nature and timing of such contingent surveys.

[redacted]

[redacted]

[redacted]

5.5.5.3 Seismicity Monitoring (Induced Seismicity)

[redacted]

[redacted]

[redacted]

References:

Holmes, G., Bongiovanni, N., Wulf, T., Schneider, S., Maxwell, S., Chacka, B., Sheikha, H., April 2023, Time Lapse Seismic in a CO2 EOR Flood and Implications for CCS Reservoir Monitoring, GeoGulf 23 Conference, Abstract, Houston, TX, Award: Thomas A. Philpott Excellence of Oral Presentation

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 6 – Injection Well Plugging Plan

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 6 – INJECTION WELL PLUGGING PLAN

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[redacted]

6.1 Injection Well Plugging Plan

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson County, Texas, to sequester CO_2 using four injection wells. This section for the Class VI Underground Injection Control (UIC) permit application for the project was prepared to meet the requirements of the Title 40, U.S. Code of Federal Regulations (40 CFR **§146.92)** and Texas Administrative Code (TAC), Part 1, Title 16, Chapter 5, for plugging and abandonment (P&A) of the Sunflower CCS Project Injection Wells No. 01, No. 02, No. 03, and No. 04. The purpose of the Injection Well Plugging Plan is to demonstrate the actions that ExxonMobil will take to mitigate the threat to Underground Sources of Drinking Water (USDWs) during the post-injection period.

For plugging the injection wells, ExxonMobil has selected materials that are compatible with the corrosive properties of the injection fluid to maintain the mechanical integrity of the plug and well casing. The planned plugging procedures are aligned with best practices for restoring the upper composite confining zone (UCCZ) integrity at each injection well location. [redacted]

6.2 Objectives

ExxonMobil will plug and abandon the proposed injection wells to restore the UCCZ and provide a barrier sufficient to contain CO_2 and brine in the permitted injection interval —and to isolate the USDW.

The Injection Well Plugging Plan and procedures were designed to meet the following objectives:

- Measure the bottomhole reservoir pressure prior to conducting plugging activities (40 CFR **§146.92(b)(1)**).
- Assess the external mechanical integrity of the long string casing by using appropriate testing methods to demonstrate isolation consistent with 40 CFR **§146.92(b)(2)**.
- Select the type, grade, and quantity of material to be used in plugging, to withstand contact with CO_2 and acidified liquids in the injection stages (40 CFR **§146.92(b)(5)**).
- Detail the methods, locations, and types of plugs used within the wells (40 CFR **§146.92(b)(4)** and 40 CFR **§146.92(b)(6)**).

6.3 Preparation of Wells Prior to Plugging

ExxonMobil will repair deficiencies identified during the life of the proposed injection wells to mitigate potential leaks to USDWs (40 CFR **§146.88(f)**). Historical mechanical integrity test (MIT)

data and prior remedial measures will be considered prior to plugging operations. If required, those remedial activities will be included in an amendment to this plan.

6.3.1 Flushing Well with Kill Weight Fluid

Pressure control will be accomplished using kill weight brine that is weighted and compatible with the injectate and formation fluids. The kill weight brine fluids will be circulated through the injection wells to remove fluids or fine debris that could have a significant impact on the integrity of cementing operations (40 CFR **§146.92(a)**).

6.3.2 Removal of Well Components and Obstructions

Prior to plugging, uncemented and non-permanent components of the wells will be removed. The surface and long string casings will be cemented to the surface during well construction per *Section 4 – Well Construction Plan and Operating Conditions* and will remain in place.

6.3.3 Planned Tests or Measures to Determine Bottomhole Pressure

[redacted] The bottomhole reservoir pressure will be used to estimate the density of kill weight brine needed to establish static equilibrium prior to plug placement.

6.3.4 Planned External MITs

The MIT will be used to identify the potential for significant fluid movement toward the USDW in the casing, tubing, or packer (40 CFR **§146.89(a)**). ExxonMobil will conduct at least one of the tests listed in Table 6-1 as part of the monitoring program, to verify external mechanical integrity as required in 40 CFR **§146.92(a)**.

Table 6-1 – External MIT Methods

[redacted]

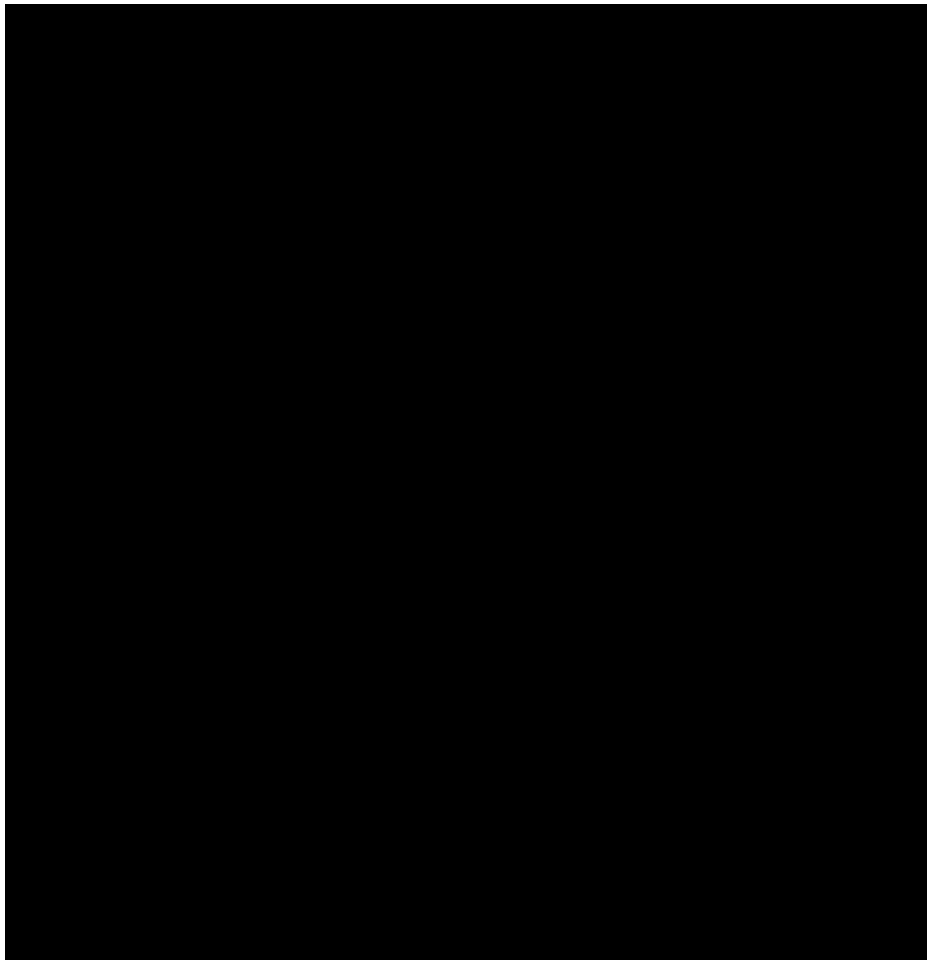
The results of the MIT will be documented and provided to the UIC Program Director (UIC Director).

6.3.5 CO_2-Compatible Materials

In accordance with 40 CFR **§146.92(b)(3)** and **(5)**, a cement that is compatible with CO_2 will be used as the UCCZ cement plug. ExxonMobil will evaluate potential cement options prior to implementing the cementing operations, with the intent to provide a barrier that can withstand the temperature, pressure, and chemical interactions.

Cement at intervals above the UCCZ will be based on blended Portland cement. A list of common cement additives is provided in Table 6-2 for the blended Portland cement, to improve setting time, reduce porosity, and improve overall strength if needed. Not all additives listed will be utilized. ExxonMobil will report the additives utilized, wet density, and will retain duplicate samples of the cement used for each plug in the plugging reports.

– Table 6-2 – Common Cement Additives



6.3.6 Planned Site Restoration Activities

After the injection wells have been plugged and abandoned, the wellhead equipment and surface facilities will be removed from the Sunflower Project site. The surface will be restored to a condition agreed upon by the landowner and by the UIC Director, as appropriate.

6.4 Injection Well Zonal Isolation and Final P&A

As discussed above, a plug will be set for injection zone isolation and the final P&A will occur at the end of the Sunflower Project. The following details outline the procedures for both types of plugs to be installed. The volume and depth of the plugs will depend on the final geology and downhole conditions of the proposed injection wells as assessed during construction, as required by 40 CFR **§146.92(b)(3)** and **(4)**.

[redacted]

ExxonMobil will comply with reporting and notification provisions for the UIC Director, which require a 60-day advanced written notice before planned recompletion efforts are undertaken (40 CFR **§146.92(c)**). A similar notice of recompletion will be communicated to the Railroad Commission of Texas (TRRC).

[redacted]

6.4.2 Final P&A

After injection operations cease and post-operational monitoring in the injection wells is completed, the wells will be prepared for final P&A—the general procedures for which are described below.

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

ExxonMobil will comply with reporting and notification provisions and provide written notification to the UIC Director 60 days before planned plugging efforts. If changes have been made to the original approved Injection Well Plugging Plan, ExxonMobil will provide the amended plan (40 CFR **§146.92(c)**). A Notice of Intention to Plug and Abandon Form W-3A will be submitted to the TRRC at least 5 days before plugging operations are planned to commence. In accordance with 40 CFR **§146.92(d)**, a plugging report will be submitted to the UIC Director and TRRC within 60 days after plugging. Plugging Record Form W-3 will be filed with TRRC District Office 3 within 30 days after plugging.

6.4.2.2 Plugging Procedure, Injection Wells

[redacted]



6.4.2.3 Plugging Details, Injection Well No. 01

Table 6-3 provides the plugging details for Injection Well No. 01 (40 CFR **§146.92(b)(3)**, **(4)**, **(5)**, and **(6)**); *Appendix H* shows the final plugged schematic.

Table 6-3 – Plugging Details for Injection Well No. 01



6.4.2.4 Plugging Details, Injection Well No. 02

Table 6-4 provides the plugging details for Injection Well No. 02 (40 CFR **§146.92(b)(3)**, **(4)**, **(5)**, and **(6)**]; *Appendix H* shows the final plugged schematic.

Table 6-4 – Plugging Details for Injection Well No. 02



[redacted]

6.4.2.5 Plugging Details, Injection Well No. 03

Table 6-5 provides the plugging details for Injection Well No. 03 (40 CFR **§146.92(b)(3)**, **(4)**, **(5)**, and **(6)**); *Appendix H* shows the final plugged schematic.

Table 6-5 – Plugging Details for Injection Well No. 03

[redacted]

6.4.2.6 Plugging Details, Injection Well No. 04

Table 6-6 provides the plugging details for Injection Well No. 04 (40 CFR **§146.92(b)(3)**, **(4)**, **(5)**, and **(6)**); *Appendix H* shows the final plugged schematic.

Table 6-6 – Plugging Details for Injection Well No. 04



6.5 Notifications and Record Keeping

The procedures described above are subject to modification during execution, as necessary, for implementation of plugging operations that protect worker safety and the USDW. ExxonMobil will submit a revised plan to the UIC director in the event it finds it necessary to change the approved plugging plan. Completed plugging forms, records, and lab information will be supplied to the regulatory agencies as required by the permit. The plugging report will be certified as accurate by ExxonMobil and the plugging contractor and will be submitted to the UIC Director within 60 days after plugging is completed (40 CFR **§146.92(d)**).

Well plugging reports, post-injection site care data (including data and information used to develop the demonstration of the alternative post-injection site care time frame), and the site closure report collected pursuant to the requirements in 40 CFR **§146.93(f)** and **(h)**, will be

retained by ExxonMobil. Site closure and reporting are discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*.

The plugging report will provide the following information:

- Results of tests to determine BHP and mechanical integrity
- Type and number of plugs used
- Cement type, grade, weight, and quantity of material for plugs
- Method of cement plug emplacement
- Top and bottom of each cement plug

6.6 Monitoring Well P&A

Monitoring wells must be plugged in accordance with 40 CFR **§146.93(e)** to not allow movement of injection or formation fluids that could endanger USDWs. Specific monitoring wells will remain in place after the proposed injection wells have been plugged and abandoned for use in monitoring activities associated with the Post-Injection Site Care and Site Closure Plan. ExxonMobil will assess the monitoring well plugging procedures prior to P&A in relation to this plan. Documentation of appropriate P&A of the monitoring wells will be submitted to the UIC Director in accordance with 40 CFR **§146.93(f)(1)**.

6.7 Amendments to the P&A Plan

The Injection Well Plugging Plan will be amended to account for changes in conditions that trigger modification to the area of review. ExxonMobil will inquire with the UIC Director to confirm whether such changes in condition warrant amendments to this plan. Revisions to the plan can be made at any time and submitted when notifying the UIC Director of the intent to plug the well at least 60 days prior to conducting the plugging activity (40 CFR **§146.92(c)**).

Appendix F – Injection Well Plugging Plan
[redacted]

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 7 – Post-Injection Site Care and Closure Plan

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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7.1 Introduction

The Post-Injection Site Care (PISC) and Site Closure Plan for the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) Injection Wells No. 01, No. 02, No. 03, and No. 04 was prepared to meet the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93** and Texas Administrative Code (TAC), Part 1, Title 16, Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the project in Jefferson County, Texas, to sequester up to approximately [redacted]

The PISC Plan describes the activities that will occur once injection operations have ceased, and the project moves into maintaining a non-endangerment condition for Underground Sources of Drinking Water (USDWs). The Site Closure Plan will be implemented once ExxonMobil demonstrates to the Underground Injection Control (UIC) Program Director (UIC Director) that no additional monitoring is required to demonstrate protection of USDWs, and that the testing and monitoring system can be dismantled. ExxonMobil's strategy for PISC monitoring is based on the same systems and processes as described in *Section 5 – Testing and Monitoring Plan*. The major monitoring elements include continued measurements of the CO_2 plume and pressure front location and monitoring the USDW and groundwater above the upper composite confining zone (UCCZ). The data collected from this activity will be used to confirm compliance with the water-quality objectives for the project, and generate information needed to support the final non-endangerment demonstration and subsequent site closure. The end of the project will occur when the closure activities have been documented and approved by the UIC Director.

7.2 Objectives

The PISC and Site Closure Plan have been developed to meet the following objectives as outlined in 40 CFR **§146.93**:

- Describe the pressure differential between pre-injection and predicted post-injection pressures in the injection zones, as well as the predicted positions of the CO_2 plume and associated pressure front at site closure.
- Describe the post-injection monitoring locations, methods, and proposed frequencies to demonstrate non-endangerment to the USDW over the time frame of the PISC.
- Identify the pre-closure, plugging, and site-restoration steps to achieve approval for site closure.
- Outline the documentation and recordkeeping practices that will provide the information for decision-making purposes.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 40 CFR **§146.93(b)(3)** has been approved by the UIC Director. Pursuant to 40 CFR **§146.93(b)(1)**, the default PISC monitoring time frame is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years after cessation of injection, unless a lesser period is approved by the

UIC Director. Once the non-endangerment demonstration has been approved, ExxonMobil will plug the monitoring wells, restore each well pad to the surface owner's agreed-upon condition, and submit a Site Closure Report to the UIC Director.

7.3 Calculation of Pre- and Post-Injection Pressure Differentials

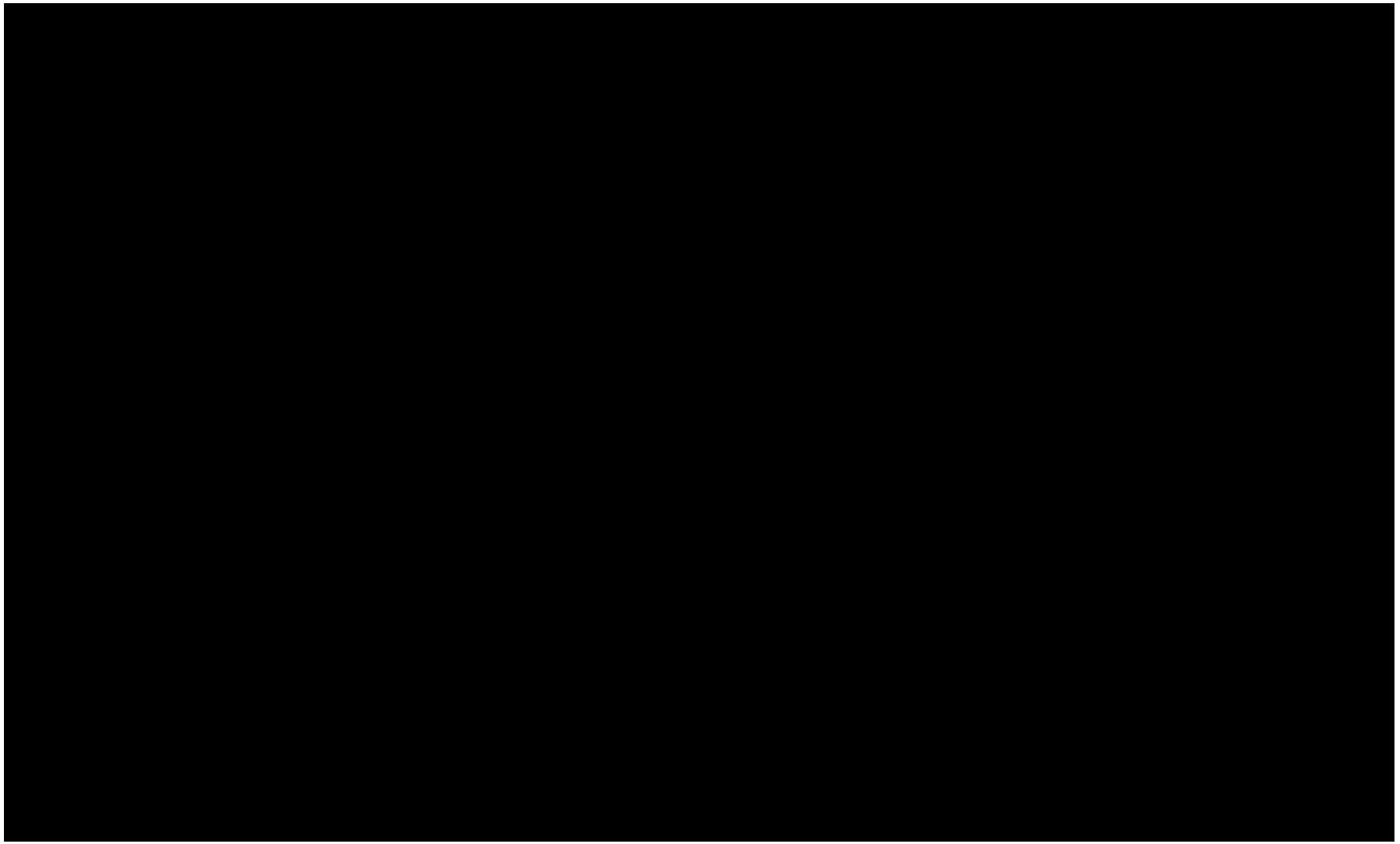
As described in 40 CFR **§146.93(a)(2)(i)**, the Class VI non-endangerment demonstration will establish that pressure has declined to a level that no longer poses potential endangerment of USDWs. For the purposes of this section, ExxonMobil evaluated the pressure differentials by comparing the pre-operating pressure with the post-injection pressure differentials predicted by the plume model. The predicted pressure differential between pre-injection and the modeled post-injection pressures are favorable, showing a steep and continuous decline in pressure toward pre-operational baseline conditions. The primary mechanisms responsible for the anticipated pressure decay rates are the injection sequencing plan, the geological conditions of the injection zones (e.g., net sand thickness, permeability, porosity) and confining zones, and the projected CO_2 storage volume for the Sunflower Project site.

A staged injection sequence is planned for the proposed injection wells to optimize the storage of CO_2 in the injection intervals. *Section 3 – Area of Review and Corrective Action Plan* and *Section 4 – Engineering Design and Operating Strategy* provide detailed discussions of the injection sequencing strategy. Figure 7-1 summarizes the injection sequence schedule for the proposed injection period. The actual injection period will depend on the issuance of the permits for each injection well.



Table 7-1 provides the model-predicted average pressure differential and the change in injection pressures in each injection interval over time pursuant to 40 CFR **§146.93(a)(2)(i)**.

Table 7-1 – Average Pressure Differential by Year for the Proposed Injection Wells



7.4 Predicted Position of the CO_2 Plume and Pressure Front at Site Closure

Pursuant to 40 CFR **§146.93(a)(2)(ii)**, the area of review (AOR) was delineated using computational modeling that accounts for all phases of CO_2 (e.g., supercritical, dissolved, etc.) under proposed operational conditions. The AOR consists of both the CO_2 plume and the extent of the pressure front. The following discussion provides the predicted evolution of both the CO_2 plume and pressure front throughout the course of the 50-year PISC time frame.

Figure 7-2 shows the extent of the AOR and its subcomponents [redacted] years from the start of injection and [redacted] years from the cessation of injection. Based on the model, the CO_2 plume stabilization is predicted to occur [redacted], with pressure differentials below the critical pressure threshold, thereby reducing the potential for USDW endangerment. The CO_2 plume from the proposed injection wells is based on the maximum extent of any injection interval. [redacted]



7.5 Post-Injection Site Care Monitoring Plan

Post-injection site care monitoring is required by 40 CFR **§146.93(b)** to demonstrate that the USDW is not endangered during the post-injection phase of the Sunflower Project. Much like the operational phase, direct and indirect forms of monitoring will be used to track the evolution of the CO_2 plume and pressure front after cessation of CO_2 injection. The strategy for the PISC monitoring is to rely on a core set of monitoring locations that were established during the operational phase of the project.

The following set of core monitoring locations were assumed to be installed and monitored pursuant to the Testing and Monitoring Plan (*Section 5*) and found sufficient pursuant to the AOR reevaluation process:

[redacted]

Figure 7-2 illustrated the locations of these USDW monitoring wells. If additional monitoring locations are added during the course of the injection operations under the direction of the UIC Director, this core set of monitoring wells will be updated to reflect the monitoring system in place at the close of the injection phase of the project.

In accordance with 40 CFR **§146.93(b)(1)**, monitoring of the pressure front and CO_2 plume will occur for at least [redacted] years, or an alternate duration approved by the UIC Director. ExxonMobil is proposing a schedule to submit PISC monitoring results annually and within 30 days of the anniversary date of injection cessation (40 CFR **§146.93(a)(2)(iv)**).

The following discussion provides details on the elements of the PISC monitoring strategy outlined above.

7.5.1 PISC and Site Closure Plan Reviews and Amendments

As required by 40 CFR **§146.93(a)(3)**, ExxonMobil will submit an amended PISC and Site Closure Plan or demonstrate that no amendment is needed upon cessation of injection. Amendments to the plan, or the demonstration that no revisions are necessary, will be based on monitoring data collected during injection and the most-recent AOR delineation.

During PISC monitoring, ExxonMobil will conduct periodic reviews to incorporate new monitoring data, changes to the site computational model that may warrant changes in PISC monitoring,

and/or changes in the methodology proposed to demonstrate non-endangerment of the USDW. This approach will also support the use of new technologies that may be available in the future that facilitate a higher level of performance than the existing system. Pursuant to 40 CFR **§146.84(e)** and as described in *Section 4 – Engineering Design and Operating Strategy*, ExxonMobil will reevaluate the AOR periodically by comparing model predictions with monitoring results.

Following an AOR reevaluation process, if the AOR and Corrective Action Plan are amended, ExxonMobil will review the PISC and Site Closure Plan to determine whether any updates are needed to ensure consistency across all plans. ExxonMobil may submit an amended PISC that describes how changes to the model affect predictions of pressure dissipation, plume migration rates, CO_2 trapping, and additional processes that need to be accounted for in the non-endangerment demonstration.

In accordance with 40 CFR **§146.93(a)(4)**, at any time during the life of the project, ExxonMobil may modify and resubmit the PISC and Site Closure Plan for the UIC Director's approval within 30 days of such change.

7.5.2 Monitoring Above the UCCZ and USDW

During the injection phase, periodic monitoring of groundwater quality for significant geochemical changes above the UCCZ is required by 40 CFR **§146.90(d)** for the purpose of detecting potential leakage through the UCCZ. In accordance with 40 CFR **§146.93(b)(1)**, groundwater quality and geochemical characteristics will be monitored in the AZMI at [redacted], and in the USDW at [redacted] during the post-injection period.

ExxonMobil's strategy for monitoring groundwater above the UCCZ is a risk-based approach correlated to modeled CO_2 plume and injection-zone characteristics. By the time the PISC monitoring program is initiated, the risk-mitigating effects of the injection sequence plan, the operating strategy, and corrective actions taken on artificial penetrations will likely have demonstrated protection of the USDW throughout the operational phase of the project. The list of analyses to be performed at these monitoring wells is summarized in Table 7-2 based on the same approach used for the operational phase of the project.

Table 7-3 provides a summary of indirect monitoring technologies to be used for above-zone CO_2 plume and pressure front monitoring during the PISC phase of the project. This monitoring strategy is consistent with the details and rationale provided in *Section 5 – Testing and Monitoring Plan*. The results of the monitoring activities will be submitted in the annual report for the year in which they occur—and within 30 days of the anniversary date of injection cessation or through an alternate schedule agreed upon with the UIC Director.

Table 7-2 – Direct Above-Zone Monitoring and USDW Sampling and Analysis Program

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency[1]	Geochemical Analyses
USDW [redacted]	Water Level Gauging and Collection of Fluid Samples	[redacted]	[redacted]	[redacted]
First Laterally Continuous Permeable Formation Above the UCCZ	Collection of Fluid Samples	[redacted]	[redacted]	[redacted]
	Pressure, Temperature	[redacted]	[redacted]	
[redacted]				

Table 7-3 – Indirect Above-Zone Monitoring Program

Testing/Monitoring Activity	Frequency	Reporting Schedule	Comment
[redacted]			

The analytical methods and quality assurance/quality control measures discussed in *Section 5 – Testing and Monitoring Plan* for collecting and analyzing fluid samples will apply to the data collection program of the PISC, as appropriate.

7.5.3 In-Zone CO_2 Plume and Pressure Front Tracking

ExxonMobil proposes to use direct and indirect methods to track the extent of the CO_2 plume and pressure front in the injection zone during the PISC period. Direct monitoring in the injection zone includes continuous pressure and temperature measurements for [redacted] By the start of the PISC phase of the Sunflower Project, the direct and indirect monitoring activities will have been used for approximately [redacted] years and will be a proven set of monitoring technologies for detection monitoring of CO_2 plume and brine crossflow potential.

Table 7-4 describes the proposed CO_2 and pressure plume tracking methods for the PISC Plan. The water quality and geochemical parameters to be analyzed are presented in Table 7-5, consistent with *Section 5 – Testing and Monitoring Plan*, which includes additional information on the monitoring methods described and how deviations would be identified.

Table 7-4 – Direct and Indirect In-Zone Monitoring Program for PISC

Monitoring Element	Strategy
Time Period	Immediately following and for up to [redacted] years from cessation of injection operations
Monitored Locations, Conditions, and Frequency	[redacted]
Planned Changes in Monitoring Techniques	None. The model-predicted rapid decrease in CO_2 plume movement and pressure significantly reduces the potential for USDW endangerment following injection and eliminates the need for additional monitoring.
Triggers	*Section 3 – AOR and Corrective Action Plan* provides a list of triggers for the AOR reevaluation process. Those triggers are applicable to the monitoring program.

Table 7-5 – USDW and AZMI Monitoring and Sampling Program During the PISC Phase

Monitoring Well	Frequency	Parameter/Analyte
[redacted]		

7.5.4 Submitting PISC Monitoring Results

In accordance with 40 CFR **§146.93(a)(2)(iv)**, ExxonMobil will submit PISC monitoring data to the UIC Director in annual reports within 30 days following the anniversary of the date that injection

ceases. The annual reports will contain information and data generated during the reporting period, such as the following:

- A list of monitoring events performed during the reporting period and the associated dates
- A brief description of sampling/testing/analytical locations, elevations/depths, equipment, and procedures, indicating whether (and why) departures from the procedures specified in the PISC and Site Closure Plan occurred
- Changes to the monitoring program that took place during the reporting period (e.g., repair to monitoring wells, implementation of approved changes in the frequency of monitoring activities based on criteria established in the PISC and Site Closure Plan and on approval of the UIC Director)
- Synthesis and interpretation of the results that describe trends in parameter values or lack of trends, alignment between actual and plume model predictions, the appearance of anomalous or unexpected results, and progress toward attaining the EPA and Railroad Commission of Texas (TRRC) criteria for non-endangerment
- Map(s) and cross section(s) showing the AOR, monitoring locations, and the interpreted extent of the separate-phase CO_2 plume and the pressure front
- Any recommended changes to the PISC and Site Closure Plan to continue protection of the USDWs

7.6 Demonstration of Non-Endangerment of USDW

Prior to the approval of the site closure authorization and in accordance with 40 CFR **§146.93(b)(2)** and 40 CFR **§146.93(b)(3)**, ExxonMobil will provide documentation to assess the potential for the USDW to be at risk of endangerment from the CO_2 plume at the end of the PISC phase of the Sunflower Project. The non-endangerment demonstration will be based on monitoring data and a demonstration that the structure of the confining zones, combined with the geochemical conditions of the subsurface, have effectively permanently sequestered the stored CO_2. This information will be used to demonstrate that additional monitoring is not needed to protect the USDW and that the project has met the compliance obligations to receive authorization for site closure.

This demonstration will be in the form of a detailed report submitted to the UIC Director that synthesizes site- and project-specific information and demonstrates a current understanding of system behavior at the time of the non-endangerment demonstration. The following subsections outline the type of information to be presented in the non-endangerment demonstration report.

ExxonMobil will engage the UIC Director as soon as the available data are aligned with the criteria for site closure, which may ultimately be less than the default PISC duration of 50 years pursuant to 40 CFR **§146.93(b)(2)** and 40 CFR **§146.93(c)**.

7.6.1 Introduction and Overview for Non-Endangerment Demonstration

A summary of relevant background information will be provided in the introduction section, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

7.6.2 Summary of Existing Monitoring Data

The monitoring data collected throughout the project's life cycle will be summarized and used to describe how the UCCZ functioned as a barrier to mitigate endangerment of the USDW, and how the CO_2 is effectively trapped in the injection zones. The non-endangerment demonstration will include a summary of previous monitoring data collected at the site, pursuant to the details in *Section 4 – Engineering Design and Operating Strategy* and *Section 5 – Testing and Monitoring Plan*, as well as the PISC and Site Closure Plan.
Data submittals will be in a format acceptable to the UIC Director (40 CFR **§146.91(e)**) and will include:

- An explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time,
- An explanation of the monitoring infrastructure that has existed at the site.
- A comparison with baseline data collected during the site characterization to assess trends in key parameters that support the proposal for site closure.

7.6.3 Summary of Computational Modeling History

A series of data sources detailed in *Section 5 – Testing and Monitoring Plan* will be used to update the computational model at least once every [redacted] years—more frequently if warranted. The following measured data will be utilized to update the computational model to demonstrate non-endangerment:

- In-zone temperature and pressure data
- Injection rate and volume data
- CO_2 plume location based on indirect geophysical monitoring
- AZMI data regarding the performance of the UCCZ

The procedure used to reevaluate the AOR will be based on the data collected between reevaluations and the well conditions at the time of reevaluation. The post-injection data will include historical injection rates, pressures, pressure falloff, and historical operational parameters of the four proposed injection wells. ExxonMobil will rely on a process of history matching the plume model results with the actual monitoring data. The measured data will be used as a calibration point for the plume model, and the input parameters adjusted to provide a

reasonable match between the two data sets. Through this or a similar process, ExxonMobil will provide a validation of the model performance for the CO_2 plume and pressure front.

7.6.4 Evaluation of Reservoir Pressure

The non-endangerment demonstration will include an evaluation of the residual pressure and the potential for continued trends in pressure dissipation that might endanger USDWs in the future. Information will be provided to describe how the pressure and buoyancy effects on plume and pressure migration decayed over time, and how the residual levels comply with the requirements for non-endangerment. This evaluation will consider the most-recent AOR delineation/modeling results and pressure monitoring data. The same model that supported the delineation of the AOR or a similar model approved by the UIC Director will be used for this modeling, as it will be verified (or calibrated) by actual monitoring and operational data via AOR reevaluations.

7.6.5 Evaluation of the CO_2 Plume

The non-endangerment demonstration will include an evaluation of the gas-phase CO_2 plume and the dissolved-phase CO_2 plume, as appropriate. The evaluation of the potential CO_2 plumes will rely on monitoring data, including geochemical and geophysical analyses and the most recent AOR modeling results. Direct measurements of the temperature and pressure of CO_2 in the injection zone, as well as the results of geophysical measurements, will be used to confirm plume location and demonstrate plume migration rates.

7.6.6 Evaluation of Emergencies or Other Events

[redacted] If any subsequent artificial penetrations are discovered to have a potential to threaten USDW, they will be remediated using the same procedures so that no artificial penetrations of concern remain at the time of site closure.

The data and evaluation methods specified pursuant to the requirements of *Section 5 – Testing and Monitoring Plan* as well as the PISC Plan provide the basis for demonstrating that no future endangerment of the USDW is likely to occur.

7.7 Site Closure Plan

ExxonMobil will conduct site closure activities to meet the requirements of 40 **§CFR 146.93(d)** through **(h)** as described below. ExxonMobil will submit a final Site Closure Plan and notify the UIC Director at least 120 days prior to its intent to close the site. Once the UIC Director has approved closure of the site, ExxonMobil will plug all injection and monitoring wells and submit a site closure report to the EPA and TRRC. The activities, as described below, represent the

planned activities based on information provided to EPA. The actual Site Closure Plan may employ different methods and procedures.

Additionally, ExxonMobil will record a notation on the deed to the site that the land has been used to sequester CO_2. Site closure activities will also include removing all surface equipment and restoring the site to its prior land surface condition.

7.7.1 Pre-Closure

In accordance with 40 CFR **§146.93(d)**, a notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

The site closure notice submitted to the UIC Director will include the following:

- Facility information, name, and location
- A list of contact personnel for allowing timely direct communication to resolve any pressing issues
- A projected closure date, no less than 120 days following the site closure notification submission, unless the UIC Director has approved a different period prior to notice submission

7.7.2 Plugging Activities

Injection Wells No. 01 through No. 04, [redacted] will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*. After injection ceases and after the appropriate post-injection monitoring period is complete, the monitoring wells will be plugged and abandoned to meet the requirements at 40 CFR **§146.92** and in compliance with applicable state requirements. The plugging procedure and materials will be designed to mitigate fluid movement and protect the USDW. Prior to plugging the wells, the necessary procedural revisions to address new information will be submitted to the UIC Director for review and approval. The final plugging plans will be submitted to the UIC Director no later than 60 days prior to the plugging of the wells.

Following receipt of the approved plugging plans, the wells below the lowermost USDW and above the UCCZ will be logged and pressure-tested to ensure mechanical integrity. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with plugging operations. The casing in these wells will be left in place and will not be retrieved at abandonment. A combination of bridge plugs and cement plugs will be set to plug the wells. All casing strings will be cut at least 3 feet below ground level. A steel plate with the required permit information will be welded to the top of the casing to meet the requirements of the Railroad Commission of Texas.

7.7.3 Site Restoration

Once the injection and monitoring wells are plugged and abandoned, the surface equipment will be decommissioned and removed from the well site. The well site will be restored to a condition agreed upon with the surface owner.

7.7.4 Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the UIC Director per the requirements of 40 CFR **§146.93(f)** and include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats (40 CFR **§146.93(f)(1)**)
- The survey plat, indicating the locations of the injection wells relative to permanently surveyed benchmarks and including the location of the monitoring well
- Documentation of the well-plugging report, to be filed with the TRRC (40 CFR **§146.93(f)(2)**)
- Post-injection monitoring records, summarized
- Records of the nature, composition, and volume of the CO_2 stream for the injection period, summarized (40 CFR **§146.93(f)(3)**)

Pursuant to 40 CFR **§146.93(g)**, a record of notation in the Sunflower Project facilities and infrastructure will be filed on the property deed to provide notice to landowners of the following:

- The land having been used to sequester CO_2
- The name of the state agency with which the survey plat was filed (TRRC) and the EPA Regional Office (Region VI) at which it was submitted
- The total volume of CO_2 injected, the injection zones into which it was injected, and the period over which injection occurred

As required by 40 CFR **§146.93(h)**, ExxonMobil will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, ExxonMobil will deliver all records to the UIC Director for retention at a location designated by the Director for that purpose.

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 8 – Emergency and Remedial Response Plan

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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8.1 Emergency and Remedial Response Plan

This Emergency and Remedial Response Plan (ERRP) was developed in compliance with the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.94** to develop and maintain an ERRP that describes actions to be taken to address movement of the injection or formation fluids that may cause endangerment to an Underground Source of Drinking Water (USDW) during the construction, operation, and post-injection site care periods of the Sunflower Carbon and Storage (CCS) Project (Sunflower Project). Under 40 CFR **§146.90(g)**, the actions described in the ERRP are to be implemented immediately to address a rare event where the movement of the injection fluid or formation fluid endangers a USDW. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) prepared this ERRP to provide both the scope of actions to be taken and the schedule under which the actions would be expected to be implemented.

ExxonMobil is undertaking the project in Jefferson County, Texas, to sequester a [redacted] The ERRP was developed for injection of CO_2 into the proposed Sunflower CCS Project Injection Wells No. [redacted], which will sequester a total of approximately [redacted]

ExxonMobil will use engineering design and planning safeguards (Figure 8-1) to reduce the potential for a rare emergency and remedial response event from occurring. These steps are based on ExxonMobil's global experience and expertise with risk management for rare events in site selection, well drilling and completion, and reservoir operations.



8.2 Overview

ExxonMobil took the findings from *Section 1 – Site Characterization* and *Section 3 – Area of Review and Corrective Action Plan* and identified hypothetical risk scenarios that could—in the rare event of occurrence—pose a threat to USDWs. ExxonMobil's risk assessment process was used to estimate the probability and consequence of each risk scenario based on the experience and judgment of the risk subject matter experts for the project. The ERRP will apply over the life of the project, including throughout the post-injection site care period (40 CFR **§146.94(a)**).

This ERRP describes the actions that ExxonMobil plans to perform 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.

If ExxonMobil obtains verified evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to a USDW, ExxonMobil will perform the following actions:

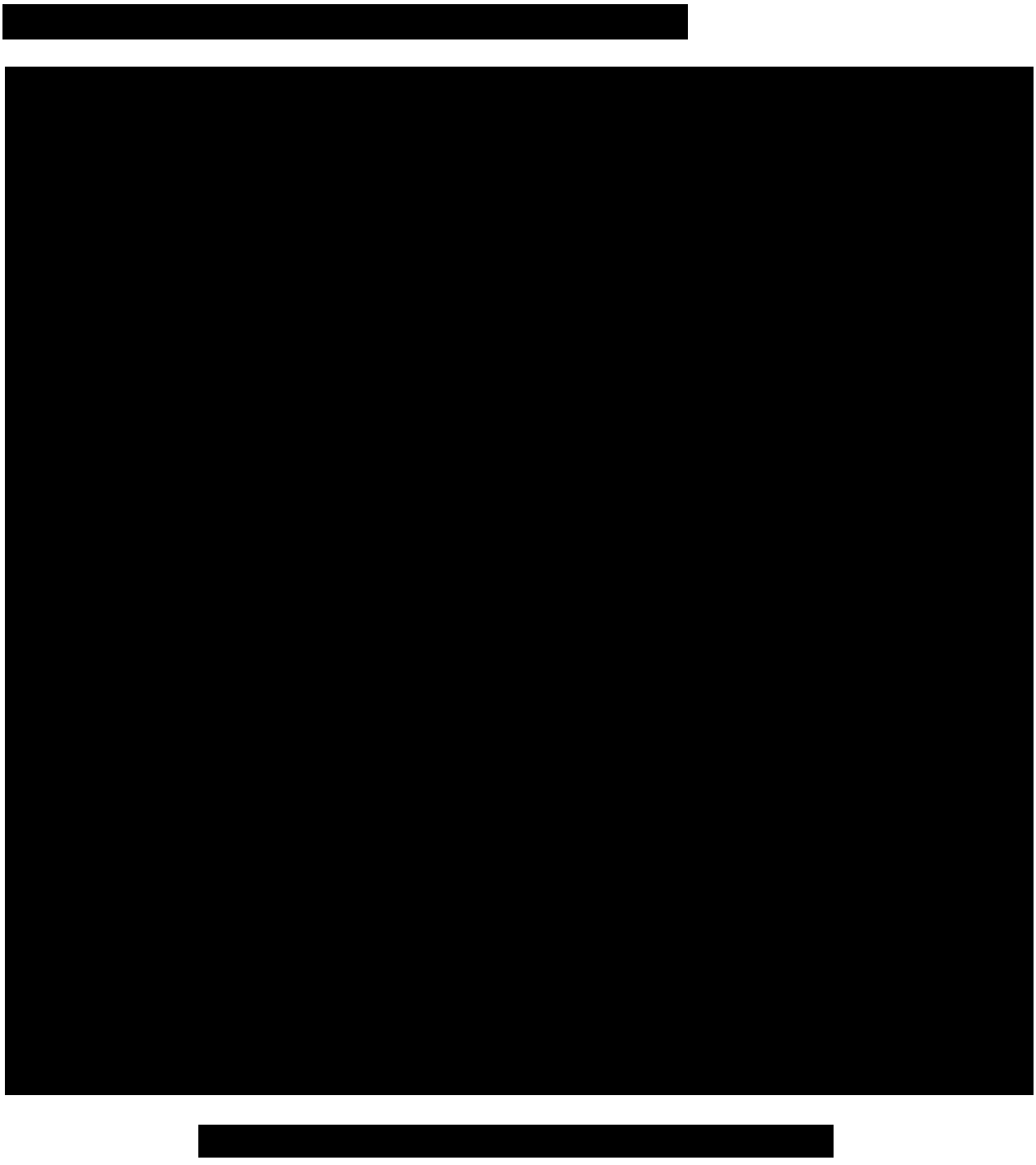
1. Initiate the shutdown plan for the injection well(s).
2. Take all steps reasonably necessary to identify and characterize the release.
3. Notify the permitting agency's Underground Injection Control (UIC) Program Director (UIC Director) of the emergency event within 24 hours.
4. Implement the approved ERRP.
5. Prepare and submit an incident report to the Injection and Post-Injection Phase reporting module of the EPA's Geologic Sequestration Data Tool (GSDT).

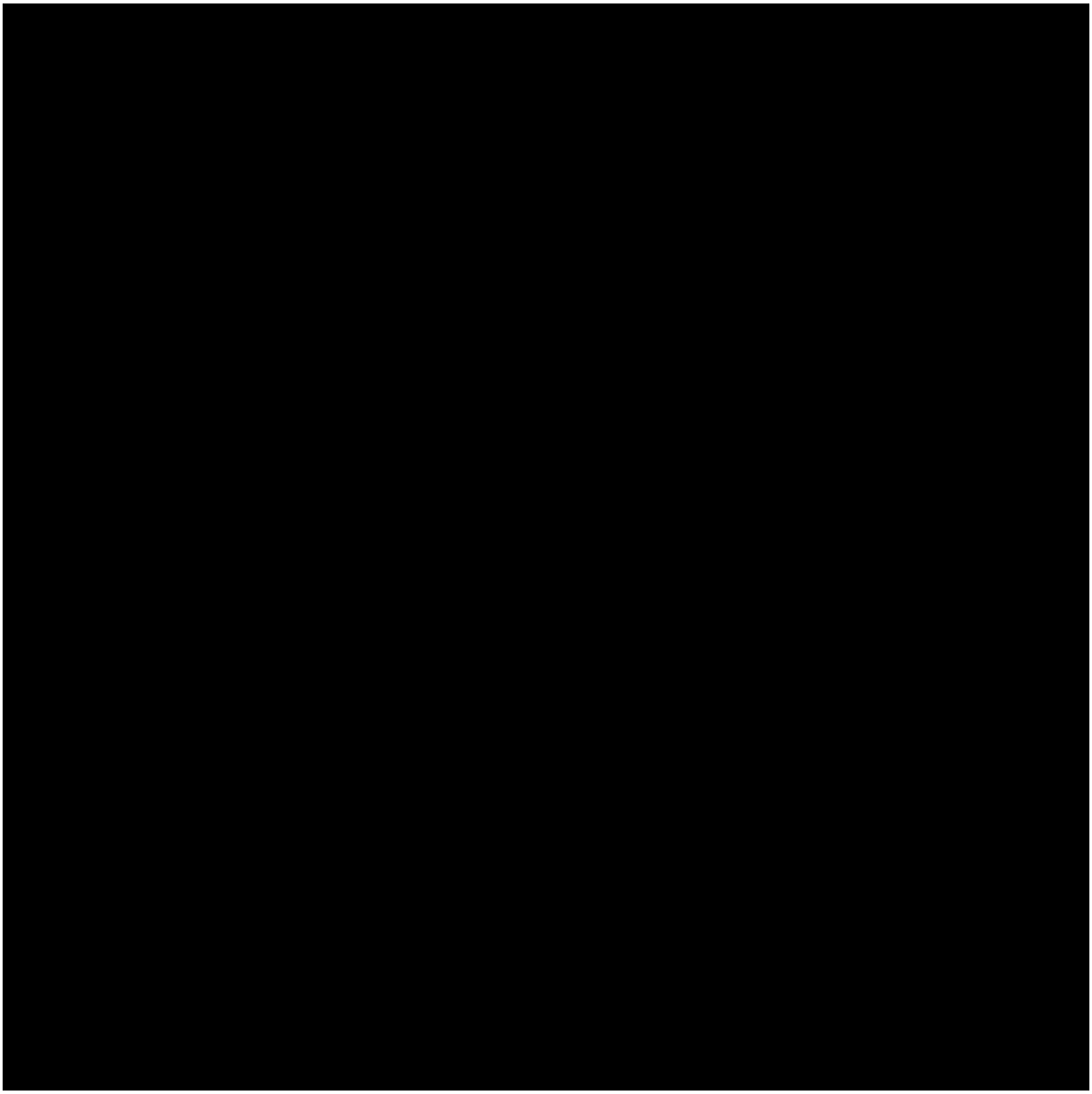
Where the phrase "initiate the shutdown plan" is used, the following protocol will be employed: First, ExxonMobil will implement the steps needed to immediately cease injection. In some circumstances, e.g. for safety reasons, ExxonMobil will, in consultation with the UIC Director, gradually ramp down injection as appropriate as part of the process of immediately ceasing injection. Additionally, ExxonMobil will coordinate with the UIC Director to determine if an emergency scenario does not warrant shutdown for wells, e.g., because there is not an endangerment to a USDW.

8.3 Identification of Resources and Infrastructure in AOR and Flood Hazard Risk

[redacted] t. The infrastructure development is primarily in the form of county roads, pipelines, and power transmission lines to service the developed areas.

Figure 8-3 displays the proposed injection wells and the AOR with respect to flood hazard areas, with the data shown in FIRM panels. There is no digital coverage of the FEMA flood hazard layer for Jefferson County. [redacted]





8.4 Potential Risk Scenarios

The following are events that could potentially result in an emergency response:

- USDW-quality impact event
- An equipment integrity, control system, or monitoring system failure, such as damage to a wellhead, valve, pipe, or flange connection that may cause a CO_2 release to the atmosphere
- A natural disaster or other unplanned event (e.g., hurricane, tornado, lightning strike, earthquake)

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 8-1.

Table 8-1 – Degrees of Risk for Emergency Events

Emergency Condition	Definition
Major	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious	Event poses a potential, significant near-term risk to human health, resources, or infrastructure if conditions worsen, or no response actions are taken.
Minor	Event poses no immediate risk to human health, resources, or infrastructure—but could escalate if not addressed.

8.5 Emergency Identification and Response Actions

Steps to identify and characterize an emergency event will depend on specific issues identified and the severity of the event. The potential risk scenarios are detailed below.

8.5.1 Well Integrity Failure

Integrity failure of an injection or monitoring well may have occurred with the potential to endanger USDWs if monitoring results identify a loss of mechanical integrity, or automatic shutdown devices are activated as follows:

- Wellhead pressure exceeds the maximum injection pressure specified in the permit.
- Annulus pressure indicates a loss of external or internal well containment.

Emergency Condition: Minor to major, depending on the results of the investigation into the incident and identified remedial activities.

Timing of Event: Construction, pre-injection, injection, and post-injection phases.

Avoidance Measures:

- Proper well design, construction, inspection, and maintenance
- Routine mechanical integrity testing
- Routine inspection of monitoring equipment

Detection Methods:

- Well pressure monitoring
- Annulus pressure and fluid-level monitoring
- Monitoring drilling-fluid returns and parameters during well construction and workovers

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Begin an investigation into the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.
- Prepare and submit an incident report to the Injection and Post-Injection Phase reporting module of the GSDT.



Response Personnel: Drilling, workover, or injection crew; supervisory personnel

Equipment: Depending on the severity of the event, the equipment required may include a workover rig, drilling rig, casing and cementing equipment, drilling fluids/muds/kill fluids, logging equipment, and surface monitoring equipment.

8.5.2 Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem that could endanger USDWs.

Emergency Condition: Minor to major, depending on the results of the investigation into the incident and identified remedial activities.

Timing of Event: Injection, post-injection phases

Avoidance Measures:

- Preventative and routine maintenance of monitoring equipment
- Backup monitoring equipment

Detection Methods:

- Continuous monitoring and recording of well parameters (*Section 5 – Testing and Monitoring Plan*)

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Begin an investigation into the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.
- Prepare and submit an incident report to the Injection and Post-Injection Phase reporting module of the GSDT.



Response Personnel: Supervisory personnel, maintenance technicians, contract personnel

Equipment: Applicable equipment for repair and/or replacement of monitoring systems

8.5.3 Fluid (CO_2, Brine, Formation Fluid) Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) as identified in the Testing and Monitoring Plan—or other verified evidence—indicate a fluid (brine) leakage into a USDW.

Emergency Condition: Major, due to potential contamination of USDWs

Timing of Event: Injection, post-injection phases

Avoidance Measures:

- Following the methods and sampling schedules as specified in the Testing and Monitoring Plan (*Section 5*).

Detection Methods:

- Elevated concentrations of indicator parameters in USDW samples
- Anomalies in the results of any monitoring outlined in the Testing and Monitoring Plan or during the post-injection site care period may be cause for additional samples to be taken in the USDW to investigate a potential leakage.

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Begin an investigation into the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.
- Prepare and submit an incident report to the Injection and Post-Injection Phase reporting module of the GSDT.





Response Personnel: Supervisory personnel, environmental professionals/subcontractors

Equipment: Depending on the severity of the event, response equipment may include water testing and treatment/sampling equipment, and water supply equipment

8.5.4 Fluid (CO_2, Brine, Formation Fluid) Leakage to Surface

Elevated concentrations of indicator parameter(s) in surface water, soil gas, ambient air sample(s) as specified in the Testing and Monitoring Plan—or other verified evidence—indicate a CO_2 or brine leakage to the surface.

Emergency Condition: Major, due to potential contamination of surface water, soil, and ambient air

Timing of Event: Injection, post-injection phases

Avoidance Measures:

- Following the methods and sampling schedules as specified in the Testing and Monitoring Plan (*Section 5*)

Detection Methods:

- Elevated concentrations of indicator parameters in surface water, soil gas, and ambient air samples
- Anomalies in the results of any monitoring outlined in the Testing and Monitoring Plan or during the post-injection site care period may be cause for additional samples to be taken to investigate a potential leakage.

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Begin an investigation into the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.

- Prepare and submit an incident report to the Injection and Post-Injection Phase reporting module of the GSDT.



Response Personnel: Supervisory personnel, environmental professionals/subcontractors

Equipment: Depending on the severity of the event, response equipment may include sampling equipment for surface water, soil gas, ambient air, and surface water remediation equipment.

8.5.5 Induced or Natural Seismicity Event

Natural or induced seismicity events of sufficient magnitude to create damage were found to be (1) highly improbable for the site location and (2) under permitted operating conditions that are below the critical fracture pressure. In the very rare chance that such seismicity conditions occurred, the consequences could be of significance regarding the integrity of the artificial penetrations of the upper composite confining zone (UCCZ) and the natural faults and fractures. Therefore, the following response actions were developed to gather information regarding the potential for CO_2 and brine confinement issues to arise under such events.

ExxonMobil will rely on U.S. Geologic Survey seismicity monitoring data for the site and surrounding area to provide information on a seismicity event, should one occur. If a review of the data indicates that the event was more than likely not associated with the injection zone in or near the AOR, ExxonMobil will notify the UIC Director of the intent to install a site-specific network of seismicity stations to provide additional information with the regional seismicity data. The details of the site-specific seismicity monitoring system will be provided to the UIC Director

as a modification of *Section 5 – Testing and Monitoring Plan*. Table 8-2 provides the response actions depending on severity of the seismicity event.

[redacted]

[redacted]

[1] Specified magnitudes determined by local or U.S. Geological Survey (USGS) seismicity monitoring stations or reported by the USGS NEIC using the national seismicity network.

[2] Based on Railroad Commission of Texas Seismicity Review: https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/oil-and-gas-waste-disposal/injection-disposal-permit-procedures/seismicity-review/

8.5.6 Natural Disaster and Other Unplanned Events

A natural disaster (e.g., hurricane, tornado, lightning strike) affecting the normal operation of the injection well could impact site operations by loss of well integrity, fluid leakage, and/or equipment malfunction. A seismicity event may disturb surface and/or subsurface facilities, and weather-related events may affect surface facilities.

Due to the proximity of the location to the Gulf of Mexico, hurricanes and severe storms involving tornadoes are the most likely natural disasters/severe weather events to occur at the facility.

Emergency Condition: Minor to major, depending on the type and severity of the natural disaster. Any immediate, near-term, or prolonged risk to human health, resources, or infrastructure will be assessed immediately to determine emergency actions that will be taken.

Timing of Event: Construction, pre-injection, injection, and post-injection phases

Avoidance Measures:

- Preparation measures may be taken by monitoring current and predicted conditions.

Detection Methods:

- Weather forecast monitoring

Potential Response Actions: If a natural disaster occurs that affects the normal operation of the injection well, ExxonMobil will perform the following:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Begin an investigation into the extent of the problem and determine an appropriate course of action to repair and/or remediate any issues caused by or resulting from the disaster.
- Prepare and submit an incident report to the Injection and Post-Injection Phase reporting module of the GSDT.



[redacted]

Response Personnel: Supervisory personnel, and applicable personnel to diagnose, repair, and remediate as needed

Equipment: Applicable equipment to diagnose, repair, and remediate as needed

8.6 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP and will be dispatched in the case of an emergency. In the event of an emergency, appropriate city, county, and state emergency responders and agencies may be notified based on the severity of the risk. Contact information for ExxonMobil Emergency Authorities and state and local emergency services are outlined in Tables 8-3 and 8-4, respectively.

A site-specific emergency notification chart will be developed and maintained during the life of the project. ExxonMobil will provide the current site-specific emergency contact list to the UIC Director.

Table 8-3 – Contact Information of ExxonMobil Emergency Authorities

Name	Title	Telephone Number
[redacted]	Low Carbon Solutions (LCS) U.S. Gulf Coast Venture Executive	[redacted]
	Emergency Response & Preparedness Manager	
	Advisor, Public & Government Affairs – Low Carbon Solutions	

Table 8-4 – Emergency Services

Agency	Telephone Number
Jefferson County Emergency Services District (ESD) 3	911 or 409-752-5100
Jefferson County ESD 4	911 or 409-796-3036
Jefferson County Sheriff	911 or 409-835-8411

Agency	Telephone Number
Jefferson County Public Health Unit #1	409-835-8530
Jefferson County Office of Emergency Management	409-835-8757
Jefferson County Local Emergency Planning Committee	409-835-8757
Texas Division of Emergency Management	512-424-2208
Texas Department of Public Safety	512-424-2000
State of Texas Spill-Reporting Hotline	1-800-832-8224
Texas Parks and Wildlife Department	512-389-4800
EPA Region 6	1-800-887-6063 or 214-665-2760
EPA Class VI Contact – Brandon Maples	214-665-7252
Texas Commission on Environmental Quality (TCEQ)	512-239-1000
TCEQ Office of Water	512-239-6696
National Response Center	1-800-424-8802
State of Texas Spill-Reporting Hotline	1-800-832-8224
EPA National Response Center (24 hours)	1-800-424-8802

Necessary equipment for emergency and remedial response may vary depending on the event. Generally, no specialized equipment will be required for response actions (such as cessation of injection, well shut-in, and evacuation). If specialized equipment (such as a drilling rig or logging equipment) is required, ExxonMobil will be responsible for its procurement.

8.7 Communications Plan and Emergency Notification Procedures

As appropriate, ExxonMobil will communicate to the relevant public authorities about an event that may require emergency response—so that the public understands the emergency event—and if there are any environmental, health, or safety concerns. Based on the emergency event, ExxonMobil will determine the appropriate information, timing, and communication method for the event. This information may include the following:

- Description of the event
- Severity
- Potential impact to the environment
- Investigation steps
- Mitigation actions taken or planned
- Current status

ExxonMobil will notify the EPA and state/local emergency management agencies of any event that requires an emergency response and that has the potential to impact the public immediately, within 24 hours.

If required, ExxonMobil will also communicate with other entities who may need to be informed about or act in response to the event. These may include local water purveyors or operators, CO_2 suppliers, pipeline operators, oil and gas operators, landowners, regional response teams, and other departments or authorities as guided by the UIC Director.

8.8 Plan Review

The UIC Director will evaluate this proposed ERRP to verify that it meets the requirements of 40 CFR **§146.94(a)** and that the plan accounts for all site-specific conditions. The approved ERRP is enforceable, whether or not it is a condition of the permit, because the plan itself and the UIC Director's approval are required by the Class VI Rule (40 CFR **§146.93(a)**).

This ERRP will be reviewed as follows:

- At least once every 5 years following its approval by the permitting agency [40 CFR **§146.94(d)**]
- Within 1 year of any AOR reevaluation [**§40 CFR 146.94(d)(1)**]
- Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the UIC Director [40 CFR **§146.94(d)(2)**]
- When required by the UIC Director [40 CFR **§146.94(d)(3)**]

If the review indicates that no amendments to the ERRP are necessary, ExxonMobil will provide the permitting agency with the documentation supporting the "no amendment necessary" determination. If the review indicates that amendments to the ERRP are necessary, amendments will be made and submitted to the permitting agency within 30 days following an event that initiates the ERRP review procedure.

The amended plan must be approved by the UIC Director and would then be incorporated into the Class VI permit. If significant changes to the plan are needed, the UIC Director may need to modify the permit. A permit modification under 40 CFR **§144.39** would require notification of the public and an opportunity for comment. Minor changes to the plan, as defined under 40 CFR **§144.41**, do not require a permit modification or a public process under 40 CFR Part 124.

8.9 Staff Training and Exercise Procedures

ExxonMobil will train all personnel on the knowledge they need to conduct their job safely. Incident Command System (ICS) training is required for personnel who are named in either the Spill Management Team in a Facility Plan or the Emergency and Remedial Response Plan—or who are reasonably expected to fulfill a supervisory role in the management of an incident/emergency. All personnel expected to participate in an emergency response will be trained annually on the hazardous substances that they may encounter during an emergency response, and will be provided training on mitigating those hazards.

Hazardous Waste Operations (HAZWOPER) and Emergency Response Operations level training is required for personnel who are required to participate in the active response to an incident/emergency. The training program administrator will certify personnel as HAZWOPER trained through the completion of comprehensive quarterly training, hands-on training, response drill participation, and applicable on-the-job experiences.

ExxonMobil will offer appropriate training and provide response plans to emergency first responders as required by organizations with geographic and logistical jurisdiction at the facility.

Appendix G – Emergency And Remedial Response Plan

[redacted]

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 9 – Financial Assurance

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 9 – FINANCIAL ASSURANCE

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9.1 Financial Assurance

Under Title 40, U.S. Code of Federal Regulations (40 CFR), **§146.85**, owners or operators of geologic sequestration (GS) injection wells are required to demonstrate financial responsibility for GS activities.[1] ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) plans to construct four Class VI injection wells as part of the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) for the purpose of sequestering a [redacted] Consistent with these regulatory requirements, ExxonMobil has prepared this document to demonstrate financial responsibility for the injection wells that comprise the Sunflower Project.

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

9.2 Facility Information

Facility Name:	ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) – Sunflower CCS Project
Facility Contact:	[redacted] ExxonMobil Low Carbon Solutions Onshore Storage LLC
Project Site Name:	Sunflower CCS Project
Project Location:	Jefferson County, Texas
Well Name and Number	Sunflower CCS Project Injection Well No. 01
County	Jefferson
Latitude / Longitude (NAD 83)	[redacted]
Well Name and Number	Sunflower CCS Project Injection Well No. 02
County	Jefferson
Latitude / Longitude (NAD 83)	[redacted]
Well Name and Number	Sunflower CCS Project Injection Well No. 03
County	Jefferson
Latitude / Longitude (NAD 83)	[redacted]

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

Well Name and Number	Sunflower CCS Project Injection Well No. 04
County	Jefferson
Latitude / Longitude (NAD 83)	[redacted]

*NAD 83 – North American Datum of 1983

9.3 Financial Assurance Demonstration

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

[redacted]

In support of the financial assurance demonstration, EEHC has provided a corporate guarantee to ExxonMobil, which is consistent in form with the corporate guarantee language included in Appendix B of the EPA's July 2011 Class VI financial responsibility guidance. *Appendix H-2*

contains a copy of the executed corporate guarantee. As shown in Table 9-1, the EEHC satisfies both Part 1 and Part 2 of the corporate financial test criteria in 40 CFR **§146.85(a)(6)(v)**.

Table 9-1 – Financial Coverage and Threshold Criteria for EEHC, as Guarantor to ExxonMobil for the Sunflower Project

Financial Coverage / Threshold Requirement per 40 CFR §146.85(a)(6)(v)[2]	EEHC Financial Measure
Part 1	
1. Tangible net worth of at least $100 million?[3]	[redacted]
2. Net working capital at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?	
3. Tangible net worth of at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?	
4. Assets in the United States amounting to at least 90% of total assets or assets in the United States amounting to at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR cost estimates?	
Part 2	
5. Total liabilities to net worth ratio less than 2.0?	[redacted]
6. Current assets to current liabilities ratio greater than 1.5?	
7. Sum of net income plus depreciation, depletion, and amortization to total liabilities ratio greater than 0.1?	
8. Current assets minus current liabilities to total assets ratio greater than *minus* 0.1?	
9. Net profit (revenues minus expenses) greater than $0?	

Appendix H-3 is a completed letter from the EEHC's [redacted], that demonstrates the company's ability to meet the requisite financial coverage and threshold criteria, per 40 CFR **§146.85(a)(6)(v)**. *Appendix H-3* is consistent in form to the "Letter from Chief Financial Officer" included in Appendix B of the EPA's July 2011 guidance.[4]

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

[3] ExxonMobil recognizes that 40 CFR **§146.85(a)(6)(v)** requires that its guarantor meet a tangible net worth of an amount approved by the UIC Director. For the purposes of this financial assurance demonstration, EEHC affirms that it maintains a tangible net worth of at least $100 million, per the recommended threshold included in the EPA's July 2011 guidance (p. 15).

[4] EPA, *op.cit.* See B-19, Appendix B: Recommended Financial Responsibility Instrument Language (Forms/Templates).

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

9.4 Estimated Coverage Amounts

The total current cost estimate for the Sunflower Project's GS activities necessitating financial assurance at the project site is [redacted] in 2024 dollars. This total cost estimate assumes the hiring of independent, third-party contractors to perform the required activities for each project phase.

The cost estimate is separated into the following phases[5]:

[redacted]

Table 9-2 summarizes the total estimated cost of performing each GS activity, along with the timeline for which financial assurance coverage is expected to be needed. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the application process and assume the hiring of third-party contractors to perform the services—or to procure the goods associated with the performance of each GS activity. These values are subject to change during the life of the project to account for inflation of costs and changes to the project that may affect the cost of covered activities.

Per 40 CFR **§146.85(c)**, ExxonMobil will, during the active life of the project, adjust the cost estimates for inflation within 60 days prior to the anniversary date of the establishment of the financial assurance instrument. In addition, ExxonMobil will provide to the UIC Director written updates of adjustments to the cost estimates within 60 days of any amendments to the AOR and Corrective Action Plan (40 CFR **§146.84**), the Injection Well Plugging Plan (40 CFR **§146.92**), the PISC and Site Closure Plan (40 CFR **§146.93**), and the Emergency and Remedial Response Plan (ERRP) (40 CFR **§146.94**).

ExxonMobil will adjust the value of its financial assurance instruments in response to any changes in cost estimates and will resubmit its revised demonstration of financial responsibility to the UIC

[5] Assumes receipt of permit in 2027, start of injection in 2027, and 12 years of injection.

[6] Financial responsibility coverages for well plugging reflect the current estimated cost for plugging the four injection wells and two monitoring wells related to the Sunflower Project.

Director or their designee for review and approval. ExxonMobil will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Director, or their designee.

[redacted]

[redacted]

9.5 Corrective Action

The Corrective Action Plan is discussed in detail in *Section 3 – Area of Review and Corrective Action Plan*. Per the requirements of 40 CFR **§146.84**, the plan specifically outlines both a plugging plan for the artificial penetrations found within the CO_2 plume and brine pressure front, and the recompletion schedule whereby the wellbore modifications will have been completed.

For the planned activities at the Sunflower Project, workovers on the legacy wells found to have sufficient deficiency as to represent a potential loss of CO_2 or brine containment will be reentered and plugged prior to receiving approval from the UIC Director to inject. [redacted] The estimated financial assurance coverage value for this GS activity is shown in Table 9-3.

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

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

GS Activity	Estimated Financial Assurance Coverage Value
[redacted]	

9.6 Well Plugging

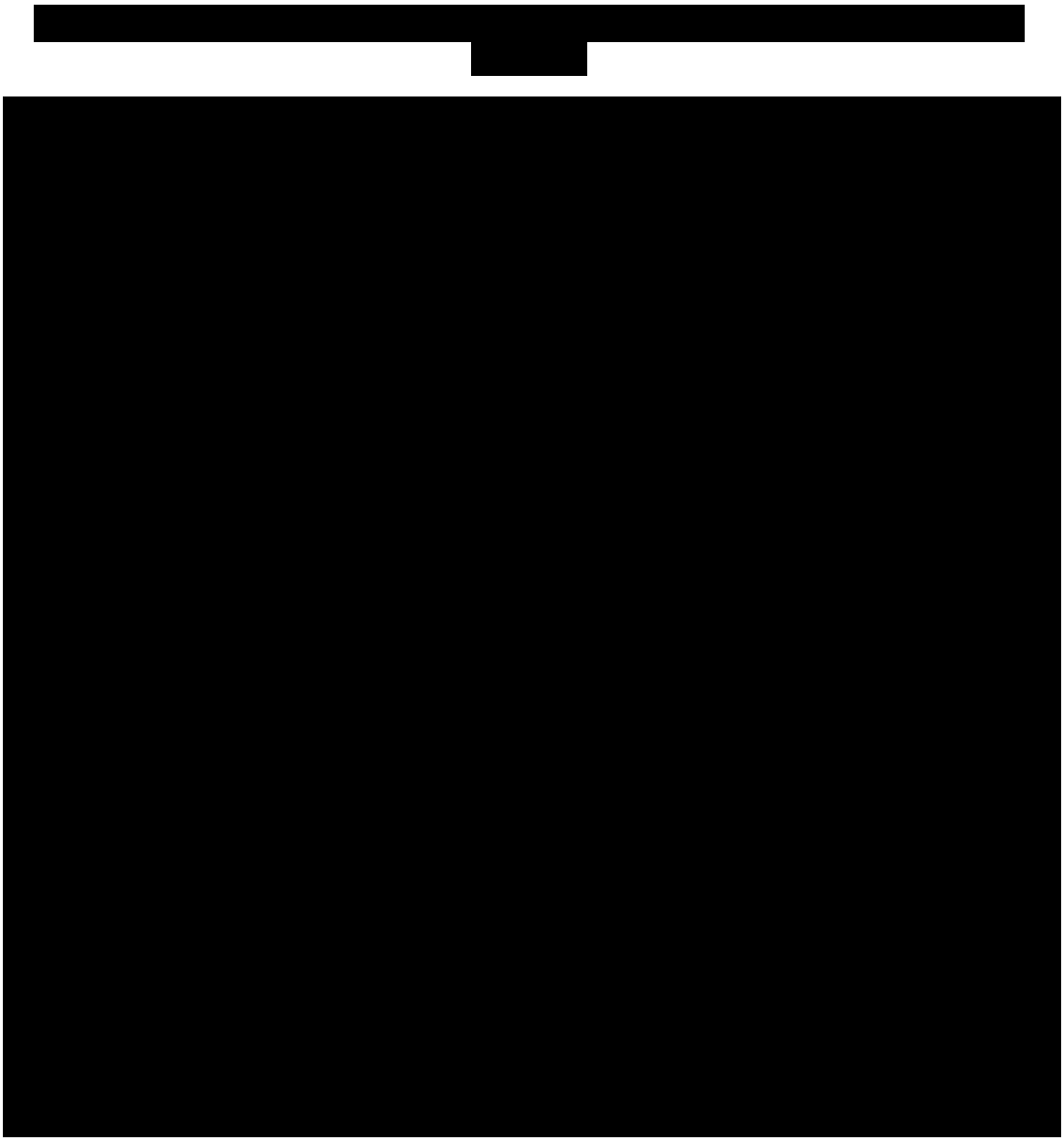
9.6.1 Injection Well Plugging

Plugging and abandonment (P&A) of the injection wells at the Sunflower Project will meet the requirements of 40 CFR **§146.92**. The P&A plan for the proposed injection wells was designed to reduce the potential for movement of CO_2 or brine from the injection interval through the [redacted] and toward Underground Sources of Drinking Water (USDWs).

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

9.6.2 Monitoring Well Plugging

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



9.7 Post-Injection Site Care and Site Closure Plan

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

9.7.1 Post-Injection Monitoring

As discussed in *Section 5 – Testing and Monitoring Plan*, [redacted] and pressure and temperature monitoring will be conducted during operations and after the end of injection to assess the integrity of the wells and to track the migration of the CO_2 plume and brine pressure front.

9.7.2 Site Closure Plan

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

[redacted]

9.8 Emergency and Remedial Response

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

The financial assurance coverage value for ERR is estimated to be [redacted] in 2024 dollars and summarized in Table 9-6. This estimate assumes coverage for the following event-based risk activities at the Sunflower Project: mechanical integrity of the injection well casing or cement seal, artificial penetrations of the [redacted], mechanical integrity of the operating equipment, natural features affecting the sealing properties of the [redacted], and incidents/unplanned events. Details

regarding the approach used to develop the scenarios; the levels of severity considered; and the actions to be taken to avoid, monitor, respond to, and notify about the occurrence of risk events are summarized in detail in *Section 8*.

[redacted]

[redacted]

Appendix H – Financial Assurance:

[redacted]

Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, No. 03, and No. 4

SECTION 10 – Environmental Justice

Sunflower Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

December 2024

SECTION 10 – ENVIRONMENTAL JUSTICE[1]

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[1] Note: ExxonMobil is including this analysis due to its commitment to, and the importance of, community engagement in the Class VI well permitting process, as well as existing federal guidance. ExxonMobil reserves the right in the future to revise this analysis if interpretation or implementation of federal law or regulation should change.

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10.1 Abstract

This report includes the use of an initial "EJ Study Area" to assess the presence of communities that may be associated with potential environmental justice (EJ) concerns. [redacted]

The EJ Study Area includes 12 U.S. Census Block Groups (CBGs),[3] located in Jefferson, Hardin, and Liberty Counties (EPA, 2023a) (Figure 10-1). As the project is defined in further detail and community engagement continues, it is possible that additional CBGs may warrant assessment. This EJ assessment revealed the CBGs that may contain communities with potential EJ concerns based on the environmental indexes of the EPA's EJScreen tool, applying the EPA's recommended threshold of focusing on areas in the 80th percentile or higher. With respect to environmental indicators, the communities of Nome and China, Texas, are identified as areas for further "ground-truthing" or verifying the data.

10.2 Introduction

ExxonMobil is submitting this Class VI permit application to the EPA for the Sunflower Project. An initial EJ assessment has been conducted in compliance with regulatory requirements and to demonstrate that the relevant EPA guidance has been appropriately considered in developing this application, including the August 2023 "Memorandum of Environmental Justice Guidance for UIC [Underground Injection Control] Class VI Permitting and Primacy" (Fox, 2023).

The EPA defines Environmental Justice as the:

> "[F]air treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This goal will be achieved when everyone enjoys:

[2] For the purposes of this report, the project footprint does not include the existing roadways that will be used to transport project construction materials or workers.

[3] A CBG is the smallest geographic unit used by the U.S. Census Bureau to collect data for decennial census data. A CBG consists of block groups within Census tracts (CTs). Throughout this EJ report, individual CBGs are referred to by an identifier in the form "CT XXX BG X."

- The same degree of protection from environmental and health hazards; and
- Equal access to the decision-making process to have a healthy environment in which to live, learn, and work."

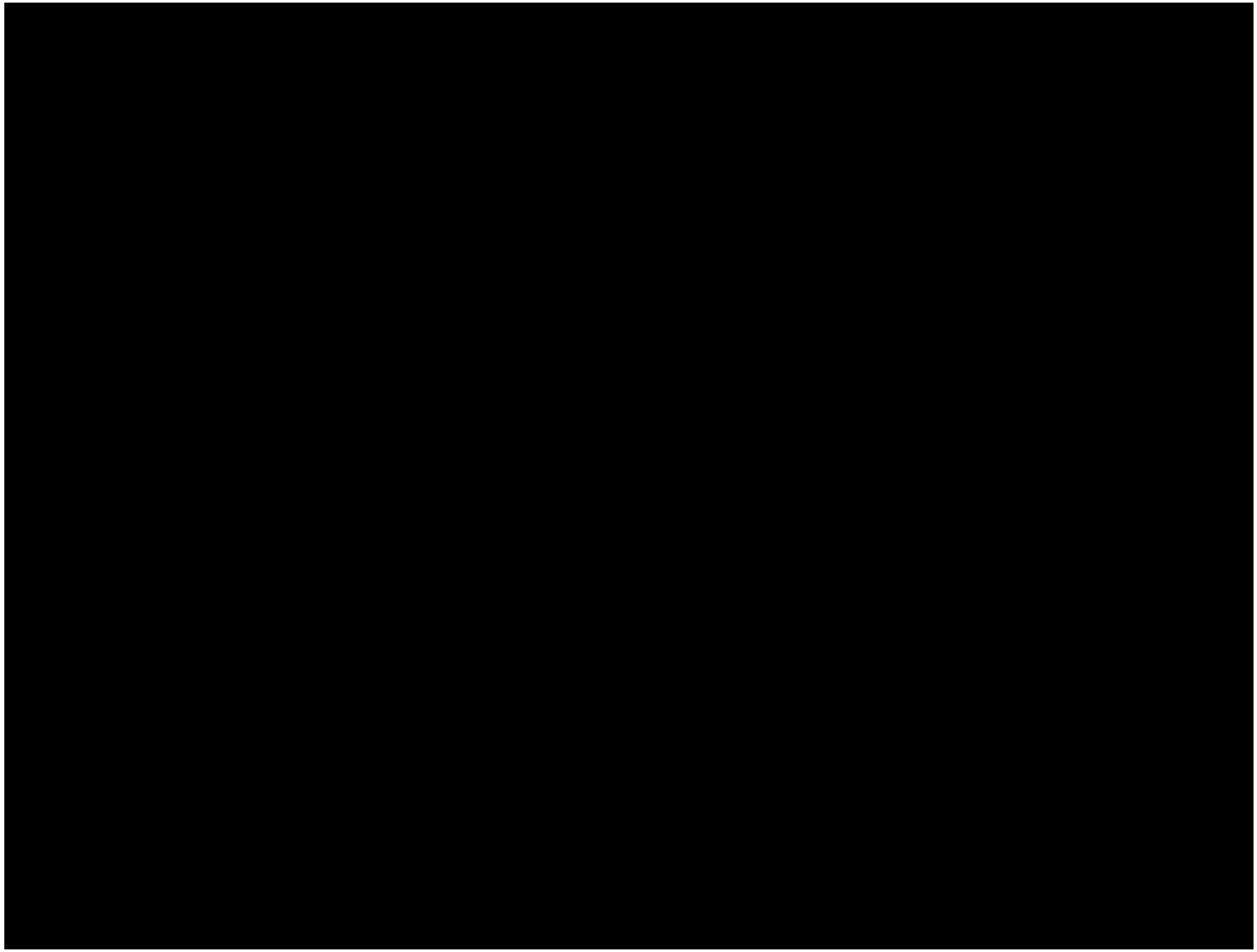
The EPA's EJ guidance does not prescribe a method for assessing potential EJ impacts. However, it does recommend that an appropriate methodology be adopted and applied. ExxonMobil has a socioeconomic, standards-driven corporate process that assesses environmental, socioeconomic, and health considerations throughout a project.[4] As ExxonMobil's understanding of the local environment evolves during the project's life cycle—and if otherwise warranted—the EJ assessment may be updated.

This EJ screening report for the proposed Sunflower Project is an initial desktop assessment of potential EJ-related concerns that could be raised by the local community in which the project will be located and will continue to be refined throughout the life of the project. This report identifies community characteristics useful in guiding engagement through project planning, permitting, construction, operation, and decommissioning.

This report includes the use of an initial EJ Study Area to assess the presence of communities that may be associated with potential EJ concerns. [redacted] The EJ Study Area includes 12 CBGs, which are located in Jefferson, Hardin, and Liberty Counties (EPA, 2023a) (Figure 10-1). As the project is defined in further detail and community engagement continues, it is possible that additional CBGs may warrant assessment.

The next sections of this report, which includes two appendices, are as follows. *Section 10.3* defines the methods used for data collection and assessment, and outlines relevant standard processes undertaken by ExxonMobil in preparing this report. *Section 10.4* presents the results of the EJ analysis tools, stakeholder engagements, and grievance mechanism to date. *Section 10.5* provides preliminary EJ and stakeholder engagement activities. *Section 10.6* presents the next steps in the engagement process. *Appendix I-1* presents the project area data reports. *Appendix I-2* presents a template for tracking feedback and respective responses.

[4] Managing socioeconomic impacts | ExxonMobil



10.3 Methods

10.3.1 Summary

ExxonMobil used a multi-stage process to assess EJ and stakeholder considerations (Figure 10-2) in the Sunflower Project area and a surrounding area defined from the edge of the AOR. This began with an initial screening using the EPA's EJScreen tool Version 2.3. A secondary screening was undertaken using additional EJ indicators, including the Climate and Economic Justice Screening Tool (CEJST), the EPA Inflation Reduction Act (IRA) tool, and the U.S. Department of Energy (DOE) Disadvantaged Communities Reporter tool.

These initial screening stages are built upon through local analysis and engagement, which may include environmental assessments, initial stakeholder engagements, and ground-truthing. A Stakeholder Engagement Plan (SEP) and community benefits considerations are created from data collected in these stages. The engagement process is iterative and designed to incorporate findings and feedback from communities to refine and enhance overall engagement. Insights from stakeholder engagements, grievance mechanism inputs, and community activities are integrated as collected. These studies are updated as needed.



[redacted]

10.3.2 Initial and Secondary Screening

The EPA's EJScreen Version 2.3 (EPA, 2024) was used to assess demographic and environmental characteristics in areas crossed by or within the EJ Study Area (Figure 10-1). The use of EJScreen is intended as a starting point in the identification of communities with potential EJ concerns. As discussed further in *Section 10.4*, EJ Indexes at or above the 80th percentile nationally were used as a starting point for identifying geographic areas that may warrant further consideration, analysis, or engagement with respect to potential EJ concerns.

Based on results from within both a 1- and 5-mile radius (which includes the AOR), ExxonMobil concluded it would be appropriate to analyze EJ considerations across the broader 5 mile radius. Following that, ExxonMobil did a more in-depth analysis of the EJ Study Area using the CEJST and the EPA IRA tools, as well as the DOE Disadvantaged Communities Reporter tool. The results are presented and discussed in *Section 10.4*

10.3.3 Environmental and Socioeconomic Assessments

ExxonMobil conducts assessments that identify and evaluate potential environmental, socioeconomic, and health interactions, and the cumulative effects of a project/activity. These assessments are conducted prior to major decisions being taken and commitments being made, with the intent of addressing those effects by incorporating appropriate mitigation measures into a project's design, execution, and operating plans. The assessments may also define measures to be taken and/or to avoid, reduce, and/or remedy potential environmental, socioeconomic, and health risks associated with a project/activity.

10.3.4 Local Screening and Analysis

ExxonMobil will seek to work collaboratively and transparently with local communities to promote positive, long-term relationships. ExxonMobil consults with local groups and individuals regularly and seeks to have stakeholders represented as community concerns are discussed and decisions made. The engagement process is continually tailored to be locally and culturally appropriate, and to provide accessible, inclusive, and effective channels for exchanging information and proactively identifying issues or concerns. Engagement formats are tailored to respective communities and audiences.

ExxonMobil will develop an initial SEP to facilitate meaningful community engagement with local leaders, residents, economic developers, environmental organizations, and others. The SEP guides the management of the socioeconomic dynamics that may impact—or be impacted by—the project. Considerations related to (1) potential communities warranting further assessment from an EJ perspective, (2) community benefits, (3) workforce development, and (4) grievances

are routinely measured, assessed, and used to inform stakeholder engagement and to impact mitigation strategies throughout the project's life cycle.

The stakeholder grievance/feedback process—described in *Section 10.3.4.2*—is consistent with ExxonMobil's socioeconomic management principles (ExxonMobil, 2024).[5] The Community Grievance Mechanism (CGM) will allow stakeholders to have access to ExxonMobil throughout the project's life cycle.

The results from screenings and local engagements are presented and discussed in *Section 10.4*.

10.3.4.1 Stakeholder Engagement

ExxonMobil works to engage and inform a variety of stakeholders, including but not limited to local community individuals, community leaders, and elected officials, on topics related to CCS and the overall project. Initial engagements are discussed in *Section 10.5*.

Stakeholder engagements will be tracked via a stakeholder register and updated on a regular basis, as summarized in the table in *Appendix I-2*—including, but not limited to, community gatherings, individual meetings (e.g., with elected officials and other relevant stakeholders), and open houses to provide project updates.

Community engagement will be continuous throughout the life cycle of the project. As involvement with the local community grows, the SEP will continue to be refreshed.

10.3.4.2 Community Grievance Mechanism

ExxonMobil will develop a CGM, which receives complaints, concerns, issues, requests, or other feedback (collectively termed "input" herein) related to the Sunflower Project, and allows for response to this input in a consistent, transparent, and timely manner. The CGM will be active throughout the life cycle of the project. The objectives of a CGM are as follows:

- Provide an accessible mechanism for stakeholders to provide input to the project team.
- Facilitate the project's processing of stakeholder input so that the input is acknowledged, tracked, and addressed in a timely manner, respecting confidentiality.
- Continuously improve project performance based on consideration of stakeholder input provided through the CGM.
- Demonstrate a commitment to meaningful stakeholder engagement and respect for stakeholder input.

The Sunflower Project's CGM will be aligned with International Petroleum Industry Environmental Conservation Association best practices, as shown in Figure 10-3.

[5] https://corporate.exxonmobil.com/sustainability-and-reports/sustainability/engaging-communities-and-our-supply-chain/managing-socioeconomic-impacts/community-engagement-and-grievance-management



The CGM will be structured so that stakeholders may submit input in multiple ways. A CGM log is used to record all engagements with stakeholders and all input received from them. This allows for analysis of trends in stakeholder interest and concern—which can help to design further engagement programs and activities—and tracking of project responses to stakeholder input.

10.3.5 Integration of Feedback

ExxonMobil seeks inclusive engagement as it helps in considering a broader set of community perspectives. Where appropriate, ExxonMobil integrates the results of these discussions into its decisions to help avoid or reduce potential negative impacts, enhance benefits, support effective investments, and resolve issues. In addition, the information gathered may be used to refine the SEP and community benefits discussions.

10.4 Results and Findings

This report employs the use of U.S. Census and other data for early identification of potential Sunflower Project related impacts and opportunities associated with potential EJ concerns. The EJ Study Area includes Census tracts (CTs) in Jefferson, Hardin, and Liberty Counties. [redacted], which demonstrate a range of socioeconomic characteristics. Based on an analysis of the data provided in this report, the following are noted:

- The centralized CBGs have similar socioeconomic characteristics that are not identified as above the 80th percentile threshold for any of the EJ Indexes or demographic considerations. The possibility of potential EJ concerns may increase to the west in Liberty County where higher unemployment and low-income areas are indicated. Additionally, potential EJ concerns may exist at the eastern end of the EJ Study Area.

- Three of the twelve CBGs in the EJ Study Area have minority populations exceeding 50% in Jefferson County [redacted]

- Low-income population percentages greater than the county averages for Hardin and Liberty Counties occur in one CBG each, respectively: [redacted] Neither of these CBGs has minority populations exceeding 50%.

- Seven CBGs in the EJ Study Area have one or more EJ Indexes[6] at or above the 80th percentile nationally. The majority of the CBGs in the EJ Study Area have EJ Indexes below the 80th percentile nationally.

- The environmental indicators with EJ Indexes at or above the 80th percentile nationally include Toxic Releases to Air (nine CBGs), Risk Management Plan (RMP) Facility Proximity (two CBGs), and Drinking Water Non-Compliance (two CBGs).

- Jefferson, Hardin, and Liberty Counties are above the 80th percentile for Toxic Releases to Air. All seven CBGs in Jefferson County and two of the three CBGs in Hardin County are at or above the 80th percentile for Toxic Releases to Air. No study area CBGs are above the 80th percentile in Liberty County.

[6] For each CBG, each environmental indicator has its own EJ Index, which combines the demographic index (which averages low-income people and people of color populations) with the respective environmental indicator percentile value for the CBG. For example, the EJ Index for traffic for a given CBG is calculated as (traffic indicator percentile for the CBG) x (average of low-income population percentage and the people of color population percentage for the CBG).

- Three of the ten CBGs in the EJ Study Area with EJ Indexes at or above the 80th percentile nationally [redacted] also have a minority population above 50% for Jefferson County.

10.4.1 Minority Populations

In accordance with the EPA's EJ guidance (EPA, 2016, 2022), this EJ report used demographic and socioeconomic data to assess levels of minority[7] population percentages present in the EJ Study Area. The U.S. Council on Environmental Quality (CEQ) states that "minority populations should be identified where either: (a) the minority population of the affected area exceeds 50% or (b) the minority population percentage of the affected area is *meaningfully greater* [emphasis added] than the minority population percentage in the general population or other appropriate unit of geographic analysis" (CEQ, 1997).

The CEQ recommends using an "appropriate unit of geographic analysis" that does not "artificially dilute or inflate the affected minority population" (CEQ, 1997). While "meaningfully greater" is not explicitly defined in the CEQ's guidance, federal guidelines suggest that 10% more than the reference population is considered a reasonable threshold for "meaningfully greater" (EJ Interagency Working Group (IWG) and National Environmental Policy Act (NEPA) Committee, 2019). To identify minority populations for the CBGs in the EJ Study Area, Jefferson County was used as the reference population.

For this EJ report, potential minority populations are identified as present in a CBG if they meet either of the following criteria:

- The percentage of minorities in the CBG is more than 50%.
- The percentage of minorities in the CBG is at least 10% higher than that of Jefferson, Hardin, and Liberty Counties.

10.4.2 Low-Income Populations

Utilizing the EPA's EJ guidance (EPA, 2016, 2022), this EJ report evaluated socioeconomic data to assess levels of low-income percentages of populations present in the EJ Study Area and the broader Jefferson, Hardin, and Liberty Counties. Guidelines for identifying low-income populations vary among federal and state agencies. Low-income populations can be identified using either (1) the U.S. Census Bureau poverty thresholds, (2) local data sources on poverty, or (3) the U.S. Department of Health and Human Services poverty guidelines. Additionally, low-income communities can be identified by using the "meaningfully greater" analysis, the percentage of *individuals* below the poverty level, the percentage of *households* below the

[7] "Minority" was initially defined by the Federal Interagency Working Group on Environmental Justice in an appendix to the 1997 CEQ EJ Guidance as "individuals who are members of the following population groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic."

poverty level, and/or the percentage of *families with children* below the poverty level (EJ IWG and NEPA Committee, 2019). The National Environmental Policy Act uses the "meaningfully greater" analysis to identify low-income populations.

For this report, potential low-income populations are identified as present in a CBG if they meet the following criterion:

- The percentage of households below the poverty level in the CBG is greater than that of Jefferson, Hardin, or Liberty Counties.

One Liberty County CBG [redacted] is identified as being at poverty level according to this metric (Table 10-2).

10.4.3 Additional Socioeconomic Indicators

Additional socioeconomic indicators measured by the EJScreen tool include unemployment rate, percentage of the population that is limited in English speaking, percentage of the population with less than a high school education, percentage of the population under age 5, percentage of the population over age 64, a Demographic Index,[8] and a Supplemental Demographic Index.[9] Values for each of these indicators are compared among Jefferson, Hardin, and Liberty Counties and each of the CBGs (Table 10-2).

10.4.4 EJ Indexes Defined

There are 13 EJ Indexes in the EJScreen tool corresponding to 13 environmental indicators, each combined with demographic indicators. An EJ Index can be used to characterize CBGs in terms of the combination of their low-income people and people of color[10] populations and a given environmental indicator for the CBG. To calculate a CBG's EJ Index for a given environmental indicator, EJScreen multiplies the CBG's associated environmental indicator percentile by the average percentages of low-income people and people of color (i.e., the Demographic Index) in the CBG.

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[8] The Demographic Index in EJScreen is a combination of the percentage of low income and percentage of minorities, the two socioeconomic factors that were explicitly named in Executive Order 12898, on Environmental Justice. For each CBG, these two percentages were averaged together to derive the Demographic Index as follows: Demographic Index = (% low income + % minority) / 2.

[9] The Supplemental Demographic Index in EJScreen is a combination of five socioeconomic factors averaged together for each CBG. This index can provide an additional perspective on potential community vulnerability and may be more relevant for use in certain situations. The formula is as follows: Supplemental Demographic Index = (% low-income + % unemployed + % less than high school education + % limited English speaking + % low life expectancy) / 5. For CBGs where low life expectancy data is missing, the formula will average the other four factors.

[10] In EJScreen, "low income" is defined by the EPA as the percentage of a block group's population in households where the household income is less than or equal to twice the federal poverty level. "People of color" are defined by the EPA as the percentage of individuals in a block group who list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino (i.e., all people other than non-Hispanic, white-alone individuals, where the word "alone" in this case indicates that the person is of a single race, not multiracial) (EPA, 2022, 2023b).

Technical documentation for EJScreen recommends the use of an initial filter to promote consistency and as a pragmatic first step when interpreting screening results. The EPA has identified the 80th percentile filter as that initial starting point (i.e., an area with any of the 13 EJ Indexes at or above the 80th percentile may warrant further review).

EJScreen reports present the EJ Index percentiles both nationally and statewide. The national percentiles are the focus of this report based on EPA technical guidance documents (EPA, 2016, 2022). The national and state percentiles are in *Appendix I-1,* which includes the full EJScreen Community Reports for Jefferson, Hardin, and Liberty Counties. Tables 10-1 and 10-2 present individual demographic and environmental indicators that have resulted in a particular percentile. Table 10-3 presents critical service gaps.

10.4.5 EJ Assessment and Analysis

10.4.5.1 EJ Indexes Assessed

Of the 12 CBGs in the EJ Study Area, 10 have 1 or more EJ Indexes at or above the 80th percentile nationally. EJ Indexes with one or more CBGs with rankings at or above the 80th percentile nationally include Toxic Releases to Air, RMP Facility Proximity, and Wastewater Discharge. The most common EJ Index at or above the 80th percentile nationally in the EJ Study Area is Toxic Releases to Air, present above the 80th percentile nationally in nine CBGs.

Table 10-1 summarizes the EJ Index national percentile rankings for Jefferson, Hardin, and Liberty counties and each of the CBGs in the EJ Study Area. Values at or above the 80th percentile nationally are shown in bold.

[redacted]

[redacted]

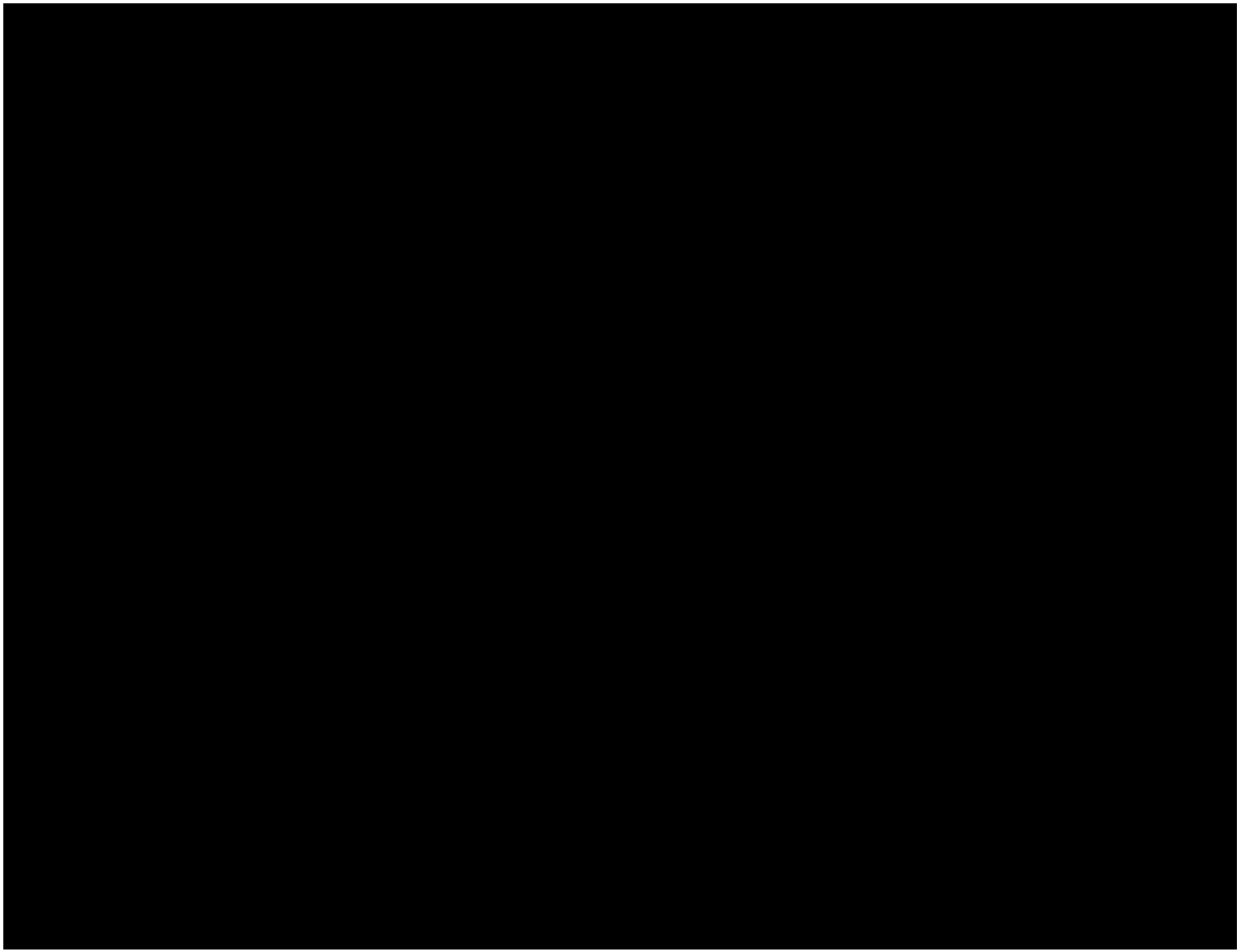
10.4.5.2 Demographic Indicators

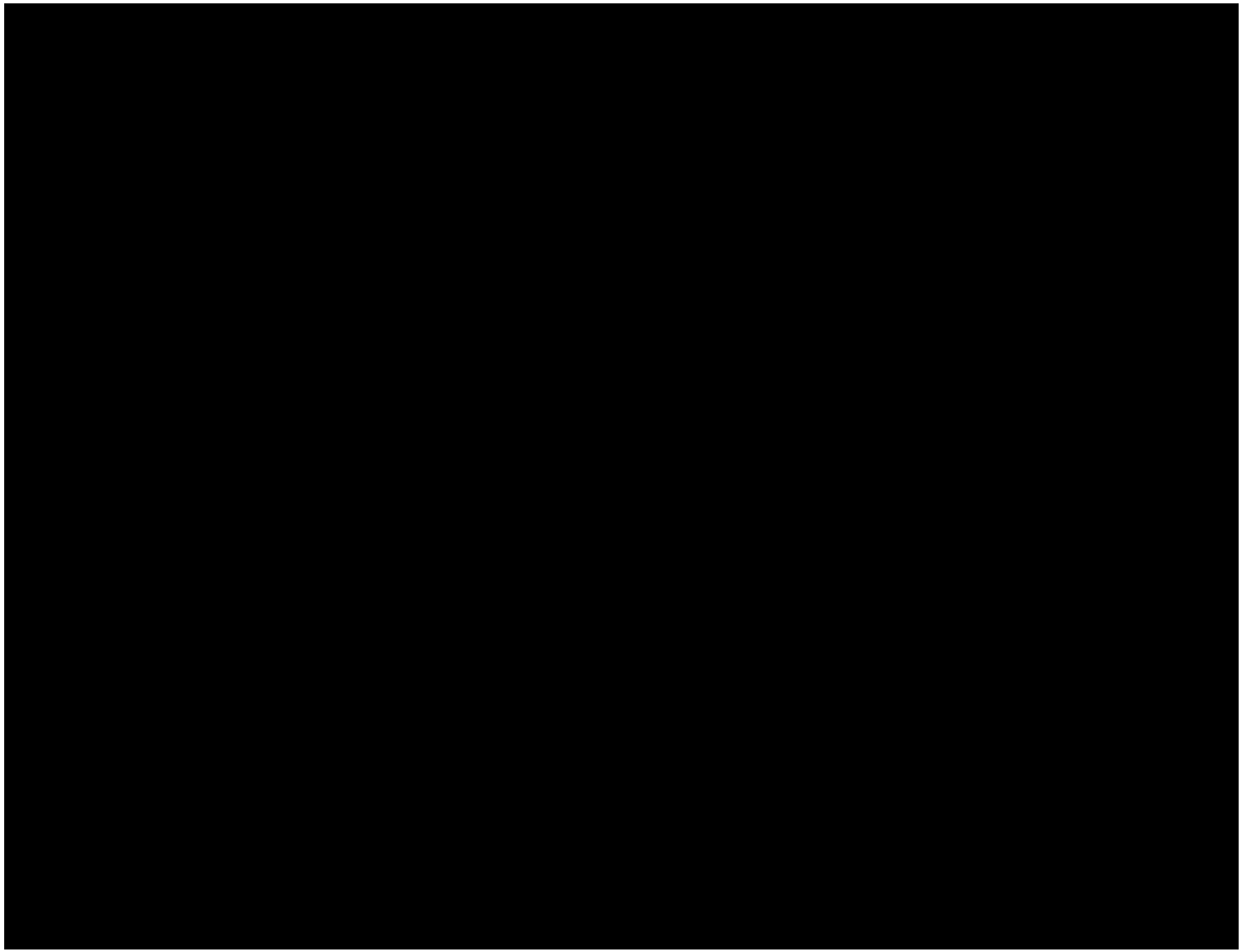
This report considers a subset of EJScreen demographic indicators for the CBGs in the EJ Study Area. The full EJScreen reports for each county are provided in *Appendix I-1*. Table 10-2 summarizes the percentage values for demographic indicators for each CBG and for Jefferson, Hardin, and Liberty Counties, whereas Figure 10-4 presents the data as percentiles. The table uses the combined "meaningfully greater" and 50% threshold methodologies to identify the CBGs that may warrant further evaluation on the basis of minority population percentages. For all

other demographic indicators, Table 10-2 uses a direct comparison of the value for the CBG and that of Jefferson, Hardin, and Liberty counties. The CBG values exceeding these comparison thresholds are shown in bold. Three of the twelve CBGs have populations of people of color greater than 50%. Also, [redacted] has higher low-income and unemployed populations than the Liberty County reference population. Additionally, Figures 10-5 and 10-6 present the CBGs identified as "disadvantaged" in these counties according to the CEJST and EPA IRA screening tools, respectively. The CBGs identified as "disadvantaged" according to the tools are not in areas that are would potentially be impacted by the project.

[redacted]







10.4.5.3 Critical Service Gaps

EJScreen includes indicators for deficiencies in critical services such as broadband internet subscription gaps, lack of health insurance,[11] housing burden, transportation access burden, and presence of food deserts—described as follows:

- Broadband gaps refer to the percentage of households with an internet subscription as reported in the Census Bureau's American Community Survey (ACS) 5-year summary estimates.

- Lack of health insurance is the percentage of all persons without health insurance coverage as reported in the Census Bureau's ACS data.

- Housing burden is a percentile related to housing cost, which is the percentage of households that are both earning less than 80% of the Housing and Urban Development's area median family income and are spending more than 30% of their income on housing costs (CEJST (CEQ, 2023)).

- Transportation access is an average of four transportation-related indicator percentiles: transportation cost burden, national walkability index, percentage of households with no vehicle available, and mean commute time to work (CEJST).

- Food desert tracts are those that are both low income and "low access," the latter of which is identified as tracts that are separated from affordable and nutritious foods by a distance of 1 mile for urban areas and 10 miles for rural areas, as reported by the U.S. Department of Agriculture.

Table 10-3 shows critical service gaps identified in the EJ Study Area. The CBGs higher than the county averages or with a "Yes" designation are shown in bold. Broadband internet subscription gaps at or above the EJ Study Area range between 6–13%, with one CBG above the Jefferson County average. Lack of health insurance surpasses the Hardin County average in three CBGs and Liberty County in one CBG. Housing burden does not exceed the U.S. or county averages in the EJ Study Area. Transportation access burdens occur in all 12 CBGs in the EJ Study Area. The food desert designation appears in both CBGs in Liberty County within the EJ Study Area.

[11] This refers to the percentage of all persons without health insurance coverage as reported in the Census Bureau's ACS data.

[redacted]

The EJ assessment revealed a few CBGs that may contain communities with potential EJ concerns based on the EJScreen environmental indexes, applying the EPA's recommended threshold of focusing on areas in the 80th percentile or higher. With respect to environmental indicators, the communities of Nome and China are identified as areas for further ground-truthing.

10.5 Preliminary EJ and Stakeholder Engagement

While there are inherent risks in any type of development or operation, the Sunflower Project seeks to avoid identified risks, mitigate remaining risks to acceptable levels, and remedy the potential impacts. ExxonMobil uses core processes and internal frameworks to systematically identify, assess, manage, and monitor environmental and socioeconomic risks, opportunities, and impacts throughout the life cycle of the project. Community feedback, scientific understanding, and other due diligence information is considered to enable safer and responsible operations for the project. ExxonMobil periodically updates these assessments to reflect changes to operational complexity or socioeconomic sensitivities and amends the management plans as needed.

Stakeholder feedback will be received throughout the life cycle of the project via engagement, project activities, and other yet-to-be-executed activities. Initial stakeholder engagements are described in Table 10-4.

Table 10-4 – Stakeholder Engagements



[redacted]

10.5.1 Safety and Emergency Response

The Emergency and Remedial Response Plan is detailed in *Section 8 – Emergency and Remedial Response Plan*. Additionally, in support of local emergency response efforts, ExxonMobil has sponsored local firefighters to participate in Hazardous Material (HazMat) Liquid and CO_2 Pipeline and Industrial Fire Emergencies response training at Texas A&M Engineering Extension Service. [redacted]

[redacted]

10.6 Next Steps

This EJ study will be refined and updated throughout the life cycle of the Sunflower Project as appropriate. As next steps, the following project activities are being planned:

- Develop the CGM and continue community engagements.
- Continue to gather stakeholder feedback via the CGM and community engagements.
- Develop management and mitigation plans based on assessments and stakeholder feedback.

Appendix I – Environmental Justice:

[redacted]

ALL APPENDICES ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.