



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

Prepared for *Evergreen Sequestration Hub, LLC*
Houston, Texas

By
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Austin, TX

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FOREWORD

Evergreen Sequestration Hub, LLC proposes to develop a carbon sequestration facility, the Evergreen Sequestration Hub, in Beauregard and Calcasieu Parishes, Louisiana. The Evergreen Sequestration Hub is being developed to permanently sequester anthropogenic carbon dioxide (CO₂) in secure geologic storage reservoirs with CO₂ sourced from various emitters. This site is ideally suited for the sequestration of CO₂ with an injection interval with requisite and appropriate reservoir properties and substantial sealing intervals. This application is for two injection wells, the Loblolly CCS No. 001 and Loblolly CCS No. 002.

The following application will fully detail and characterize the geology of the proposed well locations, evaluate the formation for properties necessary to contain the sequestered CO₂ permanently, and describe the engineering design and safety considerations for the well. The application will also discuss the proposed monitoring system that will be utilized to compare the actual injectate plume migration to reservoir modeling and simulation of the anticipated plume.

The application has been developed to meet the requirements of both Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82** through **§146.95** and the Louisiana Code LAC 43:XVII Chapter 6, Statewide Order (SWO) 29-N-6. Both codes detail the regulations for Underground Injection Control Class VI wells. Once the permit has been issued, per the requirements of 40 CFR **§144.36(a)** and SWO 29-N-6 **§3607.M.1**, the permit will be updated every five years thereafter for the active injection life of the wells.

CERTIFICATION

CERTIFIED BY:

I, David Dell'Osso, 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.



David Dell'Osso
Chief Operating Officer
Evergreen Sequestration Hub, LLC

I, William H. George, certify that this application was prepared by me or under my direct supervision and that the information and analyses presented herein are true and accurate to the best of my knowledge.



William H. George, P.E.
Vice President
Louisiana License No. 45286
Date Signed: February 27, 2024

I, Stephen Pattee, certify that the geologic and hydrologic evaluations in this application were prepared by me or under my direct supervision and that the information and analyses presented herein are true and accurate to the best of my knowledge.



Stephen Pattee, P.G.
Sr. Vice President
Louisiana License No. 1001
Date Signed: February 27, 2024

ACRONYMS AND ABBREVIATIONS

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

AAPG	American Association of Petroleum Geologists
AOI	area of interest
AOR	area of review
API	American Petroleum Institute
AS	aquifer system
ASCII	American Standard Code for Information Interchange
ASTM	American Society for Testing and Materials
AWG	American wire gauge
AZMI	above-zone monitoring interval
bbl/ft	barrel(s) per foot
BEG	Bureau of Economic Geology
BHP	bottomhole pressure
BHT	bottomhole temperature
bpm	barrels per minute
CCS	carbon capture and sequestration
CEQ	Center for Environmental Quality
CFR	U.S. Code of Federal Regulations
Chicot EAS	Chicot Equivalent Aquifer System
CIBP	cast-iron bridge plug
CIL	casing inspection log
CRA	corrosion-resistant alloy
DAS	distributed acoustic sensing
DOTD	Department of Transportation and Development
DSA	double-studded adaptor
DTS	distributed temperature sensing
EOS	equation of state
ERRP	Emergency and Remedial Response Plan

FG	fracture gradient
FIMT	fiber-in-metal tube
FOC	fiber optic cable
FSP	fault slip potential
FZP	fault zone entry capillary pressure
g/cm ³	grams per cubic centimeter
GOM	Gulf of Mexico
GR	gamma ray
GS	geologic sequestration
GT/yr	gigaton per year
HDIL	high-definition induction log
HRVRT	high-resolution vertilog (tool)
ID	inner diameter
IEA	International Energy Agency
IMD	Injection and Mining Division
JT	Joule-Thomson
kbd	thousand barrels per day
lb/ft ³	pounds per cubic foot
LAS	Log ASCII Standard
lbm	pound mass
LCZ	lower confining zone
LDNR	Louisiana Department of Natural Resources
Mcf	thousand cubic feet
MCL	maximum contaminant level
mD	millidarcy
MD	measured depth
mg/L	milligrams per liter
Mgal/D	million gallons per day
MIRU	move in, rig up
MIT	mechanical integrity test

MMI	Modified Mercalli Intensity
MMscf	million standard cubic feet
MMscf/D	million standard cubic feet per day
MMT/yr	million metric tons per year
NAD	North American Datum
NCEDC	Northern California Earthquake Data Center
NCEI	National Centers for Environmental Information
NEPA	National Environmental Policy Act
NRC	National Response Center
NSDWR	National Secondary Drinking Water Regulations
NSHM	National Seismic Hazard Model
OBG	overburden gradient
OD	outer diameter
P&A	plugging and abandonment
PBR	polished bore receptacle
PBTD	plugged back total depth
PG	pressure gradient
PISC	post-injection site care
POOH	pull out of hole
PP	pore pressure
ppf	pounds per foot
ppg	pounds per gallon
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSTM	Pre-Stack Time Migration
P/T	pressure/temperature
QA/QC	quality assurance/quality control
QPT	quartz pressure/temperature

SAU	storage assessment unit
SCADA	Supervisory Control and Data Acquisition
scf/D	standard cubic feet per day
SEM	scanning electron microscopy
SGR	shale gouge ratio
SIC	Standard Industrial Classification
SMCL	Secondary Maximum Contaminant Level
SONRIS	Strategic Online Natural Resources Information System
SOW	slip-on weld
SP	spontaneous potential
SPE	Society of Petroleum Engineers
SWO	Statewide Order
TD	total depth
TDS	total dissolved solids
TEC	tubing encapsulated conductor
TexNet	Texas Seismological Network and Seismology Research
TVD	true vertical depth
TVDSS	true vertical depth subsea
UCZ	upper confining zone
UIC	Underground Injection Control
USACE	U.S. Army Corps of Engineers
USDW	Underground Source of Drinking Water
USDWM	USDW monitoring (well)
USGS	U.S. Geological Survey
VSP	vertical seismic profile
WBS	wellbore schematic
WHT	wellhead temperature
XRD	X-ray diffraction

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.82	Required Class VI permit information			
		§3605.G	Certification. Any person signing a document under §3605.E shall make the following certification on the application: "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."	Master Documents
		§ 3605.C.1.b	the electronic version of the application shall contain the following certification statement: This document is an electronic version of the application titled (Insert Document Title) dated (Insert Application Date). This electronic version is an exact duplicate of the paper copy submitted in (Insert the Number of Volumes Comprising the Full Application) to the Louisiana Office of Conservation.	Electronic Document Certification
§146.91(e)	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.	§3629.A.3	Regardless of whether the State of Louisiana has primary permit and enforcement authority (primacy) for Class VI wells, owners or operators of Class VI wells, or applicants for Class VI wells must submit all required submittals, reports, and notifications under §§3605, 3607, 3615, 3617, 3619, 3621, 3623, 3625, 3627, 3629, 3631, and 3633 to the USEPA in an electronic format approved by the USEPA.	Electronic Document Certification

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
Introduction				
§146.82(a)(1)	Information required in §144.31(e)(1) through (6) of this chapter;			
§144.31(e)(8)	A brief description of the nature of the business.	§3607.B.6	a brief description of the nature of the business associated with the activity;	Introduction (Project Overview & Injectate Information)
§144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§3607.B.7	the activity or activities conducted by the applicant which require the applicant to obtain a permit under these regulations;	Introduction (Project Overview and Additional Permits)
§146.82(a)(7)(iii)	The source(s) of the carbon dioxide stream; and	§3607.C.2.f.iii	source(s) of the carbon dioxide stream; and	Introduction (Project Overview)
§146.82(a)(7)(iv)	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	§3607.C.2.f.iv	analysis of the chemical and physical characteristics of the carbon dioxide stream.	Introduction (Injectate Information)
§144.31(e)(2)	Name, mailing address, and location of the facility for which the application is submitted.	§3607.B.3	the name and mailing address of the applicant and the physical address of the sequestration well facility;	Introduction (General Application Information)

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§144.31(e)(3)	Up to four SIC codes which best reflect the principal products or services provided by the facility.	§3607.B.8	up to four SIC Codes which best reflect the principal products or services provided by the facility;	Introduction (General Application Information)
§144.31(e)(4)	The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	§3607.B.4	the operator's name, address, telephone number, and email address;	Introduction (General Application Information)
§144.31(e)(5)	Whether the facility is located on Indian lands.	§3607.B.10	acknowledgment as to whether the facility is located on Indian lands or other lands under the jurisdiction or protection of the federal government, or whether the facility is located on state water bottoms or other lands owned by or under the jurisdiction or protection of the state of Louisiana;	Intro (General Application Information)
§144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§3607.B.7	the activity or activities conducted by the applicant which require the applicant to obtain a permit under these regulations;	Introduction (Additional Permits)
§144.31(e)(6)	A listing of all permits or construction approvals received or applied for under any of the following programs:	§3607.B.9	a listing of all permits or construction approvals that the applicant has received or applied for under any of the following programs or which specifically affect the legal or technical ability of the applicant to undertake the activity or activities to be conducted by the applicant under the permit being sought:	Introduction (Additional Permits)
§144.31(e)(6)(i)	Hazardous Waste Management program under RCRA.	§3607.B.9.a	the Louisiana Hazardous Waste Management;	
§144.31(e)(6)(ii)	UIC program under SDWA.	§3607.B.9.b	this or any other underground injection control program;	
§144.31(e)(6)(iii)	NPDES program under CWA.	§3607.B.9.c	NPDES program under the Clean Water Act;	
§144.31(e)(6)(iv)	Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§3607.B.9.d	prevention of significant deterioration (PSD) program under the Clean Air Act;	
§144.31(e)(6)(v)	Nonattainment program under the Clean Air Act.	§3607.B.9.e	nonattainment program under the Clean Air Act;	
§144.31(e)(6)(vi)	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.	§3607.B.9.f	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act;	
§144.31(e)(6)(vii)	Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.	§3607.B.9.g	ocean dumping permit under the Marine Protection Research and Sanctuaries Act;	
§144.31(e)(6)(viii)	Dredge and fill permits under section 404 of CWA.	§3607.B.9.h	dredge or fill permits under section 404 of the Clean Water Act; and	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§144.31(e)(6)(ix)	Other relevant environmental permits, including State permits.	§3607.B.9.i	other relevant environmental permits including, but not limited to any state permits issued under the Louisiana Coastal Resources Program, the Louisiana Surface Mining Program or the Louisiana Natural and Scenic Streams System;	Introduction (Additional Permits)

Section 1 - Site Characterization & Appendix B, C				
§146.82(a)(3)	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	§3607.C.1.b	information on the geologic structure and hydrogeologic properties of the proposed sequestration site and overlying formations, to include:	Sections 1.3.4, 1.8, Appendix B
§146.82(a)(3)(ii)	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;	§3607.C.1.b.iii	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;	Section 1.10, 2.4.2, Appendix B
§146.82(a)(3)(iii)	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;	§3607.C.2.a	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	Sections 1.3, Appendix B
§146.82(a)(3)(iv)	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	§3607.C.2.b	geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Section 1.4
§146.82(a)(3)(v)	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	§3607.C.2.c	information on the region’s seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Section 1.10
§146.82(a)(3)(vi)	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	§3607.C.1.b.i	geologic and topographic maps and cross-sections illustrating regional geology, geologic structure, and hydrology.	Sections 1.2, 1.3.4, 1.8, Appendices A & B
§146.82(a)(5)	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;	§3607.C.2.d.iv	maps and stratigraphic cross-sections showing the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their position relative to the injection zone(s) and the direction of water movement, if known	Section 1.8, Appendix B
§146.82(a)(6)	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	§3607.C.2.e	baseline geochemical data on subsurface formations, including injection zones, confining zones and all USDWs in the area of review;	Section 1.6, 1.7, Appendix E

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.83(a)	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:	§3615.A	Minimum Criteria for Siting. Applicants, owners, or operators of Class VI wells must demonstrate to the satisfaction of the commissioner that the wells will be sited in areas with a suitable geologic system. The demonstration must show that the geologic system comprises:	Section 1.11
§146.83(a)(1)	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	§3615.A.1	an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Sections 1.5.3, 1.11
§146.83(a)(2)	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).	§3615.A.2	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).	Sections 1.4.5, 1.10, 1.11
§146.83(b)	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.	§3615.A.2.a	The commissioner 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(c)	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:	§3615.B.3	Area of Review Boundary Delineation. 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:	
§146.84(c)(1)	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:	§3615.B.3.a	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 commissioner. The model must:	Sections 2.7.2, 3.3, 5.5.5, Appendix C

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.84(c)(1)(i)	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;	§3615.B.3.a.i	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;	Sections 1.3, 2.2, 4.4, Appendix B
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§3615.B.3.a.ii	take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Section 1.3, Appendix B
§146.86(b)(1)(vii)	Lithology of injection and confining zone(s);	§3617.A.2.a.vii	lithology of injection and confining zone(s);	Section 1.3
§146.93(c)(1)(vii)	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;	§3633.A.3.a.vii	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;	Sections 1.3.2, 1.3.3, 1.10, 1.11
§146.93(c)(1)(x)	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	§3633.A.3.a.x	the distance between the injection zone and the nearest USDW above the injection zone; and	Section 1.8.1, Appendix B

Section 2 - Plume Model				
§146.84(a)	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.	§3615.B.1	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	Sections 2.6-2.8, 3.3
§146.84(c)	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:	§3615.B.3	Area of Review Boundary Delineation. 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:	

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§146.84(c)(1)	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:	§3615.B.3.a	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 commissioner. The model must:	Sections 2.7.2, 2.7.3, Section 3.3
§146.84(c)(1)(i)	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;	§3615.B.3.a.i	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;	Sections 2.3.5, 2.4 - 2.5
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§3615.B.3.a.ii	take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Sections 2.2.2, 2.4 - 2.5
§146.93(c)(1)(iii)	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	§3633.A.3.a.iii	the predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	Section 2.7.2.1

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(c)(1)(iv)	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;	§3633.A.3.a.iv	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;	Section 2.3
§146.93(c)(1)(v)	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	§3633.A.3.a.v	the predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	Section 2.3.5
§146.82(a)(7)(ii)	Average and maximum injection pressure;	§3607.C.2.f.ii	average and maximum injection pressure;	Section 2.7.1, Tables 2-9 - 2-10, Figures 2-32 - 2-35

Section 3 - AOR & Appendix C				
§146.82(a)(1)	Information required in § 144.31(e)(1) through (6) of this chapter;	§3607.B.12	names and addresses of all property owners within the area of review of the Class VI well or project.	Appendix A
§146.82(a)(2)	A map showing the injection well for which a permit is sought and	§3607.C.1	Maps and Related Information	Appendix C
§146.82(a)(2)		§3607.C.1.a	map(s) showing property boundaries of the facility, the location of the proposed Class VI well, and the applicable area of review consistent with §3615.B and §3615.C. USGS topographic maps with a scale of 1:24,000 may be used. The map boundaries must extend at least two miles beyond the area of review and include as applicable:	Appendix C -6
§146.82(a)(2)		§3607.C.1.a.i	the section, township and range of the area where the activity is located and any parish, city, municipality, state, and tribal boundaries	Section 3.1; Appendix C-6

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.82(a)(2)	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;	§3607.C.1.a.ii	within the area of review, the map(s) must identify all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or USEPA-approved subsurface cleanup sites, surface bodies of water, springs, surface and subsurface mines, quarries, water wells, other pertinent surface features including structures intended for human occupancy, and roads.	Appendices C-2, C-4, C-6
§146.82(a)(2)		§3607.C.1.a.iii	only information of public record is required to be included on the map(s), however, the applicant is required to make a diligent search to locate all wells not listed in the public record.	Section 3.3.4
§146.82(a)(2)		§3607.C.1.a.iv	for water wells on the facility property and adjacent property, submit a tabulation of well depth, water level, owner, chemical analysis, and other pertinent data. If these wells do not exist, submit this information for a minimum of three other wells in the area of review or a statement why this information was not included	Section 3.3.4; Appendix C-5
§146.82(a)(2)		§3607.C.1.a.v	the protocol followed to identify, locate, and ascertain the condition of all wells within the area of review that penetrate the injection or confining zone.	Section 3.3.4
§146.82(a)(3)(i)	Maps and cross sections of the area of review;			
§146.82(a)(4)	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;	§3607.C.2.d	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;	Section 3.3.4, Table 3-4, Appendix C-3
§146.82(a)(13)	Proposed area of review and corrective action plan that meets the requirements under § 146.84;	§3607.C.2.l	proposed area of review and corrective action plan that meets the requirements under §3615.B and §3615.C;	Sections 3.3, 3.4
§146.82(a)(20)	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	§3607.C.2.s	a list of contacts, submitted to the commissioner for those states and tribes identified to be within the area of review based on information provided in §3607.C.1.a.i; and	Intro, Section 8.6
§146.84(a)	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.	§3615.B.1	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	Sections 2.6-2.8, 3.3

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§146.84(b)	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:	§3615.B.2	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for the proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of these regulations and is acceptable to the commissioner. 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, the owner or operator must submit an area of review and corrective action plan that includes the following information:	Sections 3.3, 3.4, 3.5.1,
§146.84(b)(1)	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;	§3615.B.2.a	the method for delineating the area of review that meets the requirements of §3615.B.3, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Sections 1, 2.4-2.5, Section 3.3
§146.84(b)(2)	A description of:	§3615.B.2.b	a description of:	
§146.84(b)(2)(i)	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	§3615.B.2.b.i	the minimum fixed frequency—not to exceed five years—at which the owner or operator proposes to reevaluate the area of review;	Section 3.5.1
§146.84(b)(2)(ii)	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.	§3615.B.2.b.ii	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 §3615.B.2.b.i.	Section 3.5.1, Table 3-6
§146.84(b)(2)(iii)	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	§3615.B.2.b.iii	how monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	Section 3.5.1, Table 3-6

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§146.84(b)(2)(iv)	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.	§3615.B.2.b.iv	how corrective action will be conducted to meet the requirements of §3615.C, including what corrective action will be performed prior to injection and what, if any, portions of the area of review the operator proposes to 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.	Section 3.4, 3.5, 5.5.4.4
§146.84(c)	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:	§3615.B.3	Area of Review Boundary Delineation. 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:	
§146.84(c)(1)	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:	§3615.B.3.a	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 commissioner. The model must:	Sections 2.7.2, 3.3.3
§146.84(c)(1)(i)	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;	§3615.B.3.a.i	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;	Sections 2.2.2, 2.7.1
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§3615.B.3.a.ii	take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Sections 1, 2.2.2

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§146.84(c)(1)(iii)	Consider potential migration through faults, fractures, and artificial penetrations	§3615.B.3.a.iii	consider potential migration through faults, fractures, and artificial penetrations.	Section 2.5.1.2
§146.84(c)(2)	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	§3615.B.3.b	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	Section 3.3.4, Table 3-4, Appendix C-3
§146.84(c)(3)	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.	§3615.B.3.c	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.	Section 3.4
§146.84(d)	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.	§3615.C.1	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.	Section 3.4

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§146.84(e)	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:	§3615.C.2	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:	Section 3.5.1
§146.84(e)(1)	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	§3615.C.2.a	reevaluate the area of review in the same manner specified in §3615.B.3.a;	Section 3.5.1
§146.84(e)(2)	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	§3615.C.2.b	identify all wells in the reevaluated area of review that require corrective action in the same manner specified in §3615.B.3;	
§146.84(e)(3)	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	§3615.C.2.c	perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in §3615.C.1; and	
§146.84(e)(4)	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.	§3615.C.2.d	submit an amended area of review and corrective action plan or demonstrate to the commissioner 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 commissioner, must be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate.	
§146.84(g)	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	§3615.C.4	All modeling inputs and data used to support area of review reevaluations under §3615.C.2 shall be retained for at least 10 years.	Section 3.3.2

Section 4 - Construction & Appendix D				
§146.82(c)(5)	Final injection well construction procedures that meet the requirements of § 146.86;	§3619.A.5	Final injection well construction procedures that meet the requirements of §3617.A;	Section 4
§146.86	Injection well construction requirements.			

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§146.86(a)	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	§3617.A.1	General. All phases of Class VI well construction shall be supervised by a person knowledgeable and experienced in practical drilling engineering and is familiar with the special conditions and requirements of injection well construction. All materials and equipment used in the construction of the well and related appurtenances shall be designed and manufactured to exceed the operating requirements of the specific project, including flow induced vibrations. The owner or operator must ensure that all wells are constructed and completed to:	Sections 4.2, Appendix D
§146.86(a)(1)	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	§3617.A.1.a	prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Sections 4.2., Appendix D
§146.86(a)(2)	Permit the use of appropriate testing devices and workover tools; and	§3617.A.1.b	allow the use of appropriate testing devices and workover tools; and	Section 4.2; 4.2.1.3
§146.86(a)(3)	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	§3617.A.1.c	allow for continuous monitoring of the annulus space between the injection tubing and long string casing.	Sections 4.2.1.5, 4.2.1.7
§146.86(b)	Casing and cementing of Class VI wells.	§3617.A.2	Casing and Cementing of Class VI Wells	
§146.86(b)(1)	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:	§3617.A.2.a	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 that 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 commissioner. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the commissioner to evaluate casing and cementing requirements, the owner or operator must provide the following information:	Sections 4.2.1., 4.5, Appendix D
§146.86(b)(1)(i)	Depth to the injection zone(s);	§3617.A.2.a.i	depth to the injection zone(s);	Section 4.4, Figures 4-1, 4-2, Table 4-35
§146.86(b)(1)(ii)	Injection pressure, external pressure, internal pressure, and axial loading;	§3617.A.2.a.ii	injection pressure, external pressure, internal pressure, and axial loading;	Sections 4.2.1.1 - 4.2.1.3, Section 4.4, Table 4-35, Appendix D
§146.86(b)(1)(iii)	Hole size;	§3617.A.2.a.iii	hole size;	Sections 4.2.1.2 - 4.2.1.3, Figures 4-1, 4-2, Appendix D
§146.86(b)(1)(iv)	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	§3617.A.2.a.iv	size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	Sections 4.2.1.2 - 4.2.1.3, Figures 4-1, 4-2, Appendix D
§146.86(b)(1)(v)	Corrosiveness of the carbon dioxide stream and formation fluids;	§3617.A.2.a.v	corrosiveness of the carbon dioxide stream and formation fluids;	Sections 1.7, 4.2, Appendix E

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§146.86(b)(1)(vi)	Down-hole temperatures;	§3617.A.2.a.vi	down-hole temperatures;	Section 1.5, 1.7.4, 4.3.2, Table 4-30, 4-32
§146.86(b)(1)(vii)	Lithology of injection and confining zone(s);	§3617.A.2.a.vii	lithology of injection and confining zone(s);	Sections 1.3.1 - 1.3.3
§146.86(b)(1)(viii)	Type or grade of cement and cement additives; and	§3617.A.2.a.viii	type or grade of cement and cement additives including slurry weight (lb/gal) and yield (cu. ft./sack); and	Sections 4.2.1.2 - 4.2.1.3, Appendix D
§146.86(b)(1)(ix)	Quantity, chemical composition, and temperature of the carbon dioxide stream.	§3617.A.2.a.ix	quantity, chemical composition, and temperature of the carbon dioxide stream.	Section 4.2.1
§146.86(b)(2)	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.	§3617.A.2.b	The surface casing of any Class VI well must extend into a confining bed—such as a shale—below the base of the deepest formation containing a USDW. The casing shall be cemented with a sufficient volume of cement to circulate cement from the casing shoe to the surface. The commissioner will not grant an exception or variance to the surface casing setting depth.	Section 4.2.1.2, Figures 4-1, 4-2
§146.86(b)(3)	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.	§3617.A.2.c	At least one long string casing, using a sufficient number of centralizers, shall be utilized in the well. If the casing is to be perforated for injection, then the approved casing shall extend through the base of the injection zone. If an approved alternate construction method is used, such as the setting of a screen, the casing shall be set to the top of the injection interval. Regardless of the construction method utilized, the casings shall be cemented by circulating cement from the casing shoe to the surface in one or more stages.	Sections 4.2.1.3, 4.2.1.4, Figures 4-1, 4-2
§146.86(b)(4)	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.	§3617.A.2.d	Circulation of cement may be accomplished by staging. Circulated to the surface shall mean that actual cement returns to the surface were observed during the primary cementing operation. A copy of the cementing company's job summary or cementing tickets indicating returns to the surface shall be submitted as part of the pre operating requirements	Sections 4.2.1.3, 4.2.1.4, Figures 4-1, 4-2
§146.86(b)(5)	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.	§3617.A.2.e	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.	Sections 4.2, 4.2.1.3, Tables 4-31, 4-33
§146.86(c)	Tubing and packer.	§3617.A.4	Tubing and Packer	Sections 4.2.1.5 - 4.2.1.6

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§146.86(c)(1)	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.	§3617.A.4.a	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids that 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 commissioner.	Sections 4.2.1.5 - 4.2.1.6
§146.86(c)(2)	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	§3617.A.4.b	Injection into a Class VI well must be through tubing with a packer set at a depth opposite an interval of cemented casing at a location approved by the commissioner.	Sections 4.2.1.5 - 4.2.1.6, Figures 4-1, 4-2
§146.86(c)(3)	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	§3617.A.4.c	In order for the commissioner to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	
§146.86(c)(3)(i)	Depth of setting;	§3617.A.4.c.i	depth of setting;	Sections 4.2.1.5, Figure 4-1, 4-2
§146.86(c)(3)(ii)	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	§3617.A.4.c.ii	characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Sections 1.7, 4.2, Appendix E
§146.86(c)(3)(iii)	Maximum proposed injection pressure;	§3617.A.4.c.iii	maximum proposed injection pressure;	Section 4.2.1, Tables 4-5, 4-6
§146.86(c)(3)(iv)	Maximum proposed annular pressure;	§3617.A.4.c.iv	maximum proposed annular pressure;	Section 4.4, Table 4-35
§146.86(c)(3)(v)	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	§3617.A.4.c.v	proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	Section 4.2.1, Tables 4-5, 4-6
§146.86(c)(3)(vi)	Size of tubing and casing; and	§3617.A.4.c.vi	size of tubing and casing; and	Sections 4.2.1.2, 4.2.1.3, 4.2.1.5, Figures 4-1, 4-2
§146.86(c)(3)(vii)	Tubing tensile, burst, and collapse strengths.	§3617.A.4.c.vii	tubing tensile, burst, and collapse strengths.	Section 4.2.1.5, Table 4-28
§146.82(a)(7)	Proposed operating data for the proposed geologic sequestration site:	§3607.C.2.f	proposed operating data:	Section 4.4
§146.82(a)(7)(i)	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	§3607.C.2.f.i	average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	Section 4.4, Table 35
§146.82(a)(7)(ii)	Average and maximum injection pressure;	§3607.C.2.f.ii	average and maximum injection pressure;	Sections 2.7.1, 4.4, Table 4-35
§146.82(a)(8)	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;	§3607.C.2.g	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 §3617.B;	Section 4.3
§146.82(a)(9)	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	§3607.C.2.h	proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	TBD
§146.82(a)(10)	Proposed procedure to outline steps necessary to conduct injection operation;	§3607.C.2.i	proposed injection operation procedures;	Section 4.4
§146.82(a)(11)	Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	§3607.C.2.j	schematics or other appropriate drawings of the surface (wellhead and related appurtenances) and subsurface construction details of the well;	Figures 4-1, 4-2, 4-7 Appendix D

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§146.82(a)(12)	Injection well construction procedures that meet the requirements of § 146.86;	§3607.C.2.k	injection well construction procedures that meet the requirements of §3617.A;	Appendix D
		§3617.A.3	Casing and Casing Seat Tests. The owner or operator shall monitor and record the tests using a surface readout pressure gauge and a chart or a digital recorder. All instruments shall be calibrated properly and in good working order. If there is a failure of the required tests, the owner or operator shall take necessary corrective action to obtain a passing test.	Appendix D-1, D-2
		§3617.A.3.a	Casing. After cementing each casing, but before drilling out the respective casing shoe, all casings shall be hydrostatically pressure tested to verify casing integrity and the absence of leaks. For surface casing, the stabilized test pressure applied at the surface shall be a minimum of 500 pounds per square inch gauge (PSIG). The stabilized test pressure applied at the surface for all other casings shall be a minimum of 1,000 PSIG. All casing test pressures shall be maintained for one hour after stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabilized test duration.	Appendix D-1, D-2
		§3617.A.3.a.i	Casing test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Tables 4-8, 4-9, Appendix D-1, D-2
		§3617.A.3.b	Casing Seat. The casing seat and cement of any intermediate and injection casings shall be hydrostatically pressure tested after drilling out the casing shoe. At least 10 feet of formation below the respective casing shoes shall be drilled before the test. The test pressure applied at the surface shall be a minimum of 1,000 PSIG. The test pressure shall be maintained for one hour after pressure stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabilized test duration.	Appendix D-1, D-2
		§3617.A.3.b.i	Casing seat test pressures shall never exceed the known or calculated fracture gradient of the appropriate subsurface formation.	Appendix D-1, D-2
§146.87				

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(a)	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:	§3617.B.1	During the drilling and construction of a Class VI well, appropriate logs, surveys and tests must be run to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements of §3617 and to establish accurate baseline data against which future measurements may be compared. The well operator must submit to the commissioner 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:	Sections 4.3.1 - 4.3.3
§146.87(a)(1)	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	§3617.B.1.a	deviation checks during drilling of all boreholes 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;	
§146.87(a)(2)	Before and upon installation of the surface casing:	§3617.B.1.b	before and upon installation of the surface casing:	Section 4.3.2
§146.87(a)(2)(i)	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§3617.B.1.b.i	resistivity, gamma-ray, spontaneous potential, and caliper logs before the casing is installed; and	Section 4.3.2, Tables 4-30, 4-32
§146.87(a)(2)(ii)	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	§3617.B.1.b.ii	a cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented	Section 4.3.2, Tables 4-31, 4-33
§146.87(a)(3)	Before and upon installation of the long string casing:	§3617.B.1.c	before and upon installation of intermediate and long string casing:	Section 4.3.2
§146.87(a)(3)(i)	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	§3617.B.1.c.i	resistivity, gamma-ray, spontaneous potential, porosity, caliper, fracture finder logs, and any other logs the commissioner requires for the given geology before the casing is installed; and	Section 4.3.2, Tables 4-30, 4-32

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(a)(3)(ii)	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	§3617.B.1.c.ii	a cement bond and variable density log, and a temperature log after the casing is set and cemented.	Section 4.3.2, Tables 4-31, 4-33
§146.87(a)(4)	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	§3617.B.1.d	a series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	Sections 5.4.2, 5.4.3
§146.87(a)(4)(i)	A pressure test with liquid or gas;	§3617.B.1.d.i	a pressure test with liquid or gas;	Section 5.4.2
§146.87(a)(4)(ii)	A tracer survey such as oxygen-activation logging;	§3617.B.1.d.ii	a tracer-type survey to detect fluid movement behind casing such as a radioactive tracer or oxygen activation logging, or similar tool	Section 5.4.3
§146.87(a)(4)(iii)	A temperature or noise log;	§3617.B.1.d.iii	a temperature or noise log;	Section 5.4.3
§146.87(a)(4)(iv)	A casing inspection log; and	§3617.B.1.d.iv	a casing inspection log	Section 4.3.2, Tables 4-31, 4-33, Section 5.4.5
§146.87(a)(5)	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	§3617.B.1.e	any alternative methods that provide equivalent or better information and that are required by and approved by the commissioner.	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(b)	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.	§3617.B.2	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 commissioner a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. The commissioner 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 commissioner may require the owner or operator to core other formations in the borehole.	Section 4.3.1
§146.87(c)	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	§3617.B.3	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Section 4.3
§146.87(d)	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	§3617.B.4	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	
§146.87(d)(1)	Fracture pressure;	§3617.B.4.a	fracture pressure;	Section 2.5.2.3
§146.87(d)(2)	Other physical and chemical characteristics of the injection and confining zone(s); and	§3617.B.4.b	other physical and chemical characteristics of the injection and confining zone(s); and	Sections 4.3.1- 4.3.2
§146.87(d)(3)	Physical and chemical characteristics of the formation fluids in the injection zone(s).	§3617.B.4.c	physical and chemical characteristics of the formation fluids in the injection zone(s).	Section 4.3.3
§146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	§3617.B.5	Upon completion, but before operating, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	
§146.87(e)(1)	A pressure fall-off test; and,	§3617.B.5.a	a pressure fall-off test; and,	Section 4.3.4, Section 5.4.4

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(e)(2)	A pump test; or	§3617.B.5.b	a pump test; or	
§146.87(e)(3)	Injectivity tests.	§3617.B.5.c	injectivity tests.	Section 4.3.4, Section 5.4.1
§146.87(f)	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.	§3617.B.6	The owner or operator must notify the Office of Conservation at least 72 hours before conducting any wireline logs, well tests, or reservoir tests	Appendix D
§146.88	Injection well operating requirements			
§146.88(a)	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.	§3621.A.1	Injection Pressure. Except during stimulation, the injection well shall be operated so that the injection-induced pressure in the injection zone(s) does not exceed 90 percent of the fracture pressure of the injection zone(s). This shall ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone. 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 NATURAL RESOURCES Louisiana Administrative Code September 2022 170 §3607.C.2.h, all stimulation programs must be approved by the commissioner as part of the permit application and incorporated into the permit.	Section 4.4, Table 4-35
§146.88(b)	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	§3621.A.2	Injection between the outermost casing protecting USDWs and the wellbore is prohibited.	Section 4.5, Figures 4-1, 4-2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.88(c)	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.	§3621.A.3	The owner or operator must fill the annulus between the tubing and the long string casing with a non corrosive fluid approved by the commissioner or a fluid containing a corrosion inhibitor approved by the commissioner.	Section 4.2, Appendix D-1, D-2
§146.88(d)	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.	§3621.A.5	The owner or operator must maintain mechanical integrity of the injection well at all times, except when doing well workovers, well maintenance, or well remedial work approved by the commissioner.	5.4.2

Section 5 - Testing and Monitoring				
§146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	§3617.B.5	Upon completion, but before operating, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	Section 4.3.4, Sections 5.4.1, 5.4.4
§146.87(e)(1)	A pressure fall-off test; and,	§3617.B.5.a	a pressure fall-off test; and,	
§146.87(e)(2)	A pump test; or	§3617.B.5.b	a pump test; or	
§146.87(e)(3)	Injectivity tests.	§3617.B.5.c	injectivity tests.	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90	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:	§3625.A	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 included with the permit application and must include a description of how the owner or operator will meet these requirements— including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must include, at a minimum:	Section 5
§146.90(a)	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	§3625.A.1	analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Section 5.2, Sections 5.5.1 - 5.5.2, Table 5-1

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90(b)	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;	§3625.A.2	installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the tubing-casing annulus; and the annulus fluid volume added. Continuous monitoring is not required during well workovers as defined in §3621.A.5;	Sections 5.2, 5.5.1
§146.90(c)	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:	§3625.A.3	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 §3617.A.2, by:	Section 5.5.3
§146.90(c)(1)	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	§3625.A.3.a	analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	Section 5.5.3
§146.90(c)(2)	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	§3625.A.3.b	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)	Using an alternative method approved by the Director;	§3625.A.3.c	using an alternative method approved by the commissioner;	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90(d)	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:	§3625.A.4	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:	Sections 5.5.4 - 5.5.6, Tables 5-3, 5-4, Figures 5-1, 5-5
§146.90(d)(1)	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	§3625.A.4.a	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	
§146.90(d)(2)	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).	§3625.A.4.b	the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under §3607.C.2.e and on any modeling results in the area of review evaluation required by §3615.B.3.	
§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;	§3625.A.5	a demonstration of external mechanical integrity pursuant to §3627.A.3 at least once every 12 months until the injection well is permanently plugged and abandoned; and, if required by the commissioner, a casing inspection log pursuant to requirements at §3627.A.4 at a frequency established in the testing and monitoring plan;	Section 5.4.3
§146.90(f)	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;	§3625.A.6	a pressure fall-off test at least once every five years unless more frequent testing is required by the commissioner based on site-specific information;	Section 5.4.4

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90(g)	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:	§3625.A.7	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:	Section 5.5.8
§146.90(g)(1)	Direct methods in the injection zone(s); and,	§3625.A.7.a	direct methods in the injection zone(s); and	Section 5.5.8.1
§146.90(g)(2)	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;	§3625.A.7.b	indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the commissioner determines that such methods are not appropriate, based on site-specific geology;	Section 5.5.8.2
§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.	§3625.A.8	The commissioner may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW	
§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;	§3625.A.8.a	Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;	
§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 §3603.D;	§3625.A.8.b	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 §3603.D;	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§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;	§3625.A.8.c	If an owner or operator demonstrates that monitoring employed under 40 CFR 98.440 to 98.449 accomplishes the goals of §3625.A.8.a. and b., and meets the requirements pursuant to §3629.A.1.c.v, a regulatory agency that requires surface air/soil gas monitoring must approve the use of monitoring employed under 40 CFR 98.440 to 98.449. Compliance with 40 CFR 98.440 to 98.449 pursuant to this provision is considered a condition of the Class VI permit;	
§146.90(i)	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;	§3625.A.9	Any additional monitoring, as required by the commissioner, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under §3615.B.3 and to determine compliance with standards under §3619;	
§146.90(j)	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:	§3625.A.10	The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under §3625, operational data collected under §3621, and the most recent area of review reevaluation performed under §3615.C.2. 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 commissioner that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the commissioner, must be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate. Amended plans or demonstrations shall be submitted to the commissioner as follows:	Section 5.3
§146.90(j)(1)	Within one year of an area of review reevaluation;	§3625.A.10.a	within 12 months of an area of review reevaluation;	Section 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	§3625.A.10.b	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 commissioner; or	Section 5.3
§146.90(j)(3)	When required by the Director.	§3625.A.10.c	when required by the commissioner.	Section 5.3
§146.90(k)	A quality assurance and surveillance plan for all testing and monitoring requirements.	§3625.A.11	a quality assurance and surveillance plan for all testing and monitoring requirements.	5.4.4.3
§146.89(a)	A Class VI well has mechanical integrity if:	§3627.A.1	A Class VI well has mechanical integrity if:	
§146.89(a)(1)	There is no significant leak in the casing, tubing, or packer; and	§3627.A.1.a	there is no significant leak in the casing, tubing, or packer; and	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.89(a)(2)	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	§3627.A.1.b	there is no significant fluid movement into a USDW through channels adjacent to the injection wellbore.	
§146.89(b)	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);	§3627.A.2	To evaluate the absence of significant leaks, owners or operators must:	
		§3627.A.2.a	perform an annulus pressure test:	Section 5.4.2
		§3627.A.2.a.i	after initial well construction or conversion as part of the pre-operating requirements;	Section 5.4.2
No equivalent federal requirement	No equivalent federal requirement	§3627.A.2.a.ii	at least once every 12 months witnessed by an agent of the Office of Conservation; and	Section 5.4.2
		§3627.A.2.a.ii	after performing any well remedial work that involves unseating the tubing or packer.	Section 5.4.2
§146.89(b)	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);	§3627.A.2.b	continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing;	Section 5.5.1
§146.89(c)	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:	§3627.A.3	At least once every 12 months, use one of the following methods to determine the absence of significant fluid movement:	Section 5.4.3
§146.89(c)(1)	An approved tracer survey such as an oxygen-activation log; or	§3627.A.3.a	an approved tracer-type survey such as a radioactive tracer, oxygen-activation log, or similar tool; or	Section 5.4.3
§146.89(c)(2)	A temperature or noise log.	§3627.A.3.b	a temperature or noise log	Section 5.4.3

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.89(d)	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.	§3627.A.4	If required by the commissioner, run a casing inspection log at a frequency specified in the testing and monitoring plan at §3625 to determine the presence or absence of corrosion in the long-string casing.	
§146.89(e)	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.	§3627.A.5	The commissioner may require other tests to evaluate well mechanical integrity	
		§3627.A.5.a	The commissioner may allow the use of a test to demonstrate mechanical integrity other than those listed above with written approval of the USEPA. To obtain approval for the use of a new mechanical integrity test, the owner or operator must submit a written request to the commissioner with details of the proposed test and all technical data supporting its use, and the commissioner will submit a written request to the USEPA.	
§146.89(f)	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.	§3627.A.6	In conducting and evaluating the tests enumerated in this section to be allowed by the commissioner, the owner or operator and the commissioner must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the commissioner, a description of the test(s) and the method(s) used must be included. In making the evaluation, the commissioner must review monitoring and other test data submitted since the previous evaluation.	Sections 5.4.2 - 5.4.3
§146.89(g)	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.	§3627.A.7	The commissioner may require additional or alternative tests if the mechanical integrity test results presented are not satisfactory to the commissioner 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.	
§146.91	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:	§3629.A.1	The owner or operator must provide, at a minimum, the following reports to the commissioner, and the USEPA as specified in §3629.A.3, for each permitted Class VI well:	Section 5.2
§146.91(a)	monthly reports containing:	§3629.A.1.a	monthly reports containing:	Section 5.2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.91(a)(1)	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	§3629.A.1.a.i	any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	Section 5.2
§146.91(a)(2)	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	§3629.A.1.a.ii	monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	Section 5.2
§146.91(a)(3)	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	§3629.A.1.a.iii	a description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	Section 5.2
§146.91(a)(4)	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	§3629.A.1.a.iv	a description of any event which triggers a shut-off device required by §3621 and the response taken;	Section 5.2
§146.91(a)(5)	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;	§3629.A.1.a.v	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;	Section 5.2
§146.91(a)(6)	Monthly annulus fluid volume added; and	§3629.A.1.a.vi	monthly annulus fluid volume added;	Section 5.2
§146.91(a)(7)	The results of monitoring prescribed under § 146.90.	§3629.A.1.a.vii	the results of monitoring prescribed under §3625; and	Section 5.2
§146.91(b)	Report, within 30 days, the results of:	§3629.A.1.b	report, within 30 days or as specified by permit, the results of:	Section 5.2
§146.91(b)(1)	Periodic tests of mechanical integrity;	§3629.A.1.b.i	periodic tests of mechanical integrity;	Section 5.2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.91(b)(2)	Any well workover; and,	§3629.A.1.b.ii	any well workover; and	Section 5.2
§146.91(b)(3)	Any other test of the injection well conducted by the permittee if required by the Director.	§3629.A.1.b.iii	any other test of the injection well conducted by the permittee if required by the commissioner;	Section 5.2
§146.91(c)	Report, within 24 hours:	§3629.A.1.c	report, within 24 hours:	Section 5.2
§146.91(c)(1)	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	§3629.A.1.c.i	any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	Section 5.2
§146.91(c)(2)	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	§3629.A.1.c.ii	any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	Section 5.2
§146.91(c)(3)	Any triggering of a shut-off system (i.e., down-hole or at the surface);	§3629.A.1.c.iii	any triggering of a shut-off system (i.e., down hole or at the surface);	Section 5.2
§146.91(c)(4)	Any failure to maintain mechanical integrity; or.	§3629.A.1.c.iv	any failure to maintain mechanical integrity; or	Section 5.2
§146.91(c)(5)	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.	§3629.A.1.c.v	any release of carbon dioxide to the atmosphere or biosphere pursuant to compliance with the requirement at §3625.A.8 for surface air/soil gas monitoring or other monitoring technologies, if required by the commissioner;	
§146.91(d)	Owners or operators must notify the Director in writing 30 days in advance of:	§3629.A.2	Owners or operators must notify the commissioner in writing in advance of doing any well work or formation testing as required in §3621.A.9	Section 5.2
§146.91(d)(1)	Any planned well workover;			Section 5.2
§146.91(d)(2)	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and			Section 5.2
§146.91(d)(3)	Any other planned test of the injection well conducted by the permittee.			Section 5.2
§146.91(e)	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.	§3629.A.3	Regardless of whether the State of Louisiana has primary permit and enforcement authority (primacy) for Class VI wells, owners or operators of Class VI wells, or applicants for Class VI wells must submit all required submittals, reports, and notifications under §§3605, 3607, 3615, 3617, 3619, 3621, 3623, 3625, 3627, 3629, 3631, and 3633 to the USEPA in an electronic format approved by the USEPA.	
§146.91(f)	Records shall be retained by the owner or operator as follows:	§3629.A.4	Records shall be retained by the owner or operator as follows:	Section 5.2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.91(f)(1)	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.	§3629.A.4.a	all data collected for Class VI permit applications in §3607 and §3619 shall be retained throughout the life of the geologic sequestration project and at least 10 years following site closure.	Section 5.2
§146.91(f)(2)	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.	§3629.A.4.b	data on the nature and composition of all injected fluids collected under §3625.A.1.a shall be retained at least 10 years after site closure. The commissioner may require the owner or operator to deliver the records to the commissioner at the conclusion of the retention period.	Section 5.2
§146.91(f)(3)	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	§3629.A.4.c	monitoring data collected under §3625.A.2 through §3625.A.9 shall be retained at least 10 years after it is collected.	Section 5.2
§146.91(f)(4)	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.	§3629.A.4.d	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 §3633.A.6 and §3633.A.8 shall be retained at least 10 years following site closure.	Section 5.2
§146.91(f)(5)	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.	§3629.A.4.e	The commissioner may require the owner or operator to retain any records required under these regulations for longer than 10 years after site closure.	
§146.88(e)(1)	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	§3621.A.6.a	continuous recording devices shall monitor:	Sections 5.5.1 - 5.5.2
		§3621.A.6.a.i	surface injection or bottom-hole pressure;	Section 5.5.1
		§3621.A.6.a.ii	flow rate, volume and/or mass, and temperature of the carbon dioxide stream;	Section 5.5.1
		§3621.A.6.a.iii	tubing-casing annulus pressure and annulus fluid volume; and	Section 5.5.1
No equivalent federal requirement	No equivalent federal requirement	§3621.A.6.a.iv	any other data specified by the commissioner.	
		§3621.A.6.b	continuous recordings shall consist of digital recordings. Instruments shall be weatherproof or housed in weatherproof enclosures when located in areas exposed to climatic conditions.	Sections 5.5.1 - 5.5.2

Section 6 - Plugging Plan				
§146.92(a)	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.	§3631.A.2	Before well plugging, the owner or operator must flush each Class VI well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Sections 6.2.1.2, 6.2.2.2, 6.2.2.3

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.92(b)	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:	§3631.A.3	Well Plugging Plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan acceptable to the commissioner. 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, must be designed in a way that will prevent the movement of fluids into or between USDWs or outside the injection zone, and must include the following minimum information:	Section 6.2.2, Appendix H
§146.92(b)(1)	Appropriate tests or measures for determining bottomhole reservoir pressure;	§3631.A.3.a	appropriate tests or measures for determining bottomhole reservoir pressure;	Sections 6.2.1.1(2), 6.2.2.1(2)
§146.92(b)(2)	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	§3631.A.3.b	appropriate testing methods to ensure external mechanical integrity as specified in §3627;	Section 6.2.1.1(2)(a)
	NEQFR	§3631.A.3.c	a description of the size and amount of casing, tubing, or any other well construction materials to be removed from the well before well closure;	Section 6.2.2.2 (Table 6-1); 6.2.2.3 (Table 6-2)
	NEQFR	§3631.A.3.d	that prior to the placement of plugs, the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method;	Section 6.2.2.2, 6.2.2.3; Appendix H
§146.92(b)(3)	The type and number of plugs to be used;	§3631.A.3.e	the type and number of plugs to be used;	Section 6.2.2.2 (Table 6-3); 6.2.2.3 (Table 6-4)
§146.92(b)(4)	The placement of each plug, including the elevation of the top and bottom of each plug;	§3631.A.3.f	the placement of each plug, including the elevation of the top and bottom of each plug;	Section 6.2.2.2 (Table 6-3); 6.2.2.3 (Table 6-4)
§146.92(b)(5)	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	§3631.A.3.g	the type, grade, yield, and quantity of material, such as cement, to be used in plugging. The material must be compatible with the carbon dioxide stream;	Section 6.2.2.3 (Table 6-2, Table 6-3); Appendix H
§146.92(b)(6)	The method of placement of the plugs.	§3631.A.3.h	the method of placement of the plugs;	Section 6.2.2.3 (Table 6-2, Table 6-3); Appendix H

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.92(c)	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.	§3631.A.4	Notice of Intent to Plug. The owner or operator must submit the Form UIC-17, or successor form, to the commissioner and receive written approval from the commissioner before beginning actual well plugging operations. The form must contain information on the procedures to be used in the field to plug and abandon the well.	Sections 6.2.1.1, 6.2.2.1
§146.92(d)	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.	§3631.A.5	Well Closure Report. The owner or operator shall submit a closure report to the commissioner within 30 days after well plug and abandonment. The report shall be certified as accurate by the owner or operator and by the person charged with overseeing the closure operation (if other than the owner or operator). The owner or operator shall retain the well closure report at least 10 years following site closure. The report shall contain the following information:	Sections 6.2.2.2, 6.2.2.3
§146.82(a)(16)	Proposed injection well plugging plan required by § 146.92(b);	§3607.C.2.o	proposed injection well plugging plan required by §3631;	Section 6.1, 6.2, Appendix H

Section 7 - Post Injection Site Care and Closure Plan				
§146.93	#N/A	#N/A	#N/A	
§146.82(a)(17)	Proposed post-injection site care and site closure plan required by § 146.93(a);	§3607.C.2.p	proposed post-injection site care and site closure plan required by §3633.A.3;	Section 7
§146.82(a)(18)	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);	§3607.C.2.q	at the commissioner's discretion, a demonstration of an alternative post-injection site care timeframe required by §3633.A.3;	Section 7.6
§146.93(a)	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.	§3633.A.1	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 §3633.A.1.b and is acceptable to the commissioner. 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)	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.	§3633.A.1.a	The owner or operator must submit the post injection site care and site closure plan as a part of the permit application.	Section 7
§146.93(a)(2)	The post-injection site care and site closure plan must include the following information:	§3633.A.1.b	The post-injection site care and site closure plan must include the following information:	Section 7

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(a)(2)(i)	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	§3633.A.1.b.i	the pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	Section 7.2, Table 7-1, Figures 7-1, 7-2
§146.93(c)	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.	§3633.A.3	Demonstration of Alternative Post-Injection Site Care Timeframe. The commissioner may approve, in consultation with the USEPA, 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 §3607 and §3615, 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.	Section 7.6
§146.93(c)(1)	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	§3633.A.3.a	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	
§146.93(c)(1)(i)	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	§3633.A.3.a.i	the results of computational modeling performed pursuant to delineation of the area of review under §3615.B and §3615.C;	
§146.93(c)(1)(ii)	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;	§3633.A.3.a.ii	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)(ix)	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	§3633.A.3.a.ix	a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	
§146.93(c)(1)(viii)	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;	§3633.A.3.a.viii	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;	
§146.93(c)(2)	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	§3633.A.3.b	Information submitted to support the demonstration in §3633.A.3.a must meet the following criteria:	
§146.93(c)(2)(i)	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	§3633.A.3.b.i	all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(c)(2)(ii)	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	§3633.A.3.b.ii	estimation techniques must be appropriate and USEPA-certified test protocols must be used where available;	
§146.93(c)(2)(iii)	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;	§3633.A.3.b.iii	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;	
§146.93(c)(2)(iv)	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;	§3633.A.3.b.iv	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;	
§146.93(c)(2)(v)	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;	§3633.A.3.b.v	reasonably conservative values and modeling assumptions must be used and disclosed to the commissioner whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	
§146.93(c)(2)(vi)	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.	§3633.A.3.b.vi	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	
§146.93(c)(2)(vii)	An approved quality assurance and quality control plan must address all aspects of the demonstration; and,	§3633.A.3.b.vii	an approved quality assurance and quality control plan must address all aspects of the demonstration; and	
§146.93(c)(2)(viii)	Any additional criteria required by the Director.	§3633.A.3.b.viii	any additional criteria required by the commissioner.	
§146.93(a)(2)(ii)	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);	§3633.A.1.b.ii	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 §3615.B.3.a;	Section 7.3, Figure 7-3

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(a)(2)(iii)	A description of post-injection monitoring location, methods, and proposed frequency;	§3633.A.1.b.iii	a description of post-injection monitoring location, methods, and proposed frequency;	Section 7.4, Section 7.5, Table 7-2
§146.93(a)(2)(iv)	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	§3633.A.1.b.iv	a proposed schedule for submitting post injection site care monitoring results to the commissioner and to the USEPA pursuant to §3629.A.3; and,	Section 7.5 (Table 7-2)
§146.93(a)(2)(v)	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.	§3633.A.1.b.v	the duration of the post-injection site care timeframe and, if approved by the commissioner, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	Sections 7.4 - 7.6, (Table 7-2)
§146.93(a)(3)	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.	§3633.A.1.c	Upon cessation of injection, owners or operators of Class VI wells must either submit an amended postinjection site care and site closure plan or demonstrate to the commissioner 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 commissioner, be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate.	Section 7.4
§146.93(a)(4)	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.	§3633.A.1.d	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 commissioner's approval within 30 days of such change.	Section 7.4
§146.93(b)	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.	§3633.A.2	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.	Section 7.4

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§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.	§3633.A.2.a	Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the commissioner-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 commissioner pursuant to requirements in §3633.A.3, unless the owner or operator makes a demonstration under §3633.A.2.b. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under §3633.A.2.b is submitted and approved by the commissioner.	Sections 7.4 - 7.6
§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.	§3633.A.2.b	If the owner or operator can demonstrate to the satisfaction of the commissioner 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 commissioner 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 the owner or operator has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	Section 7.6
§146.93(b)(3)	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.	§3633.A.2.c	Prior to authorization for site closure, the owner or operator must submit to the commissioner 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	Section 7.6

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(b)(4)	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.	§3633.A.2.d	If the demonstration in §3633.A.2.c 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 commissioner does not approve the demonstration, the owner or operator must submit to the commissioner a plan to continue post-injection site care until a demonstration can be made and approved by the commissioner.	
§146.93(d)	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.	§3633.A.4	Notice of Intent for Site Closure. The owner or operator must notify the commissioner 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 commissioner may allow for a shorter notice period.	Section 7.7.1
§146.93(e)	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.	§3633.A.5	After the commissioner 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.	Section 7.7.2, Section 7.7.4
§146.93(f)	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:	§3633.A.6	The owner or operator must submit a site closure report to the commissioner within 90 days after site closure, which must also be retained by the owner or operator for at least 10 years. The report must include:	Section 7.7.4
§146.93(f)(1)	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;	§3633.A.6.a	documentation of appropriate injection and monitoring well plugging as specified in §3631 and §3633.A.5. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the commissioner. 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 USEPA as in §3629.A.3;	Section 7.7.4, Appendix A-3
§146.93(f)(2)	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	§3633.A.6.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	Section 7.7.4

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(f)(3)	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	§3633.A.6.c	records reflecting the nature, composition, and volume of the carbon dioxide stream	Section 7.7.4
§146.93(g)	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:	§3633.A.7	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:	Section 7.7.4
§146.93(g)(1)	The fact that land has been used to sequester carbon dioxide;	§3633.A.7.a	the fact that land has been used to sequester carbon dioxide;	Section 7.7.4
§146.93(g)(2)	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	§3633.A.7.b	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 USEPA Regional Office to which it was submitted; and	Section 7.7.4
§146.93(g)(3)	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	§3633.A.7.c	the volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	Section 7.7.4
§146.93(h)	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.	§3633.A.8	The owner or operator must retain for at least 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the commissioner at the conclusion of the retention period, and the records must thereafter be retained in a form and manner and at a location designated by the commissioner.	Section 7.7.4

Section 8 - Emergency Response

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.82(a)(19)	Proposed emergency and remedial response plan required by § 146.94(a);	§3607.C.2.r	proposed emergency and remedial response plan required (contingency plans for well failures or breaches) by §3623;	Section 8
§146.84(f)	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.	§3615.C.3	The emergency and remedial response plan (as required by §3623) and the demonstration of financial responsibility (as described by §3609.C must account for the area of review delineated as specified in §3615.B.3.a or the most recently evaluated area of review delineated under §3615.C.2, regardless of whether or not corrective action in the area of review is phased.	Section 8.2, Appendix G
§146.88(e)(2)	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	§3621.A.7.a.i	for onshore wells, alarms and automatic surface shut-off valves or—at the discretion of the commissioner—down-hole shut-off systems (e.g., automatic shut-off, check valves) or, other mechanical devices that provide equivalent Protection; and	Section 8.3
§146.88(e)(3)	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.	§3621.A.7.a.ii	for offshore wells, alarms and automatic down hole 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 beyond permitted ranges or gradients specified in the permit.	
§146.88(f)	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:	§3621.A.7.b	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 is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, the owner or operator must:	Section 8.3
§146.88(f)(1)	Immediately cease injection;	§3621.A.7.b.i	immediately cease injection;	Section 8.3
§146.88(f)(2)	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;	§3621.A.7.b.ii	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;	Section 8.3
§146.88(f)(3)	Notify the Director within 24 hours;	§3621.A.7.b.iii	notify the commissioner within 24 hours;	Section 8.3
§146.88(f)(4)	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	§3621.A.7.b.iv	restore and demonstrate mechanical integrity to the satisfaction of the commissioner prior to resuming injection; and	Section 8.3
§146.88(f)(5)	Notify the Director when injection can be expected to resume.	§3621.A.7.b.v	notify the commissioner when injection can be expected to resume.	Section 8.3
§146.94	Emergency and remedial response		Emergency Response	Section 8.8

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.94(a)	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.	§3623.A.1	As part of the permit application, the owner or operator must provide the commissioner 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.	Sections 8.3, 8.8
§146.94(b)	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:	§3623.A.2	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:	
§146.94(b)(1)	Immediately cease injection;	§3623.A.2.a	immediately cease injection;	Section 8.3
§146.94(b)(2)	Take all steps reasonably necessary to identify and characterize any release;	§3623.A.2.b	take all steps reasonably necessary to identify and characterize any release;	Section 8.3
§146.94(b)(3)	Notify the Director within 24 hours; and	§3623.A.2.c	notify the commissioner within 24 hours; and	Section 8.3
§146.94(b)(4)	Implement the emergency and remedial response plan approved by the Director.	§3623.A.2.d	implement the emergency and remedial response plan approved by the commissioner.	Section 8.3
§146.94(c)	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.	§3623.A.3	The commissioner may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	
§146.94(d)	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:	§3623.A.4	The owner or operator shall review the emergency and remedial response plan developed under §3623.A.1 at least 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 commissioner 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 commissioner, must be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate. Amended plans or demonstrations shall be submitted to the commissioner as follows:	Section 8.8
§146.94(d)(1)	Within one year of an area of review reevaluation;	§3623.A.4.a	within one year of an area of review reevaluation;	Section 8.8

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.94(d)(2)	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	§3623.A.4.b	following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the commissioner; or	Section 8.8
§146.94(d)(3)	When required by the Director.	§3623.A.4.c	when required by the commissioner.	Section 8.8

Section 9 - Financial Assurance				
No equivalent federal requirement	No equivalent federal requirement	§3607.B.11	documentation of financial responsibility or documentation of the method by which proof of financial responsibility will be provided as required in §3609.C. Before making a final permit decision, final (official) documentation of financial responsibility must be submitted to and approved by the Office of Conservation;	Section 9.3
§146.82(a)(14)	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	§3607.C.2.m	demonstration, satisfactory to the commissioner, that the applicant has met the financial responsibility requirements under §3609.C;	
No equivalent federal requirement	No equivalent federal requirement	§3609.C.2	The amount of funds available in the financial instrument shall be no less than the amount identified in the cost estimate of the closure plan and any required post injection site care and site closure, and must be approved by the commissioner	Section 9.3
§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.	§3609.C.3	Any financial instrument filed in satisfaction of the financial responsibility requirements shall be issued by and drawn on a bank or other financial institution authorized under state or federal law to operate in the State of Louisiana.	
§146.84(f)	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.	§3615.C.3	The emergency and remedial response plan (as required by §3623) and the demonstration of financial responsibility (as described by §3609.C must account for the area of review delineated as specified in §3615.B.3.a or the most recently evaluated area of review delineated under §3615.C.2, regardless of whether or not corrective action in the area of review is phased.	Sections 9.3-9.4
§146.85	Financial responsibility			

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.85(a)	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	§3609.C.1	The permit shall require the permittee to maintain financial responsibility and resources to close, plug, and abandon the underground injection wells and, where necessary, related surface facility, and for post-injection site care and site closure in a manner prescribed by the commissioner. Class VI well operators must also comply with §3609.C.4. The permittee must show evidence of financial responsibility to the commissioner by the submission of:	Section 9.3
§146.85(a)(1)	The financial responsibility instrument(s) used must be from the following list of qualifying instruments:	N/A	*** The full language at 40 CFR 146.85(a)(1) will not be adopted since 3609.C.1 introduces the list of the qualifying instruments	
No equivalent federal requirement	No equivalent federal requirement	§3609.C.1.a	a certificate of deposit issued in sole favor of the Office of Conservation in a form prescribed by the commissioner. A certificate of deposit may not be withdrawn, canceled, rolled over or amended in any manner without the approval of the commissioner;	
§146.85(a)(1)(ii)	Surety Bonds.	§3609.C.1.b	a performance bond (surety bond) in sole favor of the Office of Conservation in a form prescribed by the commissioner;	Section 9.2
§146.85(a)(1)(iii)	Letter of Credit.	§3609.C.1.c	a letter-of-credit in sole favor of the Office of Conservation in a form prescribed by the commissioner;	
§146.85(a)(1)(i)	Trust Funds.	§3609.C.1.d	site-specific trust account, or	
§146.85(a)(1)(vii)	Any other instrument(s) satisfactory to the Director.	§3609.C.1.e	any other instrument of financial assurance acceptable to the commissioner.	Section 9.2
§146.85(a)(2)	The qualifying instrument(s) must be sufficient to cover the cost of:	§3609.C.4.a	Qualifying financial responsibility instruments must be sufficient to cover the cost of meeting the requirements of:	
§146.85(a)(2)(i)	Corrective action (that meets the requirements of § 146.84);	§3609.C.4.a.i.(a)	corrective action of §3615.C;	Section 9.4
§146.85(a)(2)(ii)	Injection well plugging (that meets the requirements of § 146.92);	§3609.C.4.a.i.(b)	injection well plugging of §3631;	Section 9.5.1
§146.85(a)(2)(iii)	Post injection site care and site closure (that meets the requirements of § 146.93); and	§3609.C.4.a.i.(c)	post-injection site care and site closure of §3633; and	Section 9.6
§146.85(a)(2)(iv)	Emergency and remedial response (that meets the requirements of § 146.94).	§3609.C.4.a.i.(d)	emergency and remedial response of §3623.	Section 9.7
§146.85(a)(3)	The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	§3609.C.4.b	Financial responsibility instruments must be sufficient to address endangerment of underground sources of drinking water.	Section 9.2
§146.85(a)(4)	The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.		Qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of	

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§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.	§3609.C.4.c	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:	Section 9.8
§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.	§3609.C.4.c.i	cancellation: 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 commissioner. The cancellation must not be final for 120 days after receipt of 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 commissioner;	Section 9.8
§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.	§3609.C.4.c.ii	renewal: 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;	Section 9.8
§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.	§3609.C.4.c.iii	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 commissioner deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the commissioner or a 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.	Section 9.8

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§146.85(a)(5)	The qualifying financial responsibility instrument(s) must be approved by the Director.	§3609.C.4.d	Qualifying financial responsibility instruments must be approved by the commissioner:	
§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).	§3609.C.4.d.i	the commissioner shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project before issuing any authorization to begin geologic sequestration of carbon dioxide in a Class VI well;	
§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.	§3609.C.4.d.ii	the owner or operator must provide any updated information related to their financial responsibility instrument(s) annually and if there are any changes, the commissioner must evaluate the financial responsibility demonstration to confirm that the instrument(s) used remain adequate. The owner or operator must maintain financial responsibility requirements regardless of the status of the commissioner's review of the financial responsibility demonstration;	Section 9.2
§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.	§3609.C.4.d.iii	the commissioner may disapprove the use of a financial instrument if he determines it is not sufficient to meet the financial responsibility requirements.	
§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.	§3609.C.4.e	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.	§3609.C.4.e.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, for example trust funds, certificates of deposit, surety bonds guaranteeing payment into a trust fund, and letters of credit. 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.	
§146.85(b)(1)	The owner or operator must maintain financial responsibility and resources until:	§3609.C.4.f	The requirement to maintain adequate financial responsibility and resources is directly enforceable NATURAL RESOURCES Louisiana Administrative Code September 2022 158 regardless of whether the requirement is a condition of the permit. 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	§3609.C.4.f.i	the commissioner receives and approves the completed post-injection site care and site closure plan; and	

REQUIREMENTS MATRIX EVERGREEN SEQUESTRATION HUB

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.85(b)(1)(ii)	The Director approves site closure.	§3609.C.4.f.ii	the commissioner approves site closure.	
§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.	§3609.C.4.h	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:	Sections 9.4 - 9.7
§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.	§3609.C.4.h.i	the cost estimate must be performed for each phase separately and must be based on the costs to the Office of Conservation of contracting 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;	Sections 9.4 - 9.7
§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).	§3609.C.4.h.ii	during the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days before the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the commissioner. The owner or operator must also provide the commissioner written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan, the injection well plugging plan, the post-injection site care and site closure plan, and the emergency and remedial response plan;	Section 9.8
§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.	§3609.C.4.h.iii	the commissioner 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 commissioner has approved the request to modify the area of review and corrective action plan, the injection well plugging plan, the post-injection site care and site closure plan, and the emergency and response plan, if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the commissioner. Any decrease to the value of the financial assurance instrument must first be approved by the commissioner. The revised cost estimate must be adjusted for inflation as specified at §3609.C.4.h.ii. above;	

REQUIREMENTS MATRIX EVERGREEN SEQUESTRATION HUB

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§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.	§3609.C.4.h.iv	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 commissioner, 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 commissioner.	
§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.	§3609.C.4.i	The owner or operator must notify the commissioner 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.	§3609.C.4.i.i	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 commissioner 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.	N/A	*** Will not be adopted. A corporate guarantee will not be an accepted form of financial assurance	
§146.85(e)	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).	§3609.C.4.j	The owner or operator must provide the commissioner with an adjustment of the cost estimate within 60 days of notification by the commissioner, if the commissioner 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, injection well plugging, post injection site care and site closure, and emergency and remedial response	
§146.85(f)	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	§3609.C.4.k	The commissioner must approve the use and length of pay-in-periods for trust funds or escrow accounts.	



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 0 – INTRODUCTION

February 2024



SECTION 0 – INTRODUCTION

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Project Overview

By 2050, the world needs to capture and store more than 1.2 gigaton per year (GT/yr) of CO₂ to meet the Sustainable Development Scenario plan outlined by the International Energy Agency (IEA).¹ To meet these climate goals, real projects and investments are paramount—such as carbon capture, which is becoming an essential addition to industrial processes emitting CO₂ into the atmosphere.² Large-scale capture of anthropogenic CO₂ is increasingly viewed as critical for the United States and the global community to meet ambitious goals for greenhouse gas reductions by companies, states, and national governments. The IEA states that, in 2021, injection slightly exceeded 40 million metric tons per year (MMT/yr) of captured CO₂ worldwide.³

Trace Carbon Solutions, LLC (Trace) is focused on developing carbon capture and sequestration (CCS) projects across North America and the midstream infrastructure required to service these projects. Trace's team has a proven track record of success and decades of experience developing large-scale upstream and midstream assets. The Trace team leverages their project development expertise and industry relationships to commercialize, construct, and operate assets across all phases of the CCS value chain. The track record of the Trace team is driven by our ability to provide excellent customer service while operating in a safe and environmentally conscious manner.

Evergreen Sequestration Hub, LLC (Evergreen), a fully owned subsidiary of Trace, and Molpus Woodlands Group (Molpus) have signed a servitude agreement providing Evergreen with exclusive rights to develop and operate a carbon sequestration site called the Evergreen Sequestration Hub (Evergreen Hub). The Evergreen Hub is located on approximately 20,000 acres in Calcasieu and Beauregard Parishes in Louisiana. Evergreen will use the site to permanently sequester industrial CO₂ in underground geologic formations, while Molpus will continue to manage the aboveground acreage as a sustainably managed working forest.

This project is designed to accommodate such geologic sequestration of anthropogenic CO₂ emissions. Located in proximity to both natural gas pipelines and industrial emitters, this project will serve as an ideal location to safely store CO₂ in the deep saline aquifers of the Gulf Coast region. The Evergreen Hub is located within 50 miles (mi) of significant industrial emissions, exceeding 70 MMT/yr. These emissions are mostly concentrated in industrial corridors surrounding Lake Charles, Louisiana (approximately 25 mi from the Evergreen Hub) and the cities of Beaumont and Port Arthur, Texas (approximately 35-40 mi from the Evergreen Hub). The Trace team is currently in talks with several emitters in the region. This phase of the project is intended to permanently sequester a combined [REDACTED] of CO₂ in two injection wells, for a total of approximately [REDACTED] over the project's life.

¹ IEA. Carbon Capture, Utilisation and Storage - Energy System. <https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage> (accessed January 2024).

² Trace Midstream. About Us: News. <https://tracemidstream.com/news> (accessed January 2024).

³ IEA. Carbon Capture. <https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage> (accessed January 2024).

The extensive screening process undertaken for the Evergreen Hub resulted in a location that meets Underground Injection Control (UIC) Program requirements with minimal existing wellbores, an injection interval with high quality storage capacity, substantial sealing zones, and minimal environmental impact to the sensitive coastal zones. The approximately 20,000-acre pore space servitude underlying the Evergreen Hub is located entirely on privately owned lands that are primarily used for sustainable forest management—with no residences, schools, hospitals, or incorporated areas within its boundary. The Evergreen Hub falls outside the Louisiana Coastal Zone Boundary, and contains no active oil and gas wells on its surface or subsurface footprint. The modeled CO₂ plume and area of review (AOR) fall entirely within the outer boundary of the proposed project acreage.

This permit application is for drilling, completing, operating, and monitoring two Class VI CCS wells, Loblolly CCS No. 001 and Loblolly CCS No. 002, located in Beauregard Parish, Louisiana. Additional injection wells may be pursued in the future to increase CO₂ injection into the Evergreen Hub area (Figure 0-1). The planned injection wells are designed to meet the requirements of American Petroleum Institute (API) 1171, along with the regulatory requirements outlined in Statewide Order (SWO) 29-N-6 [Title 40, US Code of Federal Regulations (40 CFR) §146(h)].

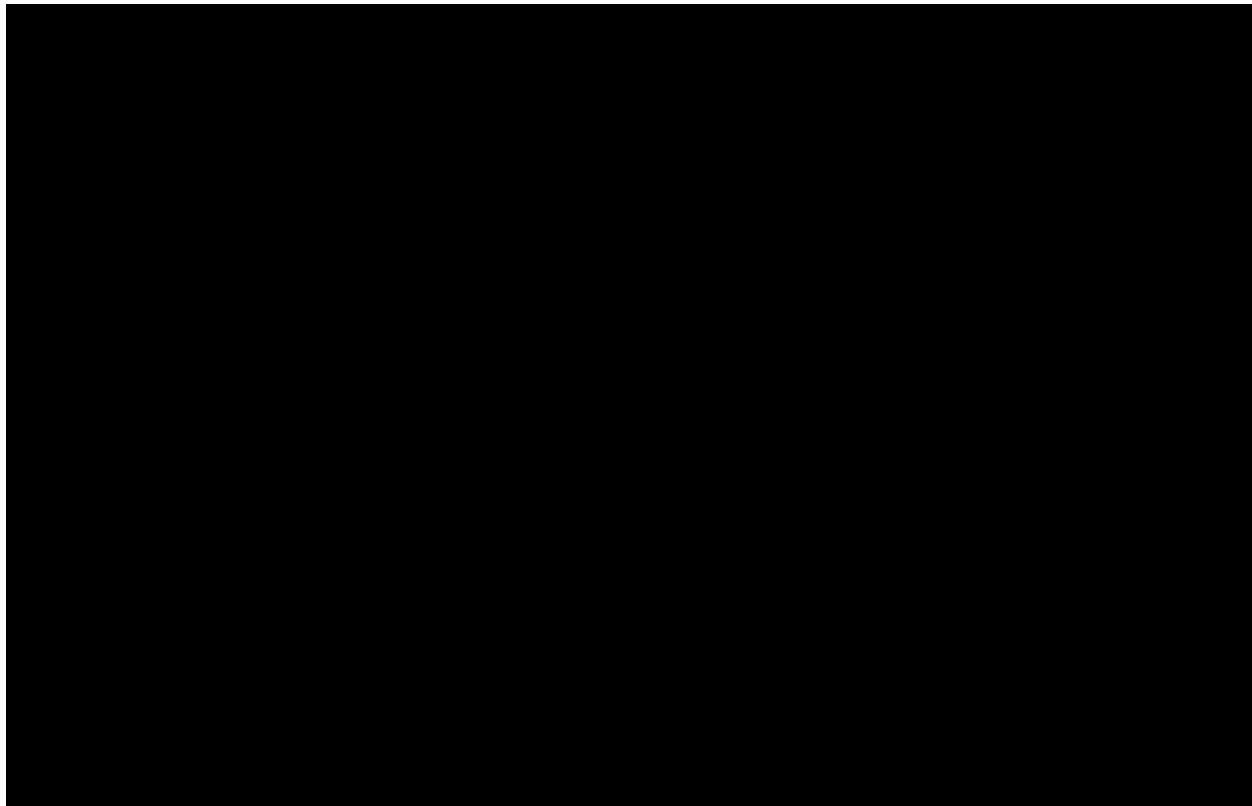


Figure 0-1 – Project Overview Map

The injection wells will be used to store CO₂ in the sand-rich Frio Formation. These sand beds were deposited in sequences with alternating, interbedded shales that offer vertical compartmentalization of the injection horizons. These sand and shale sequences are Oligocene in age and found predominantly throughout the Gulf Coast of Texas, Louisiana, and Mississippi. These saline reservoirs have tremendous storage capacity due to the high rock porosity and vertical thickness of the reservoir. That, coupled with the extremely favorable permeability, allow for the safe injection of CO₂ well below the Underground Sources of Drinking Water (USDWs). The Anahuac Shale acts as the upper confining zone (UCZ) for this project and as a very thick regional shale member that will serve as a permanent seal to prevent migration of CO₂ into shallower reservoirs.

By injecting [REDACTED] of CO₂, Evergreen supports the world's carbon-reduction efforts by removing the equivalent of [REDACTED] gasoline-powered passenger vehicles each year.⁴

Project Key Attributes

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

Pore Space Agreement Discussion

⁴ EPA. Greenhouse Gas Equivalencies Calculator. <https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator> (accessed January 2024).

[REDACTED]

-4.

Proposed CO₂ Sequestration System Discussion

The Evergreen Hub will access supercritical CO₂ from a pipeline to be located near the project. Because the delivery pressure of the CO₂ pipeline is expected to be sufficient to facilitate injection, the surface facility for this project is expected to be minimal. Flow-line distribution infrastructure to the wells will be installed, and compression, treating, and dehydration equipment will also be installed as needed.

Injectate Information

The injectate stream will be delivered from the source to the Evergreen Sequestration site through a newly constructed transportation pipeline, conforming to required pipeline specifications. [REDACTED]

Table 0-1 – Permit Injectate Major Components

Surface Facility Details

The Evergreen Hub will ultimately be a multi-well hub for sequestration of CO₂. The facilities will be made up of well sites for both injection and monitoring, and gathering lines delivering dense-phase CO₂ to the wells. The project is intended to receive CO₂ in excess of the required pressure for injection, hence no additional pumps or compression will be required on-site. The facility will have a full suite of Supervisory Control and Data Acquisition (SCADA) system, to remotely capture and monitor the site for the necessary data to operate and monitor the activities associated with the project (rate, mass, pressure, etc.)

Site Suitability

The proposed project’s surface location was selected to ensure that the CO₂ plume remains contained within the controlled pore space and avoids critical interaction with subsurface geologic features found in the vicinity of the project. Figure 0-2 shows an aerial view of the surface site for the Evergreen Hub.

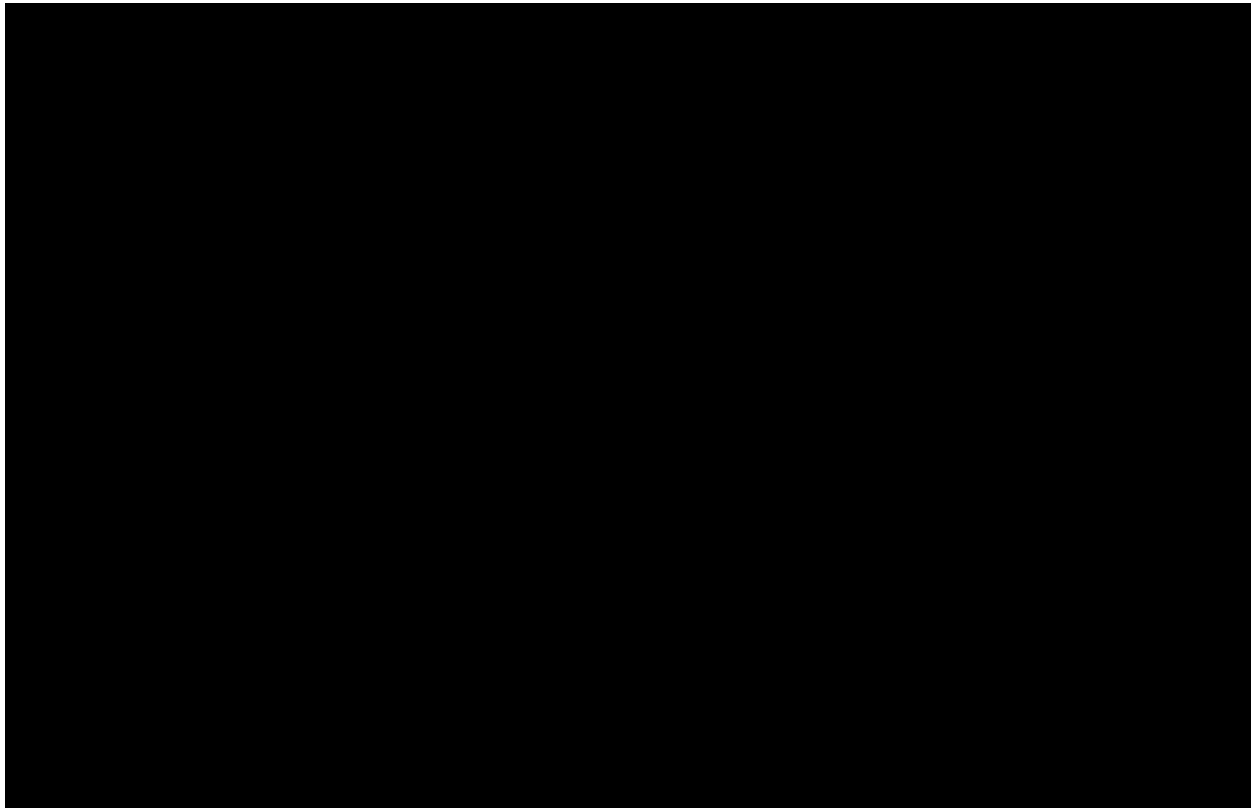


Figure 0-2 – Aerial Map of Evergreen Sequestration Hub

In compliance with regulations, an evaluation of the proposed site (“Site Suitability”) assessed factors including:

- Location of the proposed project site
- Consideration of the project area relative to federal sites/buildings/facilities, etc.
- Endangered species research
- Flood zone
- Existing infrastructure, surface, and subsurface mines or quarries
- Any existing faults or fractures in the project area based on seismic analysis and geophysical well log characterization
- State or federal subsurface cleanup sites within the project area
- Environmental justice considerations
- Artificial penetrations in the project area
- Drinking water in the project area
- Any other site-related issues

The results of this site assessment make up the content of this permit application.

Summary

The Evergreen Hub is designed to have two initial Class VI injection wells storing a combined [REDACTED] of CO₂ safely in the saline-filled Frio sands of the Gulf Coast region. Over the life of the project, approximately [REDACTED] of CO₂ will be permanently stored well beneath the USDW in Beauregard and Calcasieu Parishes, Louisiana.

This permit application includes a detailed assessment of the overall geologic environment (*Section 1 – Site Characterization*) and the resulting plume model and simulation results (*Section 2 – Plume Model*) used to determine the areal extent of the plume and the resulting AOR. As detailed in *Section 3 – Area of Review and Corrective Action Plan*, the AOR for the Evergreen Hub has five existing artificial penetrations that will require corrective action. Four of those will be converted to monitoring wells, thereby further reducing the environmental impact of this project. Well design and construction plans that take into consideration the needs of the project, modeling results, and requirements to ensure the protection of the USDWs are detailed in *Section 4 – Engineering Design and Operating Strategy*.

To ensure that the CO₂ plume is being monitored during the project's life, a detailed Testing and Monitoring Plan is provided in *Section 5 – Testing and Monitoring Plan*. The plan consists of (1) three above-confining-zone monitoring wells, (2) three USDW monitoring wells, (3) the use of permanently installed pressure gauges on the injection well to directly monitor the reservoir pressure over the life of the project, and (4) [REDACTED] the growth of the CO₂ plume during the life of the project.

The proposed Evergreen Hub therefore addresses all the requirements for Class VI sequestration wells. This project is ideally located near emitters and natural gas pipelines, to sequester significant amounts of CO₂ with minimal impact to the surface and surrounding communities.

Higher-resolution versions of the following maps are found in *Appendix A*:

- Appendix A-1 Project Overview Map
- Appendix A-2 Project Overview Aerial Map
- Appendix A-3 Well Plats
- Appendix A-4 Pore Space Owner – Landowner Map
- Appendix A-5 Pore Space Owner – Landowner List
- Appendix A-6 Project Topographic Map

Required Administrative Information

General Application Information

Injection Well Information:

Well Name and Number	Loblolly CCS No. 001
Parish	Beauregard Parish
Location	Section 34, Township 7S, Range 12W
Latitude	30° 24' 32.74" N (NAD27 (DMS))
Longitude	93° 35' 15.43" W (NAD27 (DMS))

*NAD27 – North American Datum of 1927 | Degree, Minutes, Seconds (DMS)

Well Name and Number	Loblolly CCS No. 002
Parish	Beauregard Parish
Location	Section 35, Township 7S, Range 12W
Latitude	30° 24' 29.75" N (NAD27 (DMS))
Longitude	93° 34' 6.83" W (NAD27 (DMS))

Applicant:

Name	Evergreen Sequestration Hub, LLC
Address	840 Gessner Suite 530 Houston, TX 77024

Facility contacts



Ownership Status	Limited Liability Company

Entity Status	Private

Standard Industrial Classification (SIC) Codes:

- [REDACTED]
- [REDACTED]

This facility is not located on federal or tribal lands, and it is not located on state water bottoms or other lands owned by or under the jurisdiction or protection of the state of Louisiana.

Additional Permits

Table 0-2 – Additional Required Permits

Agency	Permit and Authorization	Anticipated Filing Date	Anticipated Receipt Date	Status
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

[REDACTED]



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 1 – SITE CHARACTERIZATION

February 2024



SECTION 1 – SITE CHARACTERIZATION

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1.1. Overview

This site characterization for the Evergreen Sequestration Hub (Evergreen Hub) project was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3607.C.1.b, §3607.C.2.a, §3607.C.2.b, and §3607.C.2.c** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(3)**]. This section describes the regional and site geology for the proposed location. The site characterization incorporates analysis from multiple data types from public, proprietary, and licensed data sets, including well logs, 3D seismic surveys, academic and professional publications, and core-sample analyses.

1.2. Regional Geology

The Gulf of Mexico (GOM) basin covers nearly 1,500,000 square kilometers (km), spanning from northern Mexico to western Florida. The location of the proposed Evergreen Hub project is projected onto the bounds of the GOM basin in Figure 1-1. Sedimentation in the basin is recorded from the Triassic period of the Mesozoic era to the Holocene, in deposits up to 20 km thick. A generalized stratigraphic column of the northern GOM basin is provided in Figure 1-2 (page 8).

After rifting during the Mesozoic Period broke apart Pangea, the crust and seabed were extended and expanded, resulting in the formation of the GOM basin (Galloway, 2008). The structural opening of the basin was aided by northwest-southeast trending transfer faults, which influenced rates of subsidence and salt distribution (Galloway, 2008). Triassic red beds of clastic infill of rift-formed grabens comprise the Eagle Mills Formation, the earliest sediment in the GOM basin. Throughout the middle Jurassic period, a thick evaporate deposit, consisting mainly of halite, was precipitated along the shallow gulf margins. This evaporitic sequence is known as the Louann Salt, a primary source of structural features within the GOM basin today. Where the Eagle Mills Formation is absent, the Louann Salt is deposited directly on pre-Cambrian igneous basement rock.

Post-Louann Salt precipitation, the siliciclastic-dominated Norphlet Formation was deposited over the northern and northwestern GOM margins. Subsidence and rimming carbonate platforms dominated the remainder of the Jurassic and Early Cretaceous, creating the outline of the present-day GOM basin (Galloway, 2008). The basin continued to increase in depth until the beginning of the Eocene epoch, nearly 60 million years ago. The Cenozoic depositional episodes originate from mainland North American basins, transported by fluvial-deltaic systems (Galloway, 2008). These deposits reflect phases of eustatic change and sediment supply.

Major structures that influenced the Louann Salt were the Ouachita and Appalachian Mountain ranges, the Llano uplift, and structural flexures—such as the Balcones, Luling-Mexia-Talco, and Pickins-Gilberton fault zones. Rapid sediment loading atop a thick salt substrate, combined with basin subsidence, initiated significant gravity tectonics. The structures resulting from these tectonics produced six types of features: salt welds, salt diapirs, allochthonous salt bodies, salt-

based detachment faults, growth-faults, and basin-floor compressional fold belts (Galloway, 2008). These structures define the GOM basin.

A basin-scale, regional, dip-oriented cross section from north to south across the GOM basin's northern margin with the projected location of the Evergreen Hub is provided in Figure 1-3 (page 9). The location of this cross section is denoted by a red line in Figure 1-1, with a red star indicating the proposed project location. Generalized stratigraphic, structural, crustal, and salt features illustrate the present-day structure of the GOM basin.

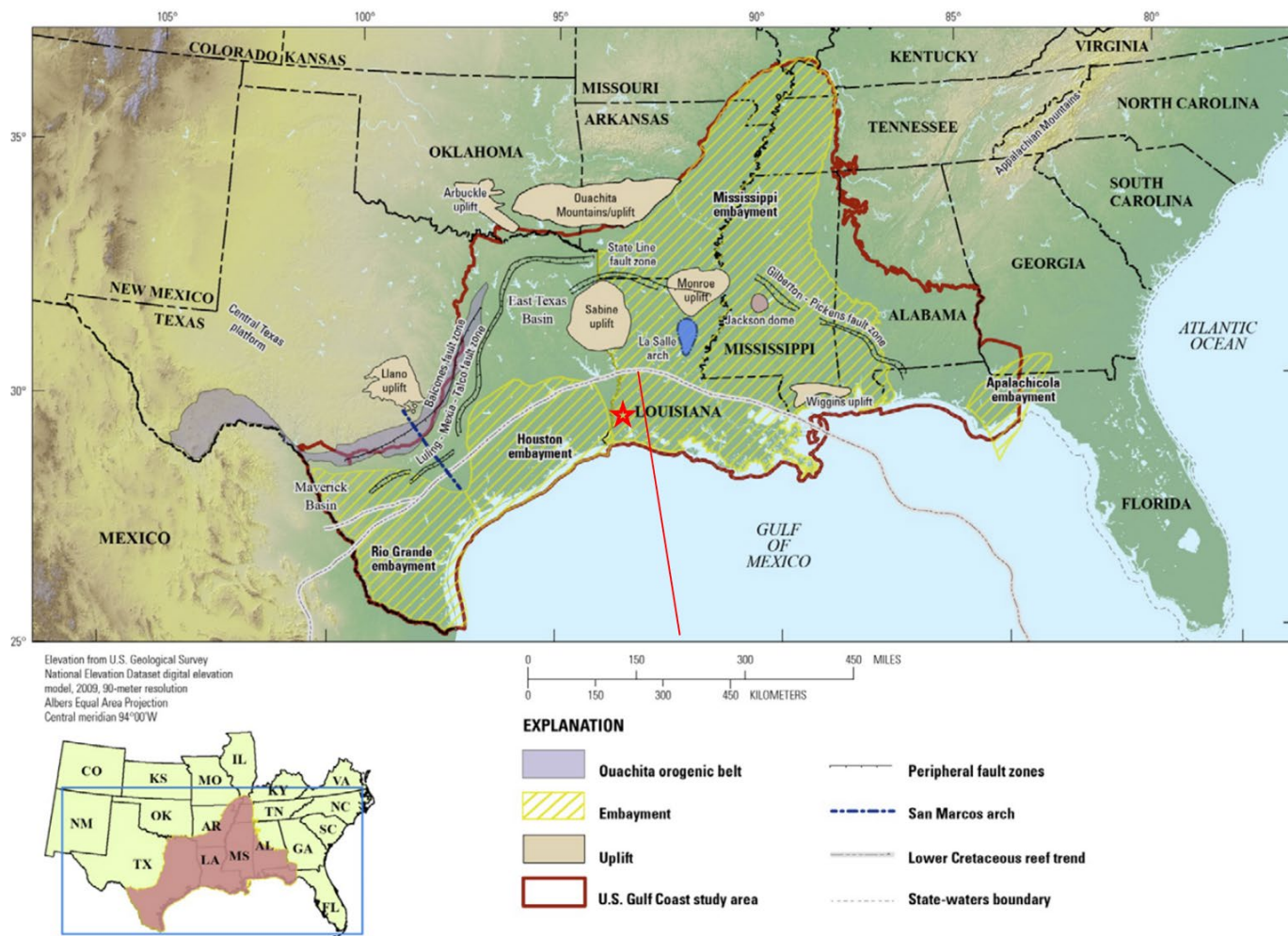


Figure 1-1 – Geologic map of the Gulf of Mexico basin and major structural features, with the red star indicating the proposed Evergreen Hub location (modified from Roberts-Ashby et al., 2012).

SYSTEM	SERIES	STAGE	GROUP OR FORMATION		
QUAT.	HOLO.				
	PLEI.	unnamed upper-middle Calabrian Gelasian	Undifferentiated		
TERTIARY	NEOGENE	Pliocene	Piacenzian Zanclean	Undifferentiated	
		Miocene	Messinian Tortonian Serravallian Langhian Burdigalian Aquitanian	Fleming	
	PALEOGENE	Oligocene	Chattian	Catahoula (Hackberry) Anahuac Frio	
			Rupelian	Vicksburg	
			Priabonian	Jackson	
	Eocene	Bartonian Lutetian	Claiborne	Sparta Sand Cane River Carrizo Sand	
		Ypresian	Wilcox		
		Thanetian Selandian Danian	Midway	Naheola	
	CRETACEOUS	UPPER	Maastrichtian	Navarro	Escondido-Olmos McNairy Sand Nacatoch Sand
			Campanian	Taylor	San Miguel- Anacacho/ Annona-Ozan
			Santonian Coniacian	Austin/Tokio/ Eutaw	
			Turonian Cenomanian	Eagle Ford/ Woodbine/Tuscaloosa Washita	
		LOWER	Albian	Fredericksburg	
				Trinity	
Aptian				Sligo (Pettet)	
Barremian Hauterivian			Hosston (Travis Peak)		
Valanginian Berriasian					
			Cotton Valley	Bossier	
JURASSIC	UPPER	Tithonian	Haynesville/ Gilmer		
		Kimmeridgian	Smackover Norphlet		
		Oxfordian			
	MID.	Callovian Bathonian	Louann Salt Werner		
L.	Hettangian				
TRIA.	UP.	Rhaetian Norian Carnian	Eagle Mills		

Figure 1-2 – Stratigraphic Column of the Northern Gulf of Mexico Basin (modified from Warwick, 2022)

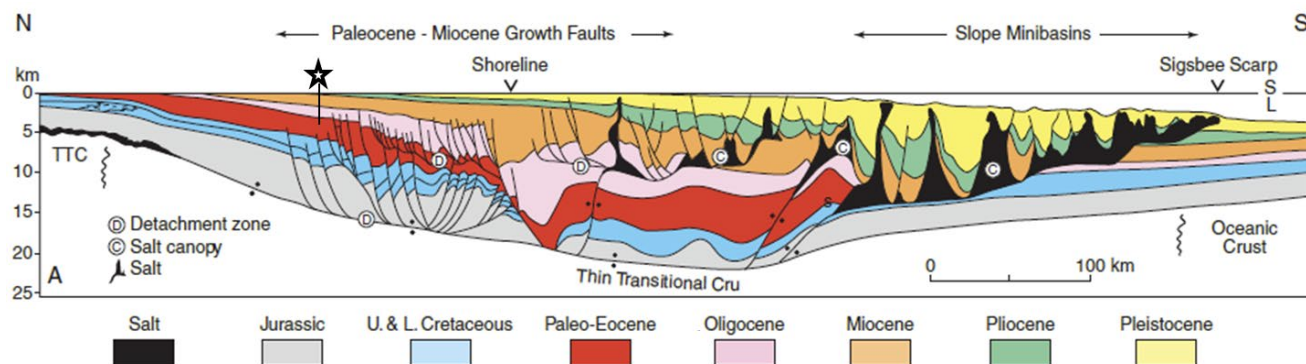


Figure 1-3 – Basin-Scale Cross Section of the Northern Gulf of Mexico Basin (modified from Galloway, 2008)

1.2.1. Major Stratigraphic Units

The major epochs reviewed in this report are the Oligocene and Eocene. The upper confining and injection zones are Oligocene in age. The lower confining zone is comprised of Oligocene and Eocene shales, separable paleontologically but lithologically undifferentiated. These stratigraphic intervals of interest are outlined in red in Figure 1-4.

PERIOD	EPOCH	AGE	Rio Grande embayment San Marcos arch East Texas basin (Texas)	Southeast Texas South Louisiana and offshore (Texas & Louisiana)	Southeast Mississippi Southwest Alabama West Florida panhandle and offshore
TERTIARY	QUAT.	HOLOC.	— — — — —	— — — — —	— — — — —
		PLEIS.	Calabrian	Undifferentiated	Undifferentiated
	NEOGENE	Pliocene	Piacenzian	Undifferentiated	Undifferentiated
		Zanclean	Undifferentiated	Undifferentiated	Undifferentiated
	NEOGENE	Miocene	Messinian Tortonian Serravallian Langhian Burdigalian Aquitainian	Goliad Fm. Lagarto Fm. Fleming Fm. Oakville Sandstone	Pascagoula Fm. Hattiesburg/Pensacola Fms. Catahoula Fm.
		Oligocene	Chattian	Catahoula/ Frio Fms.	Paynes Hammock Fm. Chickasawhay Fm.
	PALEOGENE	Rupelian	Vicksburg Gp.	Vicksburg Gp.	Vicksburg Gp.
		Priabonian	Jackson Gp.	Jackson Gp.	Jackson Gp.
	PALEOGENE	Eocene	Bartonian Lutetian	Claiborne Gp.	Claiborne Gp.
		Ypresian	Wilcox Gp.	Wilcox Gp.	Wilcox Gp.
	PAL.	Thanetian Selandian Danian	Midway Gp.	Midway Gp.	Midway Gp.

Figure 1-4 – Tertiary and Younger Stratigraphic Section of the Northern Gulf of Mexico Basin (modified from Swanson et al., 2013)

Upper Confining Zone – Anahuac Shale

The Oligocene-age Anahuac Formation (Anahuac Shale) conformably overlies the Frio Formation sandstones and marks the boundary between Oligocene- and Miocene-age sediments. The Anahuac Shale is comprised of fine-grained, open-marine sediment deposited across the GOM margin extent, approximately 75 miles (mi) inland from the current coastline at the Texas-Louisiana border (Galloway et al., 2000). The transgressive marine Anahuac Shale consists of light to dark green and gray calcareous shale interbedded with thin beds of locally calcareous sandstones and limestones.

Transgressive shales such as the Anahuac Shale tend to be regionally extensive, allowing them to act as regional sealing units between episodes of regressive deposition (Galloway et al., 2000; Roberts-Ashby et al., 2012). The Anahuac Shale, which thickens basin-ward, is identified by the US Geological Survey (USGS) Frio and Vicksburg Formations Storage Assessment Unit (SAU) C50470122 as “a robust top-seal for prospective CO₂ storage.” The Anahuac Shale was therefore selected as the upper confining zone (UCZ) of the Evergreen Hub project—supported by several published studies referenced within this application—due to its regional extent, thickness, and sealing capability (Hovorka et al., 2003; McGuire, 2009; Roberts-Ashby et al., 2012; Sakurai et al., 2006).

Injection Zone – Frio Sands

The Frio Formation represents one of the major Tertiary progradational wedges deposited along the Gulf Coast. During Oligocene time, the Texas coastal plain experienced a massive influx of sediment from Mexico and the southwestern United States due to an increase in volcanism, regional uplift, and erosion to the west. The unique depositional setting resulted in the distribution of volcanoclastics, recycled sedimentary material, and reworked ash along the western and central portions of the GOM. These Oligocene sediments were transported to the basin via the Rio Grande, Chita/Corrigan, and Gueydan fluvial systems, and tend to accumulate along four primary dispersal axes: the Norma, Norias, Houston, and central Mississippi deltas (Hovorka et al., 2003; Swanson et al., 2013).

Sediment was subsequently reworked by wave action and transported from deltaic headlands to interdeltic embayments, resulting in a thick succession of sand-rich, progradational shore-zone systems between primary deltaic deposits (Galloway et al., 2000). Frio sandstones along the upper Texas portion of the Gulf Coast and the southwestern coastal edge of Louisiana are considered mature, with high quartz content.

The Hackberry Trend, located within the Frio Formation in southern Louisiana, is split into two distinct units: an upper section of shale ranging from 100 feet (ft) to 3,000 ft, and a lower section of sandstone nearly 700 ft thick. These two sections form what is called a seaward-thickening wedge. The Hackberry shale section serves as a regional shale bed within the injection zone.

Lower Confining Zone –Vicksburg and Jackson Shales

The lower confining zone (LCZ) consists of the Oligocene Vicksburg and Eocene Jackson section that immediately underlies the proposed Frio injection zone. The section is dominated by fine-grained, deep-water shales deposited along a muddy shelf system during a period of regional transgressive flooding. The section also contains an abundance of interbedded ash beds and volcanogenic sand, which will help improve the sealing capability of the tight shale section (Galloway et al., 2000; Hovorka et al., 2003; Roberts-Ashby et al., 2012).

According to the USGS Hydrogeologic Framework of Southwestern Louisiana (2023), the Vicksburg-Jackson section is considered a “confining unit.” The USGS also selected the Vicksburg-Jackson section as the UCZ for their Yegua and Cockfield Formations SAU C50470121, because it is composed of a “regionally extensive...fine-grained facies” (Roberts-Ashby et al., 2012). The gross Vicksburg-Jackson shale section has a minimum thickness of 2,000 ft within the area of review (AOR), and can reach thicknesses of more than 3,000 ft within the AOR.

1.3. Site Geology

The Evergreen Hub project AOR, as discussed in Section 3, is located in Louisiana, 



Figure 1-5 – Overview Map of Evergreen Hub Area of Review

Evergreen Sequestration Hub, LLC (Evergreen) proposes to augment the interpretations from research conducted over the project area presented in this site characterization, with data gathered from a stratigraphic test well. A list of planned wireline logs during the drilling of the proposed injection wells is provided in Table 1-1, including target well depths, to provide rock and fluid properties specific to this site characterization. Table 1-2 then lists planned coring intervals during drilling operations of the proposed stratigraphic test well to obtain mineralogical, petrophysical, mechanical, and geochemical data specific to this site characterization.

Table 1-1 – Planned Geophysical Wireline Logs

Geophysical Log Suite	Loblolly CCS No. 001 Log Interval		Loblolly No. CCS 002 Log Interval		Use
	Top	Base	Top	Base	
Gyro Survey	████	████	████	████	Directional survey
Gamma Ray	████	████	████	████	Lithology identification
Resistivity	████	████	████	████	Fluid identification
Spontaneous Potential	████	████	████	████	Lithology/indication of permeability
Caliper	████	████	████	████	Borehole breakout direction identification
Sonic/Acoustic	████	████	████	████	Synthetic seismogram tie, rock property identification
Bulk Density/ Density Porosity	████	████	████	████	Rock property identification
Neutron Porosity	████	████	████	████	Rock property identification
Temperature	████	████	████	████	Temperature
Resistivity Imaging	████	████	████	████	Structural Dip Analysis
Ultrasonic Imaging	████	████	████	████	Stress Regime
Magnetic Resonance	████	████	████	████	Storage Potential
Formation Lithology	████	████	████	████	Mineralogy

Table 1-2 – Planned Core Intervals

Interval Top (ft)	Interval Bottom (ft)	Stratigraphic Unit	Zone
████	████	Anahuac Shale	Upper Confining
████	████	Frio Sands	Injection
████	████	Vicksburg-Jackson Shale	Lower Confining

Geological properties and reservoir characteristics of the injection and confining zones are drawn from proprietary, licensed, subscribed, and public data sources, including the Louisiana

Department of Natural Resources (LDNR) Strategic Online Natural Resources Information System (SONRIS), Texas Bureau of Economic Geology (BEG), IHS Enerdeq, Enverus, TGS R360, and published research. Regional data from publications are used to generally describe geologic setting and lithological attributes—and will be supported with offset wellbore and core data when those are available. Well logs from 132 wells—including 67 with Log *American Standard Code for Information Interchange* (ASCII) Standard (LAS) logs, and production data of wellbores proximal to the proposed sequestration project site—provide data from which anticipated geologic conditions are estimated.

The offset wellbore [REDACTED] is the closest one between the proposed injection wells Loblolly CCS No. 001 and Loblolly CCS No. 002. This well, spudded on [REDACTED], was drilled to a total depth (TD) of [REDACTED]. The induction electrical log, run by Schlumberger Well Surveying Corporation, measured spontaneous potential (SP) and resistivity/conductivity over two logging runs, from [REDACTED]

[REDACTED] Table 1-3 lists the depths and associated thicknesses of the upper confining, injection, and lower confining zones as encountered in [REDACTED]. Figure 1-6 displays a stratigraphic column of lithologies, formations, and depths as encountered in the offset well.

Table 1-3 – Formations as Encountered [REDACTED]

System	Group/Formation Name	Injection/Confining	Formation Top-Bottom (ft)	Thickness (ft)
Oligocene	Anahuac Shale	Upper Confining	[REDACTED]	[REDACTED]
Oligocene	Frio	Injection	[REDACTED]	[REDACTED]
Oligocene/Eocene	Vicksburg-Jackson	Lower Confining	[REDACTED]	[REDACTED]

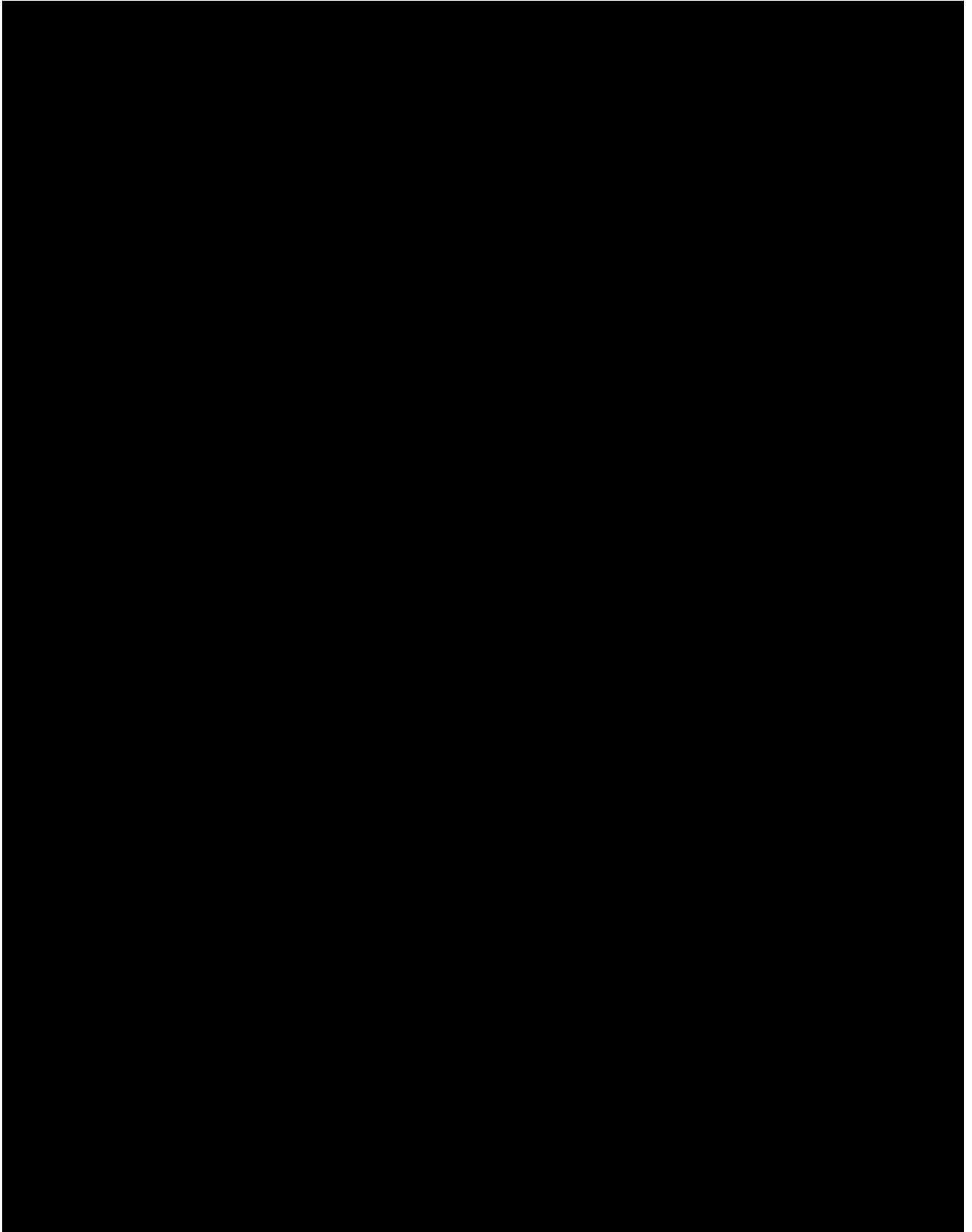


Figure 1-6 – Stratigraphic Column [REDACTED]

1.3.1. Injection Zone

The injection zone is composed of early to late Oligocene sediments of the lower, middle, and upper Frio Formation, including the encompassed Hackberry shale associated with the onset of *Gyroidina scalata*, *Bolivina mexicana*, and *Ammobaculites nummus* foraminifera. The schematic diagram in Figure 1-7 depicts the proposed injection zone relative to the stratigraphic column and foraminiferal horizon markers A1–A5, as published by Swanson et al. (2013).

Figure 1-8 (page 17) relates the Evergreen Hub location to the paleogeographic setting during late Oligocene deposition of the Frio. The proposed well sites are located within the shore zone system, between the Houston and Mississippi delta systems. Galloway et al. (2000) refers to this area as the “Buna barrier/strandplain” and suggest that sediment was supplied by longshore currents from the surrounding Houston and central Mississippi delta complexes (Galloway et al., 2000; Hovorka et al., 2003). Shore-zone and strandplain deposits are associated with reservoir development within the Frio geologic section and are anticipated to represent sandstone facies present at the Evergreen Hub project AOR.

Late Oligocene-age sediments of the upper, middle, and lower Frio Formation are primarily composed of interbedded sandstones, siltstones, and shale. Sandstones within the Frio are typically fine-grained, well-sorted, and tend to fine-upwards. Published literature for the Frio Formation identified regional changes in sand composition moving from the lower to upper Texas Gulf Coast. The sand provenance is shifting from a proximal Mexico volcanic source to a more Appalachian-rich source higher in quartz content. This resulted in the development of more mature sandstones along the upper Texas Gulf Coast, where the Evergreen Hub project is located, with fewer volcanic rock fragments and less feldspar (quartzose feldspathic volcanic litharenite), as portrayed in the Ternary diagram at Figure 1-9 (page 18) (Loucks et al., 1979; Loucks et al., 1986; Galloway et al., 2000; Hovorka et al., 2003). These sandstones share the same sediment source and depositional environment; therefore, mineralogy of the entire injection zone will be similar.

Sandstone intervals of the Frio Formation are interfingering with localized siltstone and shale beds that accumulated between sand wedges during times of relative sea-level increase. Shale intervals within the Frio section are claystones rich in swelling clays, such as smectite, mixed layer illite-smectite, and illite. Kaolinite is also present but in minor amounts. Regional published literature suggests sediments have undergone minimal diagenesis during burial and compaction, due to their quick burial and relatively shallow occurrence (Loucks et al., 1986; Galloway et al., 2000; Hovorka et al., 2003).

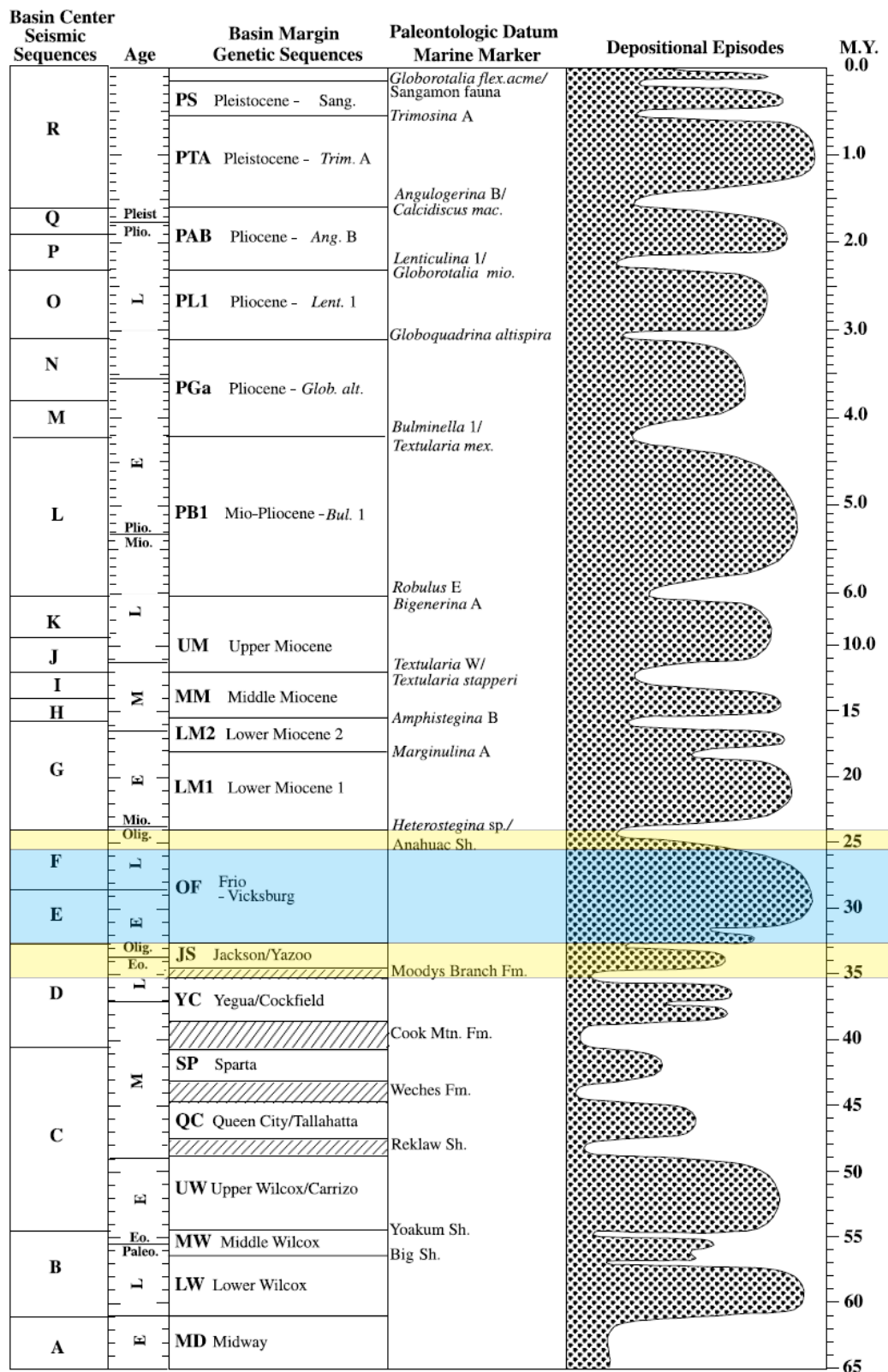


Figure 1-7 – Gulf of Mexico Cenozoic genetic sequences with bounding marine shale units and major paleontologic markers. The proposed injection zone is shaded blue and the gross confining intervals shaded yellow (Galloway et al., 2000).

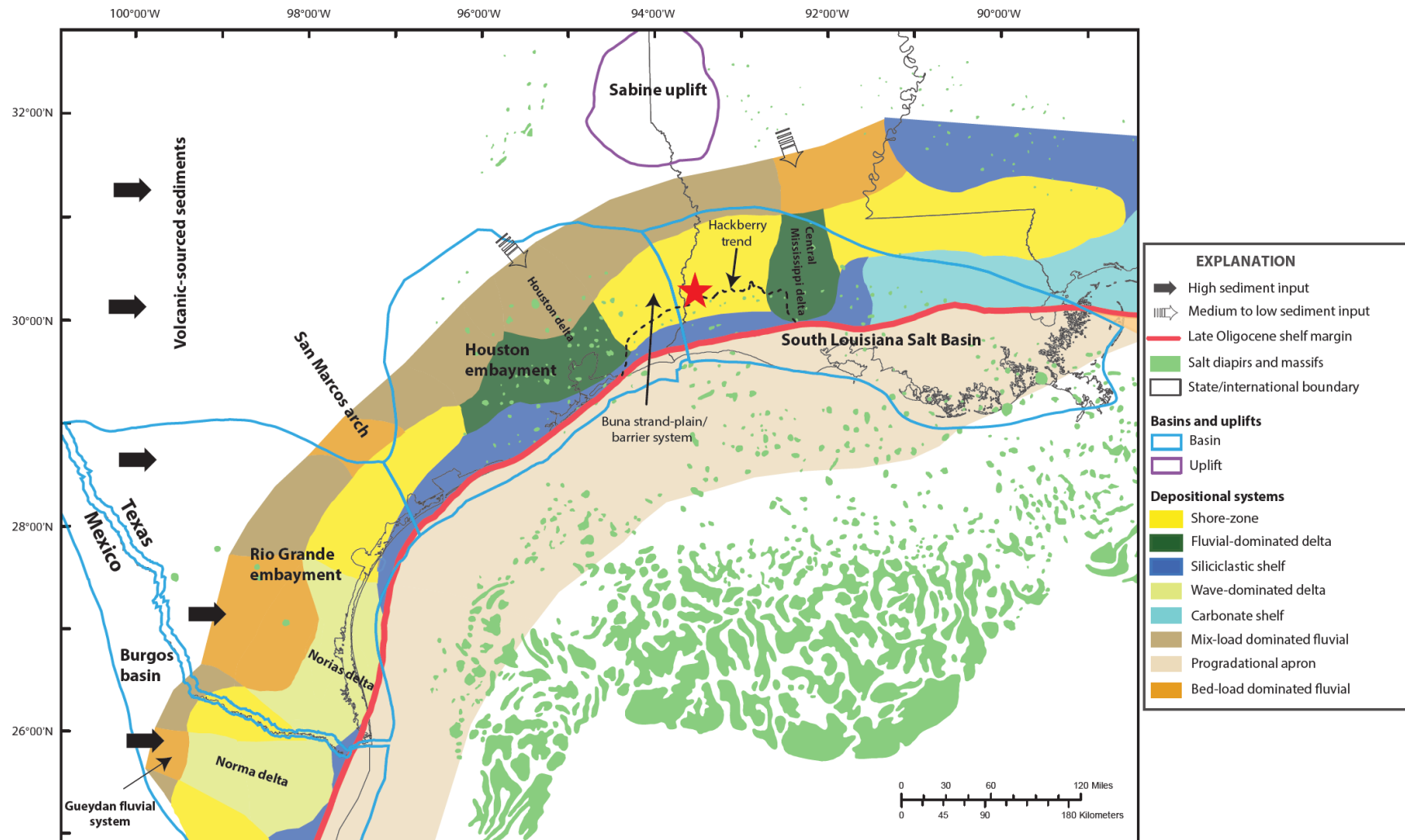


Figure 1-8 – Gulf of Mexico paleogeography and sediment sources during the late Oligocene. The red star represents the approximate location of the Evergreen Hub project (modified from Swanson et al., 2013).

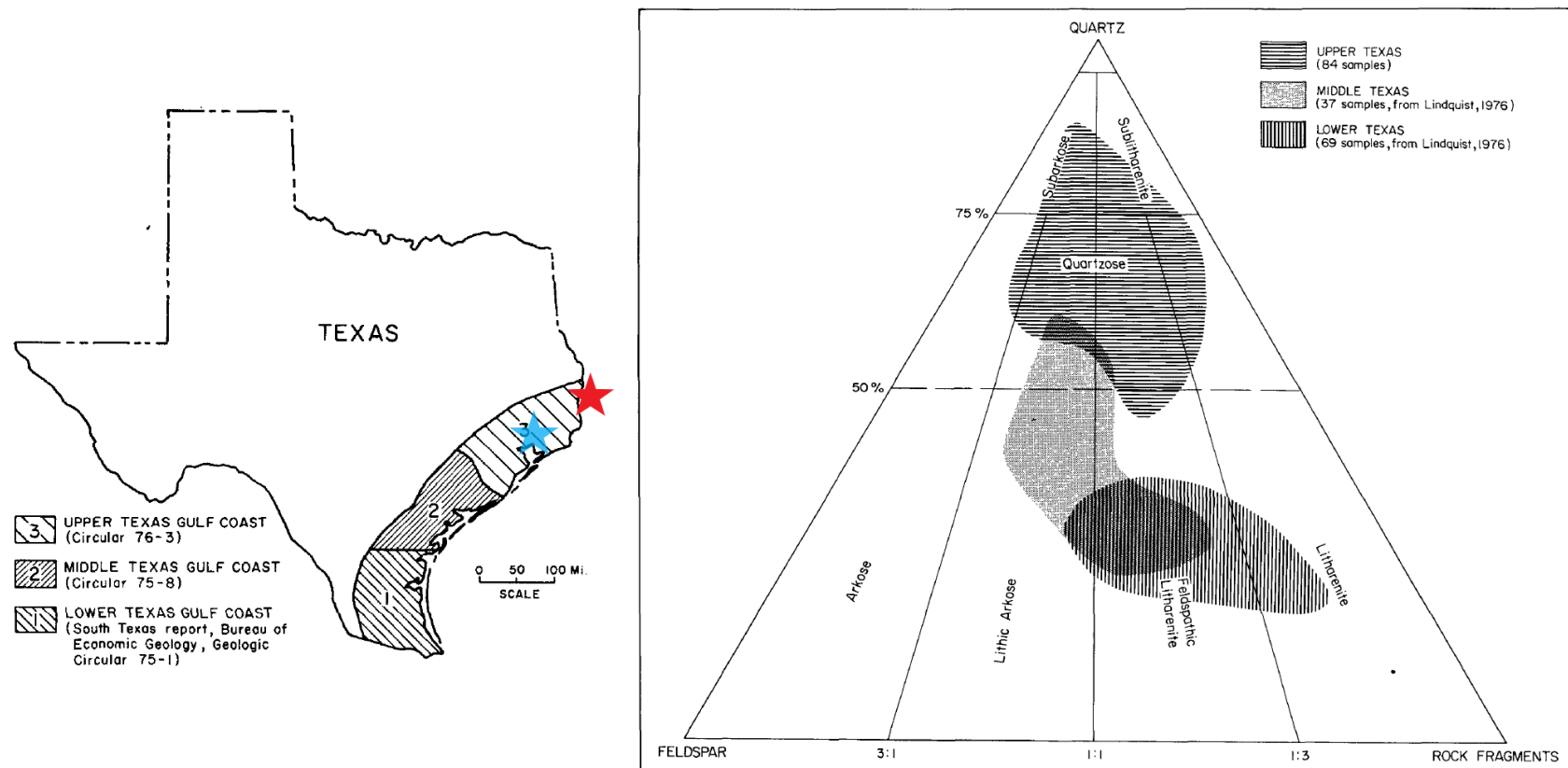


Figure 1-9 – Composition of the Frio sandstone along the Texas Gulf Coast; classification after Folk (1968). The red star represents the approximate location of the Evergreen Hub project, and the blue star represents the approximate location of the BEG Frio Brine Pilot Study (modified from Loucks et al., 1979).

Publicly available core data from the Frio stratigraphic section is limited. However, the Texas BEG released a 2005 study that identified the Frio Formation in Liberty County, Texas, as “an ideal formation and location” for CO₂ sequestration in brine-bearing sandstones. The study took place approximately [REDACTED] west-southwest of the Evergreen Hub project AOR, as was identified by the blue star in Figure 1-9. Both the BEG and Evergreen Hub projects are located within the upper Texas Gulf Coast Frio designation, target the same stratigraphic section, and are present at approximately 5,000 ft (Sakurai et al., 2006).

Three cores were collected from the Frio Brine Pilot Test well (TCEQ No. 5X2500071): one from the Anahuac Shale, and two from the Frio sandstone. Figure 1-10 displays a core photograph (5,050 ft to 5,062 ft) of a Frio sandstone capped by a darker clay-rich Frio shale bed (5,051 ft). The report noted that core recovery was difficult due to the high porosity and permeability contained within reservoir facies, also noted by the apparent lack of recovered material and rubble collected towards the base of the core shown in Figure 1-10. Thin-section analysis of upper Frio sandstones by the BEG determined that the section is “dominantly quartz with about 20% fresh-to-leached orthoclase and plagioclase feldspars and altered rock fragments, trace quantities of micas, calcite, organic materials, pyrite, and minor clays as grain coats and local matrix” (McGuire, 2009; Hovorka et al., 2003).

McGuire (2009) obtained plug and chip samples from the BEG and conducted conventional core analysis, thin-section petrography, scanning electron microscope (SEM) analysis, X-ray diffraction (XRD) analysis, and geochemical analysis of selective Frio facies. All samples were initially collected from the BEG’s Frio Brine Pilot Test well between the depths of 4,880 ft and 5,469 ft. Photomicrographs of Frio sandstone from unknown depths in the Frio Brine Pilot Test well are displayed in Figures 1-11 and 1-12, with blue epoxy signifying the abundant intergranular porosity found within the samples. Figure 1-11 (page 21) is an example of the typical Frio sandstone interpretation for the region, with a mean chemical composition of Q₇₀F₂₄L₆, as determined by McGuire (2009). Figure 1-12 (page 21) labels and identifies dominant detrital grains common within Frio sandstones as quartz (Q), feldspar (F), and volcanic rock fragments (VRF). Table 1-4 (page 22) displays the typical composition of Frio sandstones, as determined by point-count analysis of thin-section samples.

A plot of whole rock XRD obtained from McGuire’s 2009 thesis is provided in Figure 1-13 (page 23). The bulk sample was collected from a depth of 5,075 ft in the BEG’s Frio Brine Pilot Test well, within a Frio sandstone facies. The results are consistent with the point-count analysis conducted in the study, as well as descriptions that the BEG provided in their thin-section analysis.

Frio sandstones at the proposed injection wells of the Evergreen Hub project are anticipated to be composed primarily of quartz, with potassium feldspar (k-feldspar) and plagioclase feldspar forming the bulk of remaining minerals. Accessory minerals include pyrite, calcite, siderite, biotite, and halite. Clays will also be present in variable quantities, the amount of which are estimated with the calculated clay-volume curve (Figure 1-14, page 25). Clay species are anticipated to consist primarily of illite and smectite with minor amounts of kaolinite (McGuire, 2009).

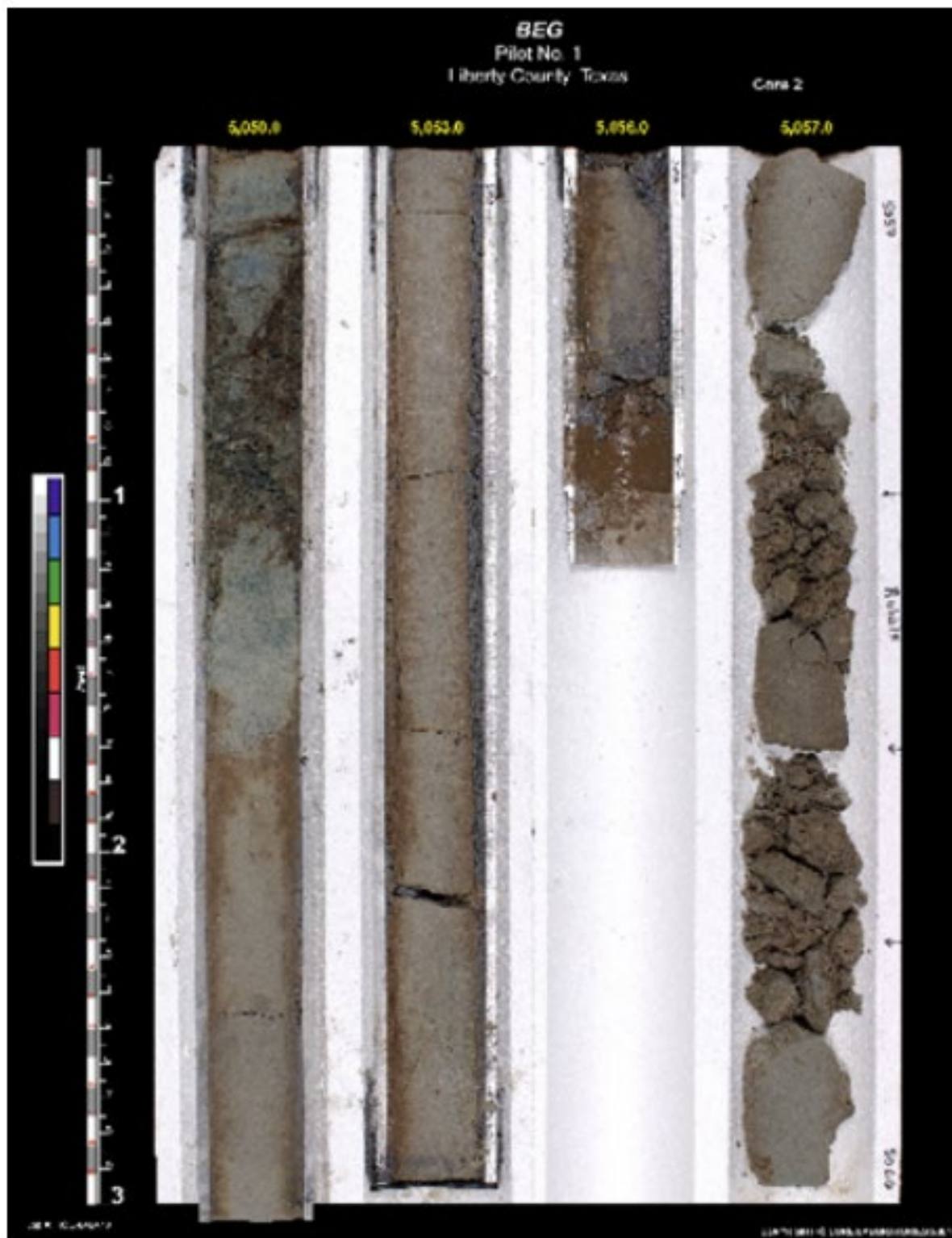


Figure 1-10 – Core Photograph of the Upper Frio Formation, Liberty County, Texas; 5,050–5,062 ft (Sakurai et al., 2006)

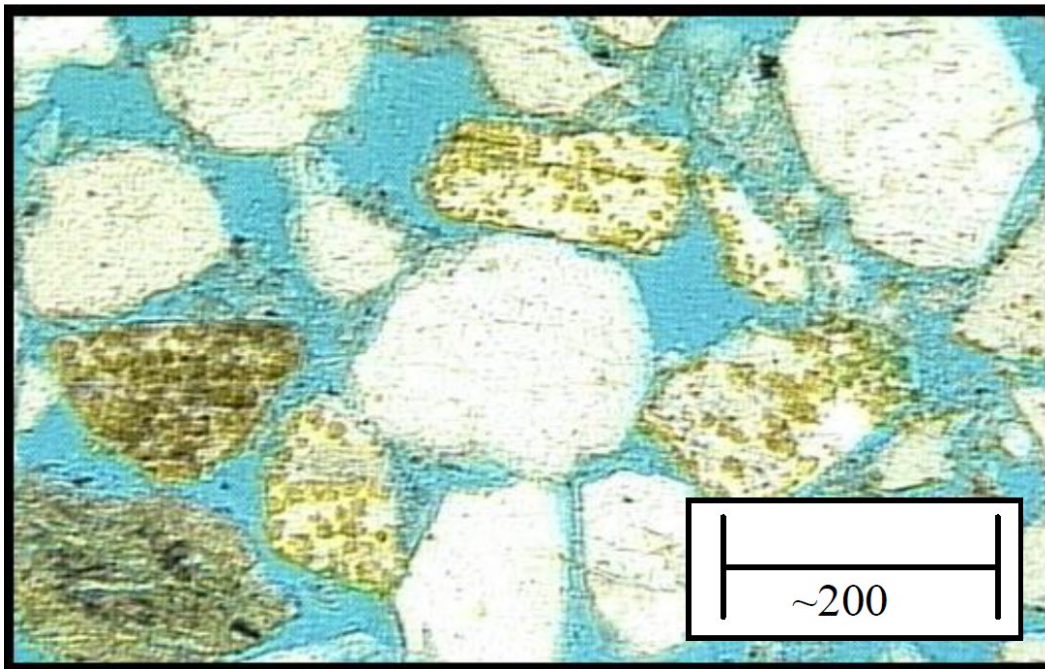


Figure 1-11 – Thin-Section Microphotograph of Frio Formation Sandstone with Mean Composition of $Q_{70}F_{24}L_6$; Liberty County, Texas (modified from McGuire, 2009)

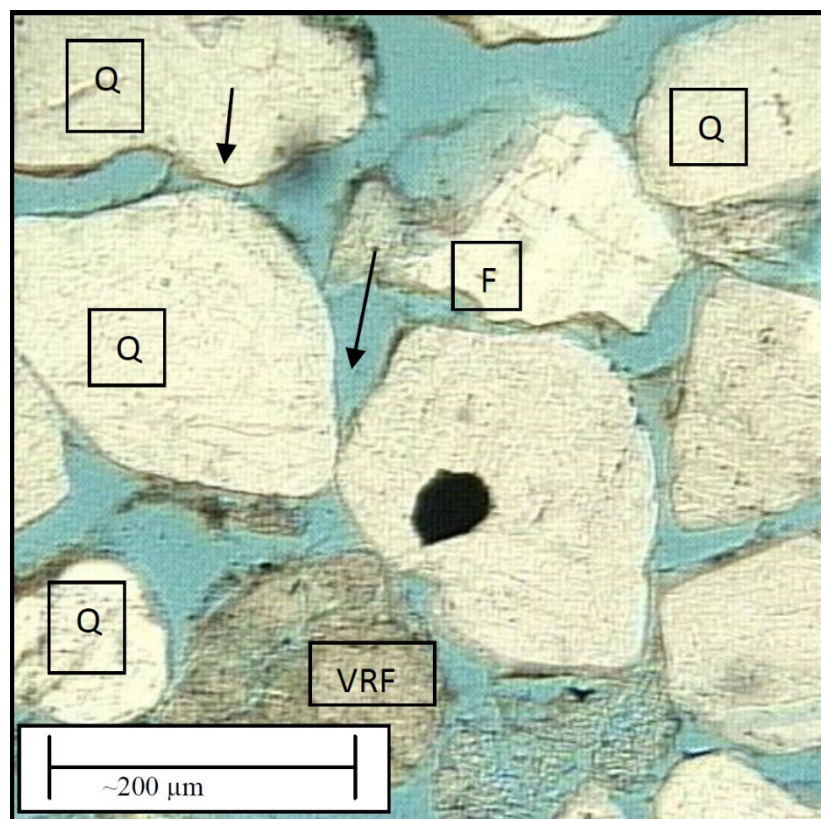


Figure 1-12 – Thin-section microphotograph of Frio Formation sandstone in Liberty County, Texas, displaying dominant detrital grains: quartz (Q), feldspar (F), and volcanic rock fragments (VRF); arrows indicate point contacts (modified from McGuire, 2009).

Table 1-4 – Composition of Frio sandstones, as determined by point-count analysis of thin sections collected from the BEG's Frio Brine Pilot Test well (TCEQ No. 5X2500071) (McGuire, 2009).

Sample	Quartz	K-Feldspar	Rock Fragment	Plagioclase	Other	Pyrite
5051.5	40	0	2	2	0	0
5052.9	34	4	2	8	0	0
5052.9	40	6	2	8	0	0
5054.7	46	3	5	5	0	0
5054.7	49	0	3	5	1	0
5056.4	48	1	7	4	0	0
5061.65	45	13	5	3	0	0
5061.65	42	11	4	1	0	0
5062.4	44	12	3	6	0	0
5062.4	45	19	5	3	1	0
5065.85	47	18	4	1	0	0
5067.85	38	14	2	4	0	0
5069.85	41	12	2	3	0	3
5068.85	40	9	3	9	0	0
5071.75	34	11	4	5	2	0
5071.75	34	8	3	5	2	1
5073.5	38	9	3	5	3	1
5075.5	35	11	5	5	3.25	1.5
5050	3	6	0	1	0	12
5056	42	11	4	5	0	0
5057	38	9	1	7	0	0
Average	39.2	8.9	3.3	4.5	0.6	0.9

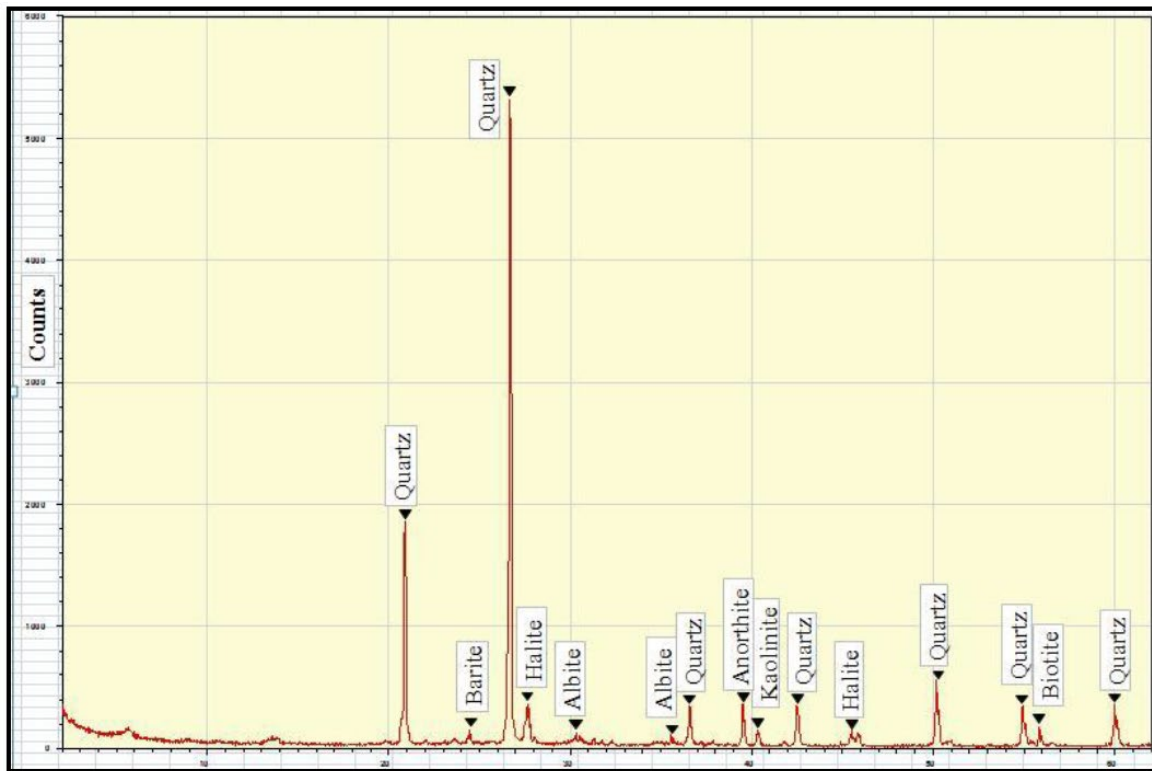


Figure 1-13 – XRD Graph of Frio Bulk Sample from 5,075 ft; Liberty County, Texas (McGuire, 2009)

Frio sandstones that occur within the proposed injection zone of the Evergreen Hub project are composed of mineralogy highly conducive to CO₂ injection. The sedimentological structures and lithological properties observed in the studies above suggest that the Frio Formation contains multiple occurrences of sandstones of high porosity and low cementation, within a gross section more than [REDACTED] thick.

The offset well log [REDACTED] is displayed in Figure 1-14. The VCLAY curve in the left track is a calculated clay volume from an SP log, shaded to represent sand content, and the DEEP RES curve in the right track is the measured deep-resistivity log (40-inch (in.) induction). The injection interval begins at the TOP_FRIO marker and includes all strata to the BASE_FRIO marker. The gross thickness of the injection zone in the well is [REDACTED]. Within the gross interval, approximately [REDACTED] is targeted for injection.

Published literature and offset log data acknowledge the presence of interbedded claystones and shales that may act as baffles or seals within the injection zone. Named as an example is the Hackberry shale, a subsurface shale wedge that consists primarily of greenish-gray shale/claystones with intermittent lenses of fine-grained sandstone. Sand facies within the Hackberry shale are highly variable depending on positioning relative to the slope (Pope, 1955).

[REDACTED] To illustrate the effect of

potential seals and baffles, a geocellular model was populated with vertical and lateral variations of sand and shale facies. This model is described in detail in *Section 2.4*.

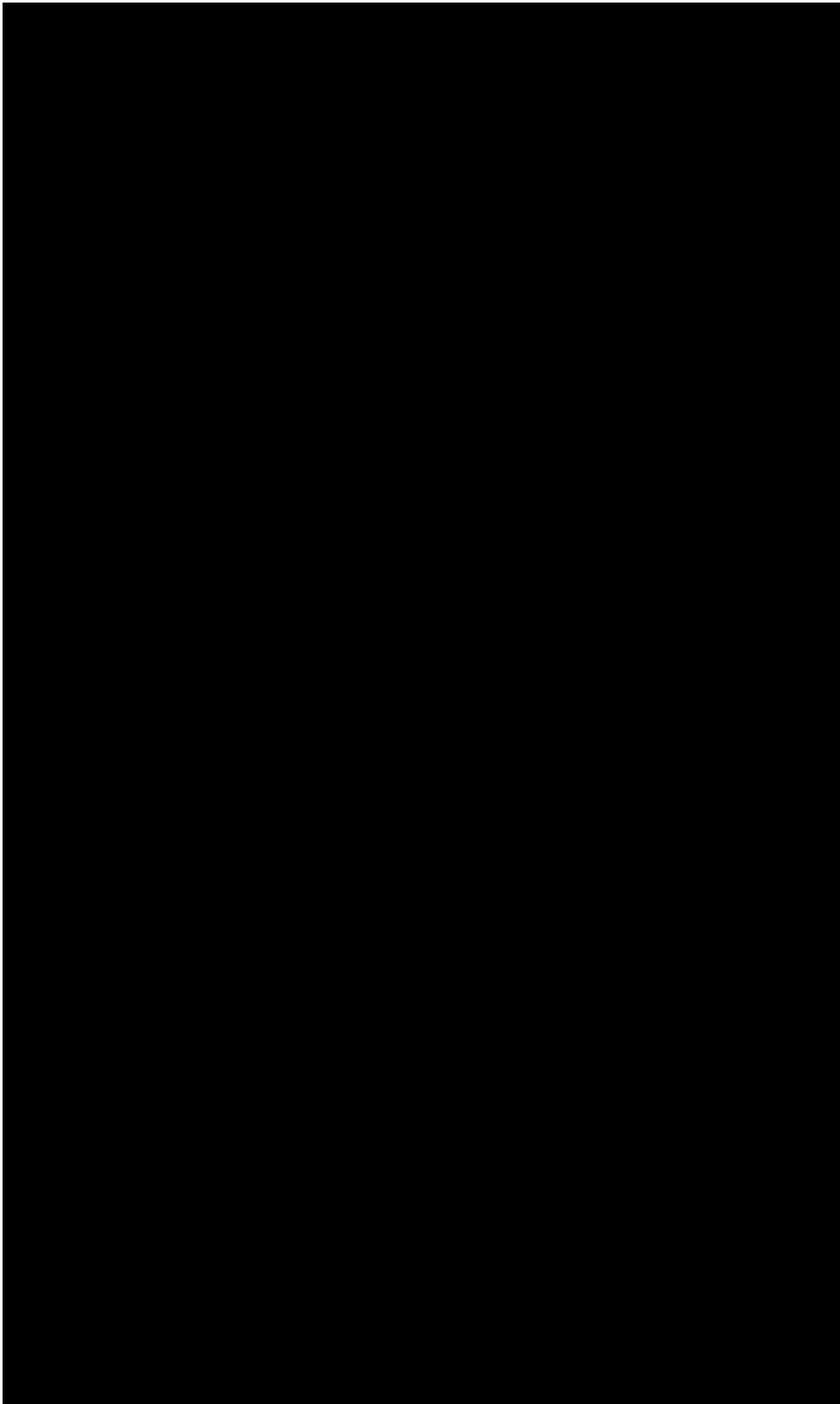


Figure 1-14 – [REDACTED]

1.3.2. Upper Confining Zone

The Frio depositional episode terminated with a regional flooding event associated with the first occurrence of the *Marginulina texana* foraminiferal biomarker (Figure 1-7, Section 1.3.1) and deposition of the Anahuac Shale (Hovorka et al., 2003; Sakurai et al., 2006). The Anahuac Shale is a regionally extensive marine shale that consists of a mixture of shelf and prodeltaic mudstones (McGuire, 2009). The section represents a retrogradational package characterized by increased sea levels, eustatic highs, and the deposition of regionally extensive fine-grained to silt-sized material.

Publicly available core data from the Anahuac Shale is very limited. The BEG acknowledged that they cored the interval in their Frio Brine Pilot Test well (TCEQ No. 5X2500071). However, the published report does not contain detailed descriptions or XRD, SEM, or thin-section analysis to improve mineralogical assumptions of the proposed UCZ within the Evergreen Hub (Hovorka et al., 2003; Sakurai et al., 2006). The BEG performed a capillary pressure test on an Anahuac Shale sample from an undisclosed depth in the test well, the results of which are provided in Figure 1-15. The sample reached a high threshold pressure of 3,500 psi, “showing high sealing capacity” (Sakurai et al., 2006). The BEG study determined “the Anahuac Shale is expected to be a good barrier for CO₂.” The Anahuac Shale is reported to be 250 ft thick at the Frio Brine Pilot Test location (Sakurai et al., 2006).

Coring in the UCZ is planned during the drilling of the stratigraphic test well. Once the data from the core is received, this permit application will be updated with the results of the analysis. The upper confining shales are anticipated to be similar in composition to fine-grained sedimentary rocks of the underlying Frio Formation—but with clay minerals comprising the bulk of the sample, followed by quartz and feldspar. Clay species are anticipated to be predominantly smectite and illite, with minor amounts of kaolinite.

Figure 1-16 (page 28) displays the UCZ from the same offset well as above [REDACTED]. The VCLAY curve in the left track is a calculated clay volume from a gamma ray (GR) log, shaded to represent sand content, and the DEEP RES curve in the right track is the measured deep-resistivity log (40-in. induction). The UCZ begins at the ANAHUAC_SH marker and includes all strata to the TOP_FRIO marker. A deflection of the VCLAY curve to the right with a corresponding increase in deep resistivity indicates fine-grained deposits—in this case, clay-rich shales. The Anahuac has a gross thickness of [REDACTED]. Additional confinement is provided by clay-rich shale intervals of the overlying Lower Miocene section, as indicated by the brown box in Figure 1-16.

Gross thickness of the UCZ ranges between [REDACTED]. Analysis of openhole logs within the Evergreen Hub AOR indicate that the Anahuac section is composed of [REDACTED]. A structure map on the

ANAHUAC_SH marker is included as *Appendix B-5* along with gross isopach and net shale maps of the UCZ as *Appendix B-11* and *B-14*, respectively.

A monitoring well will be installed in the thick sands above the UCZ, the details of which are provided in *Section 5 – Testing and Monitoring Plan*.

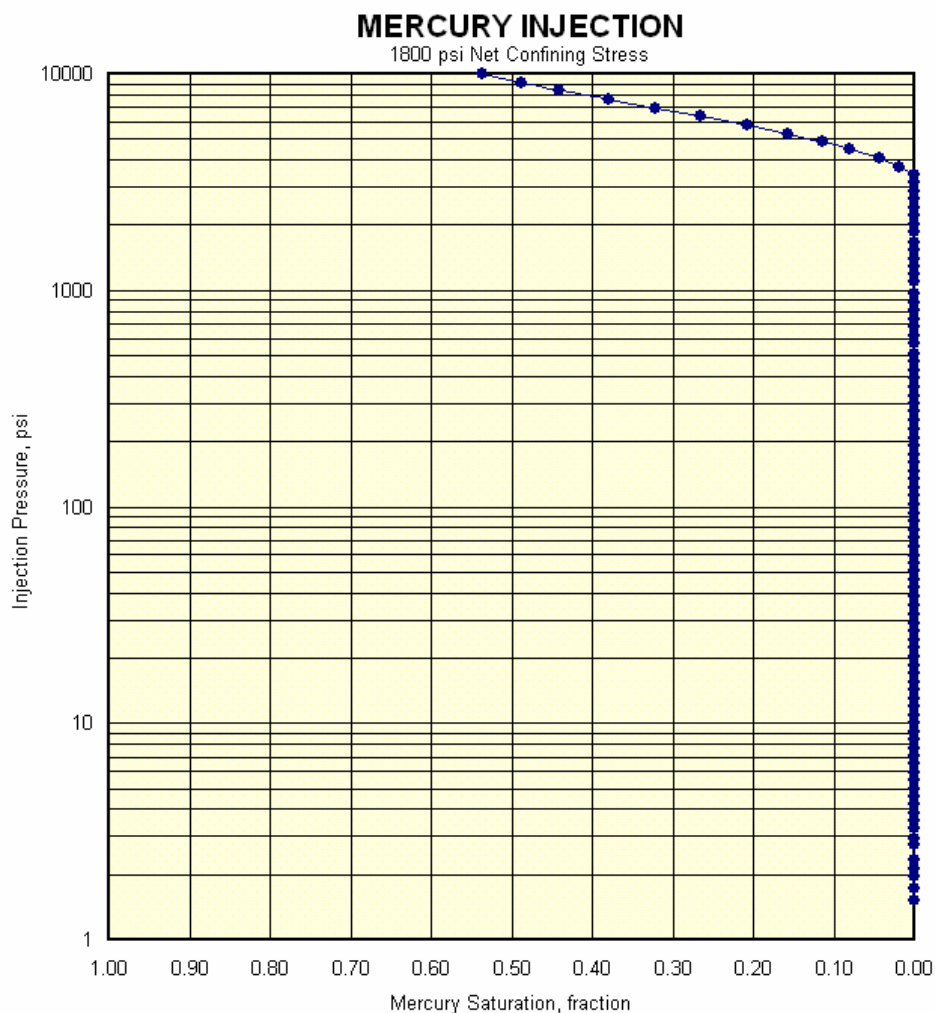


Figure 1-15 – Capillary Pressure Result for Proposed Upper Confining Zone, Anahuac Shale; Liberty County, Texas (Sakurai et al., 2006)

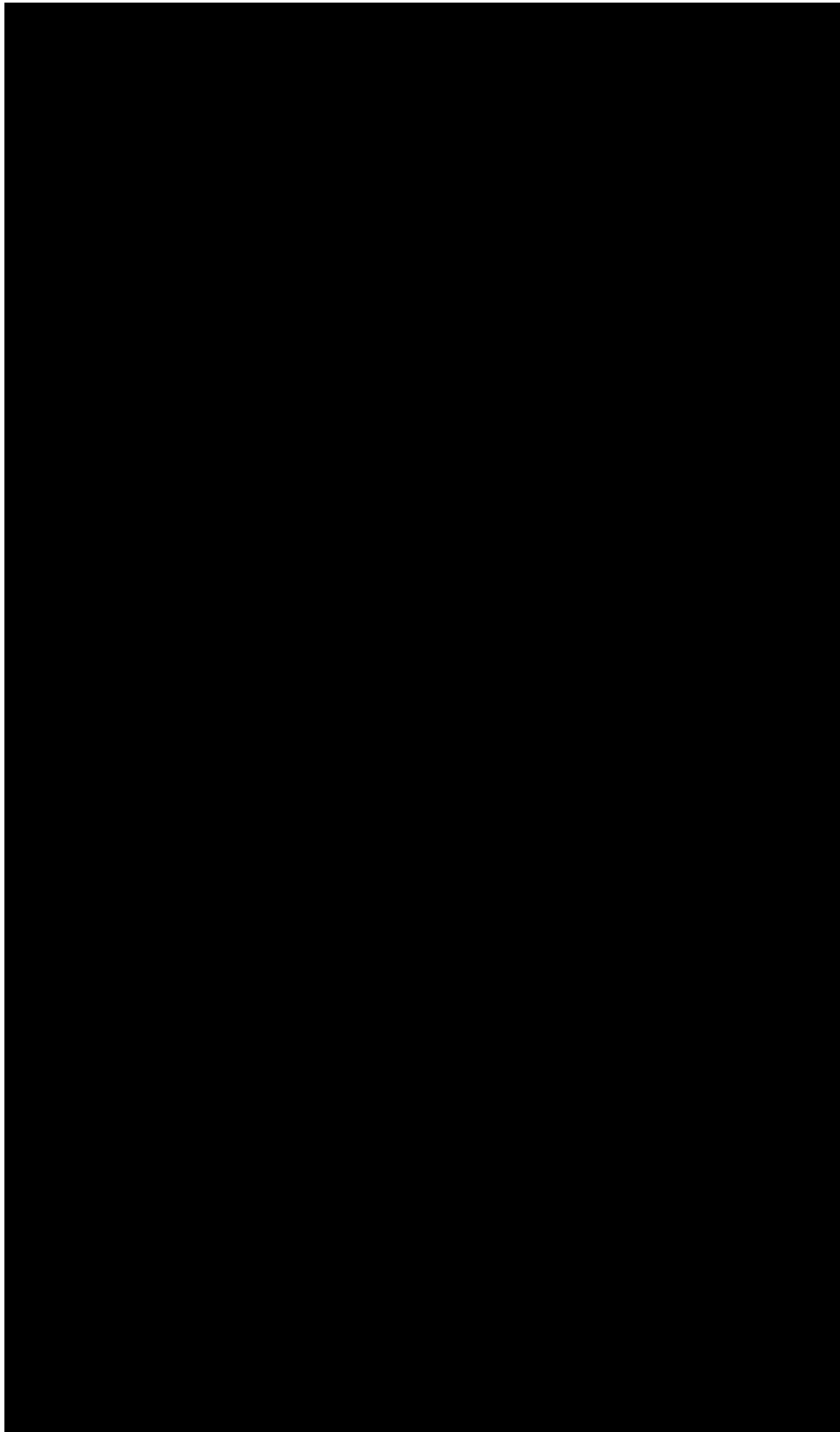


Figure 1-16 – [Redacted]

1.3.3. Lower Confining Zone

Review of public databases and published literature did not identify any available core analysis or studies to improve understanding of LCZ mineralogy. Coring in the LCZ is planned to be obtained during the drilling of a stratigraphic test well. Once the data from the core is received, this permit application will be updated with the results of the analysis. Shales within the LCZ are anticipated to be similar in composition to fine-grained sedimentary rocks of the proposed injection zone—but with clay minerals comprising the bulk of the sample, followed by quartz and feldspar. Clay species are anticipated to be predominantly smectite and illite with minor amounts of kaolinite.

Figure 1-17 displays the LCZ from the same offset well discussed above [REDACTED]. The VCLAY curve in the left track is a calculated clay volume from an SP log, shaded to represent sand content, and the DEEP RES curve in the right track is the measured deep-resistivity log (40-in. induction). The LCZ begins at the BASE_FRIO marker and includes all strata to the COCKFIELD marker. A deflection of the VCLAY curve to the right with a corresponding increase in deep resistivity indicates fine-grained deposits—in this case, clay-rich shales. Shales of the Vicksburg-Jackson have a gross thickness of [REDACTED] across the AOR.

For the purposes of this permit application, LCZ modeling was limited to the Vicksburg section, from the BASE_FRIO marker to the JACKSON marker, as displayed in Figure 1-17. Gross thickness of the modeled LCZ is [REDACTED] within the Evergreen Hub AOR. Modeling of the clay-rich section suggests it will provide a sufficient seal to the overlying injection zone. Additional confinement will be provided by the underlying Jackson Group. A structure map on the BASE_FRIO marker is included in *Appendix B-7* along with a gross isochore map of the modeled LCZ in *Appendix B-13*.

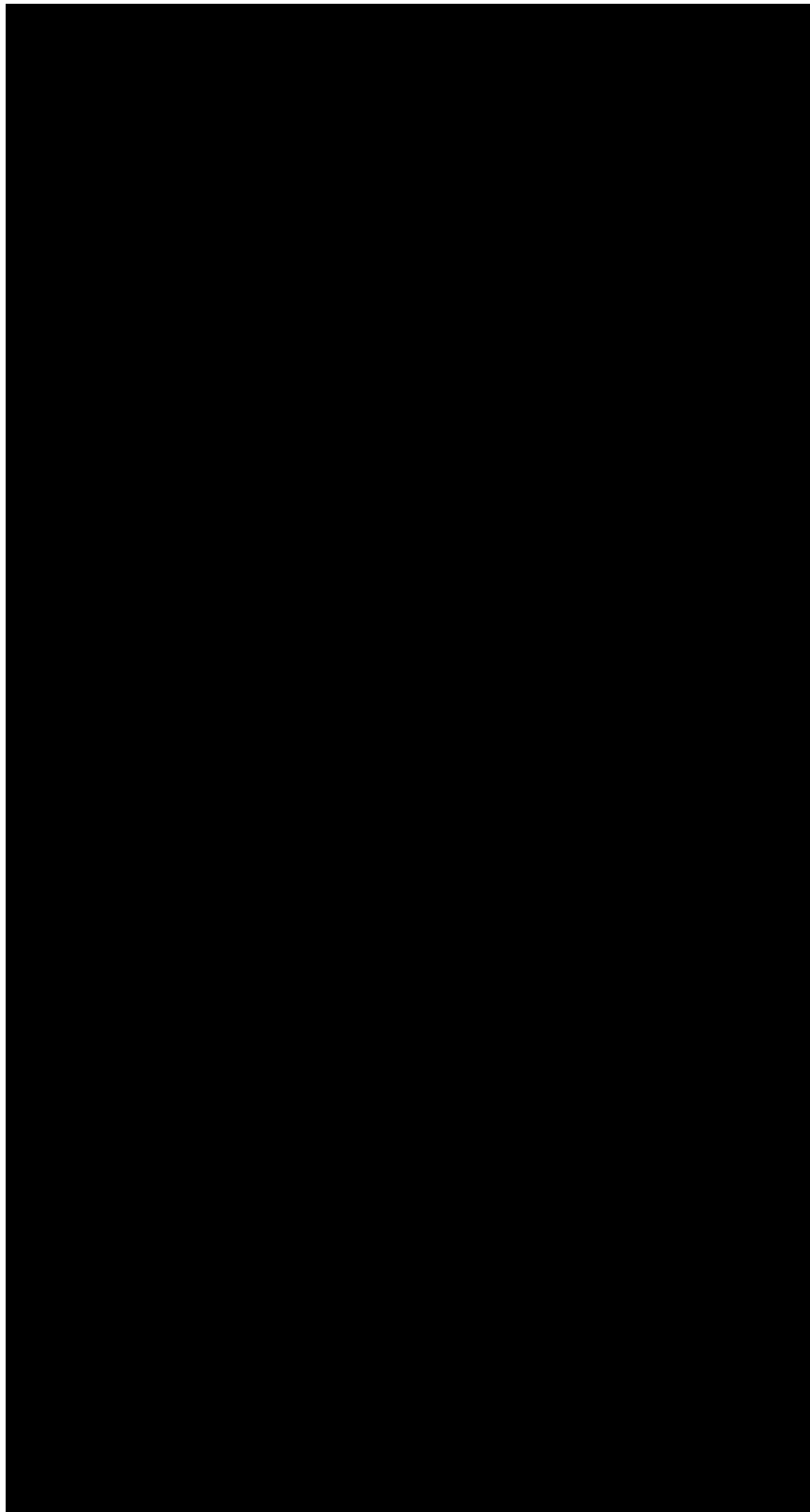


Figure 1-17 – [REDACTED]

1.3.4. Geologic Structure

Structural dips of strata within the injection and confining zones were mapped utilizing 3D seismic data and well control. The resulting structure maps, isochore maps, and cross sections are included in *Appendix B*.

1.3.4.1. Reflection Seismic Profiles

[REDACTED] 3D reflection seismic data was licensed by Trace Carbon Solutions and included in this interpretation. The location of the seismic data is presented in Figure 1-18, with the heavy black outline representing the licensed 3D seismic survey boundary.

The interpreted seismic data is part of a larger “merge” composed of multiple 3D data sets (Figure 1-19, page 33). The original surveys contributing to the licensed data are the [REDACTED]

[REDACTED] All three surveys are part of a larger survey called the Alligator East 3D. [REDACTED]

[REDACTED] The 3D reflection profiles that were utilized, which image the subsurface based on density and velocity contrasts, were combined with geologic formation tops from subsurface well control to map the proposed injection and confining zones. The interpreted seismic sections represent formation depths (north-south and west-east views at Appendix B-22 and B-23, respectively) and any discontinuities such as faulting. [REDACTED]

[REDACTED]

[REDACTED]

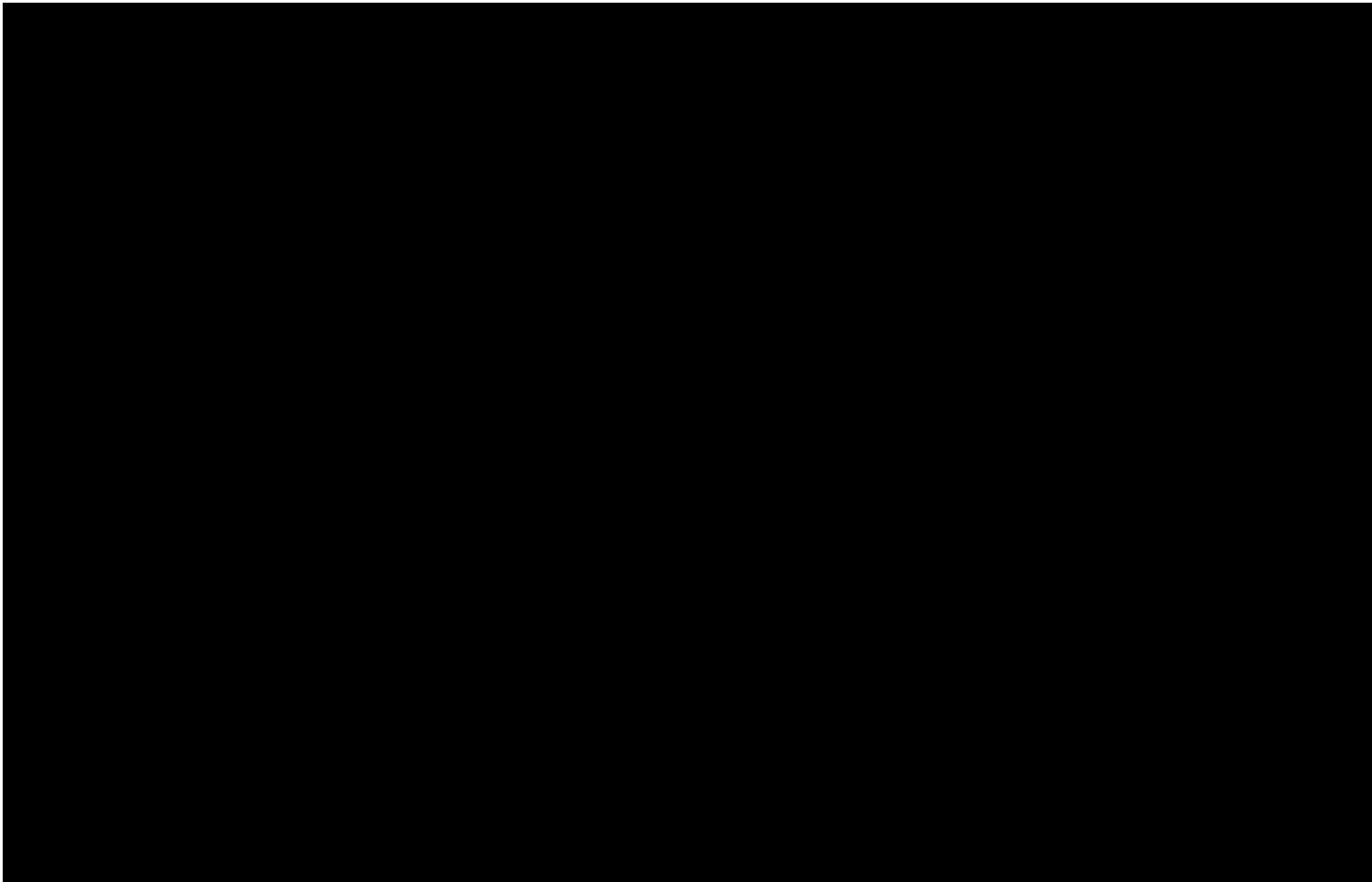


Figure 1-18 – Location of 3D Seismic Survey

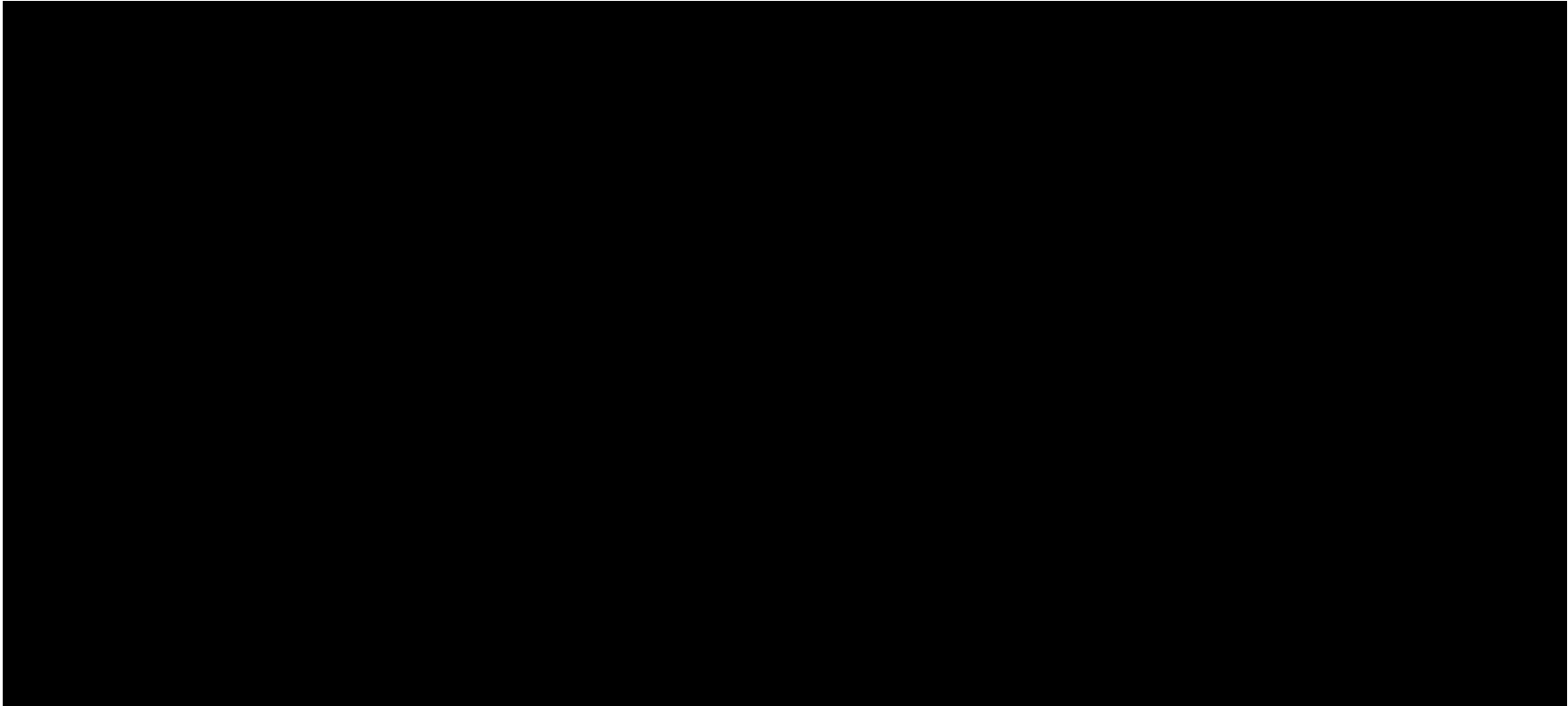


Figure 1-19 – Legacy Seismic Surveys Contributing to the Alligator East Merge

1.3.4.2. Velocity Control and Synthetic Seismogram

Five velocity (i.e., checkshot) surveys were available within the licensed 3D data and acquired for the initial seismic interpretation (Figure 1-20). The five surveys all exhibited a consistent velocity field (Figure 1-21, page 35). This velocity information, along with two synthetic seismograms (Appendix B-24) within the licensed 3D survey, were used to confirm the time-to-depth relationship (TDR).

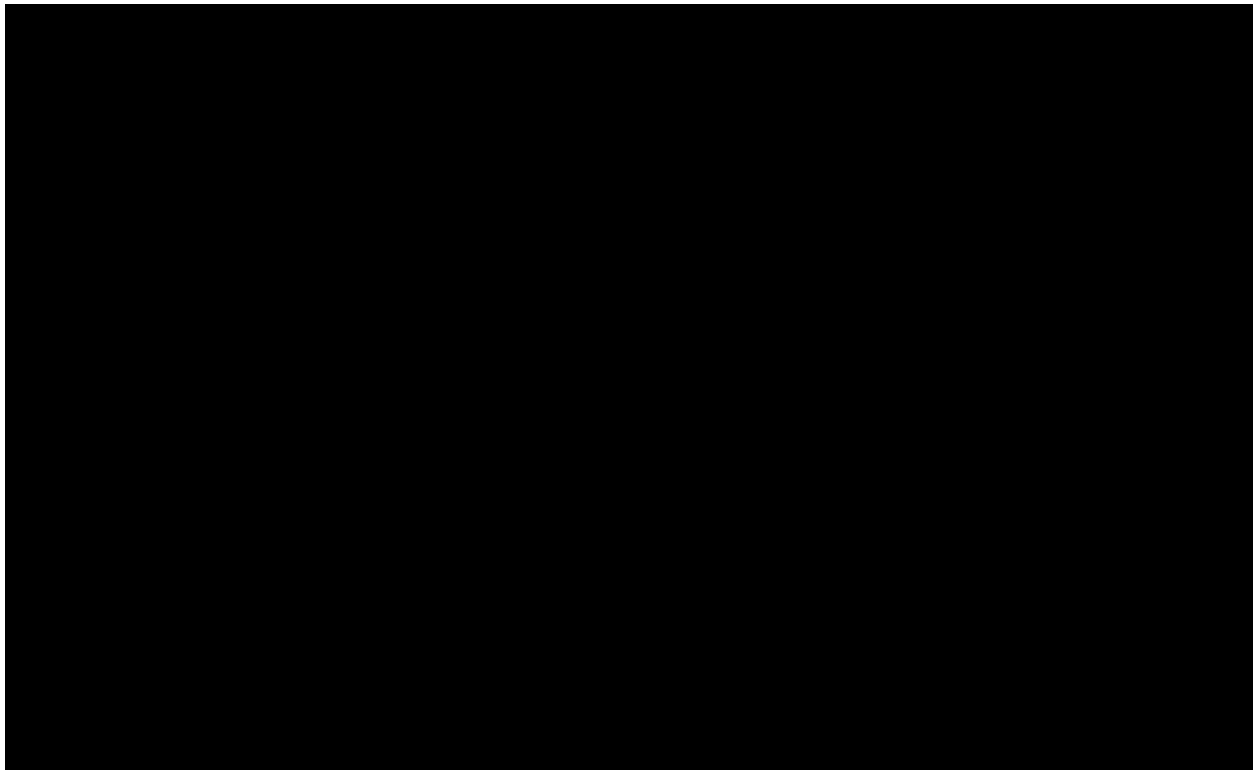


Figure 1-20 – Location of checkshot surveys (indicated by the magenta circles) and synthetic ties (black triangles) within the licensed 3D seismic data (black outline).

1.3.4.3. Depth Maps

A multi-well velocity model was built using picked seismic horizons and high-confidence geologic formation tops from the wells. This model was used to convert seismic horizons and faults to depth.

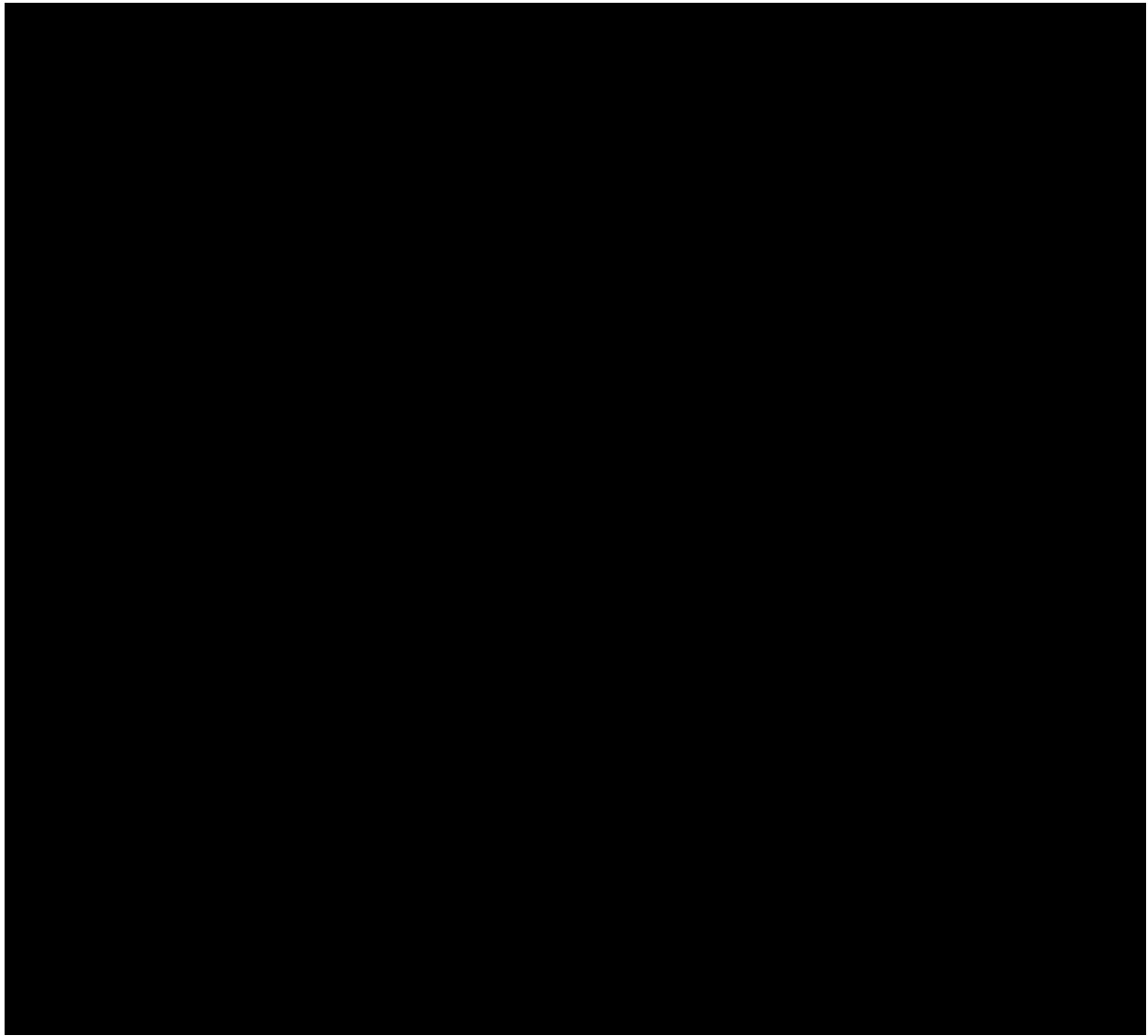


Figure 1-21 – Velocity Field of Five Checkshot Wells

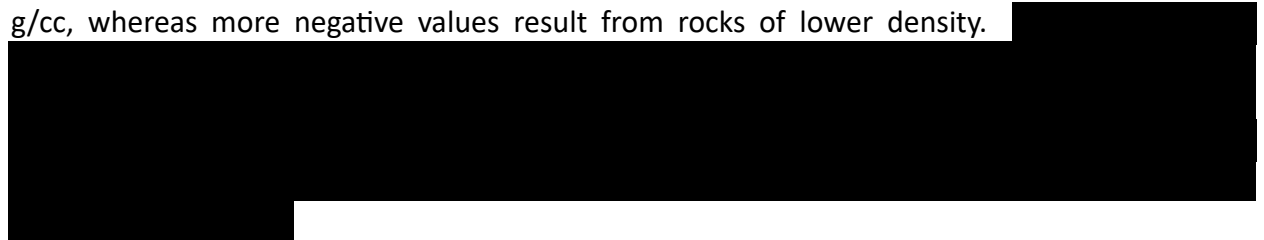
1.3.4.4. Gravity Data

Publicly accessible gravity data is available surrounding the proposed injection site. A data set of gravity station measurements from the USGS (<https://pubs.usgs.gov/ds/352/>)—which cover the proposed storage site—was utilized, shown in Figures 1-22 and 1-23 (pages 37 and 38, respectively). The USGS data points encompass a relatively wide-spaced grid (approximately one data point every 9 mi) and relatively few data points that coincide with this project area. The original data was extracted from the 1999 version of a gravity database maintained by the National Geophysical Data Center. Observed gravity measurements relative to the IGSN-71

datum were reduced to the Bouguer anomaly using the 1967 gravity formula (Cordell, Keller, and Hildenbrand, 1982) and a reduction density of 2.67 grams per cubic centimeter (g/cc). Terrain corrections were calculated radially outward from each station to 167 km (100 mi) using a method developed by Plouff (1977). Figure 1-22 is a grid of Bouguer gravity anomaly based on USGS data points.

The isostatic residual gravity map displayed in Figure 1-23 reflects variations in the Earth's gravity field caused by density variations in the rocks composing the upper part of the Earth's crust. The isostatic residual gravity grid was derived from the Bouguer gravity anomaly data by removing the gravitational effect of the compensating mass that supports topographic loads. The thickness of this compensating mass was calculated using averaged digital topography by assuming a crustal thickness for sea-level topography of 30 km (18 mi), a crustal density of 2.67 g/cc, and a density contrast of 0.40 g/cc between the crust and upper mantle.

More positive value trends delineate rocks denser than the Bouguer reduction density of 2.67 g/cc, whereas more negative values result from rocks of lower density.



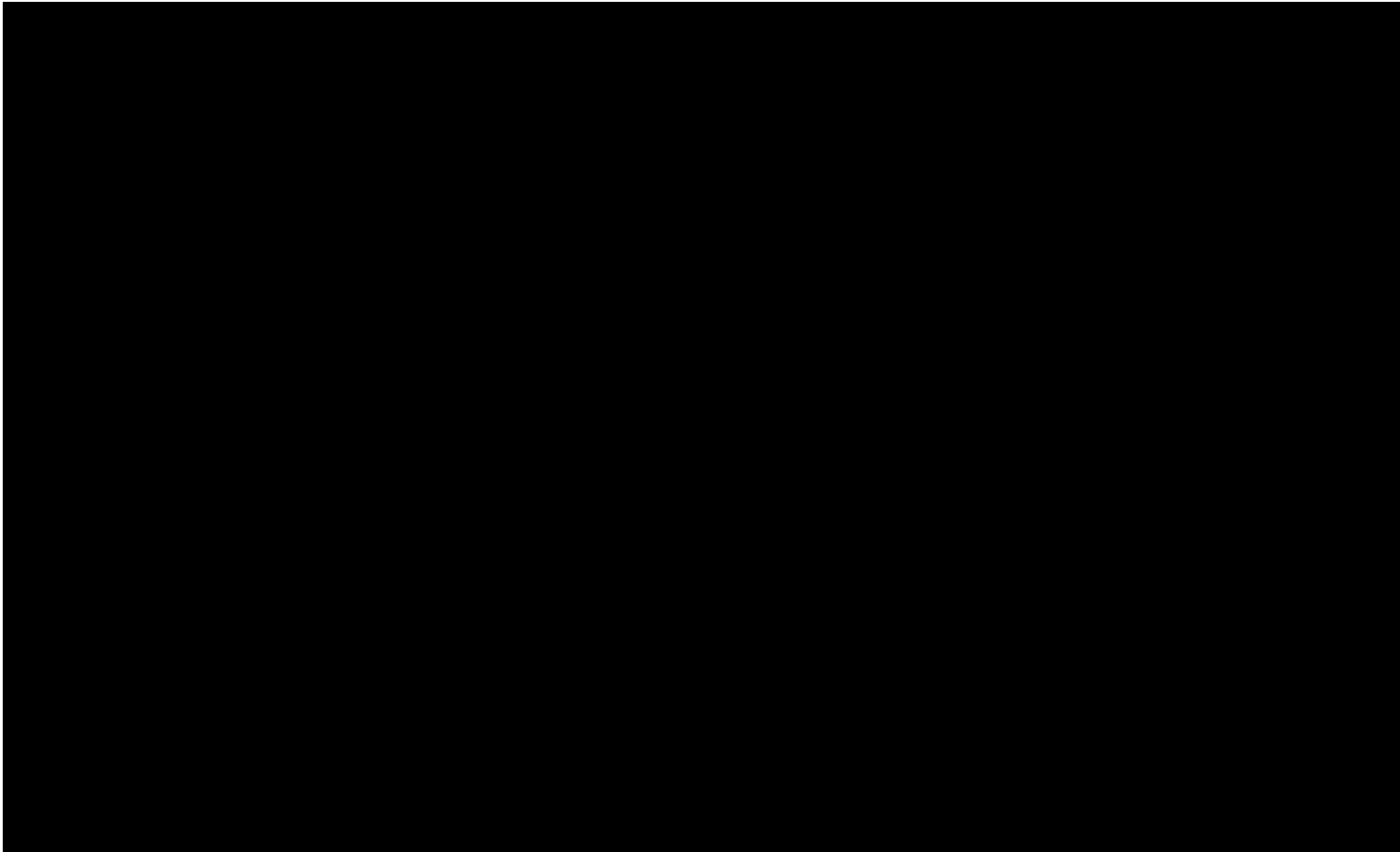


Figure 1-22 – Bouguer gravity anomaly map surrounding the proposed storage site (60 sq mi, indicated by the 3D green outline).

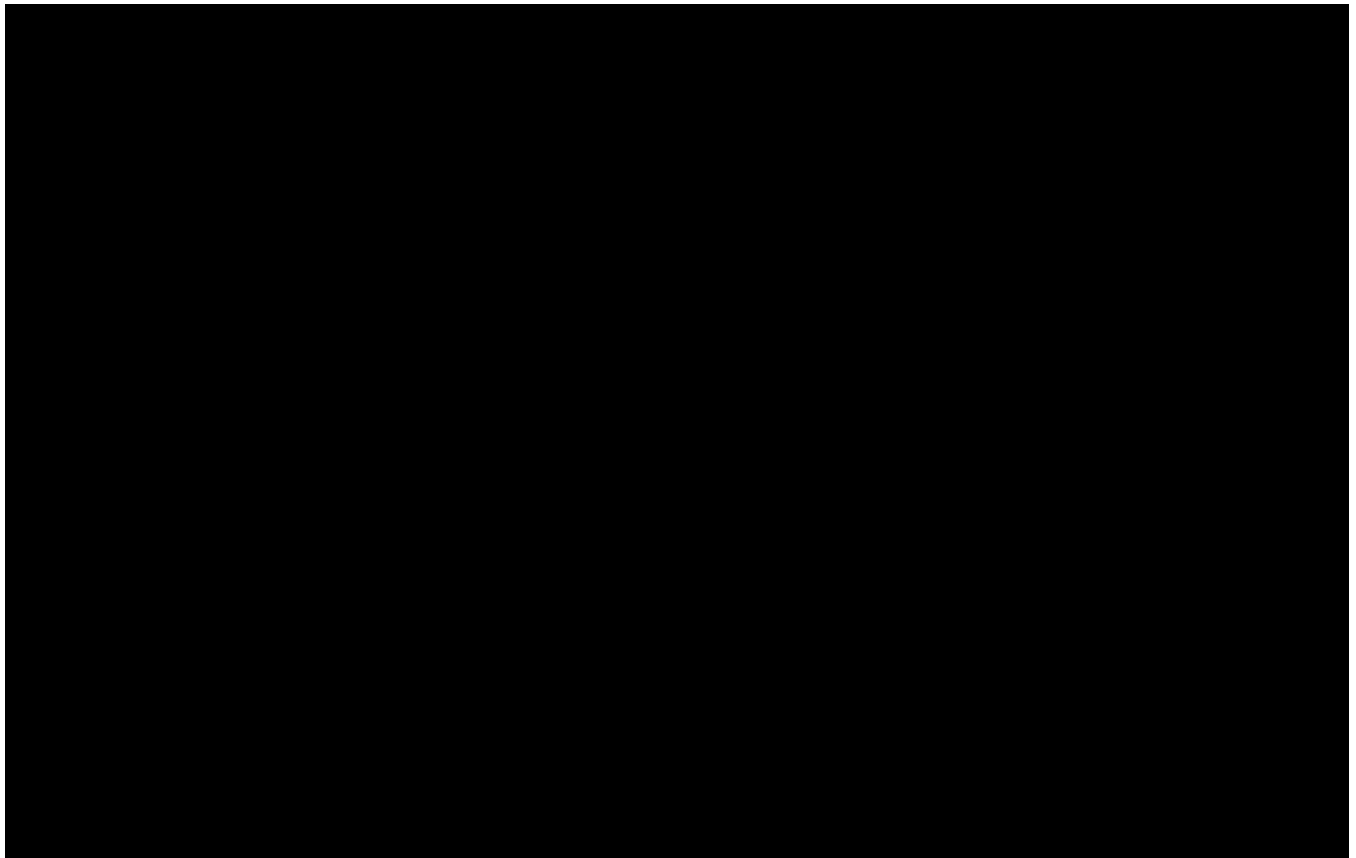


Figure 1-23 – Isostatic gravity anomaly map surrounding the proposed storage site (60 sq mi, in the 3D green outline; map from the USGS at https://pubs.usgs.gov/ds/352/arkla_iso.html).

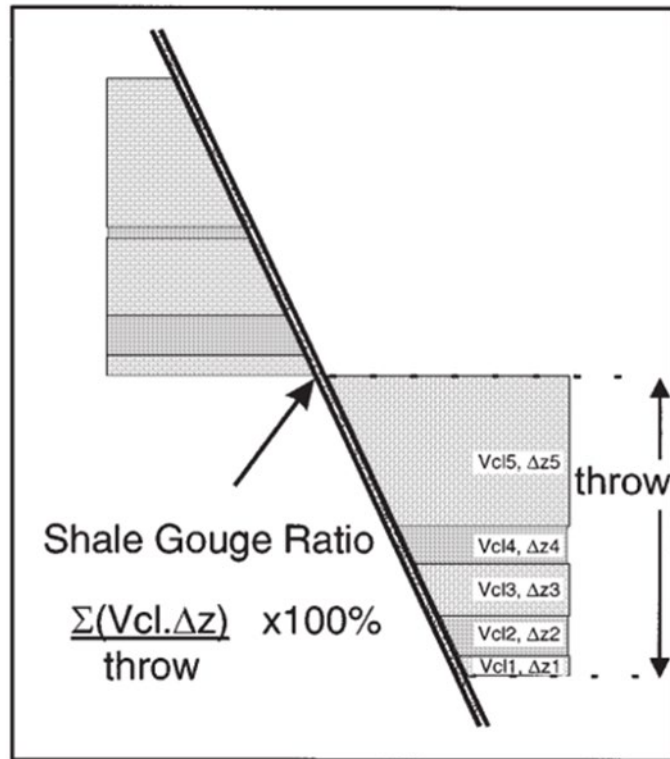
1.3.4.5. Fault Seal Analysis

The fault seal analysis is conducted to evaluate the sealing capacity of the faults. Two scenarios were analyzed to assess the faults' vertical conductivity and lateral transmissibility: (1) when the CO₂ plume reaches any fault, and (2) when the pressure front reaches any fault. One of the important applications of this analysis is an evaluation of the upper confining zone's sealing capacity. Should the CO₂ plume or pressure front reach a fault, a critical examination is performed for faults which propagate into or above the UCZ. [REDACTED]



Figure 1-24 – 3D view of the subsurface model from the south showing the confining and injection zones and fault planes (in red). [REDACTED]

A comprehensive fault seal analysis was conducted jointly for all mapped faults within the area. To estimate fault sealing capacity, the shale gouge ratio (SGR), fault zone entry capillary pressure (FZP), and fault zone permeability (kf) were calculated. The SGR is an important parameter used to estimate the amount of clay within the fault gouge, as the very fine phyllosilicates result in very small pore throats—leading to high FZP and low permeabilities within the fault zone (Yielding, 2002). The accuracy of the SGR estimations depends on the quality of input data, but overall the SGR “has proven to be a robust and quantitative predictor of fault seal in mixed clastic sequences” (Yielding, 2002). The SGR-based equation (Figure 1-25) provides calculations for a sequence of reservoir zones, where Δz is the thickness of each reservoir zone, and V_{clay} is the clay-volume fraction in the zone (Yielding et al., 1997).



$$SGR = \frac{\sum[(\text{Zone thickness}) \times (\text{Zone clay fraction})]}{\text{Fault throw}} \times 100\%$$

Figure 1-25 – Shale Gouge Ratio Conceptual Diagram and Equation (Yielding et al., 1997)

The SGR has been shown to be an effective qualitative predictor of a fault's ability to seal in hydrocarbon systems. SGR data from the fault-bounded reservoirs of both sealing and non-sealing faults show that SGR values of approximately 15–20% are the typical cutoff for sealing faults (e.g., Bretan et al., 2003; Meckel and Trevino, 2014). Therefore, anything with an SGR value greater than 20% could indicate a sealing fault.

[REDACTED]

[REDACTED] Bump et al. (2023) conducted a study for the Gulf Coast Cenozoic clastic section, proving effective sealing capabilities of composite confining systems, consisting of subhorizontal, potentially discontinuous flow barriers. [REDACTED]

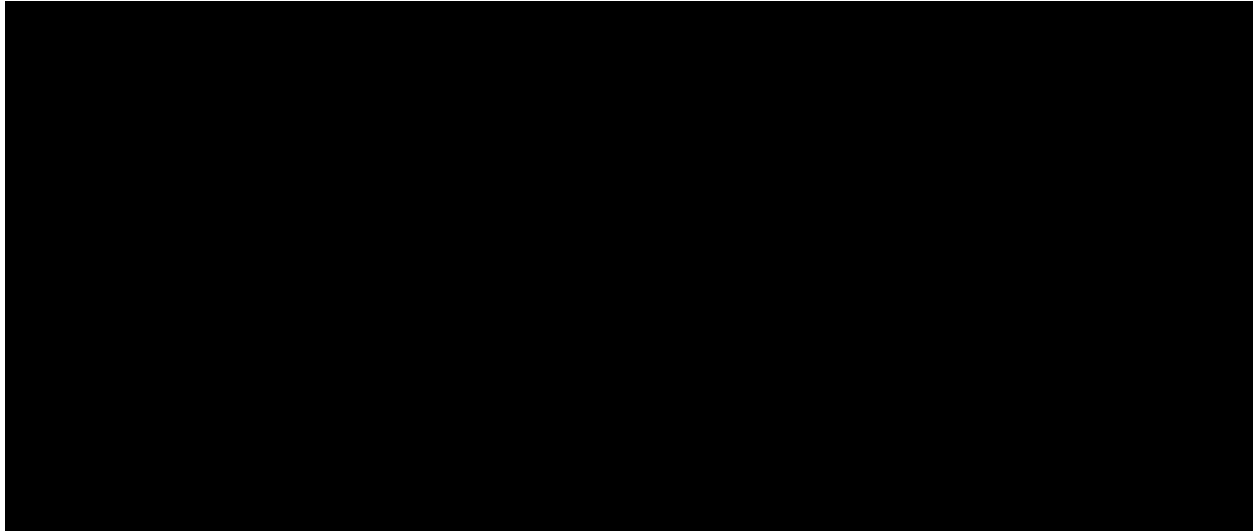


Figure 1-26 – 3D view of the shale gauge ratio on the fault planes. The SGR is calculated for each cell within the faults for confining and injection zones.

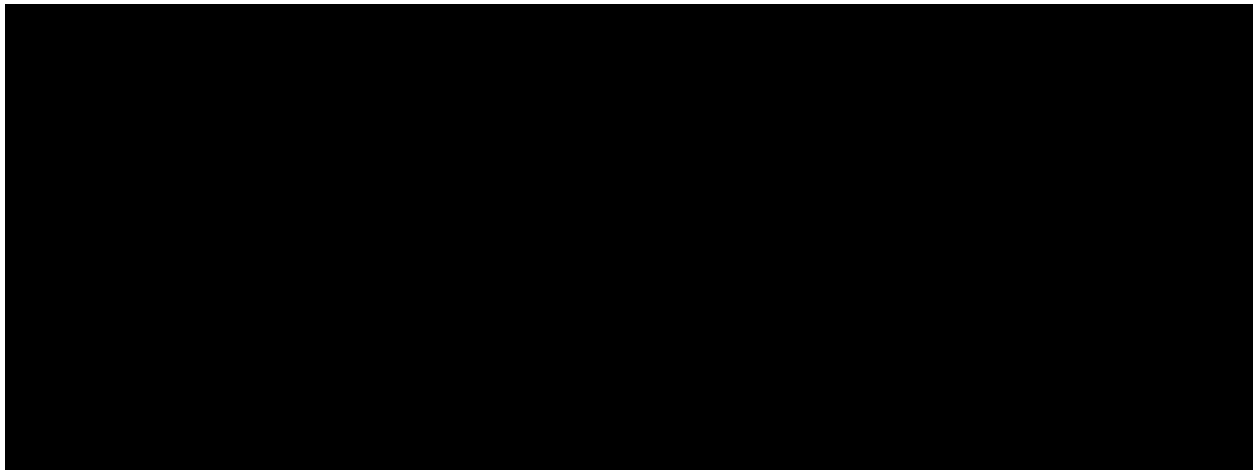
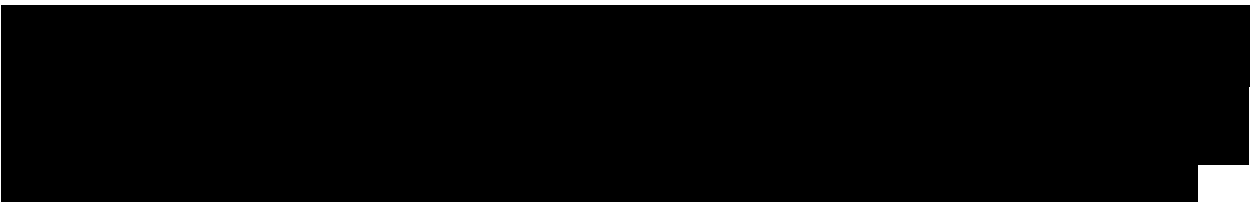


Figure 1-27 – Histograms of the SGR Distribution for (a) Upper Confining, (b) Injection, and (c) Lower Confining Zones



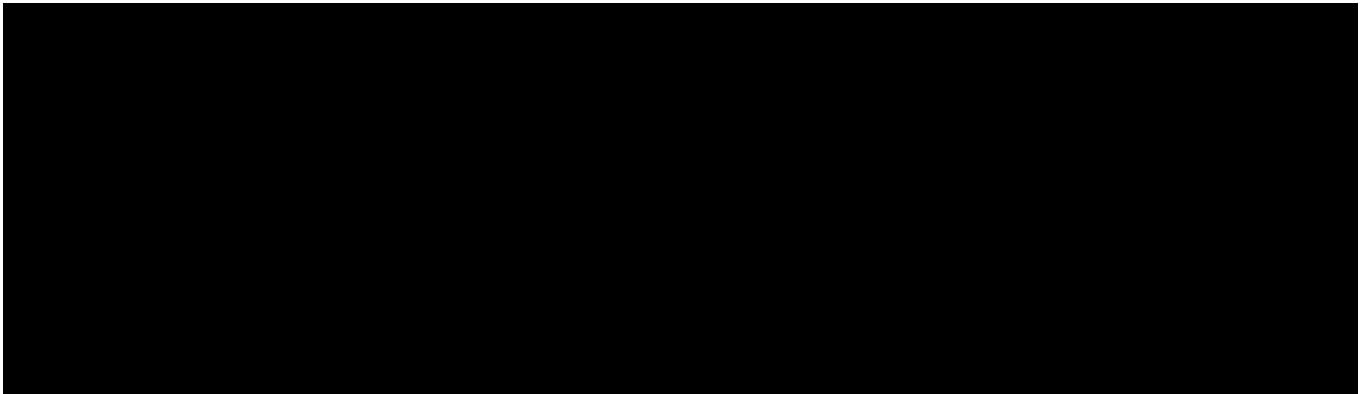


Figure 1-28 – 3D model layer slices showing facies distribution and fault SGR for (a) the upper confining and (b) injection zones. The black line indicates the cross section displayed in Figure 1-33.

Figure 1-29 shows a 3D model cross section with the fault SGR's overlaid on the Vsh and facies distribution.

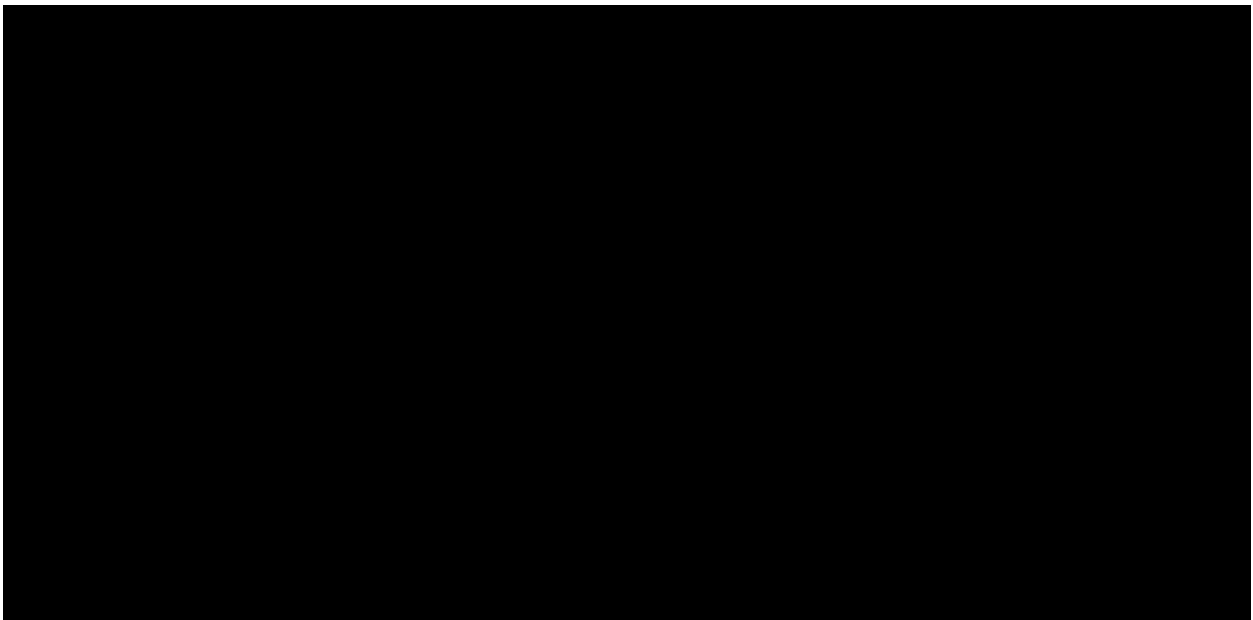
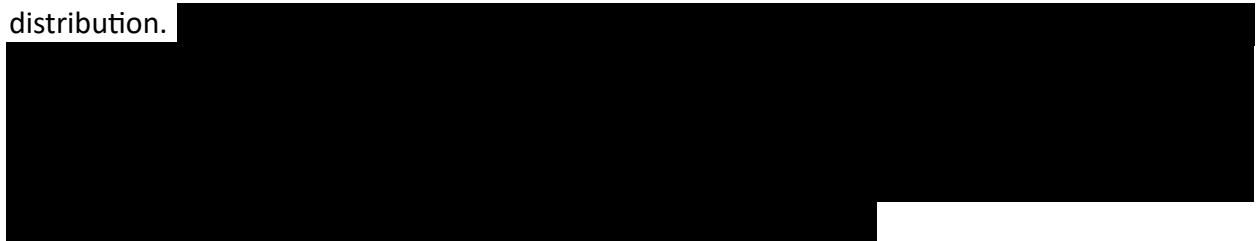


Figure 1-29 – A 3D model cross section showing (a) SGR and Vsh distribution, and (b) SGR and facies distribution. The location of this cross section was shown as a black line in Figure 1-32.



[REDACTED] The classic SGR equation for hydrocarbon systems to calculate the FZP from Bretan et al. (2003) using SGR and fault rock strength is:

(Eq. 1)

$$FZP \text{ or } P_c (\text{bar}) = 10^{\left(\frac{SGR}{27} - C\right)}$$

Where *C* is fault rock strength, which varies with depth.



[REDACTED] If FZP values remain below the threshold line (or a seal-failure envelope) at the corresponding SGR, the fault behaves as a seal. If pressure exceeds this threshold during the injection at some parts of the fault, then the fault will lose its sealing properties at those parts.

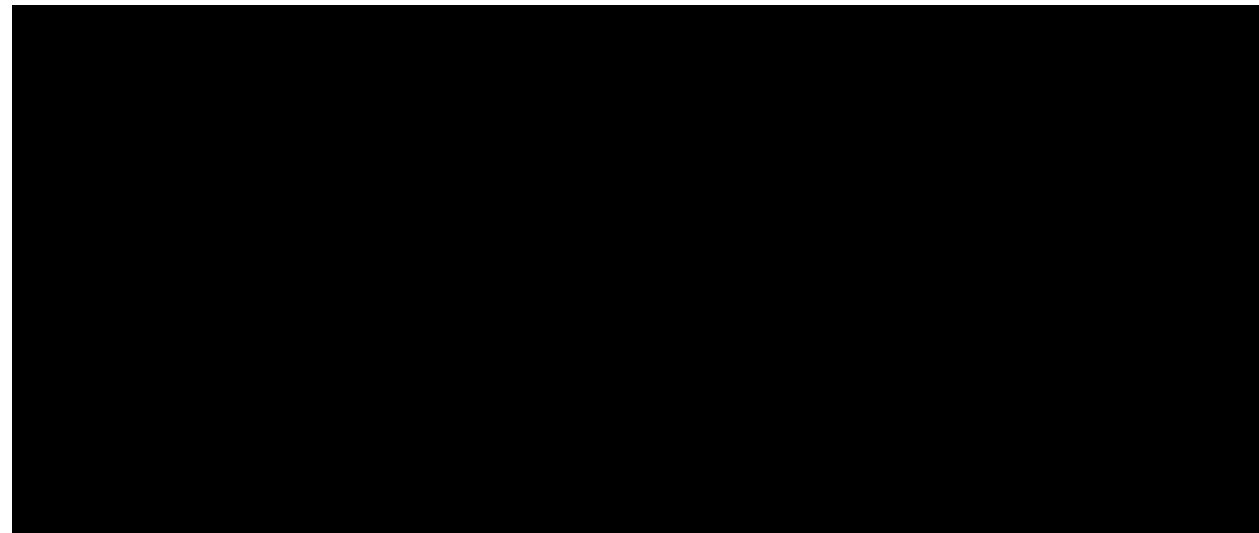


Figure 1-30 – Fault Zone Capillary Entry Pressure vs. Shale Gouge Ratio

Another useful estimation based on the SGR calculations is fault permeability (Figures 1-31 and 1-32). Different empirical equations have been proposed and used for permeability estimation.



Figure 1-31 – Fault Zones Permeability vs. Shale Gouge Ratio

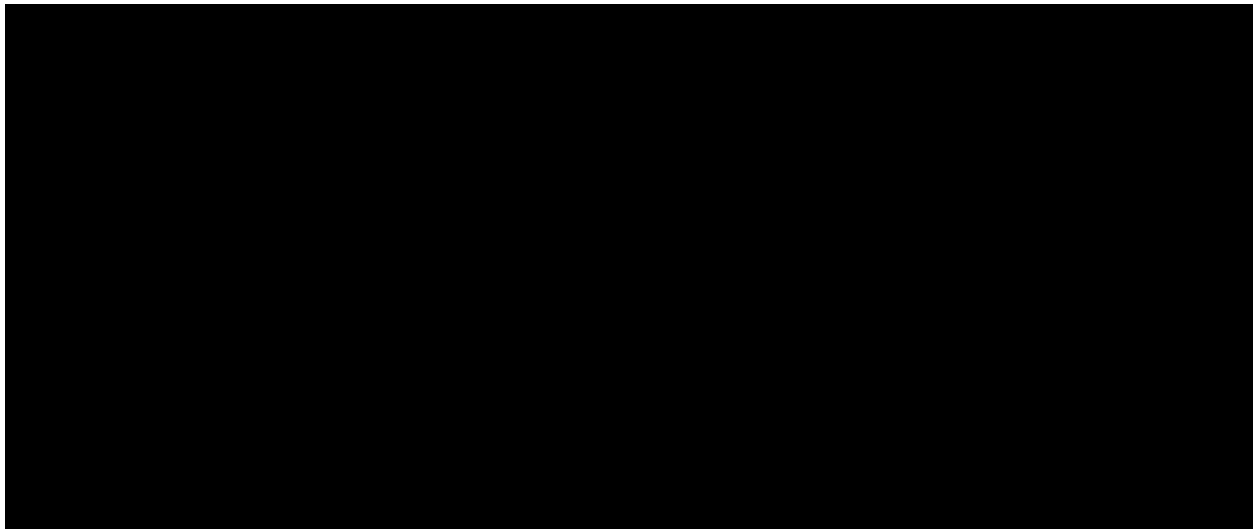


Figure 1-32 – Distribution of the fault zone's predicted permeability values on the fault planes.

Figure 1-33 shows histograms of permeability distribution for the confining and injection zones.

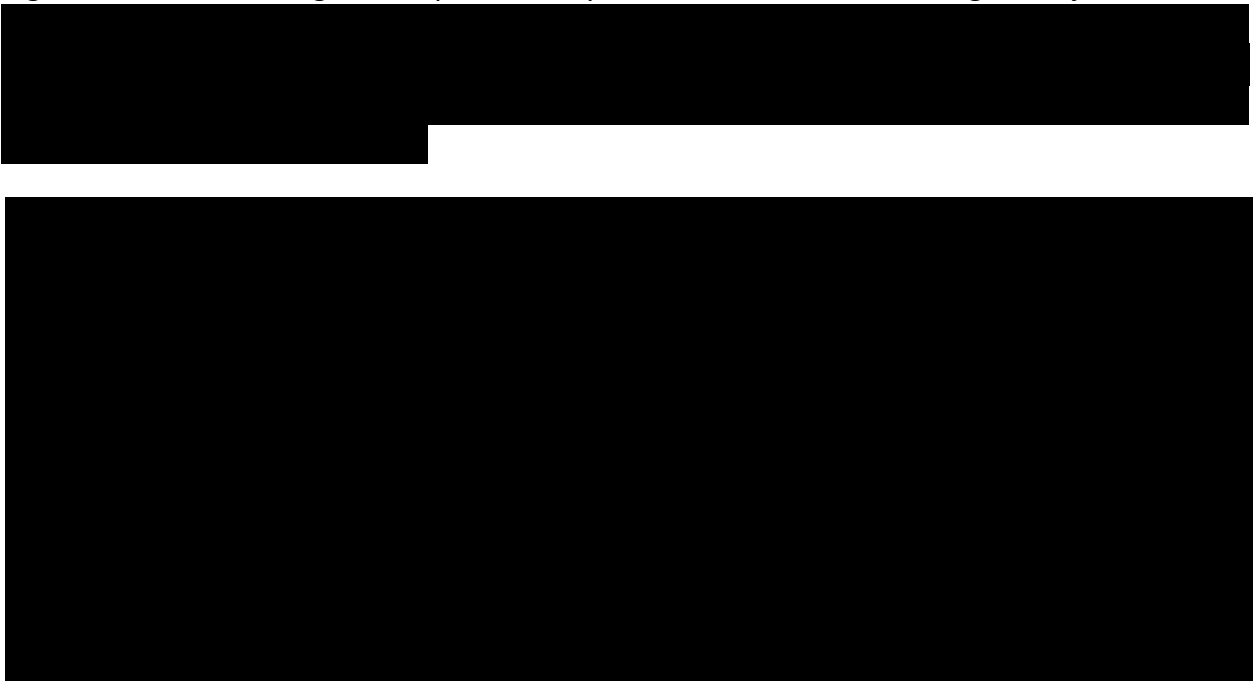


Figure 1-33 – Histograms of the fault permeability distribution for (a) the upper confining, (b) injection, and (c) lower confining zones.

The SGR-based analysis provides useful information about fault properties and estimates of their sealing capacities. [REDACTED]

[REDACTED] Three parameters provided by the fault seal analysis at the present/static conditions are SGR, FZP, and fault permeability. [REDACTED]

[REDACTED]

[REDACTED] These calculated parameters define the fault behavior under present conditions and, along with FZP, set thresholds for the fault behavior under changing dynamic conditions.

1.4. Geomechanics

1.4.1. Local Stress Conditions

The Evergreen Hub project will assess the local formation stress within the Evergreen acreage and the plume of the proposed Loblolly CCS No. 001 and Loblolly CCS No. 002 injection wells. The stress will be defined for the upper confining zone, injection zone, and lower confining zone by calibrating the core tests results with X-dipole openhole logs. The maximum horizontal stress (SHmax) of the northern coast of the GOM basin indicates stress orientation parallel to the coast, specifically in the east-northeast direction with regard to Louisiana (Yassir and Zerwer, 1997) (World Stress Map, accessed August 2023).

1.4.2. Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized as the weight of the overlying formation for a given depth due to the overburden pressure, which is a result of the densities of the rocks and fluids above that depth (Aird, 2019). The average bulk density for the injection zone was determined by the bulk density of offset logs [REDACTED] This correlates with values for porous sandstones at this depth (Galloway, Ganey-Curry, Li, and Buffler, 2000). [REDACTED]

The depths of each zone, vertical stress, average density, and overburden gradient of the injection zone and upper and lower confining zones are listed in Table 1-5.

Table 1-5 – Calculated Vertical Stresses

Formation	Depth (ft)	Avg Density (g/cm ³)	Avg Density (lb/ft ³)	Vertical Stress (psi)	Gradient (psi/ft)
Anahuac Shale					
Frio Sands					
Jackson Shale					

1.4.3. Elastic Moduli and Fracture Gradient

During the drilling of Loblolly Stratigraphic Well No. 001, core samples will be collected, tested, and correlated with log data to determine the elastic moduli and inputs for Eaton's equation of the fracture gradient. The core samples will undergo testing for triaxial compressive strength, to provide the geomechanical properties listed in Table 1-6.

The values were derived from published literature with industry-accepted values for poorly consolidated sandstones (Sun et al., 2014), and shales (Molina, Vilarras, and Zeidouni, 2016).

Table 1-6 – Triaxial Compressive Strength Test Results

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10 ⁶ psi)	Poisson's Ratio
		Upper Confining	Anahuac Shale				
		Injection	Frio				
		Lower Confining	Jackson Shale				

1.4.4. Injection Zone Fracture Gradient

The fracture pressure of the injection zone was approximated by using Eaton's equation. The equation was implemented as a reliable method to calculate the fracture pressure of a rock in the Gulf Coast sands and is accepted as the standard practice for estimating fracture gradients. The

calculation incorporates Poisson’s ratio (ν), overburden gradient (OBG), and pore pressure gradient (PG) to calculate the pressure required to fracture a zone of interest.

[REDACTED]

[REDACTED] Sandstones commonly fall within the range of 0.1–0.4 for Poisson’s ratio, with harder, compacted sandstones closer to 0.1 and soft, pliable sandstones closer to 0.4 (Lake, 2007). In 2016, a study of loosely consolidated sandstones, bound by intermittent shale layers and used for carbon injection and storage, demonstrated a refined range of Poisson’s ratio of 0.2–0.35 for the sandstone interval, with a Poisson’s ratio of 0.3 modeled in the study. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] The 10% safety margin was implemented to ensure a safe injection-pressure limit, which would not exceed the fracture pressure of the injection zone (Table 1-7).

(Eq. 3)

$$FG = \frac{\nu}{1 - \nu} (OBG - PG) + PG$$

[REDACTED]

[REDACTED]

Table 1-7 – Fracture Gradient Calculation Inputs and Results (Zhang, 2019; Sun et al., 2014)

Depth (ft)	Zone	Formation	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
[REDACTED]	Injection	Frio Sands	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Prior to injection operations, the proposed injection wells Loblolly CCS No. 001 and Loblolly CCS No. 002 are planned to undergo an injectivity test, the purpose of which is to verify the hydrogeologic reservoir parameters.

1.4.5. Confining Zone Fracture Gradient

The fracture gradient of the upper confining and lower confining zones for the Evergreen Hub acreage was approximated using Eaton's equation. [REDACTED]

[REDACTED] The above and below confining shales were determined to be clay-rich. [REDACTED]

[REDACTED]

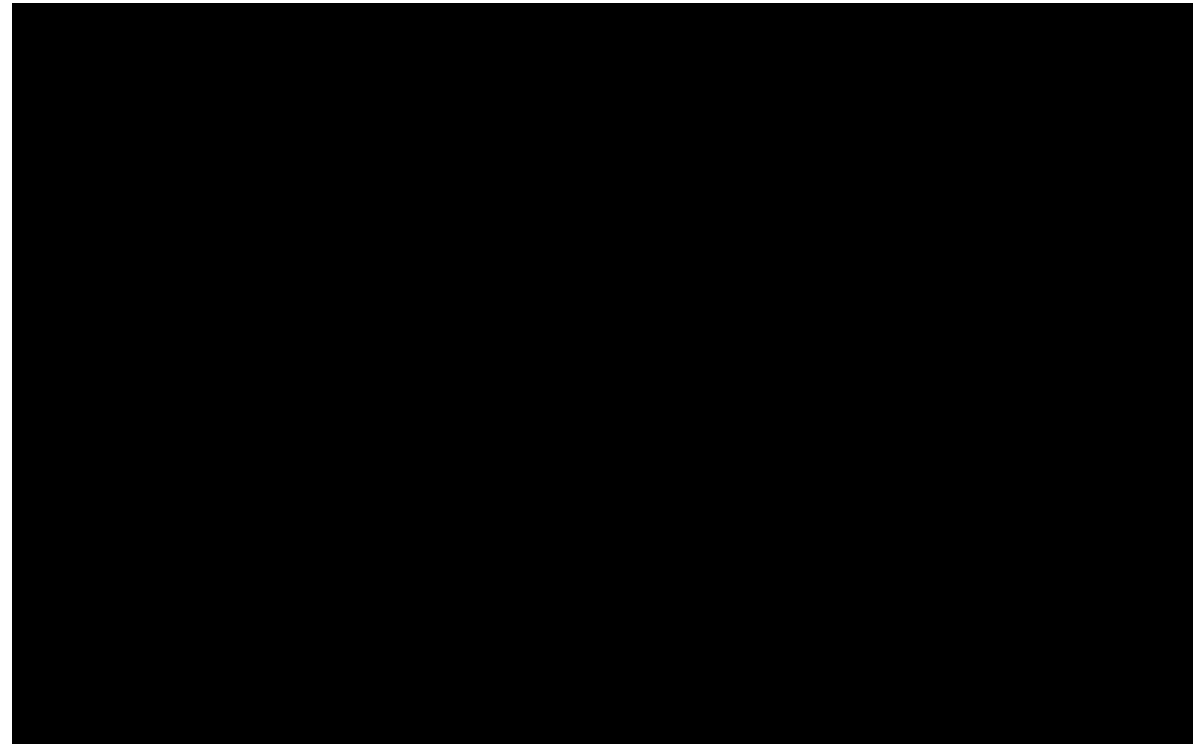


Figure 1-34 – Clay Content vs. Poisson's Ratio of Solid Rock (Zhang and Bentley, 2005)

Table 1-8 – Confining zones’ fracture gradient calculated using triaxial test results for Eaton’s equation.

Depth (ft)	Zone	Member	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
████	Upper Confining	Anahuac Shale	████	████	████	████
████	Lower Confining	Jackson Shale	████	████	████	████

1.5. Porosity and Permeability

The distribution of porosity and permeability within the proposed injection zone of the Evergreen Hub project AOR is primarily influenced by deposition and diagenesis, like other Cenozoic sandstones of the GOM basin. Reservoir development is anticipated to occur within fluvial, deltaic, and shore-zone deposits of the Frio Formation associated with enhanced porosity and permeability development, as discussed in *Section 1.3.1*. Reservoir-quality sands of the proposed injection zone are interbedded with silts, shale, and encased within upper- and lower-confining shales. The confining shale intervals were deposited in a regionally extensive, transgressive marine environment and consist of fine-grained sediment associated with low permeability.

The process of burial and compaction generally results in the degradation of porosity along with increasing burial depth. As burial depths increase, so does overburden loading, resulting in the mechanical process of compaction that causes grains to reorient, pack densely, and expel water from the pore space (Ulmer-Scholle et al., 2014). The porosity-depth relationship exhibits a nonlinear trend, as illustrated by the pink compaction-dominated model curve in Figure 1-35.

The pink-shaded area between the compaction and cementation curves in Figure 1-35 represents the potential porosity range for a sandstone at given burial depths, depending on the degree of cementation. Cementation is a diagenetic process that degrades porosity by reducing pore space between grains, the degree of which depends upon temperature. Gulf of Mexico sediments tend to be transformed by the effects of cementation and mineral alteration once temperatures surpass 100°C (212°F) (Land, Milliken, and McBride, 1987). Quartz composes the cement primarily responsible for porosity occlusion of Oligocene Frio sediments, typically in the form of quartz overgrowths (McGuire, 2009). As the temperature of the proposed injection zone is not anticipated to exceed 100°C, a low degree of cementation is expected.

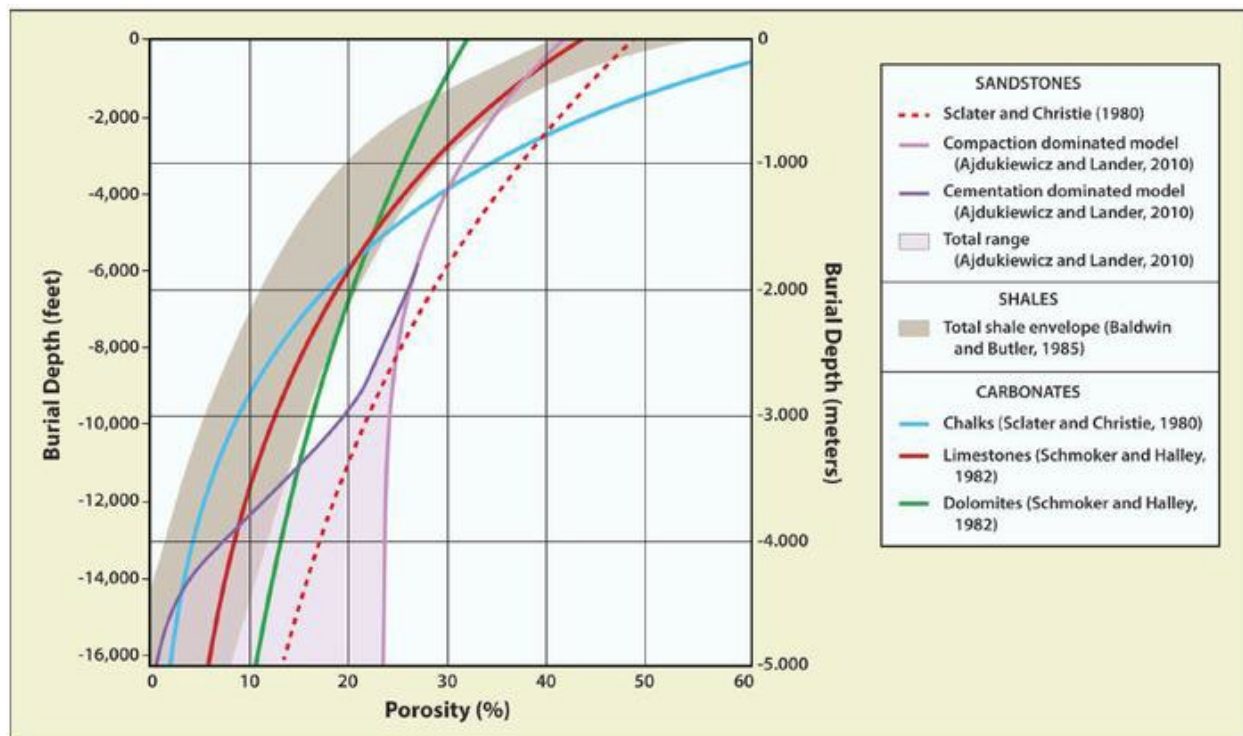


Figure 1-35 – General statistically derived porosity-depth curves for sandstones, shales, and carbonate rocks (Ulmer-Scholle et al., 2014).

Petrophysical analysis was conducted on 67 offset wells with porosity log data, to establish a relationship between lithologic indicator logs (SP and GR) and effective porosity. Effective porosity not only quantifies the extent of intergranular or connected void space within a rock, but also provides a more accurate approximation of the available pore space for fluid movement compared to total porosity. This is because total porosity encompasses intragranular pore space, which can be disconnected from the pore network and may include immovable water bound within clays.

1.5.1. Petrophysical evaluation

1.5.1.1. Porosity

To ensure only valid data is used in forward calculations, quality assurance (QA) was performed on LAS data by comparing the digital data with the corresponding raster log. Digital curves were adjusted as necessary to honor the original raster data. Spontaneous potential logs were baseline corrected. The logs were analyzed for porosity artificially heightened by washouts, caused by loss of contact between the padded density tool and the wellbore, and noted in the “bad hole flag” (BHF) log track in Figure 1-36. Sonic porosity log curves were calibrated to the density log in wells with both logs available. A trend line to explain grain compaction over the injection zone depths was established using the density, neutron, and sonic porosity logs, excluding any flagged washouts. This trend line was corrected for shale.

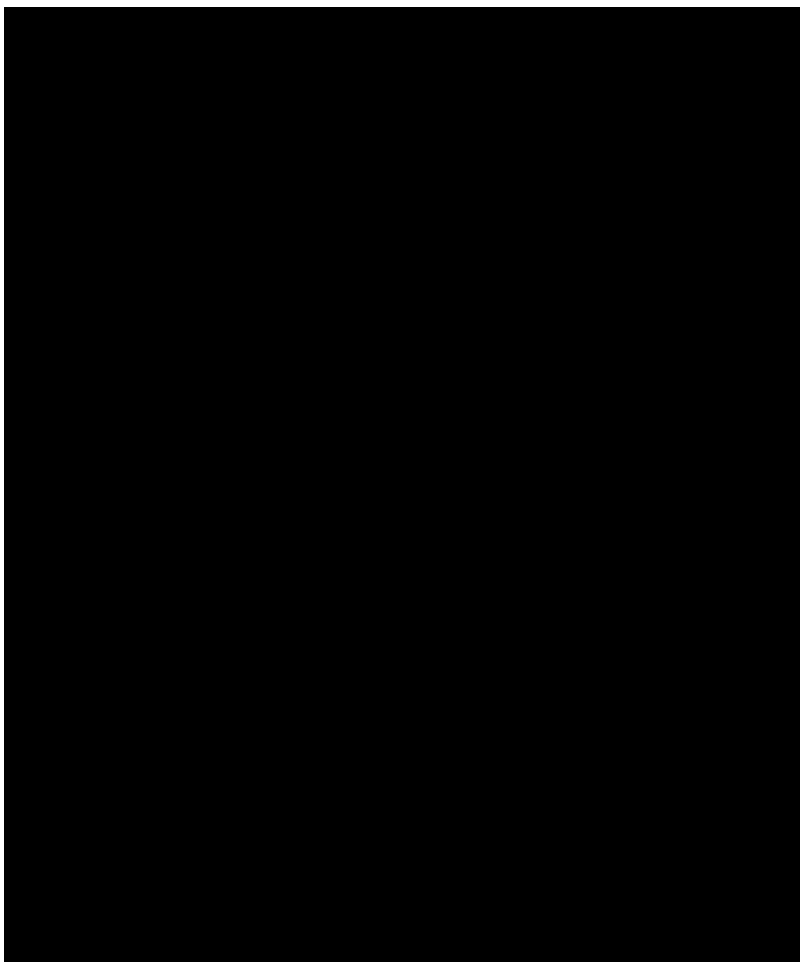


Figure 1-36 – Example of Washouts Identified During the Quality Assurance Process

After the compaction trend line is established and the anticipated total porosity by depth (PHIT) is determined, shale volume (V_{shale}) is computed from either the SP or GR logs, depending on log availability through the targeted depth interval.

V_{shale} is a ratio of shale volume calculated, in this example using the SP log, in Equation 4:

(Eq. 4)

$$V_{shl} = (SP - SP_{clean}) / (SP_{shl} - SP_{clean})$$

Where:

V_{shl} = shale volume, in percentage

SP = value of SP curve

SP_{clean} = baseline sandstone SP curve value

SP_{shl} = baseline shale SP curve value

Using the total porosity from the trend line, a relationship was determined between the total porosity and the normalized SP curve, resulting in Equation 5.

(Eq. 5)

$$\text{PHIT}_{SP} = \frac{SP - SP_{min}}{SP_{max} - SP_{min}} \times (PHIT_{max} - PHIT_{min}) + PHIT_{min}$$

Effective porosity (PHIE) is calculated using Equation 6, with Vshale and total porosity as variables:

(Eq. 6)

$$PHIE = PHIT_{SP} * (1 - V_{shale})$$

Where:

PHIE = effective porosity

PHIT_{SP} = total porosity

Vshale = shale volume, in percentage

The calculated PHIE using PHIT_{SP} was checked for accuracy against the effective porosity curve (PHIE_DT) derived from sonic total-porosity logs. Figure 1-37 demonstrates a good fit between the computed and measured curves. The PHIE equation was applied to surrounding wells with SP log data to produce estimates of effective porosities over the injection zone.

1.5.1.2. Permeability

The permeability of the reservoir and confining intervals was calculated through a petrophysical evaluation performed [REDACTED] wellbores with core data. The data set provided a wide range of porosity values [REDACTED] with associated permeabilities ranging from less than [REDACTED]. The resulting porosity-permeability crossplot, displayed in Figure 1-38, contains a compelling trend line through the data set to provide a predictive relationship between porosity and permeability for the unconsolidated to semi-consolidated sandstones of the Frio Formation. Equation 7, between porosity and permeability and describing the trend line in Figure 1-38, is:

(Eq. 7)

$$\log(k) = a \times PHIT_{SP} + b$$

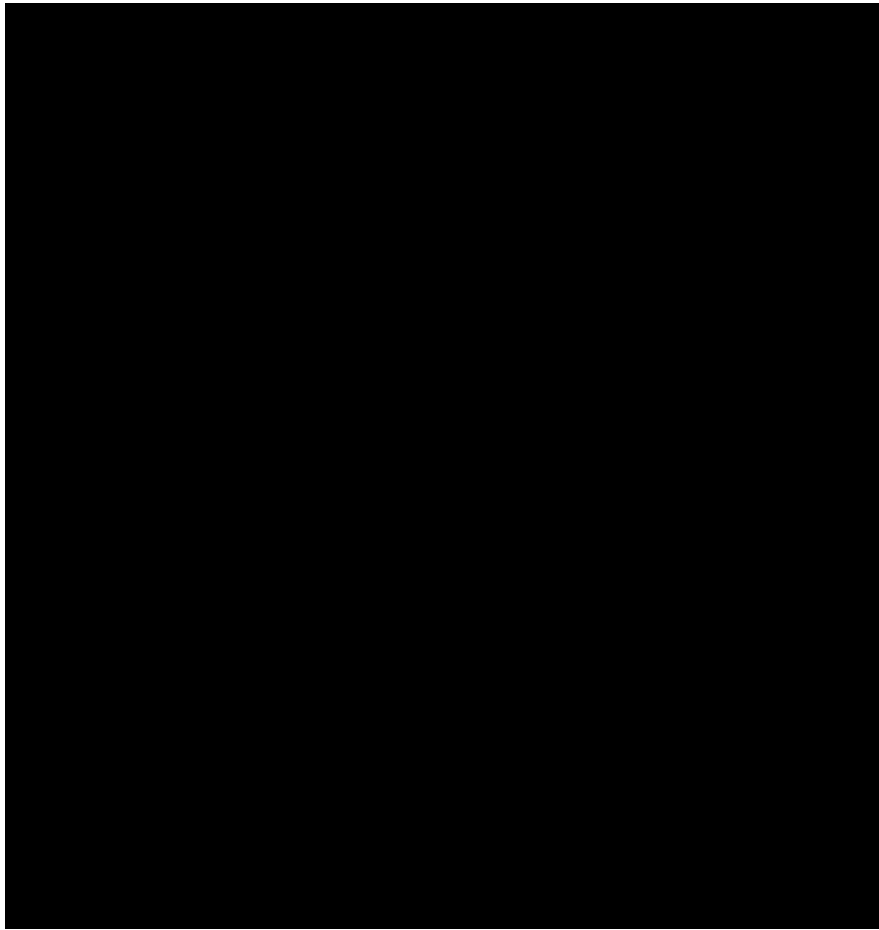


Figure 1-37 – Comparison of Calculated Effective Porosities from SP (PHIE_SP) and Sonic (PHIE_DT)

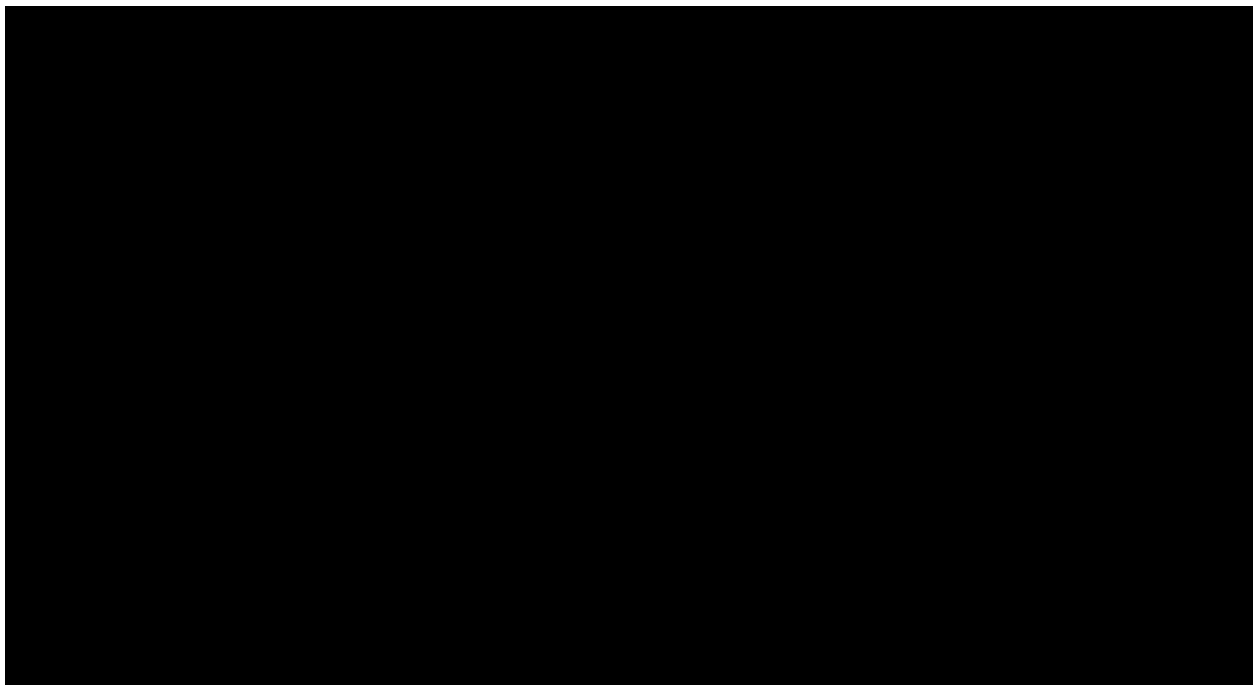


Figure 1-38 – Porosity and Permeability Relationship Established from Core

1.5.2. Upper Confining Zone

Figure 1-39 is an openhole log of offset well [REDACTED], displaying from left to right: calculated Vclay, calculated effective porosity, and calculated permeability. The Vclay curve in the figure is shaded to correspond with lithology, with values close to zero representing clean sand and values of 1 representing clay. Effective porosity is scaled from 0–50%, in decimal form. Permeability scales from 0.5 mD to 5,000 mD, in logarithmic form.

Figure 1-40 (page 57) displays a histogram with respective sand and shale volumes of the gross UCZ. [REDACTED]

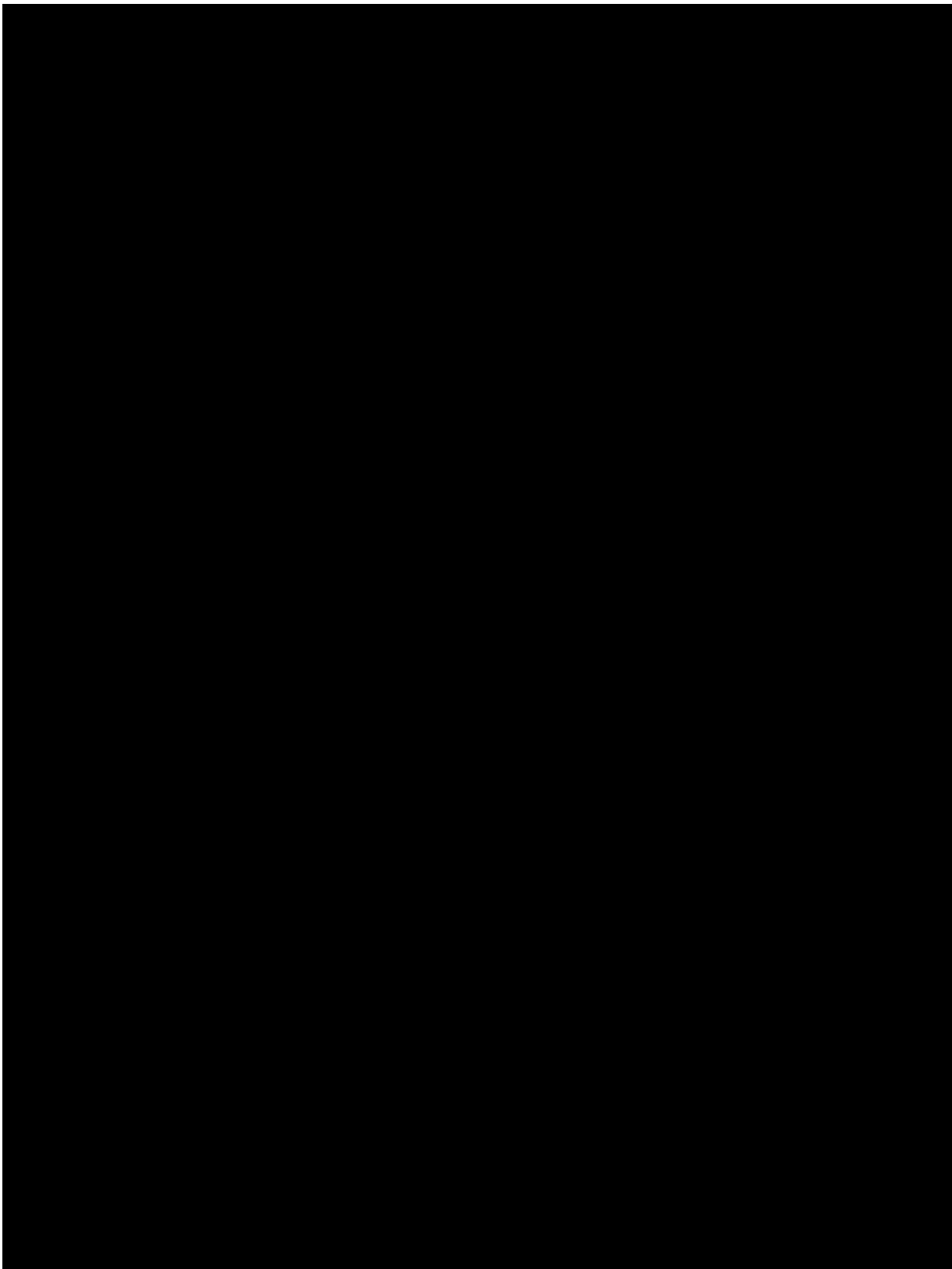


Figure 1-39 – [REDACTED]

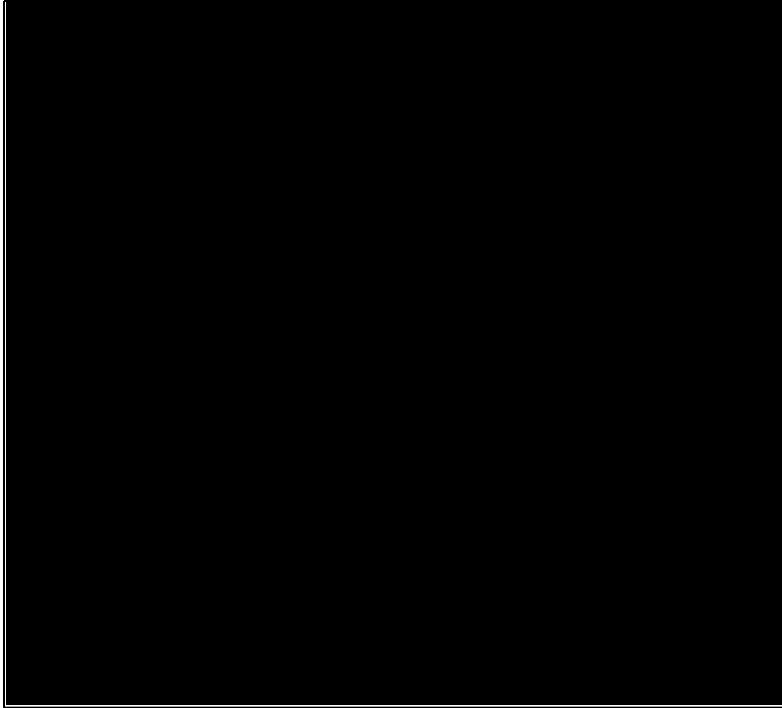


Figure 1-40 – Volume (%) of Facies Within the Upper Confining Zone (Anahuac Shale)

1.5.2.1. Upper Confining Zone Porosity

The histogram provided in Figure 1-41 illustrates the distribution of effective porosity within the Anahuac Shale UCZ, sampled from offset log data at a 0.5-ft sampling rate. The effective porosity displayed in Figure 1-42 is low within Anahuac Shale beds,

[REDACTED]

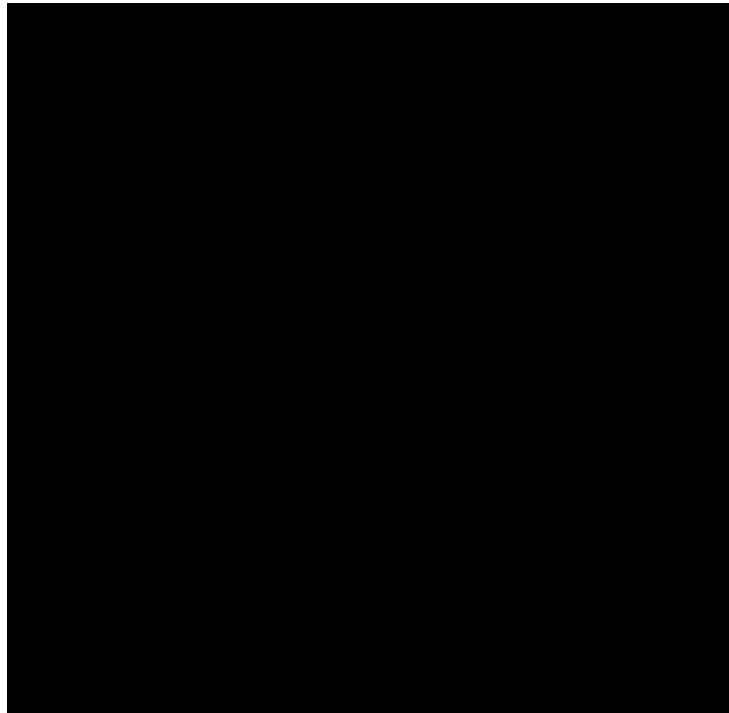


Figure 1-41 – Histogram of Upper Confining Zone Effective Porosity, in Decimal Form

1.5.2.2. Upper Confining Zone Permeability

Based on published data from analogous Anahuac Shale sections, the permeability of the UCZ shale beds is anticipated to be minimal, supporting the use of this section as a seal (Lu, Larson, and Smyth, 2015; Hovorka, 2008). [REDACTED]

[REDACTED] As noted earlier, core in the UCZ is planned during the drilling of a stratigraphic test well to validate the modeled permeability. Once the data from the core is received, this permit application will be updated with the results of the analysis.

1.5.3. **Injection Zone**

Figure 1-42 is an openhole log of [REDACTED], displaying from left to right: calculated Vclay, calculated effective porosity, and calculated permeability. The Vclay curve in the figure is shaded to correspond with lithology, with values close to zero representing clean sand and values of 1 representing clay. Effective porosity is scaled from 0–50%, in decimal form. Permeability is in a logarithmic scale from 0.5 mD to 5,000 mD.

Figure 1-43 (page 60) displays a histogram with respective sand and shale volumes of the injection zone. [REDACTED]

[REDACTED] The sand facies are porous, permeable sand bodies associated with reservoir potential within the gross injection zone. Interbedded shales of the Frio Formation are anticipated to behave as baffles or seals that will aid in trapping injected CO₂.

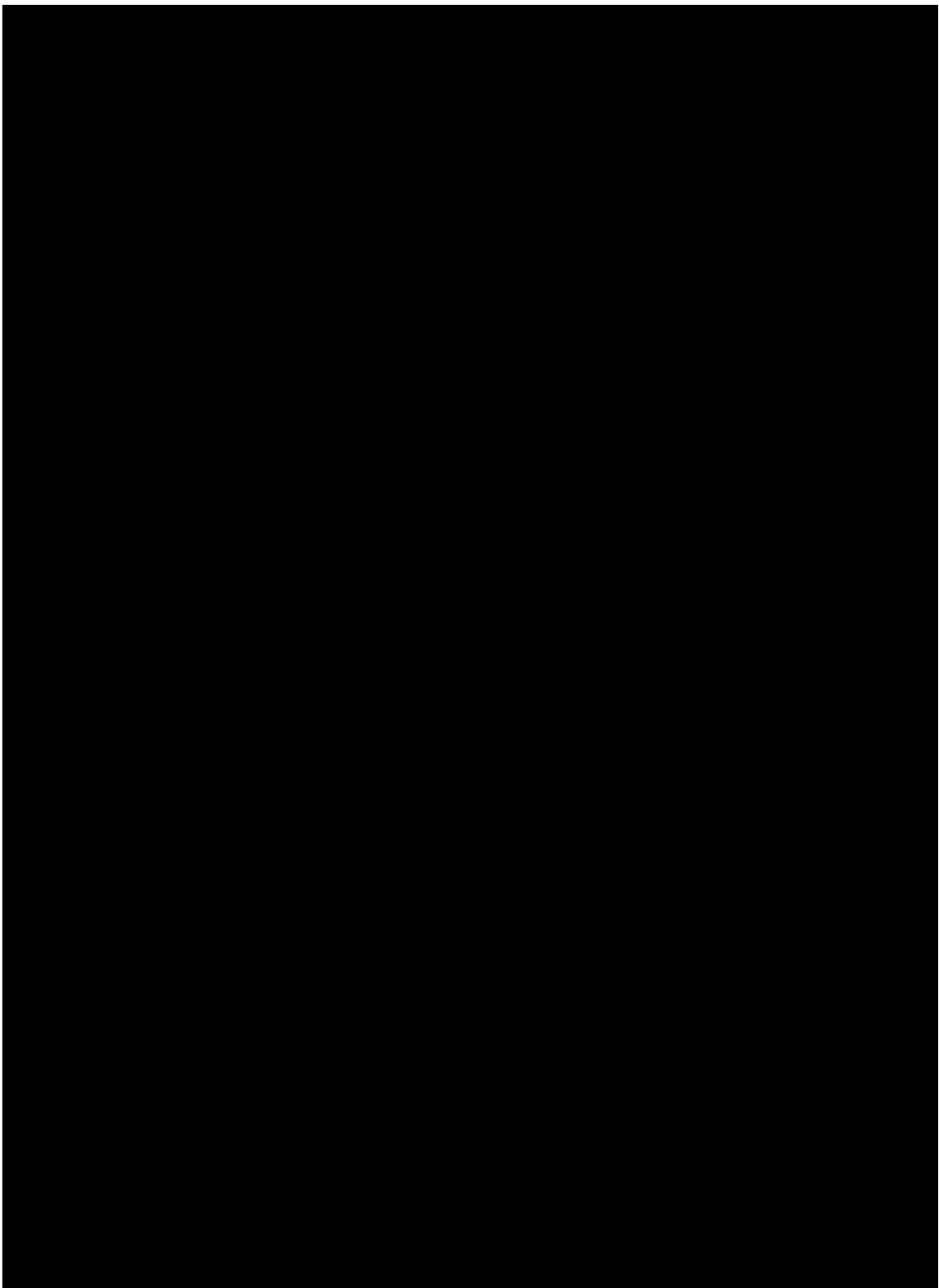


Figure 1-42 – [REDACTED]



Figure 1-43 – Facies Volume (%) of the Gross Injection Zone

1.5.3.1. Injection Zone

In Figure 1-44, two histograms are presented: (a) displays the effective porosity across the entire gross interval, and (b) displays the effective porosity specifically within sand facies of the injection zone. These histograms are derived from a well log data set with a sample rate of 0.5 feet.

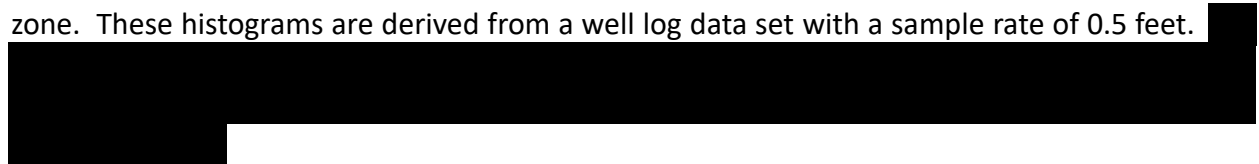




Figure 1-44 – Histograms of Effective Porosity Over the Injection Zone in Decimal Form: (a) All Facies and (b) Sand Facies

1.5.3.2. Injection Zone Permeability

Figure 1-45 plots the distribution of permeability in (a) all facies and (b) sand facies in the injection zone of the geocellular model. With core in the injection zone planned during the drilling of a stratigraphic test well, analysis from the core will be used to calibrate the measured data to log data—and to refine the current model initially built upon publicly available data.



Figure 1-45 – Histograms of Permeability (mD) Over the Injection Zone in Logarithmic Scale: (a) All Facies and (b) Sand Facies

1.5.4. Lower Confining Zone

Figure 1-46 is an openhole log of [REDACTED], displaying from left to right: calculated Vclay, calculated effective porosity, and calculated permeability. The Vclay curve in the figure shaded to correspond with lithology; with values close to zero representing clean sand and values of 1 representing clay. Effective porosity is scaled from 0–50%, in decimal form. Permeability is scaled from 0.5 mD to 5,000 mD, in logarithmic form.

Figure 1-47 (page 64) displays a histogram with respective sand and shale volumes of the modeled LCZ. [REDACTED]

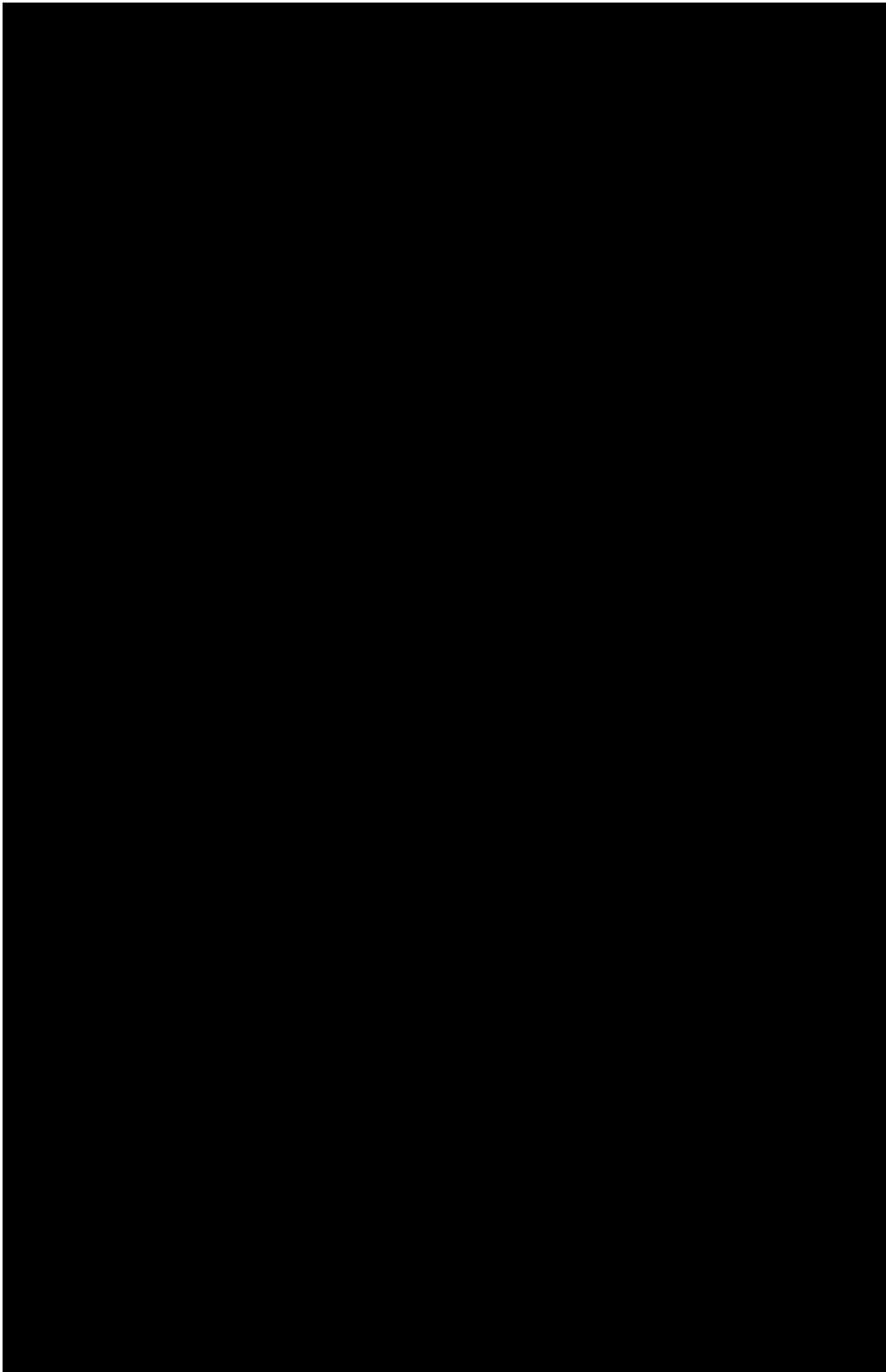


Figure 1-46 –

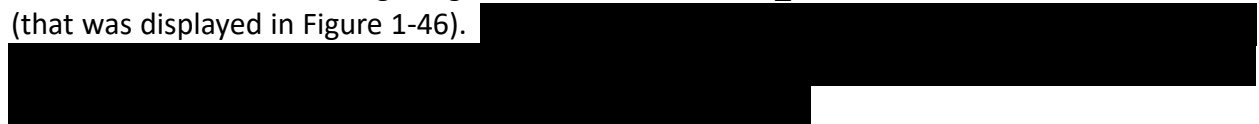
[Redacted text]



Figure 1-47 – Volume (%) of Facies in the Lower Confining Zone

1.5.4.1. Lower Confining Zone Porosity

The histogram provided in Figure 1-48 illustrates the distribution of effective porosity within the modeled LCZ, filtered to shale and sampled from offset log data at a 0.5-foot sampling rate. The modeled LCZ consists of the geologic section from the BASE_FRIO marker to the JACKSON marker (that was displayed in Figure 1-46).



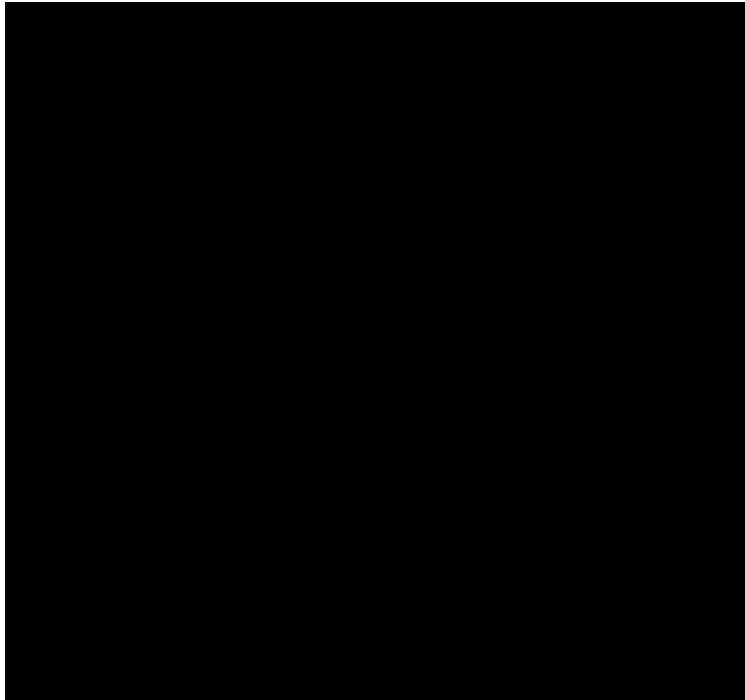


Figure 1-48 – Histogram of Lower Confining Zone Shale Effective Porosity, in Decimal Form

1.5.4.2. Lower Confining Zone Permeability

As core in the LCZ is planned during the drilling of a stratigraphic test well, the data from the core, once received, will be used to update this permit application with the results of the analysis.

1.6. Injection Zone Water Chemistry

The stratigraphic test well, once drilled, will provide fluid analysis results, including measurements of total dissolved solids (TDS) and concentrations of ions and cations from the proposed injection zone. Publicly available data through the USGS was analyzed here to provide a framework of general salinity, constituent components, and regional variability of injection water chemistry. Geochemical modeling in *Section 1.7* utilizes a composite profile from regional data; this modeling will also be updated with site-specific measured data from the stratigraphic test well. The water chemistry was analyzed from the USGS National Produced Waters Geochemical Database (Ver. 2.3).

To examine a regional relationship between TDS and depth, the USGS data set was filtered to the Allen, Beauregard, and Calcasieu Parishes, Louisiana, as well as Newton County, Texas. The depths and associated TDS (milligrams per liter (mg/L) or parts per million (ppm)) are plotted in Figure 1-49 (page 67), with the injection zone depth indicated by the red-dashed lines. Salinity varies over the injection zone. In general, a decline in TDS is observed with increased depth—a phenomena documented in literature and unique to southwest Louisiana. The overpressure

transition zone is associated with a decrease in fluid salinity, and one potential explanation offered is significant dewatering in overpressured shales (Szalkowski, 2003). [REDACTED]

To evaluate potential constituent ions and cations of injection zone brine, the USGS data set was filtered to capture the closest analogous samples. The USGS data set was filtered by parish (Allen, Beauregard, and Calcasieu Parishes), formation (Oligocene-age Frio and Hackberry), and depth (<10,000 ft). The maximum depth was applied to ensure that no overpressured samples were included in the analysis. Seven samples from four wells in the [REDACTED] fields met the criteria: [REDACTED]

[REDACTED] The USGS IDs of the wells and the brine chemistry characteristics of these samples are presented in Table 1-9. A map of these samples in relation to the Evergreen Hub project is provided in *Appendix B*.

Table 1-9 – Analog Wells’ Brine Chemistry

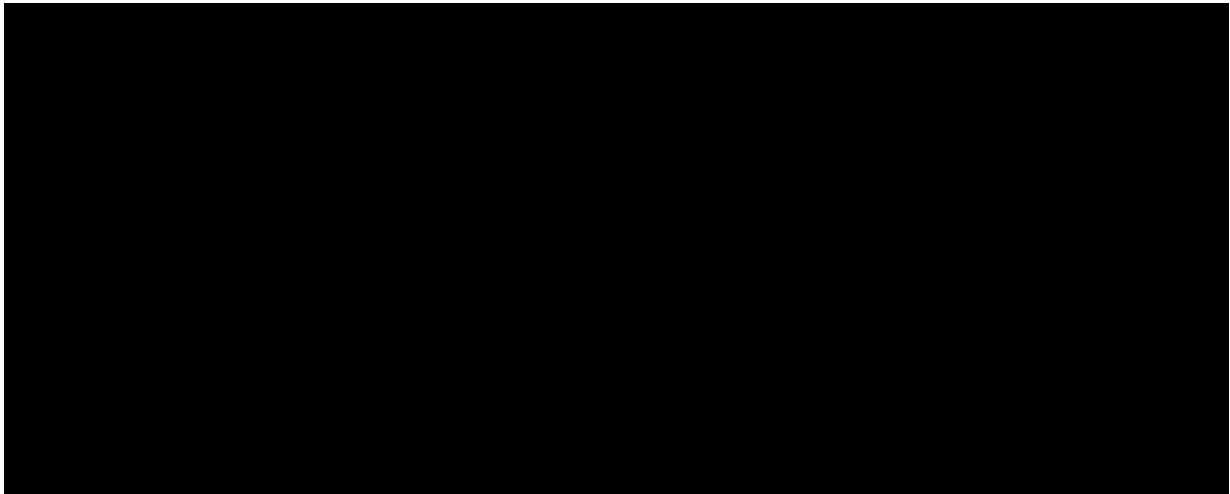




Figure 1-49 – Plot of TDS vs. Depth (ft)

1.7. **Baseline Geochemistry**

The mineral-brine-CO₂ interactions that occur during CO₂ sequestration lead to the alteration of host rock and eventual equilibrium in the mineral-brine-CO₂ system. Chemical modeling and laboratory experiments show that these reactions and eventual equilibria are driven by the specific mineralogy of the target formation, composition of the brine, acidity of the CO₂-brine mixture, and pressure and temperature in the subsurface. This section covers the modeling of

the mineral-brine-CO₂ system across the mineralogical facies associations present for the Evergreen Hub project site.

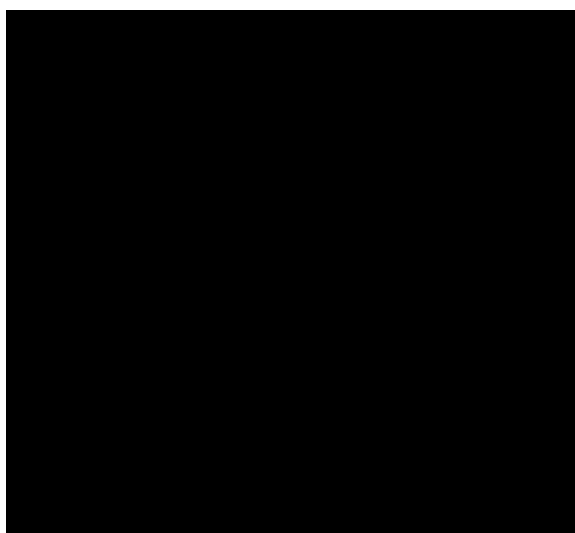
1.7.1. Methods

Simplified, batch kinetic simulation experiments (models) were created for each facies present at the subject location. The models use phase thermodynamic data in the PHREEQC Lawrence Livermore National Laboratory Database and reaction kinetics from Palandri and Kharaka (2004) to model the mineral-brine-CO₂ interactions. Each simulation experiment is isothermal, with the temperature set to match the subject location and depth. The pressure for each simulation experiment is also static and set to match the subject location and depth. The thermodynamic model is based on local equilibrium for the minerals and ions in an aqueous phase. The kinetic calculations assume that abundant CO₂ is supplied to the system during the simulation and that any consumed molecule of CO₂ is replaced. These simplifying assumptions align with the reality of the physical system in that continuous injection allows for an abundant gas supply to the system.

1.7.2. Brine Geochemistry

The brine composition used for the simulations is derived from the USGS National Produced Waters Database. The database contained seven samples of produced water from Oligocene-age (Frio Formation) reservoirs in the [REDACTED] fields of the Beauregard and Calcasieu Parishes. The available analytical values were averaged to create a composite brine composition used in the mineral-kinetics batch models for the confining and injection zones. The composition of the brine is shown in Table 1-10.

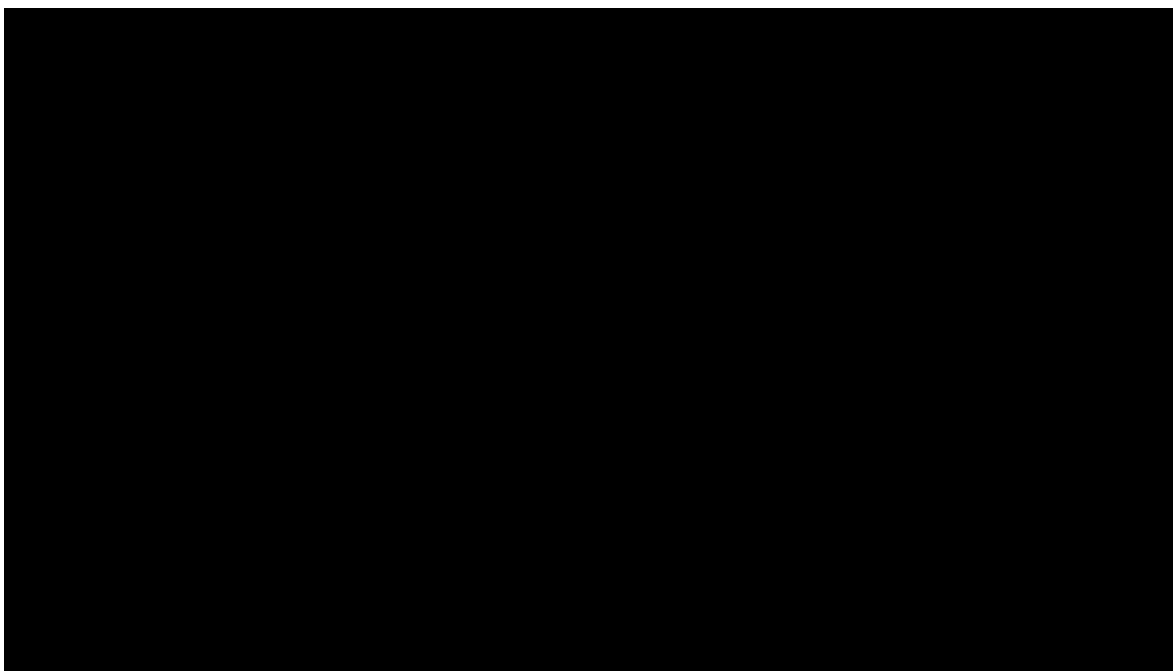
Table 1-10 – Brine composition used to model each of the four mineral facies.



1.7.3. Mineral Geochemistry

Despite the well-understood nature of the stratigraphy in the vicinity of the subject site, published XRD data across the target formations are scarce. The mineral compositions used in the simulations for the Frio injection units were estimated using lithologic descriptions and generalized XRD data from Hovorka and others (2003), Loucks and others (1977), Meckel and Trevino (2019), and McGuire (2009). The mineral compositions used in the simulations for the Anahuac and Vicksburg confining units were estimated from lithologic descriptions from Hovorka and others (2003) and Meckel and Trevino (2019), as well as from XRD analyses of silicate rocks from similar depositional environments published by Weaver (1977). The smectite-illite ratios in the confining intervals were estimated using the depth and transformation relationship published in Freed and Peacor (1989). The values used in the simulation experiments are shown in Table 1-11.

Table 1-11 – Estimated mineral compositions used to model each of the five stratigraphic units.



1.7.4. Models

A total of four geochemical models were created—one each for the UCZ and LCZ, and two for the injection zone. One of the injection zone models uses temperature, depth, and pressure near the top of the injection zone, while the other model uses temperature, depth, and pressure near the base of the zone.

The processes expected in the subsurface were modeled as a product of thermodynamic equilibrium and kinetic reactions using PHREEQC. The models were created as simplified, 1D batch models that occur at pressure and temperatures dictated by their stratigraphic position. The models assume a pressure gradient of [REDACTED] and a thermal gradient of [REDACTED],

with a mean annual surface temperature of [REDACTED]. The injected volume of CO₂ was assumed to fill the pore spaces.

1.7.5. Results

Across all of the models, the results show mild to moderate reactivity within the mineral-brine-CO₂ system. Reactions begin to occur after a few seconds of contact and accelerate through the first several hundred years of simulation time. From 1,000 years to 10,000 years, the reactions approach equilibrium. The precipitation and dissolution of all mineral constituents of the simulation experiments are shown in Figure 1-50. The precipitation and dissolution of minor mineral constituents are shown in Figure 1-51 (page 72).

In general, the confining intervals show moderate precipitation of quartz and smectite with dissolution of illite. The Vicksburg confining unit also shows precipitation of k-feldspar and dolomite.

The injection zone show moderate dissolution of quartz and anorthite with precipitation of albite and calcite. These reactions will lead to modest initial increases in porosity, while precipitation will coat grain interfaces and may occlude some porosity after long residence times.

Overall, the volume of clay species in the injection zone is subordinate to the quartz fraction. Thin-section data indicates that the high-porosity injection zone is quartz grain-supported, which suggests that alteration, dissolution, and precipitation of the subordinate mineral species will have limited impact on injection operations.

A number of necessary assumptions used in this modeling work lead to the models overrepresenting the speed and amount of alteration—compared to what will occur in the natural system. The equilibrium rates in the subsurface are expected to be much slower than those predicted. This slower rate is primarily due to the reactions taking place within the pore system of a rock volume as opposed to the simulated batch reactor. The pore system influences concentration gradients and decreases the surface area of each mineral available for reaction, leading to the slower reaction rates. Furthermore, geologic and hydrologic factors such as fluid flow paths may alter ion availability and system reactivity. Ergo, the modeling work in this section is an analysis of the upper bound of reactivity.

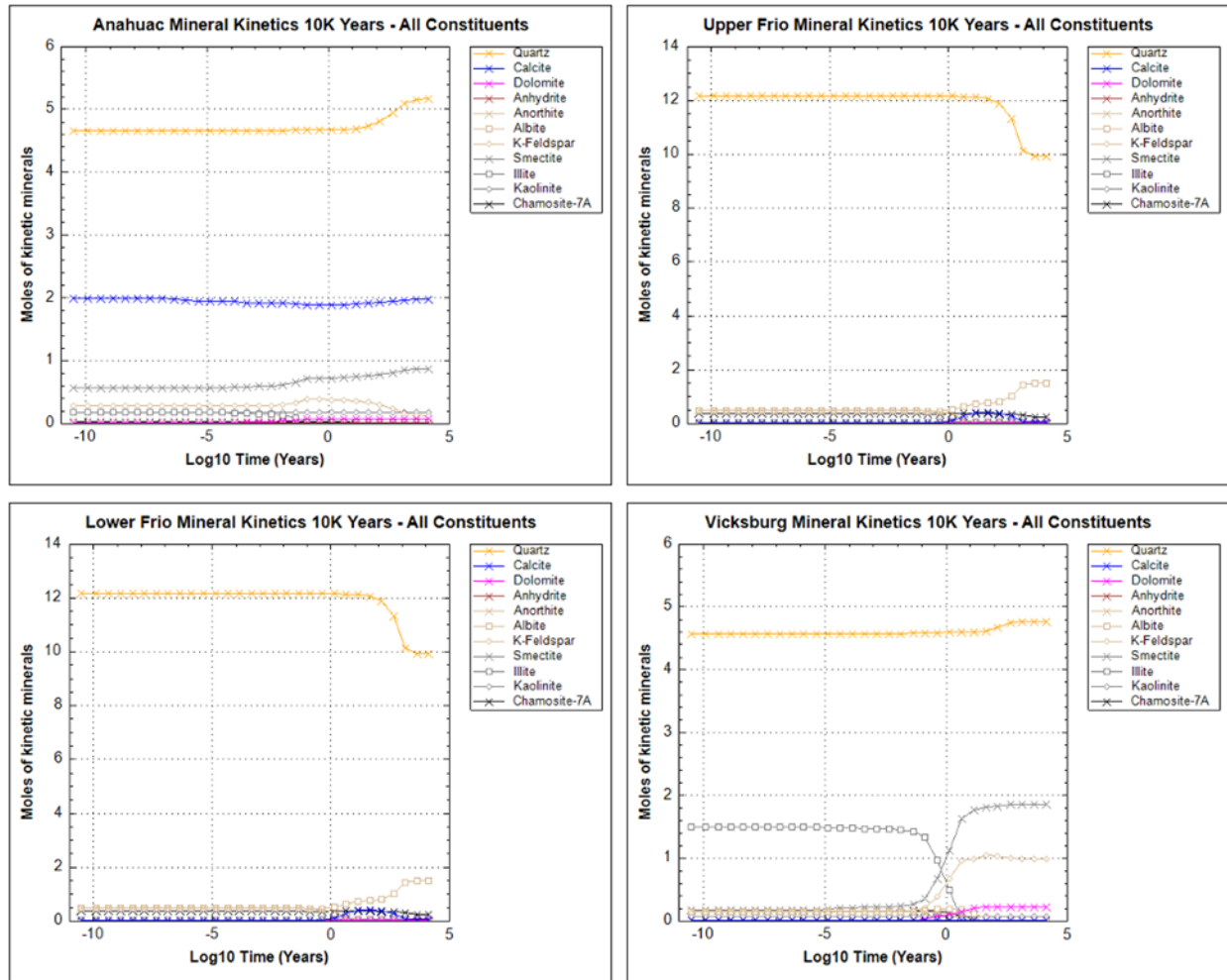


Figure 1-50 – The results of the batch simulations for all mineral constituents, shown by unit.

The x-axis is $\log_{10}$ time in years. The reaction time spans from 0.001 seconds to 10,000 years. The Anahuac and Vicksburg confining intervals show precipitation of quartz and minor mineral phases, while the injection zone graphs show dissolution of quartz and precipitation of minor mineral phases.

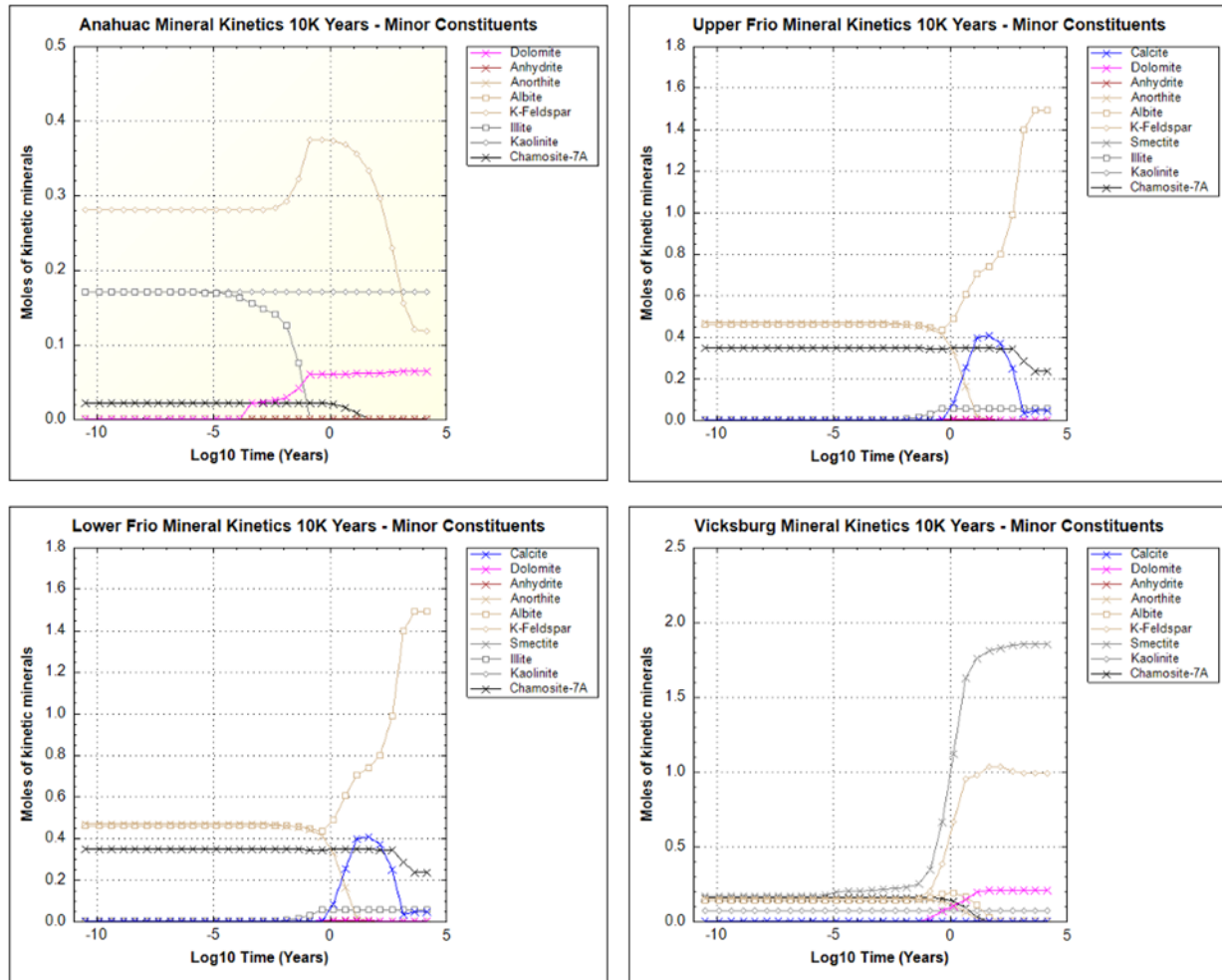


Figure 1-51 – The results for minor mineral phases of the batch, shown by unit.

The x-axis is $\log_{10}$ time in years. The reaction time spans from 0.001 seconds to 10,000 years. The confining intervals show complex precipitation and dissolution behavior, while the injection zone graphs on the right show principally precipitation of albite and dissolution of anorthite.

1.8. Hydrology

The hydrology in southwest Louisiana includes aquifers that are mostly composed of sand or gravel, and confined or separated by clay and silt layers. This study focuses on four aquifers with regional potential as an Underground Source of Drinking Water (USDW), from shallowest to deepest: Chicot aquifer, Evangeline aquifer, Jasper aquifer, and Catahoula aquifer. The extents of these aquifers are plotted in Figure 1-52(a), with the Evergreen Hub project area indicated by a red "x." A stratigraphic column of the hydrogeologic units is provided in Figure 1-52(b) (Darling & Meselhe, 2002). Publicly available data from the USGS, LDNR, and peer-reviewed journals were used for each aquifer's groundwater information, water well data, and relevant figures in this section.

Water withdrawal and usage has been reported over 5-year periods by the USGS and the Louisiana Department of Transportation and Development (DOTD) since 1960. Historically, the highest water extraction was noted in the 1980 report, with 12,500 million gallons per day (Mgal/D) of the state's total water (surface and groundwater) being used. Between 1985 and 1990, the total amount of water used decreased dramatically; starting in 1995, the rise in water withdrawals was steady until 2000, at which point they decreased once more over the following 10 years. In 2015, an estimated 8,720 Mgal/D of water was withdrawn statewide, marking a 2.6% increase from 2010 (Robinson & Sargent, 2018). Unlike Calcasieu Parish, groundwater has been the main source of water in Beauregard Parish since 1995. According to estimates made in 2015, 44.12 Mgal/D of groundwater was withdrawn in Beauregard Parish and 243.49 Mgal/D of total water in Calcasieu Parish. The primary water usage is industrial, accounting for 80% in Beauregard Parish and 70% in Calcasieu Parish. Groundwater resources in Beauregard Parish predominantly rely on the Chicot aquifer system, but surface water in Calcasieu Parish plays a key role—supplying about 60% of the total water used (LMWRR, 2020).

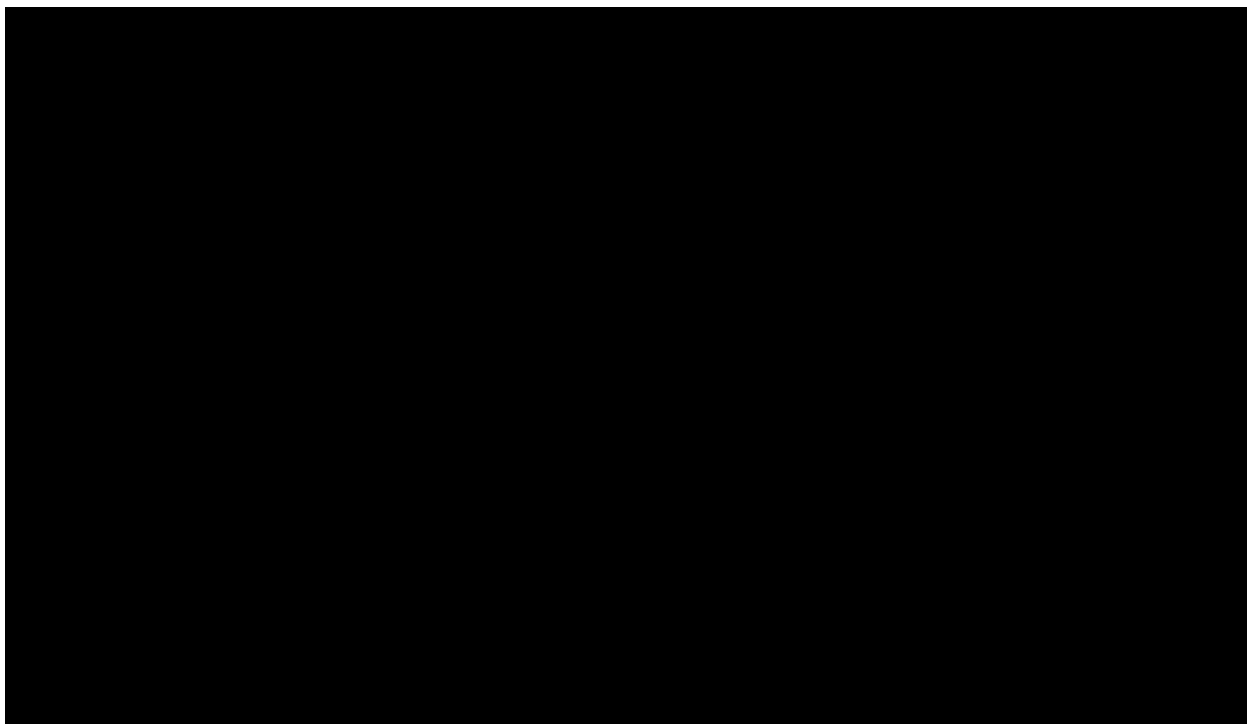


Figure 1-52 – (a) Regional aquifer extent and the approximate location of Evergreen Hub project (indicated by the red x); (b) general hydrological units (modified from Darling and Meselhe, 2002).

1.8.1. Base of USDW Determination

The base of the USDW at the Evergreen Hub site is in the Blounts Creek Member of the Evangeline aquifer. A structure map of the base of the USDW and associated cross sections at the project site are included in *Appendix B*. Figure 1-53 shows a published structure map of the base of the USDW for Calcasieu Parish, with a red “x” indicating the approximate location of the Evergreen Hub. The base of the USDW was determined using a well data method recommended by the

LDNR Injection and Mining Division, resulting in a deeper USDW at the project site than the estimated depth in Figure 1-53. Lateral variations of the USDW were mapped, as the base migrates from the deepest Blounts Creek sand to a younger sand within that unit. The average depth of the USDW's base, in the project area, is [REDACTED]

The SONRIS database contains three verified USDW base values from wells within [REDACTED] mi of the Evergreen Hub: the [REDACTED]

[REDACTED] The USDW base values provided in SONRIS are [REDACTED] measured depth (MD), respectively. These depths are consistent with the structure map provided in *Appendix B*. The proposed injection zone and the USDW base are separated by more than 1,900 ft of rock, composed of interbedded silt, clay, sand, and shale (including two regional aquitards). The groundwater and above-zone monitoring plan provided in *Section 5 – Testing and Monitoring Plan* are designed to secure the protection of all USDWs in the project area.

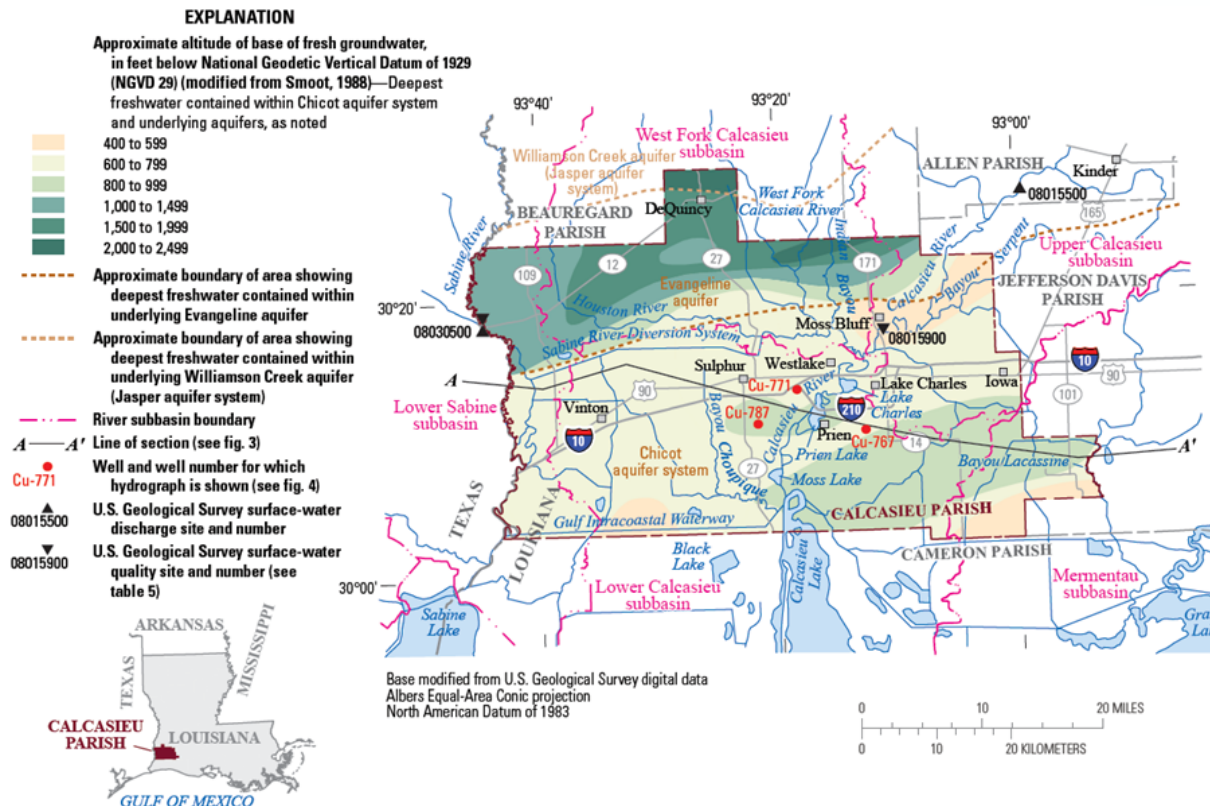


Figure 1-53 – The USDW base altitude map for Calcasieu Parish (White and Prakken, 2017). The red x represents the approximate location of the Evergreen Hub.

1.8.2. Chicot Aquifer System

1.8.2.1. Stratigraphy of the Chicot Aquifer System

The Chicot aquifer system (AS) in southwestern Louisiana covers an area of 9,000 sq mi and is considered one of the state's four major aquifers. This artesian aquifer system is composed of Pleistocene-Holocene age deposits, including massive sands, gravel, and silt, with scattered, thinner clays that are unevenly distributed as well as sandy clay (Sargent, 2004). According to Rask (2020), these strata exhibit a depositional southeastern dip that deepens as they approach the Gulf of Mexico but thins outward to the west. Laterally continuous sands in this aquifer are often thicker and more amalgamated (Lindaman, 2023). The aquifer system has a thickness of 50–1,050 ft (southward) and the water table ranges from 25–75 ft below ground level. In the northern three-quarters of the aquifer system, freshwater is encountered to its base. In the southern quarter, saltwater encroachment has occurred, and freshwater is at depths of 400–700 ft below ground surface (Darling and Meselhe, 2002). In Beauregard Parish, where the Evergreen Hub project is located, the Chicot AS is comprised of a clay-rich surficial confining unit, containing a shallow sand unit and a deeper undifferentiated sand unit (also referred to as the massive sand). South of the project location near Lake Charles in Calcasieu Parish, these vast sands become a complex succession of restricting clays and sand layers, known as the “200-foot,” “500-foot,” and “700-foot” sands (Lindaman, 2023).

Shallow Sand Unit

The Chicot AS “surficial confining unit” consists of clay and sand that thicken regionally towards the south and dip towards the GOM. Along the border between Beauregard Parish and Calcasieu Parish, the surficial confining unit has a thickness of 120–160 ft, and the shallow sands within the confining unit are made up of sporadic sandy lenses known as the “shallow sand unit” (Prakken et al., 2012; Sargent, 2004; White and Prakken, 2017). Sargent (2004) estimated the shallow sand unit to be less than 10 ft thick, with limited distribution, in northern Calcasieu Parish and south-central Beauregard Parish, near the proposed Evergreen Hub. According to the SONRIS database, Beauregard Parish has 111 registered active water wells screened in the shallow sand as of 2023. This compares to the assessment by Prakken et al. (2012) of 102 wells with a median water well depth of 26 ft below the surface. In 2015, an average of 0.17 Mgal/D of water was withdrawn for domestic and livestock use from the shallow sand (Prakken et al., 2012).

Massive Sand Unit

Below the surficial confining unit lies the massive sand interval, which serves as the primary source of fresh groundwater for the Beauregard and Calcasieu Parishes. Typically, this sand bed thickens southward, reaching several hundred feet in depth. The sediment particle sizes vary from coarse sand and gravel to finer sediments, which are interbedded by clay layers towards Lake Charles, creating a more complex system (Prakken et al., 2012). The base of the aquifer is often determined by the base of increased resistivity on geophysical logs, caused by higher sand and gravel content (Lindaman, 2023). Prakken et al. (2012) described this unit in Beauregard Parish as sand, silt, gravel, and clay beds, with freshwater well depths ranging from 16 ft to 461 ft below the ground surface. Water from this aquifer is used for agriculture, livestock, irrigation, industry, and public consumption in both Beauregard Parish and Calcasieu Parish (Prakken et al.,

2012; White and Prakken, 2017). The Chicot AS base in the Evergreen Hub AOI is situated at a TVDSS ranging from -800 ft to -890 ft, as documented by Young et al. (2012) and supported by Lindaman (2023), Ecology and Environment (2011), White and Prakken (2017), and the LDNR Water Well Registration database. In the proposed project AOI are six registered Chicot water wells, only one of which is currently active, used for hydrocarbon drilling rig supply. [REDACTED] is situated approximately [REDACTED] mi north of Loblolly CCS No. 001 and [REDACTED] mi from Loblolly CCS No. 002. Figure 1-54 plots the locations and aquifer systems of [REDACTED] and other wells discussed below. [REDACTED] is considered to be the deepest well targeting the Chicot massive sand, with a TD of 370 ft below ground level. This well supplied an oil-and-gas rig before being plugged and abandoned in [REDACTED] mi from the Evergreen Hub.

The relative west-east and north-south schematic cross sections shown in Figure 1-55 (page 77) depict the Chicot AS's variation in stratigraphy over multi-parish distances. The Chicot AS stratigraphic column provided in Figure 1-56 (page 78) identifies associated regional nomenclature.

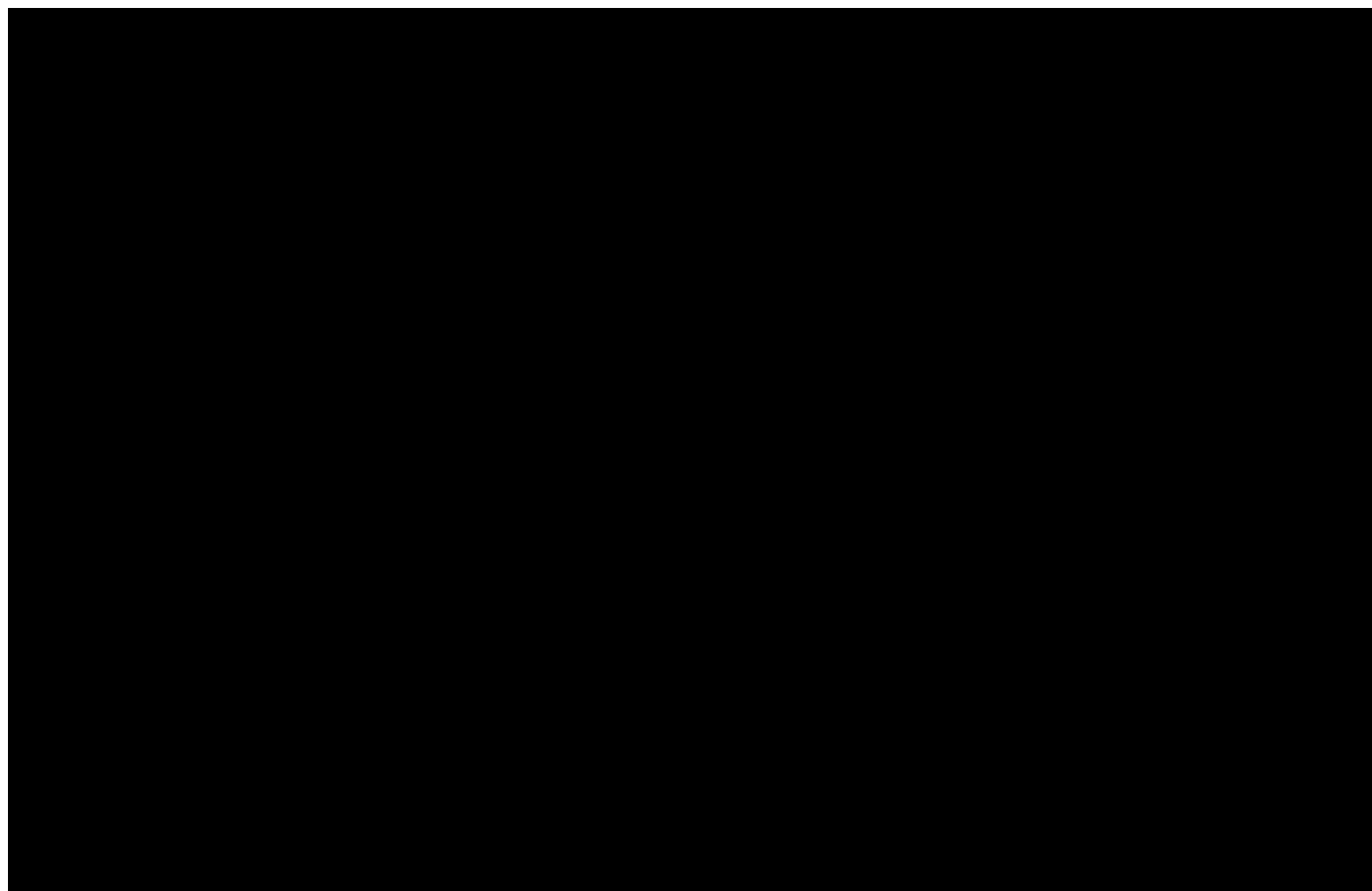


Figure 1-54 – Water Wells Near the Evergreen Hub AOI

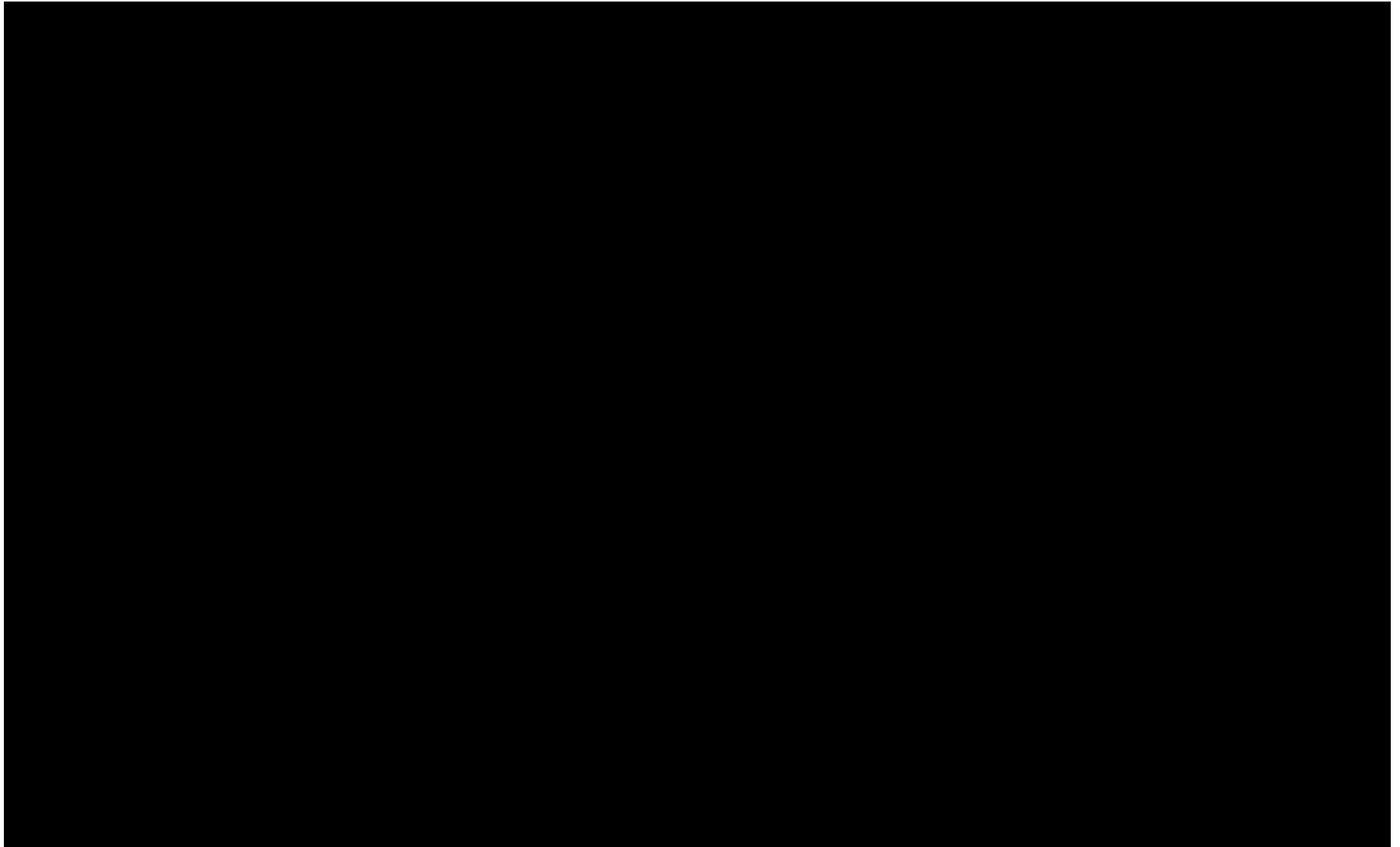


Figure 1-55 – (a) West-east profile across the Chicot aquifer system, with the Evergreen Hub location marked by a red x (modified from Ecology and Environment, 2011); (b) north-south profile across the Chicot AS (modified from Hamid and Tsai, 2021).

Era	System	Epoch	Formation symbol ¹	Stratigraphic or allostratigraphic units	Local hydrogeologic units			Hydrogeologic units (this report)	Regional aquifer system
					Lake Charles area ⁷	East of Calcasieu Parish ⁷	Outcrop area ⁷		
Cenozoic	Quaternary	Holocene	Qal	Recent alluvium, deltaic and chenier plains	Surficial confining unit and shallow sands, Atchafalaya aquifer, and Red River alluvial aquifer			Chicot aquifer system	Coastal Lowlands aquifer system (Weiss, 1992)
			Qnl						
			Qdf						
			Qds						
			Qcf						
	Qcs								
	Qtd								
	Pleistocene	Qtp	Prairie Allogroup ²	Subdivisions of Chicot aquifer system	"200-foot" sand ²	"Upper" sand ⁷	Undifferentiated sand ²		
		Qti	Intermediate Allogroup ³					"500-foot" sand ²	
					"700-foot" sand ²	Undifferentiated "lower" sand ²			
	Neogene	Pliocene	Qth	Upland Allogroup ³	Evangeline aquifer			Evangeline aquifer	
			Miocene	Mfb					
		Mfcc		Castor Creek Member	Castor Creek confining unit ⁵	Jasper aquifer system			
		Mfw		Williamson Creek Member	Williamson Creek aquifer				
		Mfd		Dough Hills Member	Dough Hills confining unit				
		Mfcb		Carnahan Bayou Member	Carnahan Bayou aquifer				
Mll		Lena Member		Lena confining unit	Catahoula aquifer				
Oligocene		Oc		Anahuac Formation ⁶		Catahoula aquifer			
			Frio Formation ⁶						
Paleogene	Oligocene	Ov	Vicksburg Group	Vicksburg-Jackson confining unit			Vicksburg-Jackson confining unit	Vicksburg-Jackson confining unit	
		Ej	Jackson Group						

Figure 1-56 – Stratigraphic column displaying Chicot aquifer system nomenclatures (modified from Lindaman, 2023).

1.8.2.2. Characteristics of the Chicot Aquifer System

Recharge and Discharge

The primary recharge sources for this aquifer system are precipitation in the upland outcrop-subcrop zones to the north, and interstream runoff that seeps into the sandy soil. South of the primary recharge area, water moves vertically through the clays and flows in from the Calcasieu River, serving as a secondary recharge source (Prakken et al., 2012). The Chicot AS is connected to the Calcasieu River's northern stretch for about 14 km, where the sands are approximately 320 ft thick (Hamid and Tsai, 2021). The primary discharge for the aquifer system is water well withdrawal (Prakken et al., 2012).

Potentiometric Surface and Groundwater Flow Direction

Groundwater flow in an aquifer relies on the aquifer slope, as the flow goes from higher hydraulic head areas to lower hydraulic head areas, with flow direction running perpendicular to potentiometric surface contours. The Chicot AS water flow has changed since 1946, as excessive water withdrawals have caused elongated depression cones to extend throughout the region, lowering the water levels (Lovelace, 1999). In Beauregard Parish, the undifferentiated sand unit's water levels typically vary by 1–2 ft per year (Prakken et al., 2012). The USGS Chicot AS potentiometric surface map (Figure 1-57) indicates that groundwater in the Evergreen Hub project area should flow southeast. This figure also highlights the Chicot AS freshwater extent and the recharge area. The array of groundwater monitoring wells displayed in *Appendix F1* is designed to protect the USDW.

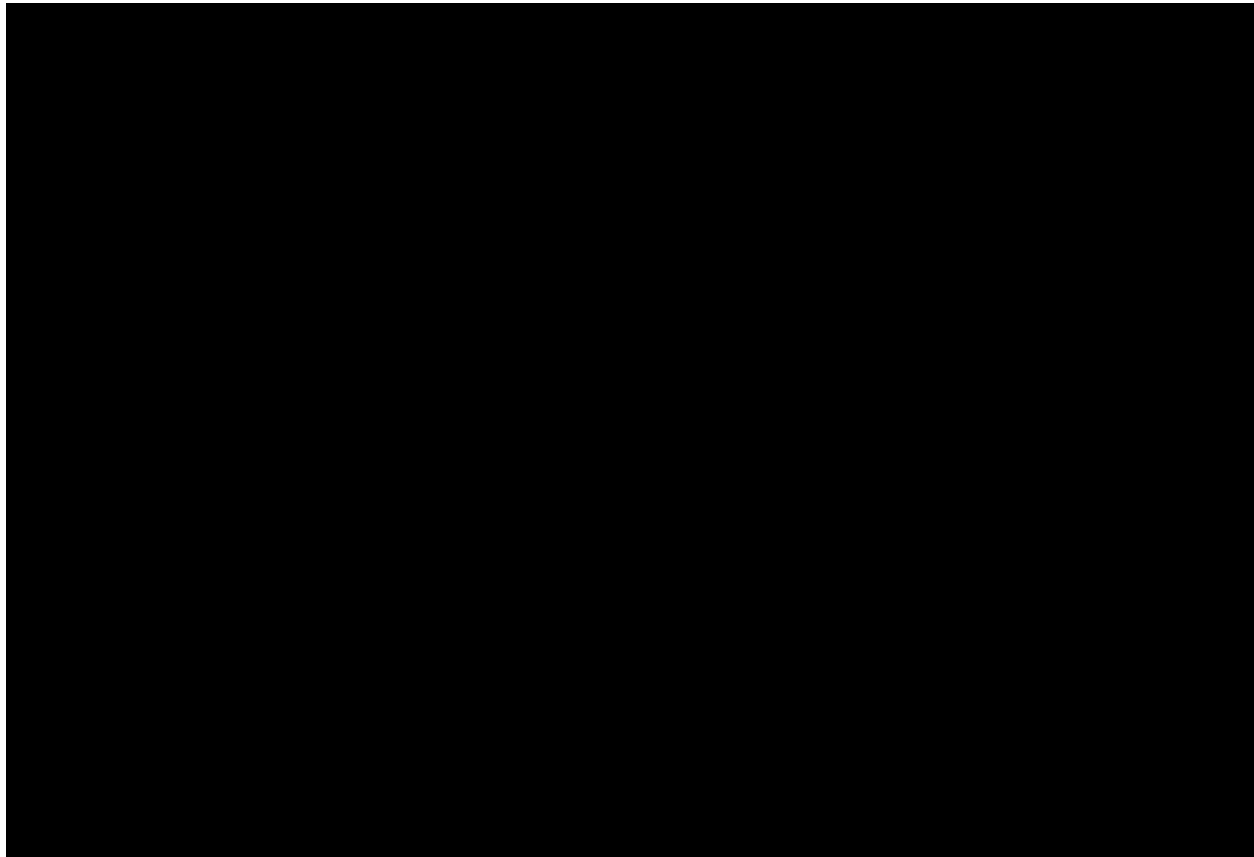


Figure 1-57 – Potentiometric surface map of the Chicot aquifer system in southwest Louisiana (modified from Lovelace, Fontenot, and Frederick, 2002). The red star approximates the location of the Evergreen Hub project.

Water Quality

The Chicot AS is regarded as one of Louisiana’s most important aquifer systems and has been the subject of numerous evaluations, in an effort to raise public awareness of water quality and management on a local and national level. Based on 62 well tests carried out in the Chicot AS massive sand studied in the Water Resources of Beauregard Parish publication, the water in that parish is classified as soft, with a median pH of 6.3, and complies with the EPA’s National Secondary Drinking Water Regulations (NSDWR). However, localized salt incursions in the southeast sections of the parish may exceed the NSDWR (Prakken et al., 2012).

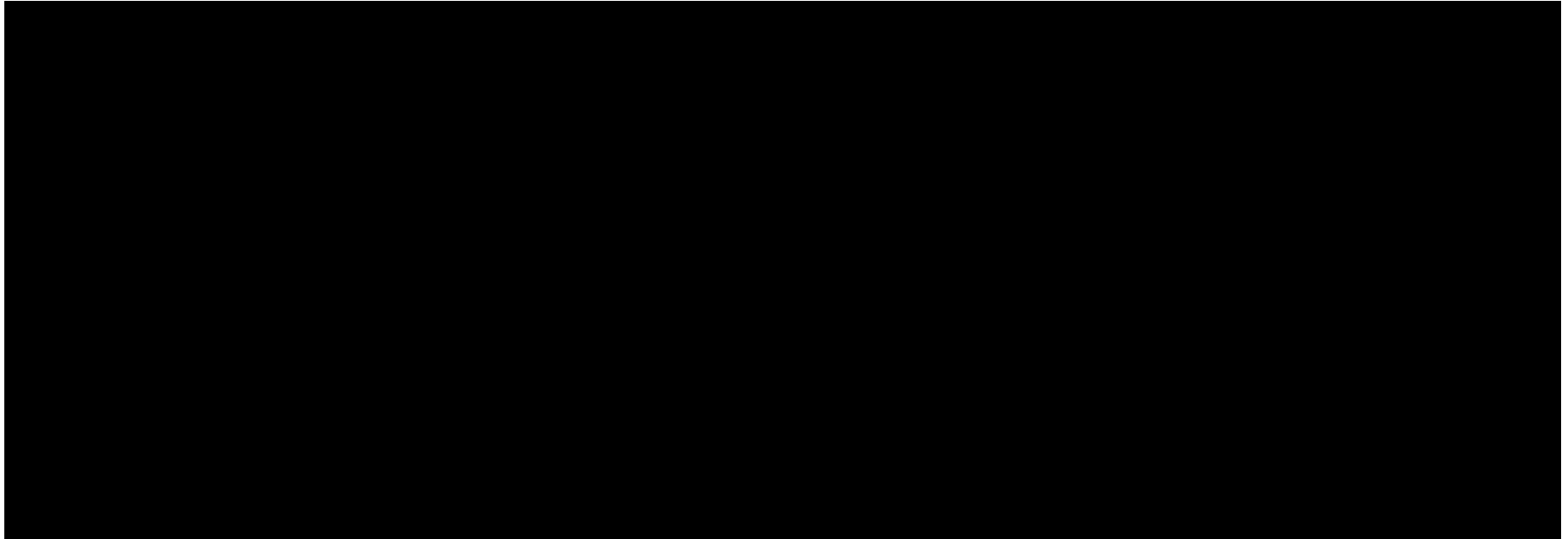
Multiple reports contain water quality data from wells near the Evergreen Hub. Table 1-12 represents the findings from tests conducted on the Chicot shallow sands. The water quality north of the proposed project AOI is good and does not exceed the NSDWR, as demonstrated by

However, this changes near the Beauregard Parish and Calcasieu Parish border, as wells located to the east

exceed the NSDWR by iron and manganese

concentrations. In a study by Young et al. (2012), regional water quality maps estimated that the Chicot AS in the Evergreen Hub AOI contain 41–80% of freshwater (with less than 1,000 ppm TDS concentration); 21–60% could be slightly saline water with a TDS between 1,000–3,000 ppm; and less than 20% could be moderately saline water with a TDS greater than 3,000 ppm.

Table 1-12 – Chicot AS Water-Quality Characteristics Near the Evergreen Hub AOI



1.8.3. Evangeline Aquifer System

1.8.3.1. Stratigraphy of the Evangeline Aquifer System

The Evangeline AS in Louisiana extends from the Vernon and Rapides Parishes in the north to the northern portions of the Calcasieu, Jefferson Davis, and Acadia Parishes—and encompasses the Beauregard, Allen, and Evangeline Parishes and portions of the Avoyelles and Saint Landry Parishes (Darling and Meselhe, 2002). The Evangeline aquifer is situated below the Chicot AS and overlies the Castor Creek confining unit. Various reports have been conducted on the Evangeline AS, defining it to include the undifferentiated Pliocene sands and the Pliocene-Miocene age Blounts Creek Member of the Fleming Group. Lindaman (2023) also includes the Castor Creek Member as part of the Evangeline AS. Generally, the aquifer dips and thickens towards the south-southeast, with depths ranging to more than 2,200 ft below sea level (Darling and Meselhe, 2002). The Evangeline AS stratigraphy and hydrogeological tops identified by Lindaman (2023) and Young et al. (2012) were adopted for this section.

Blounts Creek Member

Young et al. (2012) characterize this unit as sandstone beds from the Pliocene to Pliocene-Miocene age of the Fleming Formation, consisting of lower coastal-plain fluvial and coastal facies. The Blounts Creek Member is primarily composed of sands, silts, and silty clays, along with some gravel and lignite (Ecology and Environment, 2011). Some sand-dominated intervals can reach a thickness greater than 30 ft (Young et al., 2012). In the proposed Evergreen Hub AOI, the Evangeline AS's base ranges from -2,798 ft to -3,232 ft (TVDSS), north to south (Young et al., 2012)). This is consistent with estimates made by Prakken et al. (2012) at 3,000 ft, and Lindaman (2023) at 2,800 ft. Freshwater is prevalent throughout most of Beauregard Parish, except near the southern parish boundary line, where it contains saltwater. In 2009, approximately 39 wells drew water for the Evangeline AS in Beauregard Parish (Prakken et al., 2012), and according to the SONRIS database as of 2023, fewer than 10 wells are currently active. Within the proposed project AOI, no well has been reported to target the Evangeline AS. Additionally, the nearest well [REDACTED] is [REDACTED] mi from the project, with a TD of [REDACTED], and actively supplies water for industrial purposes, according to SONRIS (Figure 1-54, Section 1.8.2.1).

Castor Creek Member

The Castor Creek Member (Castor Creek confining unit or the Burkeville aquiclude equivalent) was described by Young et al. (2012) as a large continuous zone with low permeability, between the Evangeline and Jasper aquifer systems. This marine shale is associated with the paleomarker *Amphistegina* B (Amph B) (Lindaman, 2023). The top of the Amph B marks the top of the Castor Creek Member, and the base is the Amph B base.

1.8.3.2. Characteristics of the Evangeline Aquifer System

Recharge and Discharge

Recharge to the Evangeline AS occurs via precipitation in areas where the system outcrops; discharge is primarily by water withdrawals from wells used for domestic, public, irrigational, and industrial purposes (Prakken et al., 2012).

Potentiometric Surface and Groundwater Flow Direction

The Evangeline AS freshwater extends across multiple parishes, as displayed in Figure 1-58; to the east, the “Evangeline aquifer equivalent” is also present. However, a north-south anti-salt vortex through the Avoyelles and Saint Landry Parishes has separated the comparable stratigraphic deposits (Darling and Meselhe, 2002). The freshwater movement generally flows to the south-southwest, with an annual water-level variation of 1– 2 ft for most of Beauregard Parish (Prakken et al., 2012).

Water Quality

The general freshwater-quality characteristics in Beauregard Parish describe the water as soft and not exceeding the EPA maximum contaminant levels (MCLs) for drinking water in most parts, although this varies locally (Prakken et al., 2012). The Evangeline water quality in the Evergreen Hub AOI is expected to exceed the EPA MCLs of 300 µg/L for iron and 50 µg/L for manganese (Prakken et al., 2012; White and Prakken, 2017). Furthermore, the project AOI does not have any current or historically registered water wells drilled into the Evangeline AS. According to the Young et al. (2012) study, the water composition in the AOI might be slightly saline water with a TDS of 1,000–3,000 ppm (61–100%), and may contain some freshwater (<20%) with a TDS of less than 1,000 ppm, or some moderately saline water (0–20%) with a TDS less than 3,000 ppm.

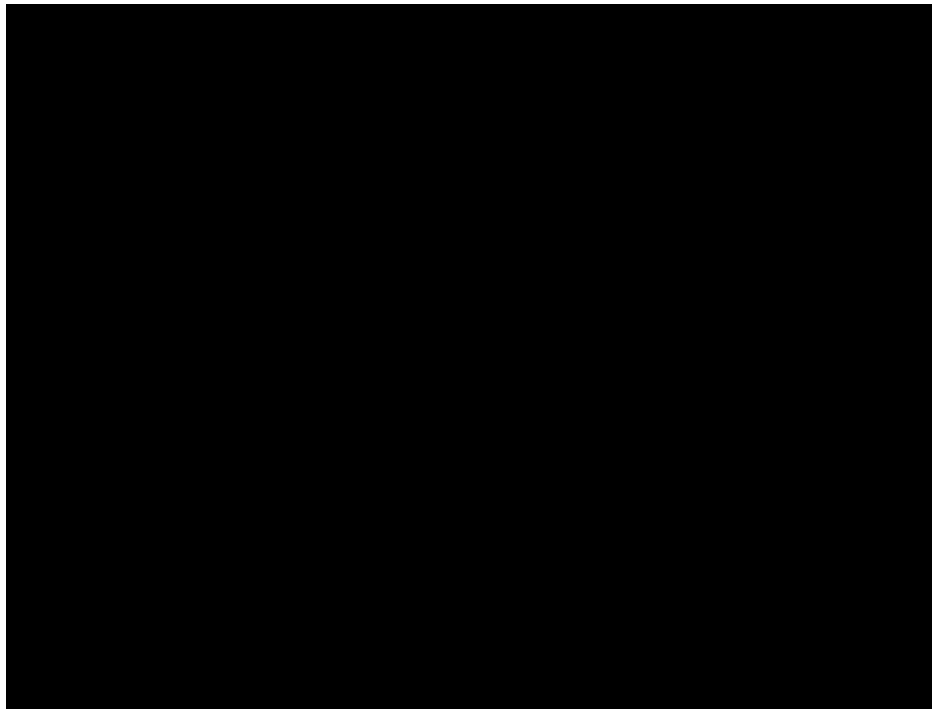


Figure 1-58 – Potentiometric surface map of the Evangeline AS in southwest Louisiana (modified from Fendick, 2005). The red star approximates the location of the Evergreen Hub project.

1.8.4. Jasper Aquifer System

1.8.4.1. Stratigraphy of the Jasper Aquifer System

The Jasper AS in Louisiana extends from the parishes of Sabine, Natchitoches, Grant, and La Salle in the north, to Beauregard and Allen in the south. The system consists of a series of Miocene-age aquifers and confining units within the Mississippi embayment, formed from marine and fluvial-deltaic depositional environments (Brantly and Seanor, 2005). This aquifer system is located between the Evangeline AS and the underlying Catahoula aquifer, and includes the Williamson Creek, Dough Hills, and Carnahan Bayou members. The aquifer dips to the south-southeast and thickens towards the south (Prakken et al., 2012). The stratigraphic nomenclature provided by Young et al. (2012) continues to be used, though thinning of the Lena confining unit towards Calcasieu Parish makes correlations difficult. Alternatively, the Anahuac Formation is recognized to be below the Jasper AS, as noted by Lindaman (2023).

Williamson Creek and Dough Hills Members

Young et al. (2012) state that this unit is composed of Fleming Group Miocene sandstones, which are similar to the Lower Lagarto in Texas but are more difficult to distinguish in the southern part of Louisiana due to variations in facies (Lindaman, 2023). These sandstones include lower coastal-plain fluvial and coastal plain facies formed by the retrogradational portion of a major fluvial-deltaic depositional episode (Young et al. (2012). The *Marginulina A* (Marg A or equivalent) paleomarker (Young et al. 2012) serves as the unit's base. In Beauregard Parish, the Williamson

Creek sandstones are well-sorted, from very fine-grained to medium-grained, with interbedded greenish-gray clays and lignite beds (Prakken et al., 2012). The Dough Hills Member is a Miocene-age silt and clay unit that acts as a confining unit between the Williamson Creek and Carnahan Bayou members.

Carnahan Bayou Member

This unit is composed of wave-dominated delta facies formed by the progradational package of a fluvial-deltaic depositional episode in the Miocene, which is equivalent in Texas to the Oakville Formation (Young et al., 2012). The Williamson Creek Member's composition is strikingly similar to the Carnahan Bayou Member. The Jasper AS thickens towards the south, reaching up to 2,300 ft thick in Beauregard Parish (Lindaman, 2023). The Jasper AS and this unit's base is delineated by the Lena confining unit—when thick enough to discern in well data. Alternatively, the top of the Anahuac Formation can serve as the base of the Jasper AS (Lindaman, 2023; Young et al., 2012). The Evergreen Hub AOI has a base ranging from [REDACTED] ft (TVDSS), and no drilled water wells have targeted this aquifer. In Beauregard Parish, Prakken et al. (2012) recorded 19 active wells for the Jasper AS in 2009, while SONRIS data as of 2023 showed there were 20 wells.

1.8.4.2. Characteristics of the Jasper Aquifer

Recharge and Discharge

The Jasper AS recharges via precipitation at locations where the system outcrops north of the AOI. Discharge is primarily by water withdrawals from pumping centers, causing depletion cones in some areas. Pumping centers are the primary source of public water supply, and only a few wells are for industrial use (Brantly and Seanor, 2005). Water levels vary 1–3 ft annually (Prakken et al., 2012).

Potentiometric surface and groundwater flow direction

Freshwater extends south from the Vernon and Rapides Parishes to Beauregard Parish and the northwestern corner of Allen Parish. Vernon Parish contains the largest volume of freshwater (Darling and Meselhe, 2002). In Beauregard Parish, freshwater in the Williamson Creek unit (also known as the Upper Jasper aquifer) occurs only in the northern half of the parish (Lindaman, 2023; Brantly and Seanor, 2005). The Carnahan Bayou Member unit only extends south to Beauregard's northern parish line (Brantly and Seanor, 2005; Prakken et al., 2012). Saltwater is expected to be present at the Evergreen Hub location (Prakken et al., 2012; Lindaman, 2023). Figures 1-63 and 1-64 illustrate the potentiometric surface maps and corresponding units for the upper and lower Jasper AS, respectively.

Water Quality

In freshwater wells in northern Beauregard Parish, the water is considered soft, with local areas exceeding the NSDWR-recommended 6.5–8.5 pH (Prakken et al., 2012). In the Evergreen Hub AOI, no Jasper AS water wells have been drilled, and direct water chemistry measurements of the Jasper aquifer are not available from literature in the AOI. Young et al (2012) did not quantify the specific TDS content for the Jasper aquifer near the project AOI, but designated the area's water quality as "more than 3,000 ppm"—the maximum value the paper assigned. Pettijohn et al. (1988) calculated the TDS of the Jasper in the AOI to be between 35,000 mg/L and 70,000 mg/L, as determined by formation-water resistivity calculated from borehole geophysical logs. Based on these classifications, the TDS is estimated as greater than 35,000 ppm. According to the SONRIS database as of 2023, the adjacent Jasper AS wells are [REDACTED] Well No. [REDACTED] is more than [REDACTED] mi to the west in Calcasieu Parish, with a TD of [REDACTED] ft (Figure 1-54, *Section 1.8.2.1*). Further examination of the well data indicates that said depth is part of the Evangeline AS, suggesting that either the depth or the name of the targeted aquifer is in error. The second-nearest Jasper AS water well, [REDACTED], is more than [REDACTED] mi to the east of the proposed injection wells and has a TD of [REDACTED] ft. The depth, aquifer name, and water extent are confirmed for this well, which is used for industrial purposes and classified as active.

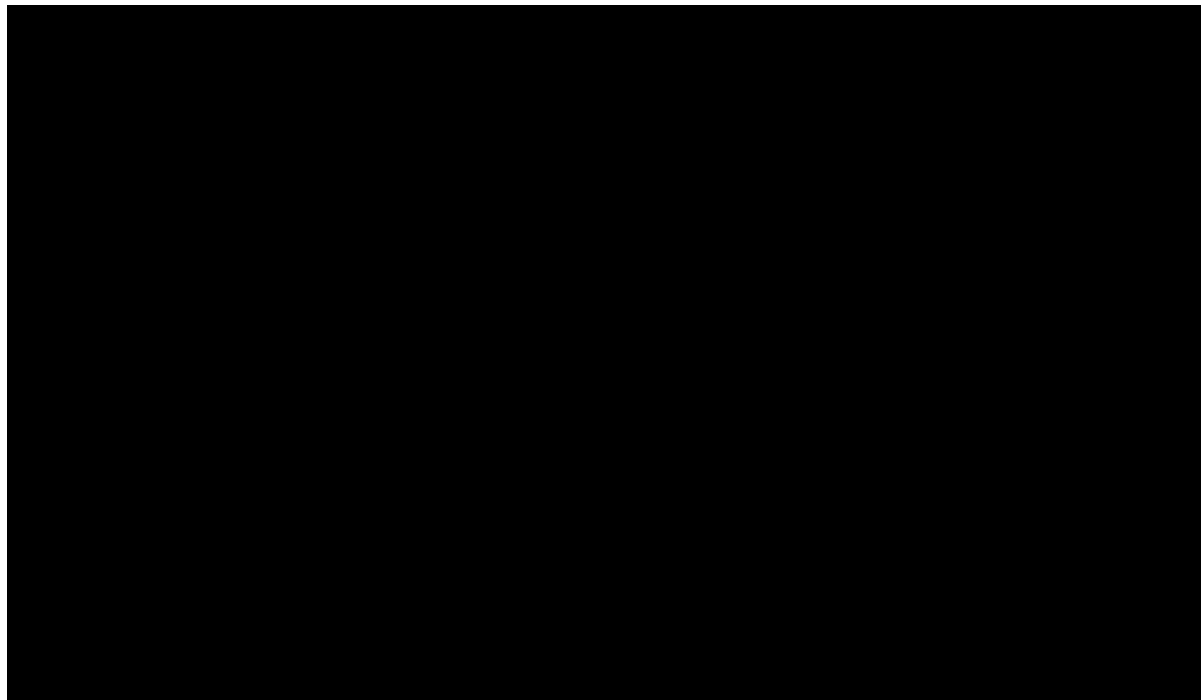


Figure 1-59 – Potentiometric surface maps of the upper Jasper aquifer system in southwest Louisiana, Williamson Creek unit (Martin, Whiteman, and Becnel, 1988). The red star approximates the location of the Evergreen Hub project.

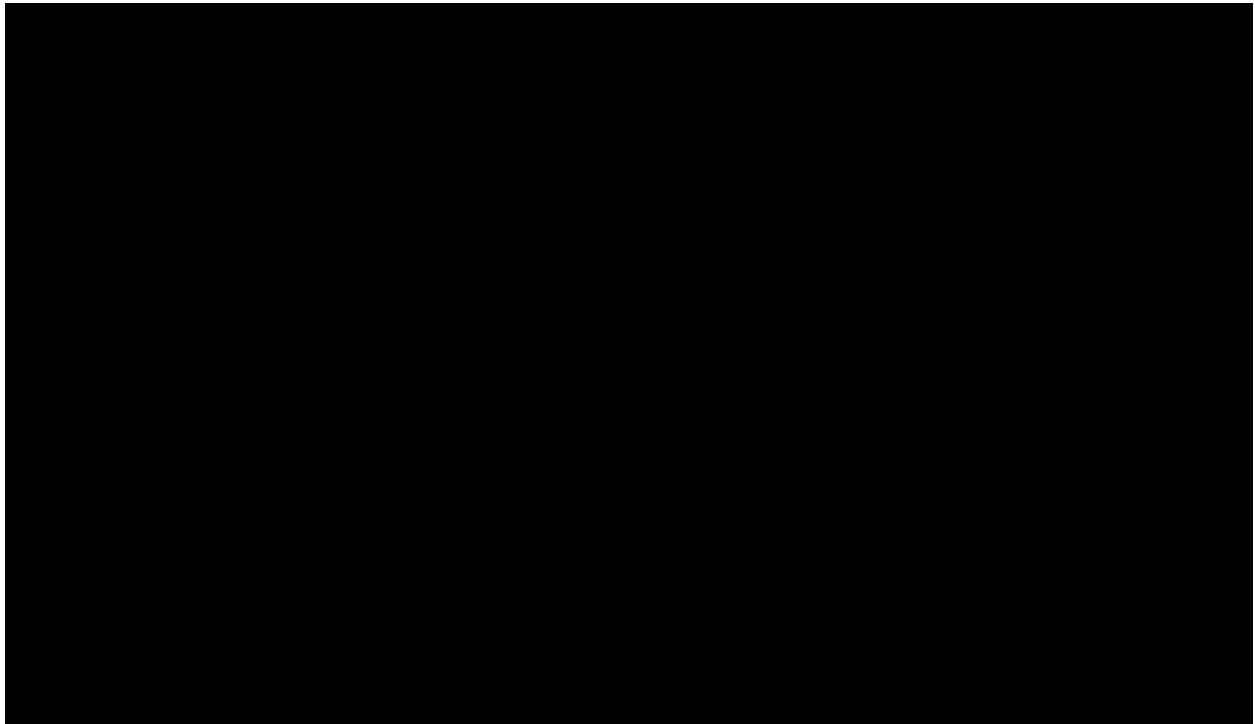


Figure 1-60 – Potentiometric surface maps of the lower Jasper aquifer system in southwest Louisiana, Carnahan Bayou unit (Martin, Whiteman, and Becnel, 1988). The red star approximates the location of the Evergreen Hub project.

1.8.5. Catahoula Aquifer

The Catahoula aquifer, which lies in central Louisiana and is stratigraphically located below the Jasper AS, is the oldest Miocene-Oligocene age aquifer. The Catahoula Formation contains two stratigraphic units, the Anahuac and Frio Formations. As discussed in *Section 1.2.1*, the Anahuac Formation is a regional, transgressive marine shale, and the Frio Formation consists of sands with some silty to sandy clays (Ecology and Environment, 2011). The base of the Catahoula aquifer is the Vicksburg-Jackson confining unit (Lindaman, 2023).

1.8.5.1. Characteristics of the Catahoula Aquifer

Recharge and Discharge

Recharge to the Catahoula aquifer occurs via precipitation at locations where the unit outcrops (to the east or west); discharge is by water withdrawn from wells, but also by water flowing into small springs or streams (Fendick and Carter, 2015).

Potentiometric Surface and Groundwater Flow Direction

The Catahoula aquifer extension is depicted in Figure 1-61 (Fendick and Carter, 2015). In the Evergreen Project AOI groundwater is expected to flow north.

Water Quality

Freshwater is restricted to central Louisiana, including the Sabine, Vernon, Natchitoches, Rapides, Grant, La Salle, Catahoula, Concordia, and Tensas Parishes (Fendick and Carter, 2015). In the Evergreen Project AOI, only saltwater is anticipated.

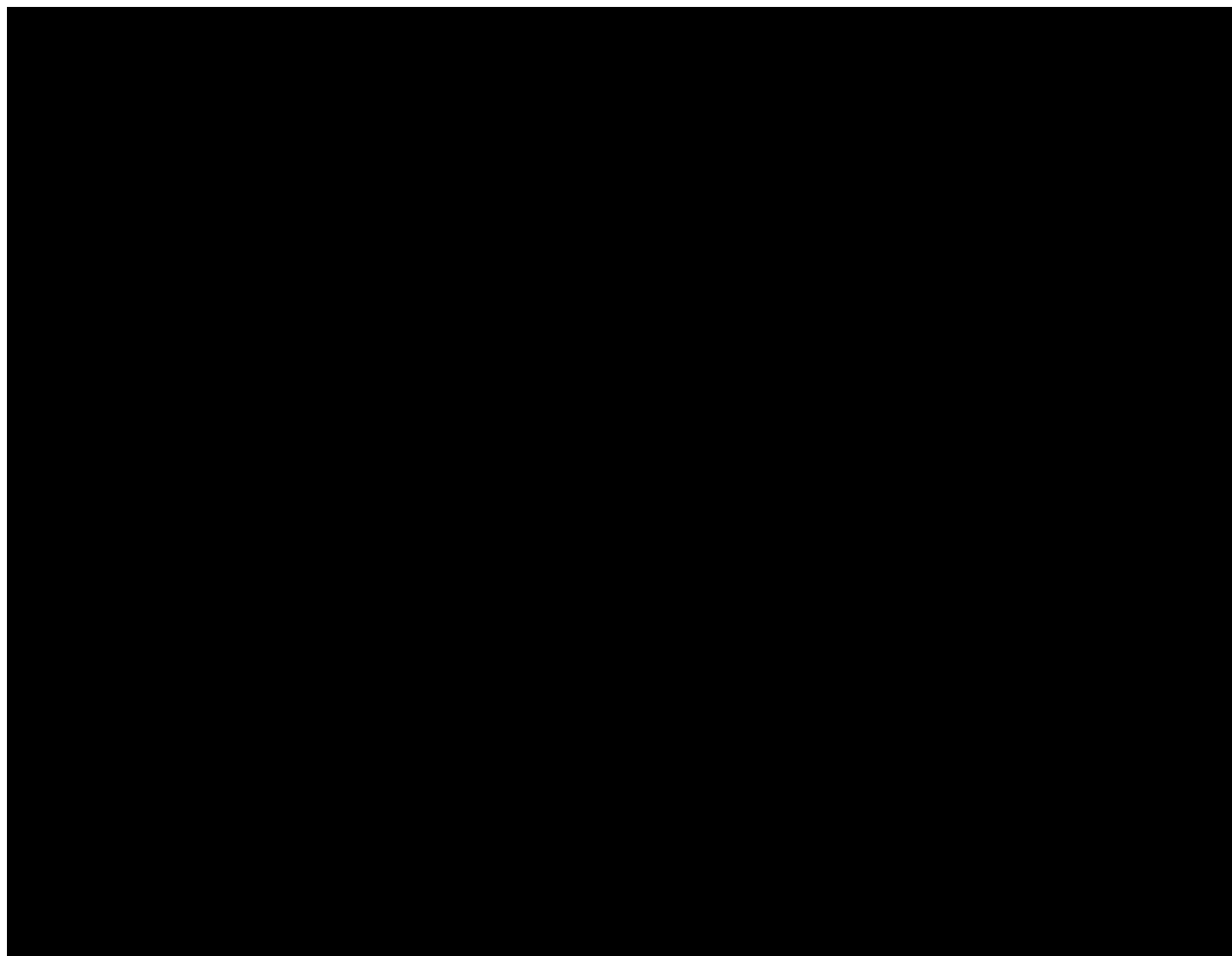


Figure 1-61 – Potentiometric surface maps of the Catahoula Aquifer in Louisiana (Fendick and Carter, 2015); the red star approximates the location of the Evergreen Hub.

1.9. Site Evaluation of Mineral Resources

1.9.1. Active Mines Near the Proposed Injection Location

A search using public data provided by the Department of Energy's Class VI Data Support Tool Geodatabase was conducted. Figure 1-62 shows the spatial relationship between the proposed site and an identified sand pit [REDACTED]. The pit is located approximately [REDACTED] mi

southwest of the location of the proposed Loblolly CCS No. 001. No surface mineral impacts will occur due to the Evergreen Hub project.

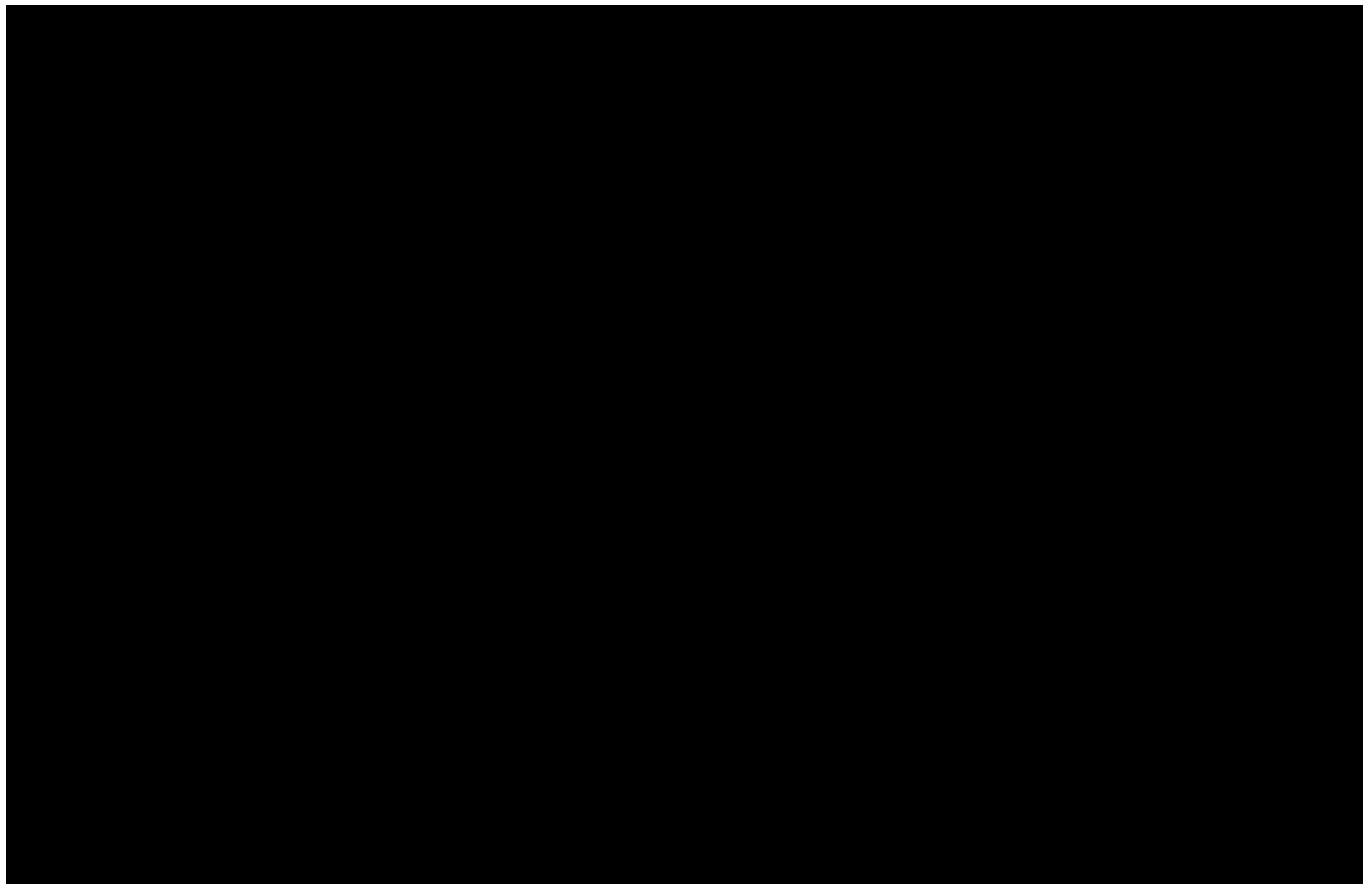


Figure 1-62 – Location of Sand Pit and Evergreen Hub Project AOR

1.9.2. Underground Mineral Resources

A search for subsurface mineral production was conducted using publicly available data from the LDNR (SONRIS and Document Access) along with subscription-based data (Enverus). The data was used to locate current and historical production zones within a 6-mi radius from the centroid of the predicted plume.

The collected data were pooled from a 6-mi radial search using the centroid coordinates of the plume AOR. The data included locations, perforations, production history, current well status, and radial distance from the proposed project location. A total of [REDACTED] wells were identified. Figure 1-63 plots the locations of all the wells within the 6-mi search, and Table 1-13 summarizes the status count of the wells within that investigative radius.

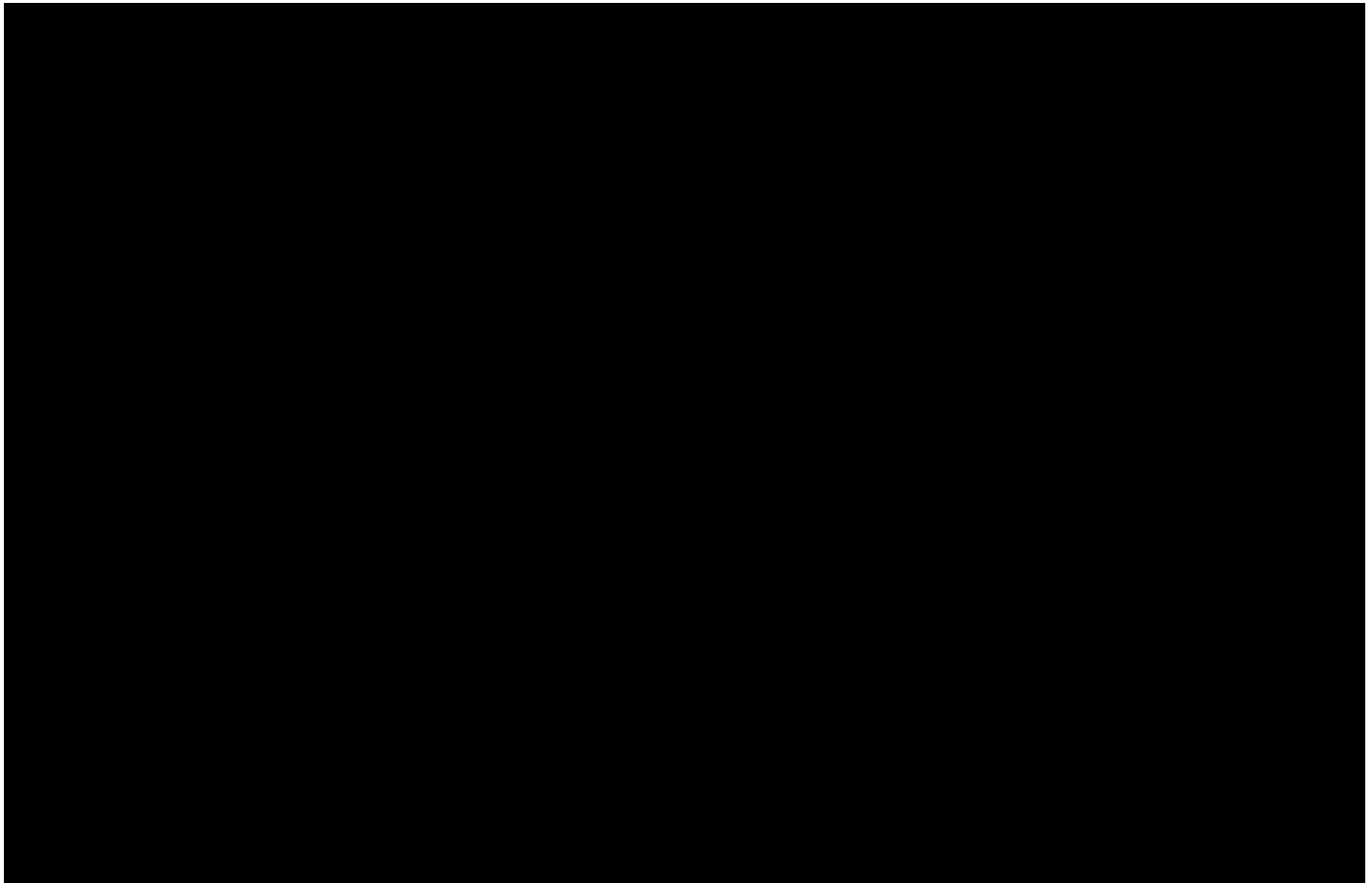


Figure 1-63 – Offset Oil-and-Gas Well Production

Table 1-13 – Wells Within the 6-Mi Investigative Radius

Sections 1.9.3 and 1.9.10 identify wells and their production intervals. The areas of investigation are subdivided into producing zones above the injection zone, producing intervals within the injection zone, and producing intervals below the injection zone. The investigations included wells that were drilled within the plume, wells that were drilled but were not perforated, nearby

active production wells, and wells with possible future utility. This review is conducted to identify any nearby production that may be affected by carbon sequestration activities.

1.9.3. Distribution of Perforated Intervals

Figure 1-64 plots the distributions of the perforation depth and distance from wells from the Evergreen Hub. The horizontal lines identify the proposed injection zone, which spans [REDACTED] ft MD to [REDACTED] ft MD. The distribution identifies the nearest possible production zones within this study's review area. As can be observed, there is no producing activity within the radial extent.

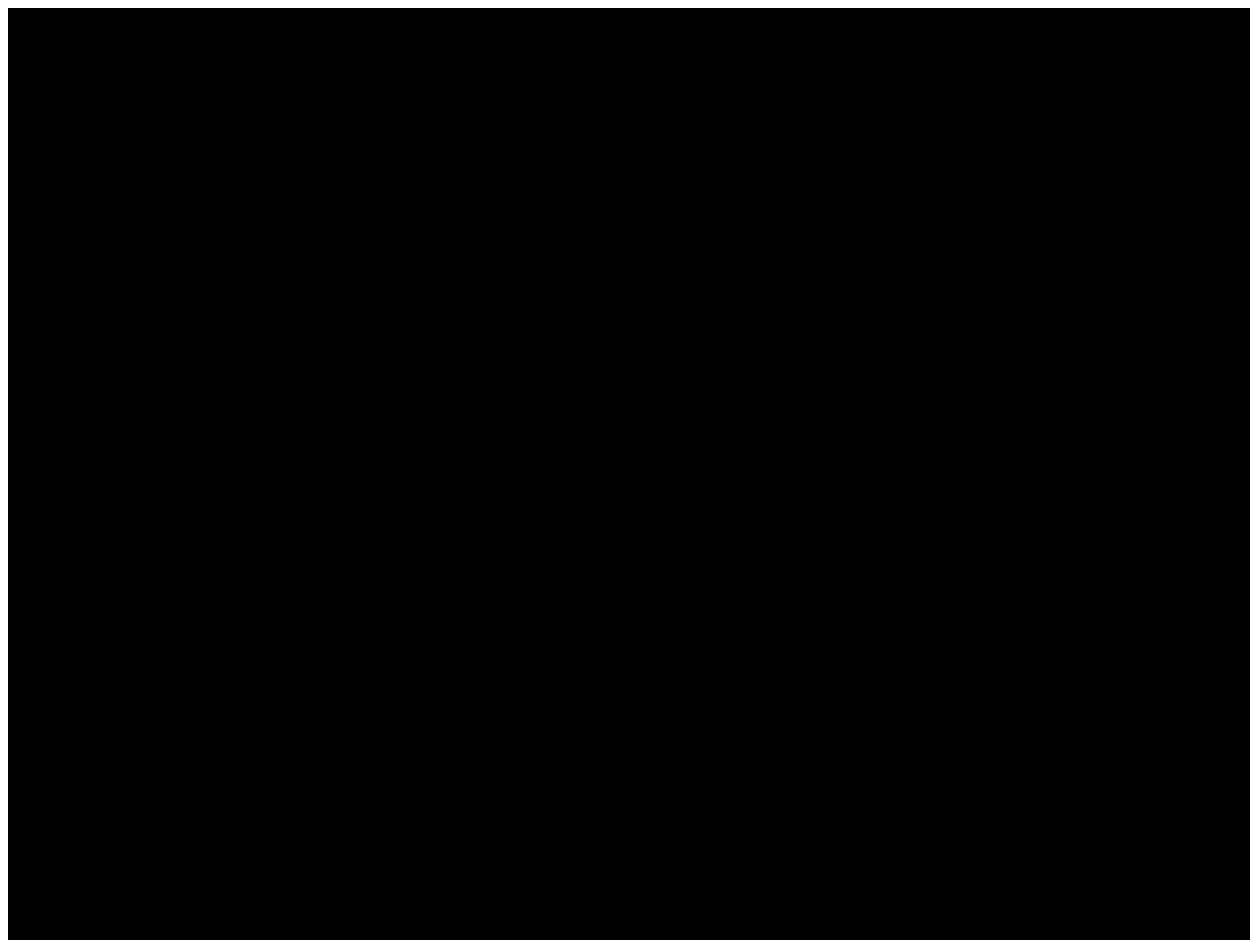


Figure 1-64 – Evergreen Hub Project Perforation and Depth Distribution

1.9.4. Nearby Production Above the Injection Zone

A search for perforation intervals within 6 mi of the centroid of the predicted plume was conducted. The search did not identify any producing intervals. Injection operations at the Evergreen Hub project will not impact any mineral production above the CO₂ plume and pressure front.

1.9.5. Nearby Production in the Injection Zone

The perforated intervals within 6 mi of the centroid of the predicted plume and in the injection zone were located. The wells in this investigation zone are listed in Table 1-14.

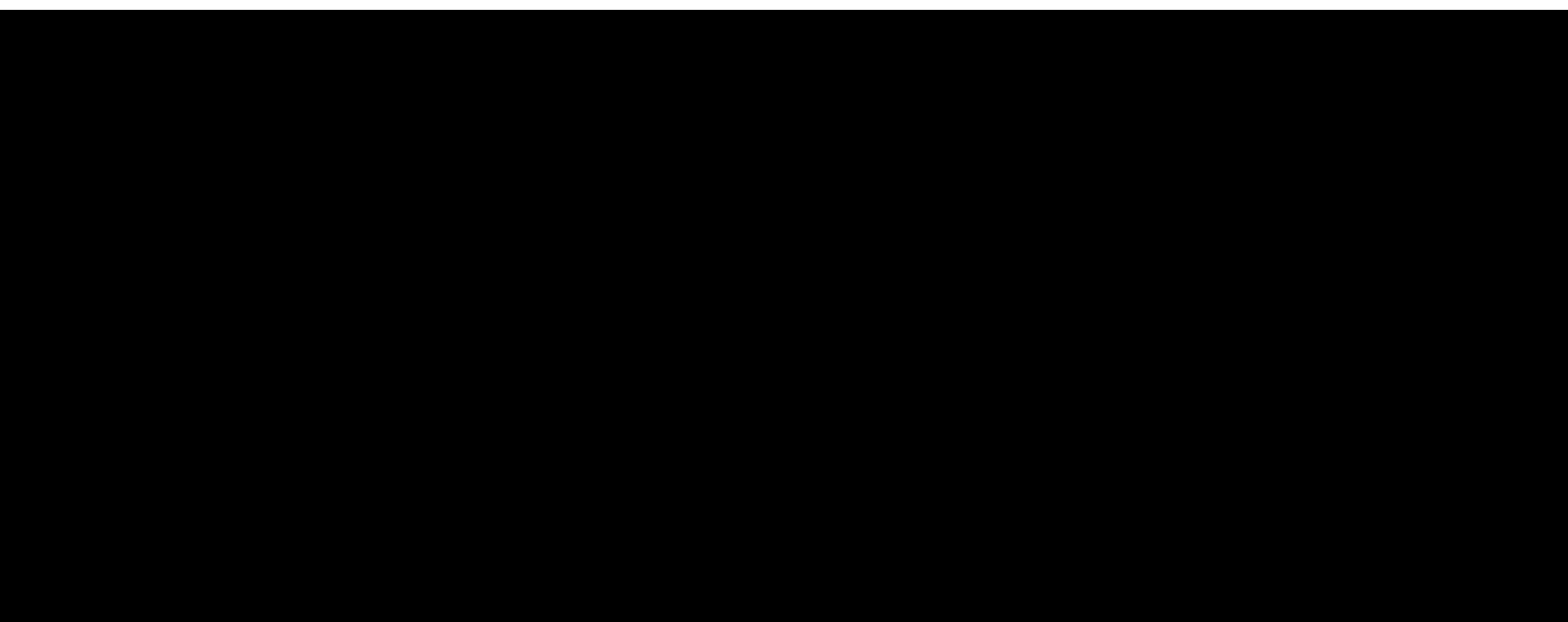
Table 1-14 – Oil and Gas Wells Within 6 Mi of Predicted Plume with Perforations Within the Injection Zone



1.9.6. Nearby Production Below the Injection Zone

The perforated intervals within 6 mi of the centroid of the predicted plume and below the confining zone are listed in Table 1-15. These wells are plugged and abandoned and lie outside the projected plume and pressure front. The proposed Evergreen Hub project will not impact the potential production of the nearby minerals.

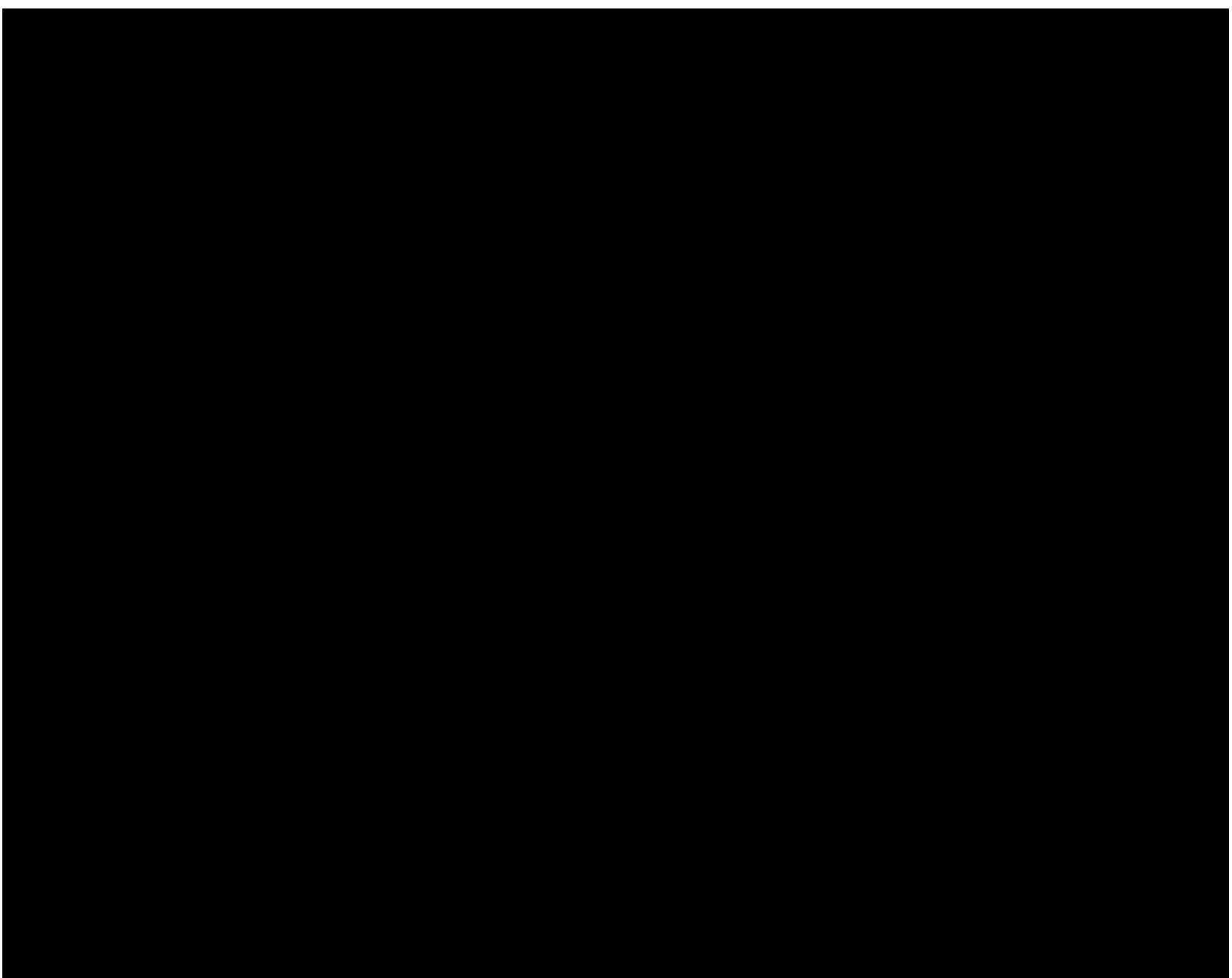
[Table 1-15 – Oil and Gas Wells with Perforations, Below the Injection Zone](#)



1.9.7. Wells Drilled in the Area Without Perforations

Table 1-16 lists wells within 6 mi of the centroid of the predicted plume. The wells were drilled and did not reflect any perforations. Analysis was performed to identify any historical production. The status of all wells within the predicted plume is dry and plugged and abandoned; therefore, the Evergreen Hub project will not affect any mineral production.

Table 1-16 – Oil and Gas Wells Within 6 Mi Drilled, not Perforated



1.9.8. Wells Located Above the Plume Location

Wells within the region that are above the predicted CO₂ plume extent and critical pressure extent were identified and listed in Table 1-17. Figure 1-65 displays the location of the identified wells. This search revealed that all wells were dry and plugged and abandoned.

Table 1-17 – Regional Wells Above the Predicted CO₂ Plume Extent

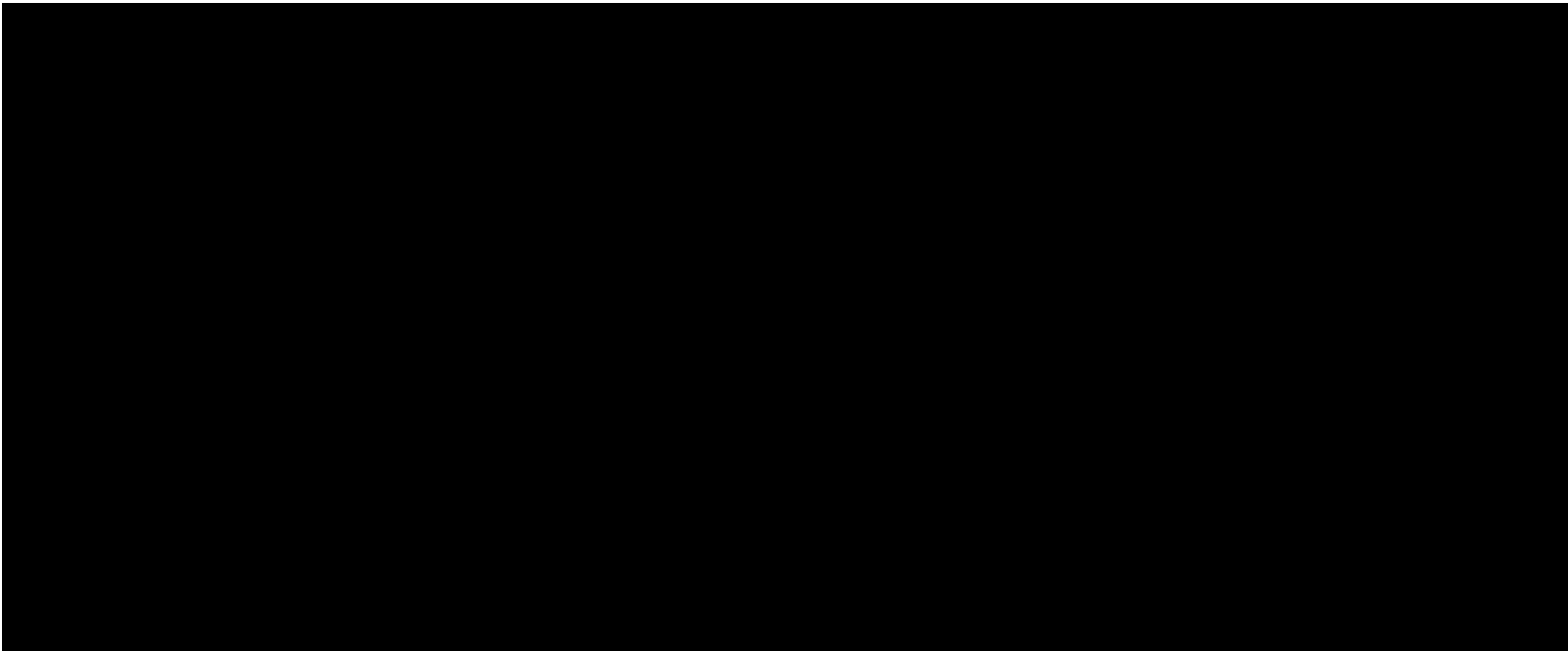
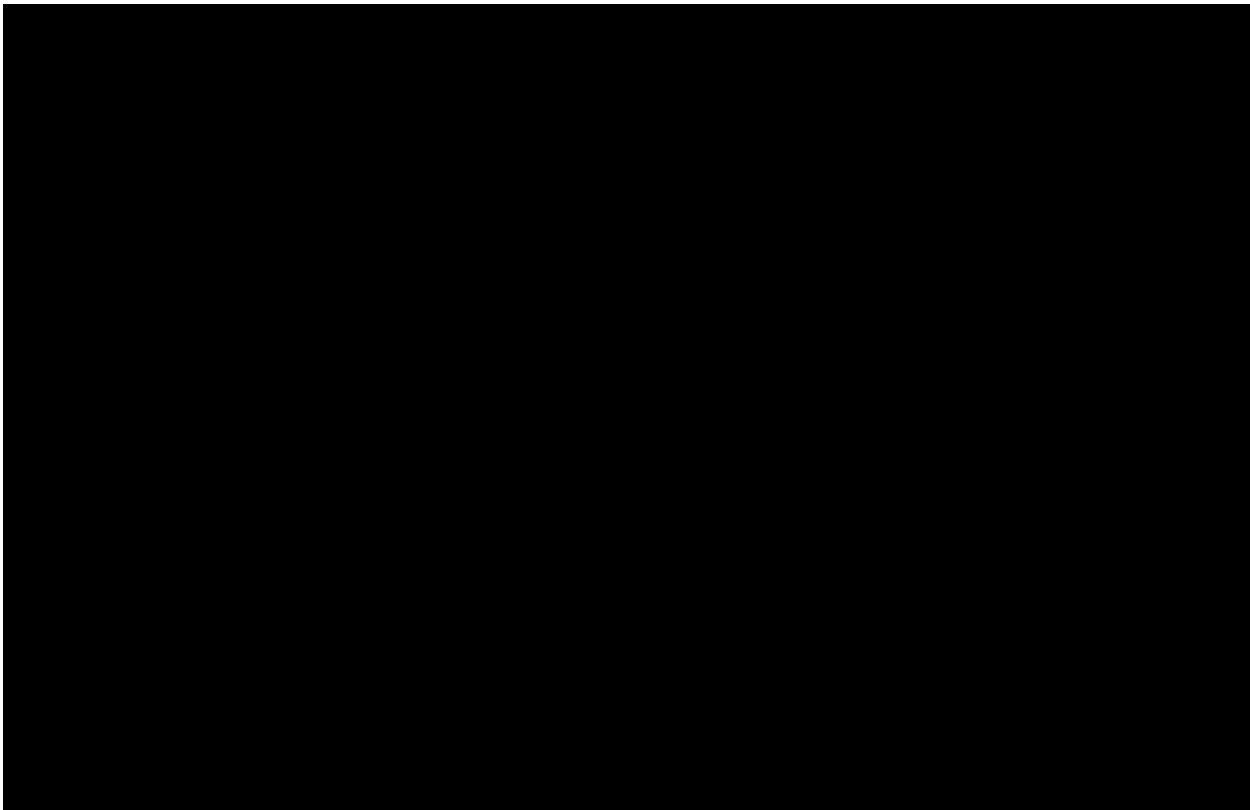
A large black rectangular box redacting the content of Table 1-17.

Figure 1-65 – Oil and Gas Wells in the Evergreen Hub Project AOR

1.9.9. Active Production Near the Proposed Injection with Perforation Depths

Figure 1-66 plots the perforation depths for active wells and their distance from the Evergreen Hub location. The nearest actively producing well, [REDACTED] lies approximately [REDACTED] mi from the proposed location. The wells identified are provided in Table 1-18. The expected plume and pressure front are not expected to extend and interact with any of the active producing activity. This distance confirms that the Evergreen Hub project will not have any effect on the nearby mineral production.

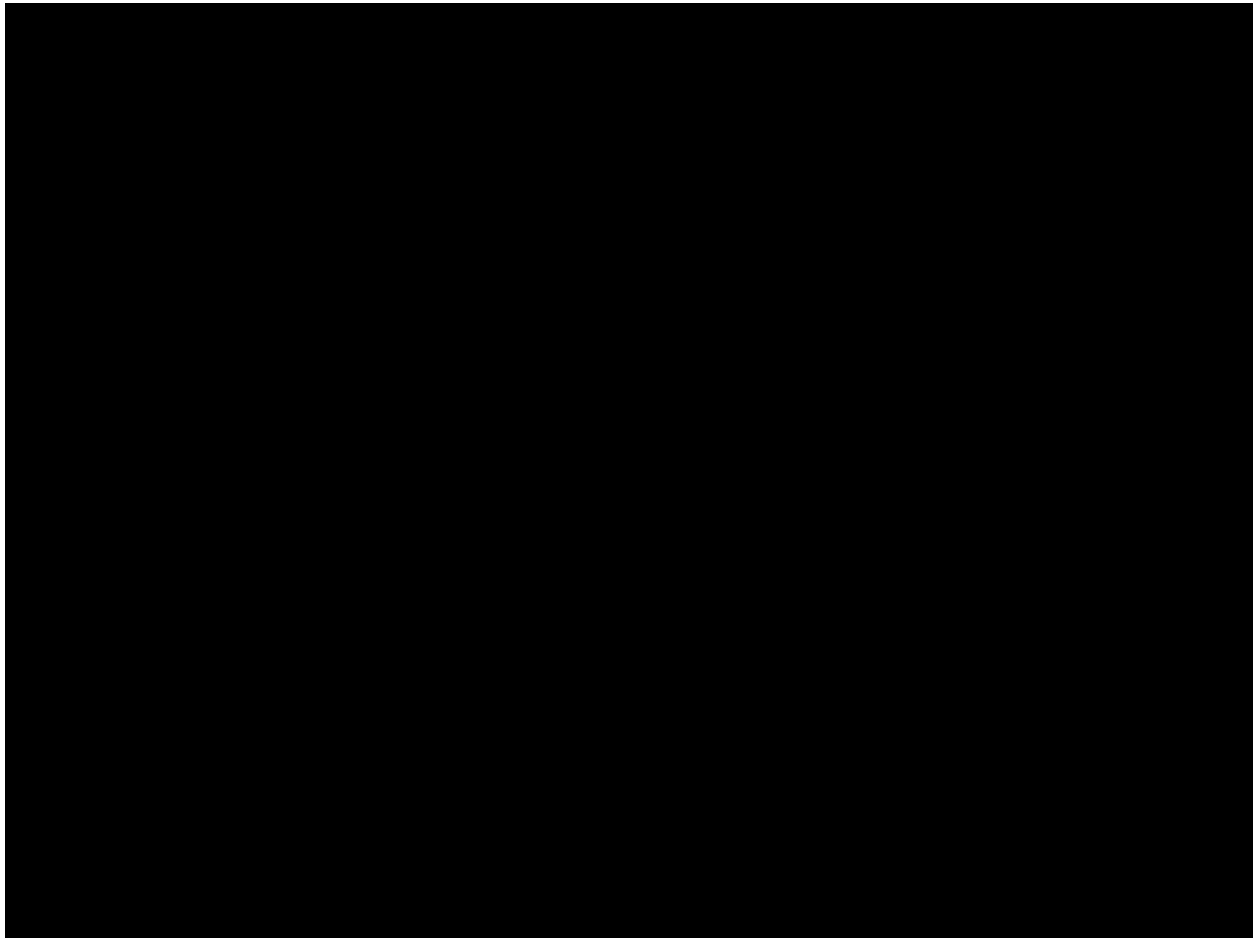
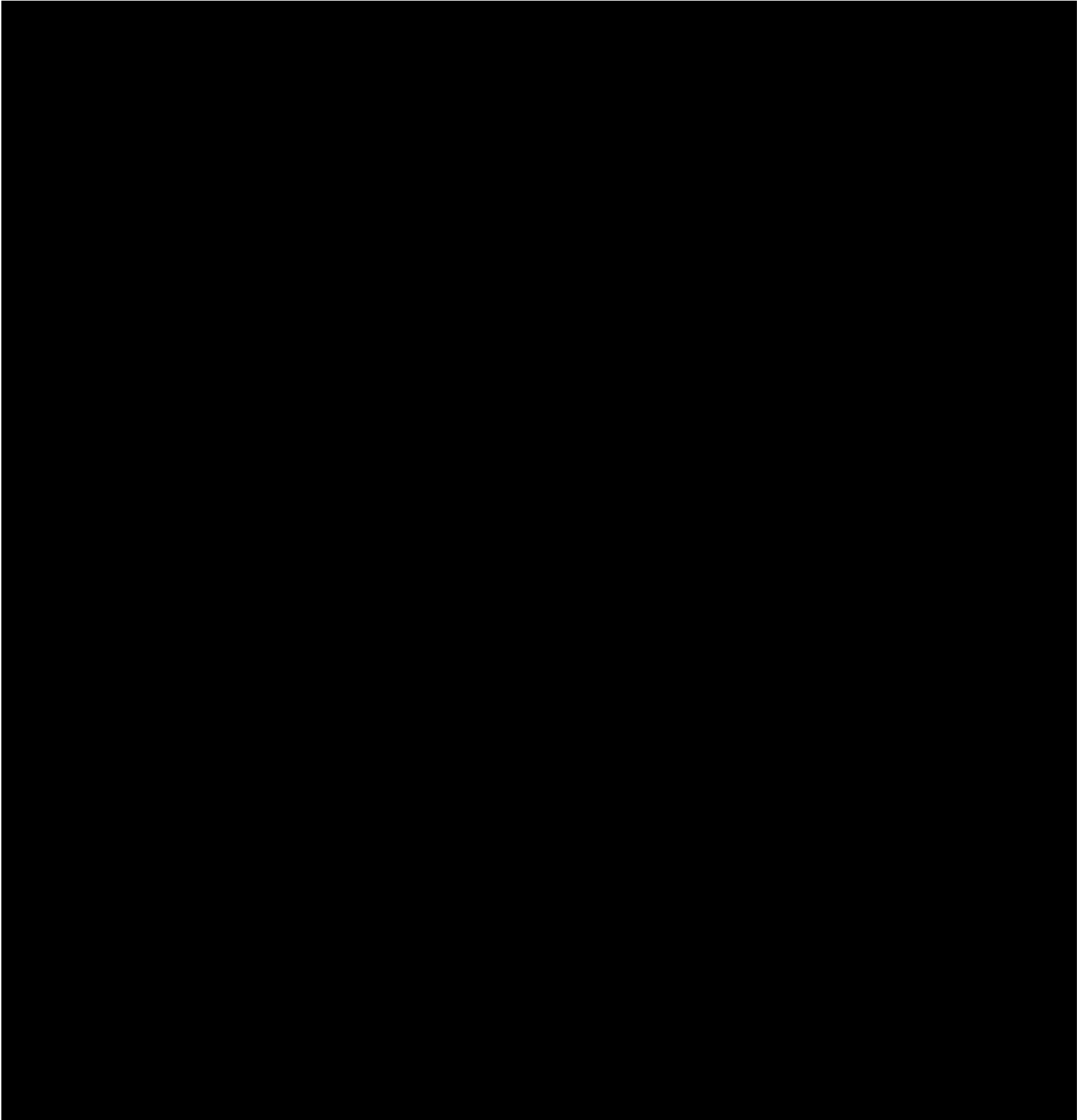
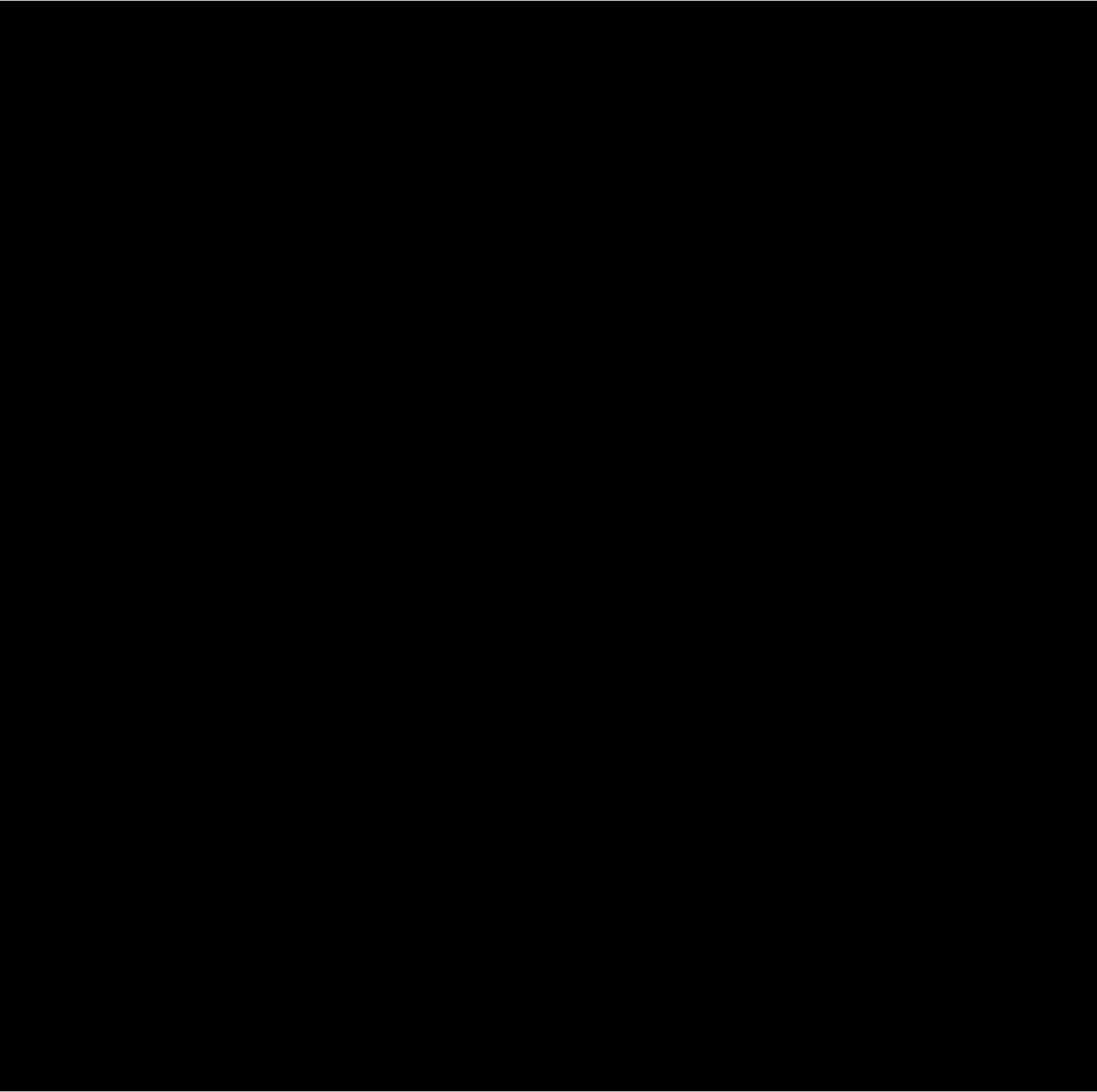


Figure 1-66 – Active Producing Oil and Gas Wells Within 6 Mi by Perforation Depth

Table 1-18 – Active Oil and Gas Wells Within 6 Mi of the Evergreen Hub Project Location





1.9.10. Nearby Wells with Potential Future Utility

Wells with status that include the potential for future utility were isolated and identified in Table 1-19. The wells are currently shut in, and an analysis was performed to identify any possible interference with potential future mineral-related utility. The nearest well, [REDACTED], is located approximately [REDACTED] mi away. The expected CO₂ plume and pressure front are not anticipated to extend and interact with any potential future utility. This distance confirms that the Evergreen Hub will not have any effect on the nearby wellbore utility.

Table 1-19 – Oil and Gas Wells of Potential Future Utility Within 6 Mi of the Evergreen Hub Location

1.10. Seismic History

All new Class VI projects must report whether a seismic event could result from the design and development of injection activities. The Class VI rule, at 40 CFR **§146.82(a)(3)(v)**, is satisfied in this section by conducting a four-step approach, as follows:

1. Identify historical seismic events in proximity to the project.
2. Determine faulting and operational influences of nearby faults.
3. Implement a fault slip potential (FSP) simulation model.
4. Review the seismic hazard.

1.10.1. Identification of Historical Seismic Events

The proposed Evergreen Hub AOI reviewed for this section was defined as a 9.08 km radius¹ around the project locations for the proposed Loblolly CCS No. 001 and Loblolly CCS No. 002 injections wells. The historical seismic event identification is based on seismograph recordings from a global network of seismological stations. According to a search of the USGS Earthquake

¹ Railroad Commission of Texas FSP AOI Standard, which was adopted for this report.

Archive conducted on November 29, 2023, no seismic events greater than a 2.0 magnitude² were recorded within a 9.08 km radius of the proposed injection well sites (Figures 1-67 and 1-68). The seismic catalog search also included investigation into additional databases—including the National Centers for Environmental Information (NCEI), Texas Seismological Network and Seismology Research (TexNet), Northern California Earthquake Data Center (NCEDC), and Volcano Discovery—and supported the results that there are no seismic events located within the AOI. Although Louisiana is characterized as an area of low seismic risk, a few seismic events caused by natural or induced seismicity have occurred in the state, shown in Figure 1-69 (page 120). The closest known earthquake to the proposed locations was a magnitude 3.8, USGS ID usp0001z1h, which occurred in Calcasieu Parish in 1983 (at an approximate depth of 5 km). That site is located ■■■ km from Loblolly CCS No. 001 and ■■■ km from Loblolly CCS No. 002.

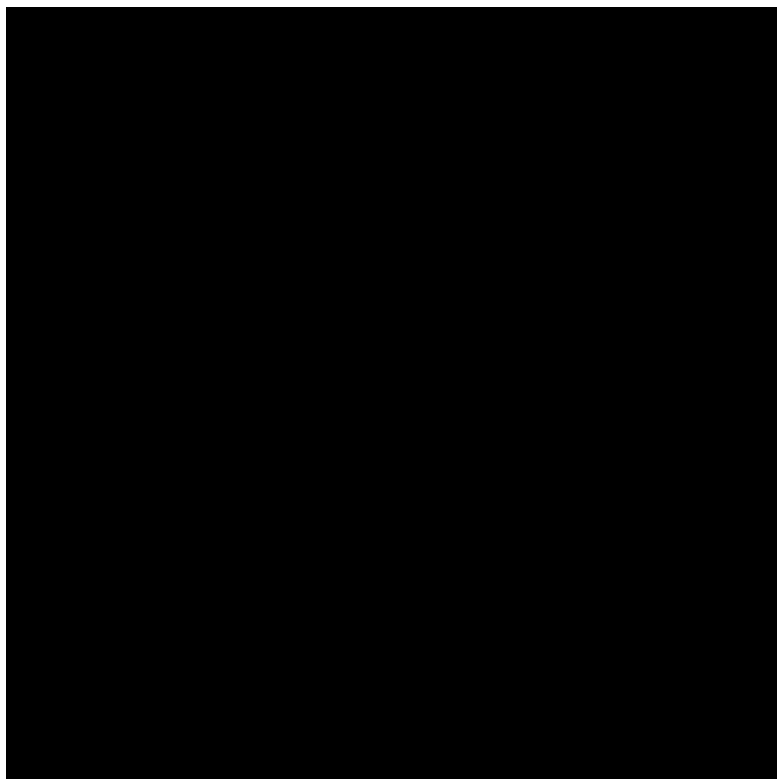


Figure 1-67 – Earthquake Search Parameters for Loblolly CCS No. 001 and Results from USGS Website

² The magnitude of an earthquake is reported using the Richter scale, which measures the amount of energy (amplitude) generated at the source of an earthquake.

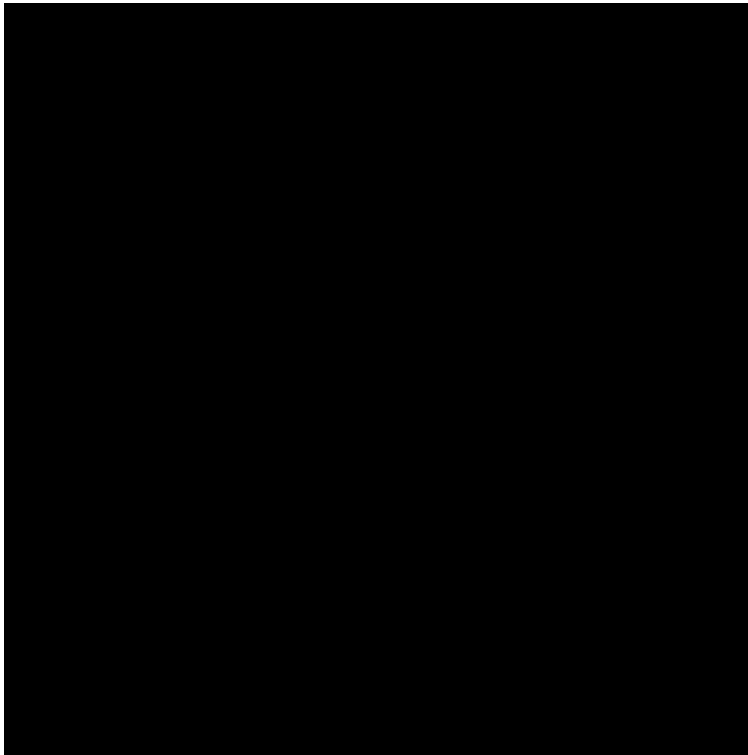


Figure 1-68 – Earthquake Search Parameters for Loblolly CCS No. 002 and Results from USGS Website

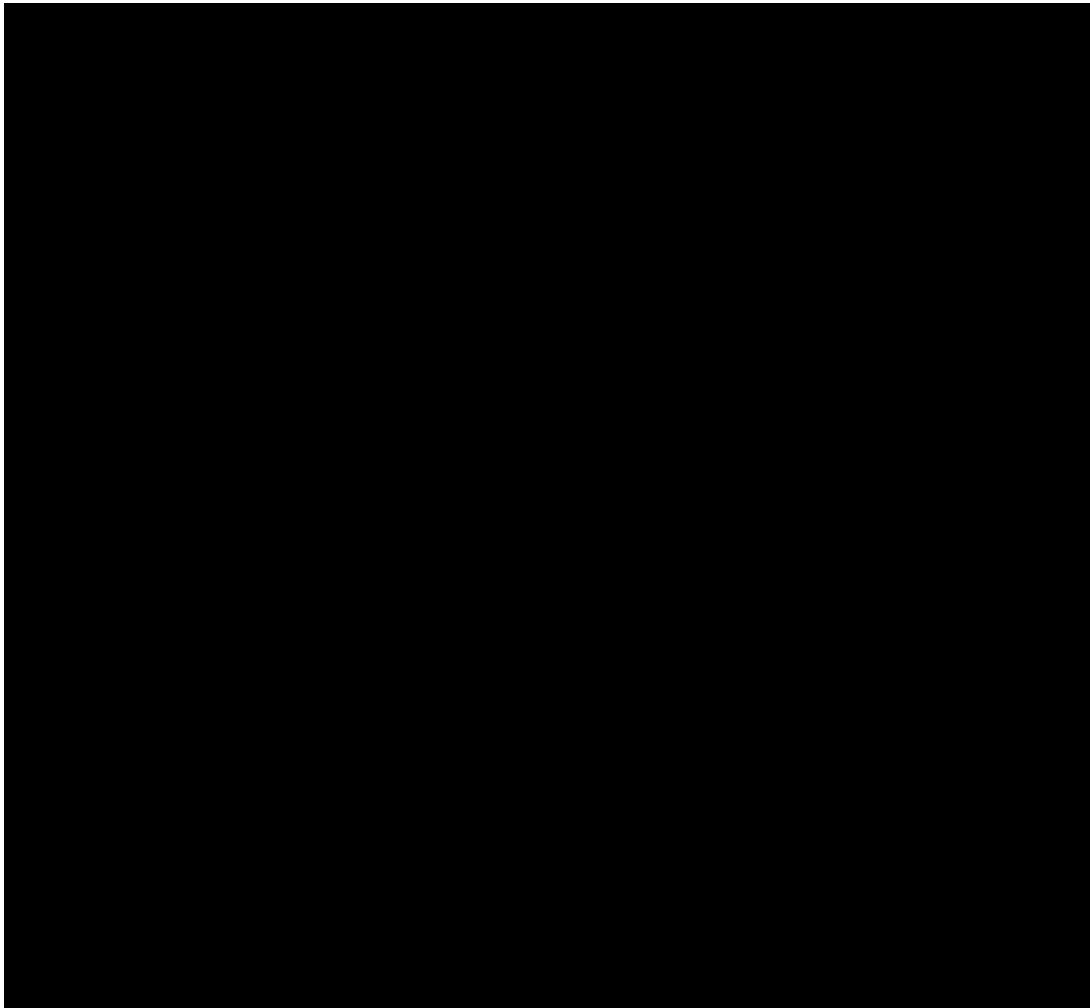


Figure 1-69 – All USGS-registered earthquakes inland and offshore LA. The red stars indicate the location of the proposed injectors, the orange circles show the 9.08 km radius around each injector, and the green dot marks the closest earthquake.

1.10.2. Faults and Influence

A USGS-produced regional report divides faults and related folds into five classes: A, B, C, D, and E, based on the geological evidence of Quaternary deformation or faulting. Faults in southwest Louisiana are classified as "Class B," as geologic evidence indicates the presence of a fault or suggests Quaternary deformation. However, these faults are located in sediments and poorly lithified rocks that are unable to sustain the major force required to propagate large seismic events that could result in harmful ground motions. A publication by Crone and Wheeler (2000) references results that indicate that the post-rift sequence of sediment and its band of normal faults along the GOM margin are mechanically separated from the underlying crust—and

therefore reduce the risk of a significant earthquake³. Regional faults exist north and south of the Evergreen Hub project and exhibit an east-west trend, as displayed in Figure 1-70. The De Quincy fault-line scarp should not be affected by the proposed injectors, as the scarp is located approximately ■ mi away. Per EPA requirements, a complete understanding of the extent and location of the resultant injection plume was determined and identified in *Section 2 – Plume Model*. That section discusses the results of the modeled pressure and CO₂ plumes in relation to the faults adjacent to the two injection locations in the Evergreen Hub project. Additional work performed was detailed in *Section 1.3.4*, which discussed how the faults in the AOI are considered to be sealing across the lower and upper confinement zones—but transmissive over the injection zone sands.

³ The USGS defines a *significant earthquake* to be >600, a number derived by magnitude, the number of “Did You Feel It” responses, and PAGER alert level.

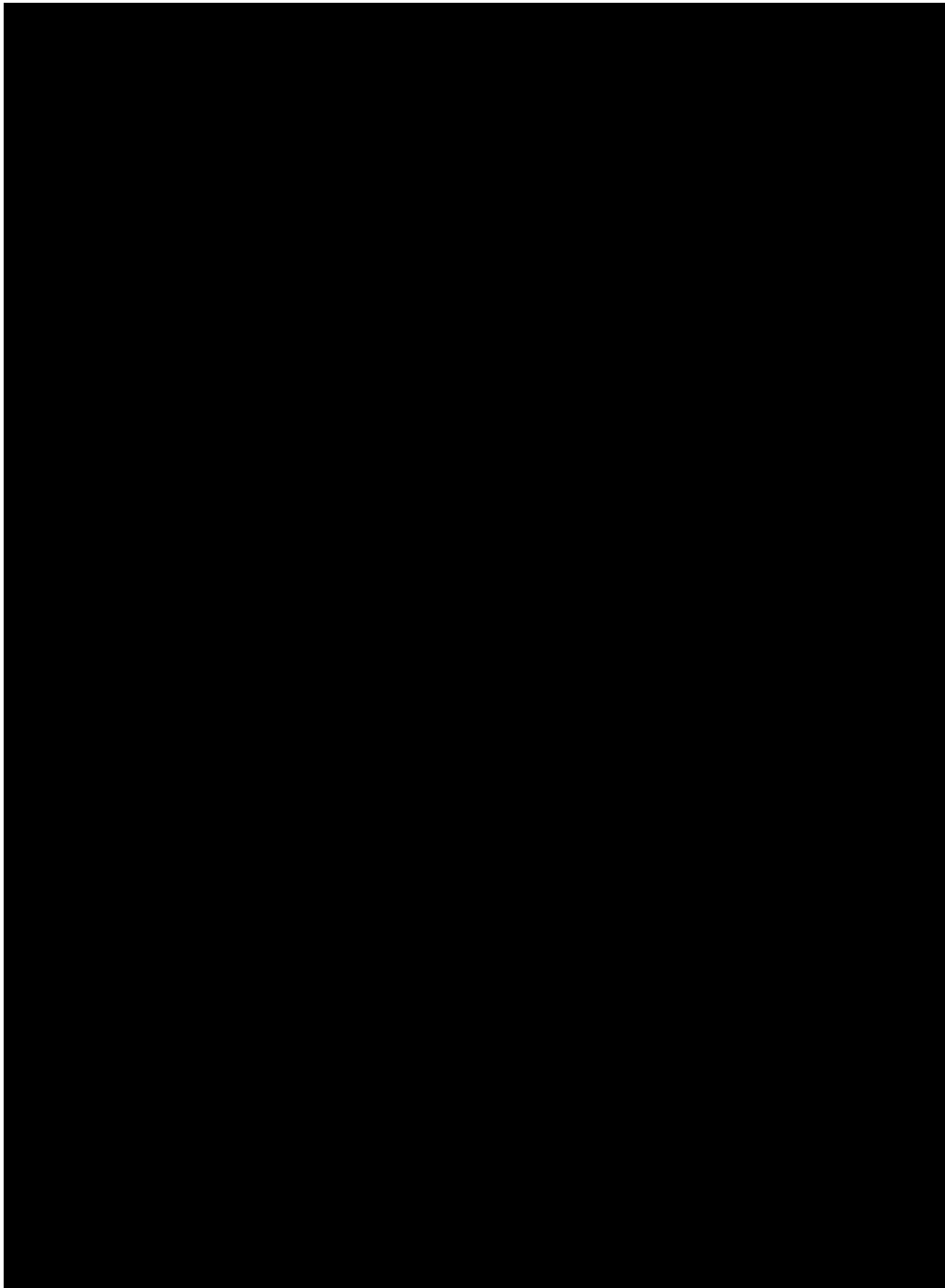


Figure 1-70 – Southwest Louisiana Geologic Map showing the fault lines, scarps, and location of the Evergreen Hub project, indicated by the blue star (Heinrich, 2005).

1.10.3. Fault Slip Potential Results

The FSP tool models the cumulative likelihood of an offset fault exceeding the Mohr-Coulomb slip criteria due to proposed CO₂ injection operations. The variation within the pressure plume is

examined to prevent either faults from reactivating or the seal from being hydraulically fractured (Meckel and Trevino, 2014). The faults that have been mapped and observed near the anticipated CO₂ and pressure plumes are considered low risk to induced seismic events, as no historical seismic events were found in the proposed project AOI. However, an FSP model was completed to assess this risk. The FSP model was generated in coordination with the injection plan, and designed to both reflect the calculated fault transmissivity and match the GEM 3D flow simulation. The assumptions and uncertainties, as well as the results, are discussed in *Appendix B-21*. The FSP was conducted with regard to the UCZ, in which the model showed a maximum FSP of [REDACTED], rated as low to slightly moderate risk based on the integrated tab default color scheme⁴. This area also showed an FSP baseline ranging from [REDACTED], resulting in a less than [REDACTED] in the FSP potential by the proposed Evergreen Hub operations.

1.10.4. Seismic Hazard Review

A seismic hazard analysis was conducted for the Evergreen Hub, which incorporated EPA-recommended tools such as the USGS 2018 National Seismic Hazard Model (NSHM) Project and provided maps. The NSHM referenced includes the 2018 updates from the 2014 model as well as population density, fault models, ground motion models, seismic catalogs, soil amplification factors, amplified shaking estimates of long-period ground motions, and seismic hazard calculation. Additionally, the 2018 Modified Mercalli Intensity (MMI) earthquake hazard map indicates the chance of peak ground accelerations exceeding the MMI index of that region in 50 years. The southwestern Louisiana region, including the proposed project location, is classified as Class V in the model, allocating a [REDACTED] of exceeding a moderate seismic event. The lithologic properties of Gulf Coast sands and shales do not support the firm rock site that the model is predicated on, suggesting that the model outcome likely exceeds the actual probability. Supported by Figure 1-71, a Class IV⁵ or V⁶ earthquake is most likely to strike southwestern Louisiana in 50 years (per the 2018 model). That region is projected to have a [REDACTED] of experiencing a class VI⁷ earthquake, noted in Figure 1-72 (page 125), which shows the likelihood of a minor damaging earthquake occurring over the conterminous United States in 100 years. An additional projection forecasts fewer than two damaging earthquakes⁸ to occur in southwestern Louisiana, in the range of 10,000 years, illustrated in Figure 1-73 (page 126).

Based on the 2018 NSHM, the proposed Evergreen Hub location is within the lowest seismic hazard areas in United States. However, future earthquakes may occur in the region, where

⁴ The MMI scale ranges from I to XII. The following summaries were taken from the USGS Earthquake Hazards Program, which were first condensed by Wood and Neumann in 1931.

⁵ Class IV: "...light; felt indoors by many, outdoors by few during the day. At night, some are awakened. Dishes, windows, and doors are disturbed; walls make cracking sounds. Sensations are like a heavy truck striking a building. Standing vehicles are rocked noticeably."

⁶ Class V: "...moderate; felt by nearly everyone; many awakened. Some dishes and windows are broken. Unstable objects are overturned. Pendulum clocks may stop."

⁷ Class VI: "...strong; felt by all, and many are frightened. Some heavy furniture is moved; a few instances of fallen plaster occur. Damage is slight."

⁸ *Damaging earthquake* shaking; meaning a level VI or higher earthquake causing structural failure.

shakes will be light to strong, with minor damage⁹ to structures to occur. The 2018 model also projects that Class IX¹⁰ earthquakes are unlikely to occur close to the AOI of the project site.

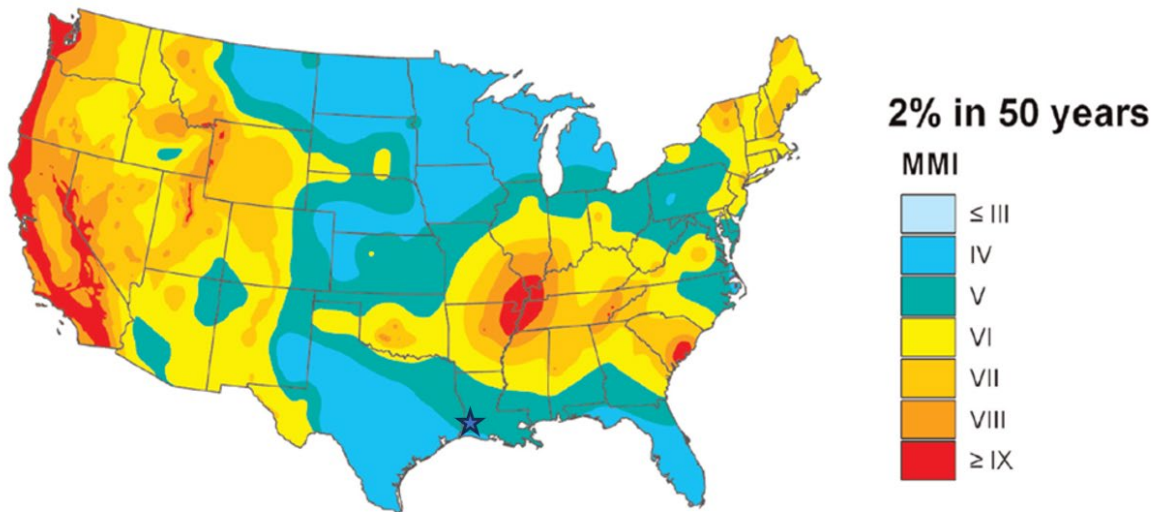


Figure 1-71 – Total mean hazard maps for 2% probability of exceedance in 50 years and location (indicated by the blue star) of the Evergreen Hub project (Petersen et al., 2019).

⁹ Minor damage; structurally stable building, but some fallen plaster could occur.

¹⁰ MMI Class IX: "...violent; damage is considerable in specially designed structures; well-designed frame structures are thrown off-kilter. Damage is great in substantial buildings, with partial collapse. Buildings are shifted off foundations. Liquefaction occurs. Underground pipes are broken."

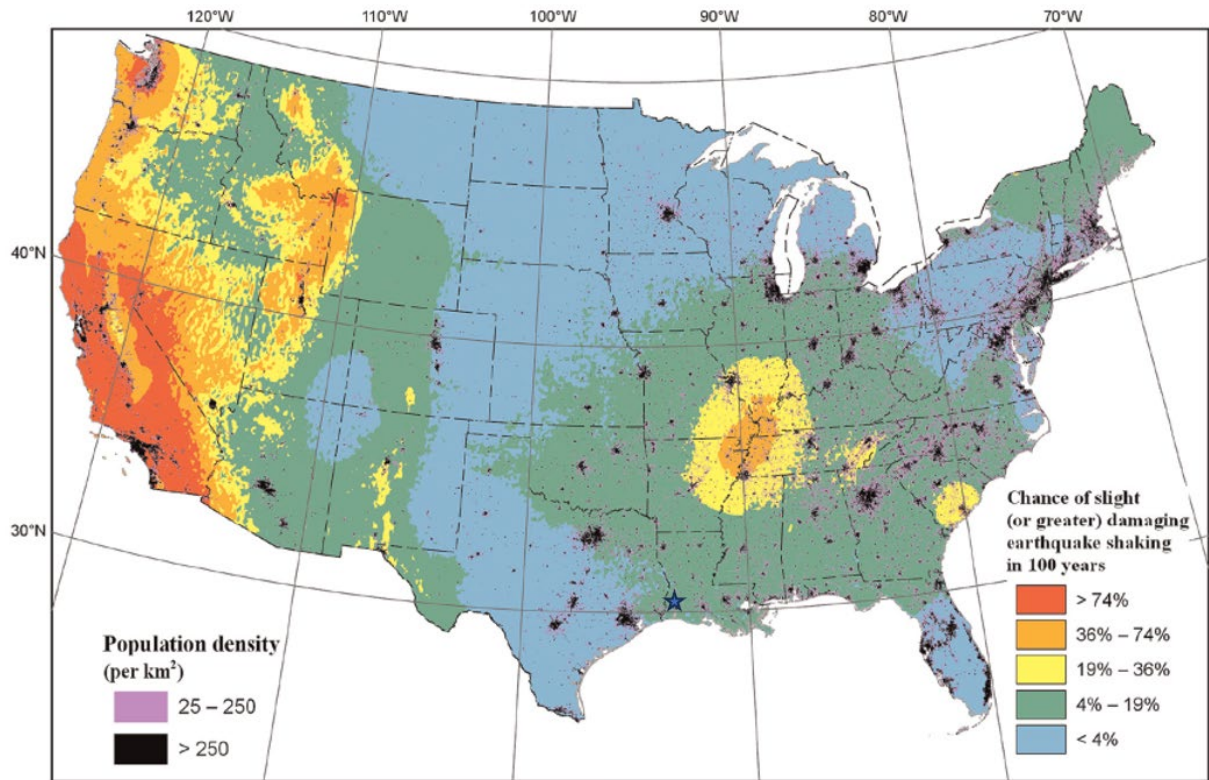


Figure 1-72 – Location of the Evergreen Hub project (indicated by the blue star), plus population density and the risk of a Class VI earthquake shaking in 100 years (Petersen et al., 2019).

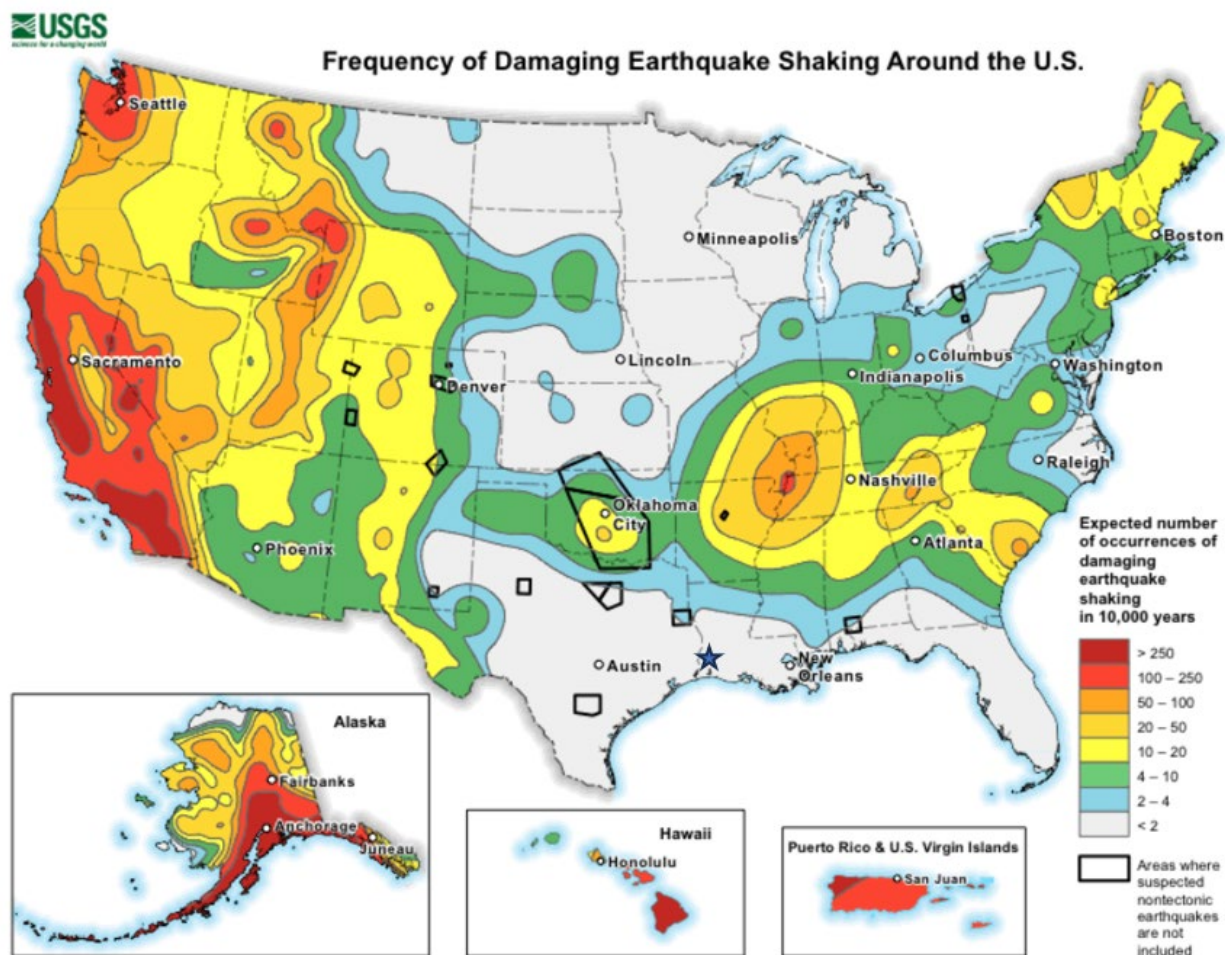


Figure 1-73 – Predicted damaging earthquakes shaking around the United States and the location of the Evergreen Hub project, indicated by the blue star (USGS, accessed 2023).

1.11. Conclusion

The stratigraphic and structural setting identified during the preparation of the Evergreen Hub project's Loblolly CCS No. 001 and Loblolly CCS No. 002 site characterization supports CO₂ injection operations and protects surrounding USDWs.

- Potential USDWs are identified, mapped, and assessed to be unaffected by proposed injection operations.
- The stratigraphy in southwestern Louisiana creates an ideal setting for injection operations, with porous and permeable Oligocene-age Frio Formation sandstone intervals deposited between the thick, low-permeability marine shales of the Anahuac and Vicksburg/Jackson formations.
- A robust data set of 3D seismic data and well control confirms low structural complexity and gentle dip.

- A thorough investigation of the 3D seismic data did not detect any transmissible faults across the upper confining zone in proximity to the CO₂ plume.
- There are no faults that intersect the USDW in proximity to the CO₂ plume.
- The regional stress regime and pressure gradients support injection operations within the Frio sand intervals.
- Mineralogy of the injection and confining zones are compatible with the in-situ water chemistry and injected fluid composition, with potential mineral precipitation along the confining zone interfaces bolstering the sealing nature of these shales.
- Analysis of historical mineral production indicates no mineral resources will be affected by proposed injection operations.
- The Evergreen Hub site is located in a low tectonic-hazard risk area. No earthquakes were identified within 15 miles of the proposed Loblolly CCS No. 001 and No. 002 wells.

The Evergreen Hub site presents an ideal location for proposed injection operations. Frio Formation sands have sufficient porosity, permeability, lateral continuity, and thickness to serve as an injection zone. The low permeability overlying the Anahuac Shale and underlying shales of the Vicksburg and Jackson formations are of sufficient thickness and lateral continuity to contain the injected fluid within the Frio Formation. There are no known conduits above the injection zone capable of transmitting fluid to USDWs, and seismic risk from injection operations is low.

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Appendices

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Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 2 – PLUME MODEL

February 2024



SECTION 2 – PLUME MODEL

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2.1 Introduction

In compliance with Statewide Order (SWO) 29-N-6, **§3615.B** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84**], the following discussion centers on the plume model for the Evergreen Sequestration Hub (Evergreen Hub) Carbon Capture and Sequestration (“CCS”) project Loblolly CCS No. 001 and Loblolly CCS No. 002 wells. The model establishes the required pore space, defines the area of review (AOR), outlines comprehensive corrective action plans, and assesses the overall feasibility of the project within the specified regulatory framework. Both *Section 3 – AOR and Corrective Action Plan* and *Section 5 – Testing and Monitoring Plan* utilize the forecasted plume to help determine the best strategies and plans to minimize the impact of carbon sequestration.

The primary objectives of the plume model are as follows:

1. Maximize the utilization of accessible pore space for carbon sequestration activities.
2. Evaluate the most strategically optimal well locations to facilitate carbon storage.
3. Assess the migration of CO₂ and the injector’s pressure influence to prevent any adverse effects on significant subsurface structures.
4. Provide supporting data to determine corrective action and monitoring plans.

2.2 Project Summary

The Evergreen Hub site is in Beauregard and Calcasieu parishes, approximately [REDACTED] miles (mi) west of Dequincy, Louisiana, and [REDACTED] mi north of Starks, Louisiana. The sequestration site encapsulates 20,073 acres of land that is viable for CCS. The focus of this permit application is on Loblolly CCS No. 001 and Loblolly CCS No. 002, where each well plans to inject [REDACTED]. Loblolly CCS No. 001 plans to inject for [REDACTED], resulting in a total of [REDACTED] of supercritical CO₂ being safely sequestered. Loblolly CCS No. 002 plans to inject for [REDACTED] years, resulting in a total of [REDACTED] of supercritical CO₂ being safely sequestered. Throughout the life of the project, [REDACTED] will be stored in the Evergreen Hub area. Figure A-2 in *Appendix A* provides a detailed description of the property.

2.2.1 Software

2.2.1.1 Petrel™ Software Suite

Industry standard SLB’s (previously Schlumberger) Petrel software has been selected for the intricate task of constructing a detailed geocellular model as part of the permit application for the CCS site. This globally recognized software seamlessly integrates data from both well logs and seismic sources to generate a highly accurate representation of the subterranean reservoir. The geocellular model, developed with Petrel, delineates various layers of the site, including the Anahuac Shale (upper seal), Frio Sands (injection zone), and Jackson and Vicksburg shales (lower seal). Utilizing Petrel, the permeability and porosity properties of the injection were spatially distributed, incorporating well-log analysis and established methodologies. These approaches enhance the accuracy of the reservoir depiction in the model.

2.2.1.2 Computer Modelling Group Software Suite

The geocellular model developed in Petrel was used as an input into Computer Modelling Group's GEM Version 2023.20 (GEM) simulator. GEM is a highly regarded solution for modeling compositional and unconventional reservoirs. Leveraging advanced computational methods and equation-of-state (EOS) algorithms, GEM adeptly evaluates compositional, chemical, and geochemical processes, making it a reliable choice for CCS simulations. The software can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis. The software is recognized for its versatility and efficiency in addressing the complexities associated with reservoir simulation in the oil and gas industry.

2.2.2 Data Sources

The data sources needed to build the geocellular and dynamic models include offset well logs, core data, 3D seismic data, public databases, and publicly available literature, such as the Society of Petroleum Engineers (SPE) and American Association of Petroleum Geologists (AAPG) peer-reviewed papers.

An initial assessment involved the examination of public databases and literature at both regional and site-specific scales. The regional review aimed to discern major trends within the project area and its vicinity. By comparing these trends with site-specific data, an increased confidence level in the reservoir properties is achieved. Utilizing public regional databases was instrumental in estimating the salinity and temperature of the reservoir. Additionally, key reservoir properties such as rock compressibility and relative permeability were deduced from information available in public literature. These assumptions are further discussed in *Section 2.5*.

Offset well log analysis was conducted to elevate the reservoir characterization and populate the geocellular model. The openhole log data encompassed comprehensive analyses including gamma ray, spontaneous potential (SP), resistivity, porosity (sonic, neutron, density), photoelectric factor, caliper, and other relevant measurements. Utilizing these well logs enabled the identification of formation tops, determination of rock properties, and assessment of temperature gradients, thereby enhancing the representation of the subsurface reservoir. Petrophysical analysis was performed on 67 wells to appraise the target injection zone and subsequent confining layers.

A comprehensive assessment of a 3D seismic survey was conducted and seamlessly integrated into the workflow to enhance the characterization of the injection zone and confining layers. The supplementary data acquired from the 3D seismic survey, coupled with the formation tops identified through well-log analysis, was employed for the identification of key structural horizons, as illustrated in Figure 2-1. The seismic data allows for an enhanced visualization of the subsurface, revealing features such as faults, a salt dome, or other structural changes in the subsurface. Integrating this data into the geocellular model substantially enhanced its precision, resulting in a more thorough comprehension of the targeted stratigraphy.

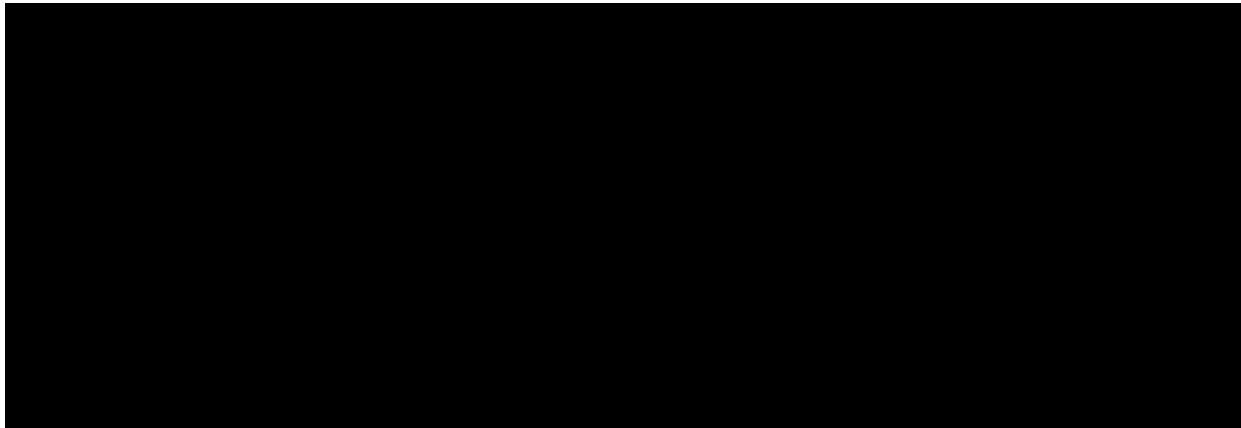


Figure 2-1 – Major Structural Horizons

Site-specific data will be collected after the submittal of this permit application. A stratigraphic test well is planned to gather core, fluid samples, and geophysical logs, including the additional data that will further increase the accuracy of the model.

2.3 Trapping Mechanisms

In a CCS project, four primary trapping mechanisms exist that sequester the supercritical CO₂, schematically represented in Figure 2-2. Structural and stratigraphic, residual gas (also referred to as residual CO₂), solubility, and mineral trapping mechanisms—all present in the current model except for mineral trapping—are discussed in the following sections.

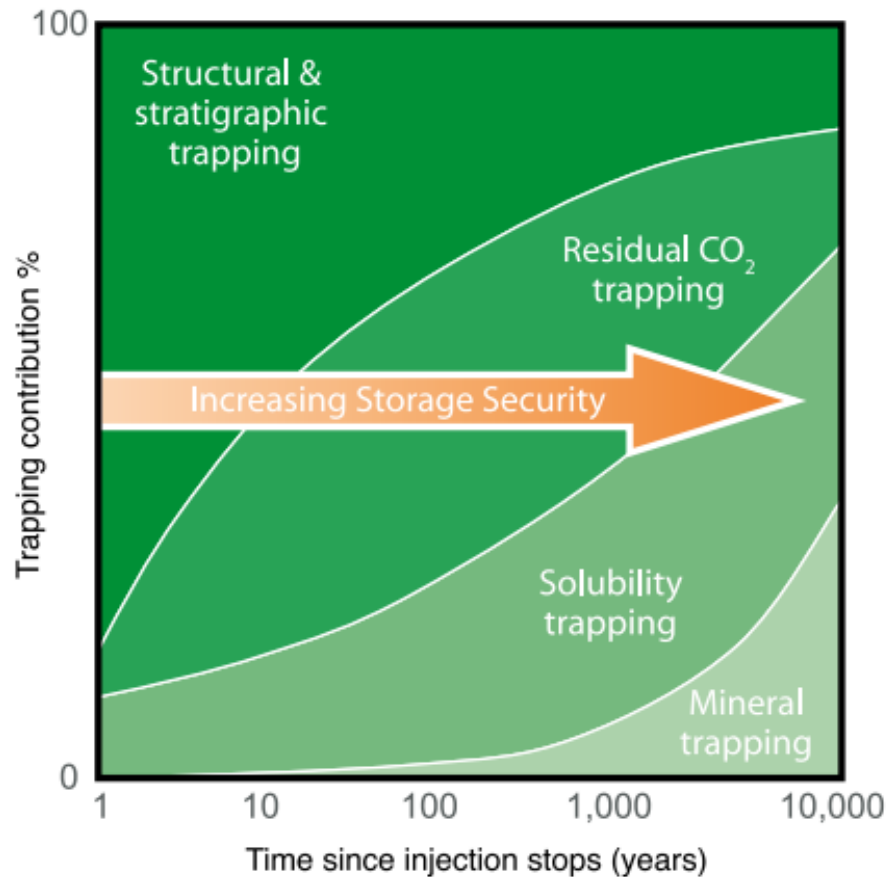


Figure 2-2 – CO₂ Storage Mechanisms (IPCC, 2005)

2.3.1 Structural/Stratigraphic Trapping

Structural trapping in CCS involves the physical confinement of injected CO₂ through the presence of sealing faults, stratigraphic, or other geological traps. Similar to naturally occurring hydrocarbon reservoirs, CO₂ can frequently be sequestered in anticlinal folds. This phenomenon is captured in the geologic model. The static model contains the confining shales and shale baffles that act as barriers inhibiting supercritical CO₂ flow. As a low-viscosity fluid, supercritical CO₂ is less dense than the surrounding brine in the injection zone. Consequently, CO₂ will ascend until its buoyant forces are no longer greater than the capillary entry pressure of the caprock. In the dynamic model, the mass density of CO₂ exhibits a range from [REDACTED] in the shallowest injection interval, to [REDACTED] in the deepest intervals. Concurrently, the surrounding brine density is consistently measured at 65.9 lb/ft³.

The EOS calculations are executed to ascertain and predict the phase behavior, density, and other thermodynamic properties of CO₂. These mathematical formulations can predict the density of the injected fluid at any given location based on the pressure and temperature conditions. GEM uses several well-known EOS formulas, including the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong method. The EOS implemented within the plume model

was the Peng-Robinson method, due to its widely accepted use for volumetric and phase equilibria.

2.3.2 Residual Gas Trapping

Residual gas trapping constitutes a physical trapping mechanism where minute quantities of CO₂ persist in the pore space as the plume continues to migrate. As water is displaced in the rock, the CO₂ fills the space. However, depending on the movement of CO₂ and the aqueous phase through saturation and capillary forces, CO₂ will remain residually trapped within the pore space.

Hysteresis modeling is used in the model to accurately predict the amount of residually trapped supercritical CO₂. GEM offers several methods to determine residual gas trapping, such as the Carlson and Land model (Land, 1968) (Land, 1971) (Carlson, 1981) and the Larsen and Skauge model. The [REDACTED] was implemented for this simulation due to (1) its use being validated for water-alternating-gas injection and (2) being the one model representing the two-phase system. The critical parameter—trapped gas saturation—will be discussed in *Section 2.5.3*.

2.3.3 Solubility Trapping

Solubility trapping is a chemical trapping mechanism characterized by the interaction between supercritical CO₂ and brine. Due to its high solubility in brine, CO₂ forms a solution with a higher density than the original connate brine. As a result, the CO₂-laden brine descends within the geologic formation, trapping the CO₂-enriched brine. This mechanism contributes to the reduction of CO₂ migration and enhances the storage capacity of the reservoir.

GEM models the solubility of CO₂ and other components using Henry's Law, the general form of which uses the following formula:

$$(Eq. 1) \quad f = x * H$$

Where:

f = the fugacity of the component

x = composition of the component in the aqueous phase

H = Henry's Law constant

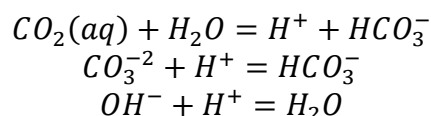
The Henry's Law constant for a specific component (e.g., CO₂) can be calculated as a function of pressure, temperature, and salinity in GEM using correlations developed by Harvey (Harvey, 1996) or Li and Nghiem (Li & Nghiem, 1986). The [REDACTED] was chosen for its improved accuracy at modeling CO₂ and hydrocarbon gas solubility in high-salinity brines.

2.3.4 Mineral Trapping

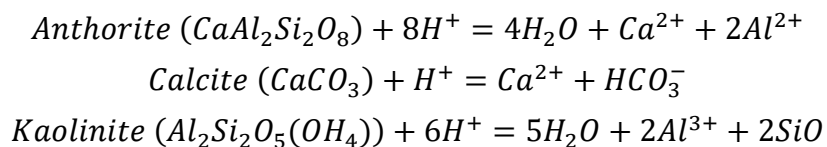
Mineral trapping or *geochemical* trapping is another form of chemical trapping that occurs due to reactions between CO₂ and the geochemistry of the formation. During CO₂ injection into the

reservoir, four primary drivers interact with one another: (1) CO₂ in the supercritical phase, (2) in situ hydrochemistry of the connate brine, (3) aqueous CO₂, and (4) the geochemistry of the formation rock. The interaction of these components results in CO₂ often being precipitated out as a new mineral. This new mineral is typically Ca-CO₃, or calcium carbonate (i.e., limestone).

Mineral trapping can also occur due to the adsorption of CO₂ onto clay minerals. Once hysteresis and solubility trapping are included in the model, geochemical formulae can be added through an internal geochemistry database to describe mineral-trapping reactions. For aqueous reactions, the following formulae were used:



These three reactions are common ionic reactions that can occur in the reservoir between water and CO₂. The following formulae show the mineral reactions used in the model. Each mineral is commonly found within sandstone in an underground aquifer and causes the precipitation of carbon oxides in a solid state:



While geochemical trapping can have a greater impact on CO₂ over hundreds or thousands of years, the short-term effects of these trapping mechanisms are small, and fluid movement is predominated by hydrodynamic and solubility trapping. Due to the current limitations in data for the compositions of these minerals and components in the reservoir, as well as the computational stress added to the software, the geochemical trapping mechanisms were not assumed in the current model. As more data are received on the reservoir's geochemical properties, sensitivities could be run to determine the applicability of these traps.

2.3.5 Trapping Summary

Following the cessation of injection (in Year 2045), the mobile CO₂ experiences a rapid reduction as supercritical-phase CO₂ migrates through the pore space and becomes entrapped. Throughout the project's life span, residual trapping of supercritical CO₂ emerges as the predominant one among the various trapping mechanisms. Approximately [REDACTED] of the injected fluid undergoes secure sequestration through residual trapping within the pore space. The solubility of CO₂ into the connate brine facilitates the safe storage of around [REDACTED] of the injected CO₂. The remaining [REDACTED] of the injectate is subject to structural and hydrodynamic trapping. Figure 2-3 provides a breakdown of each trapping mechanism during the life of the project.

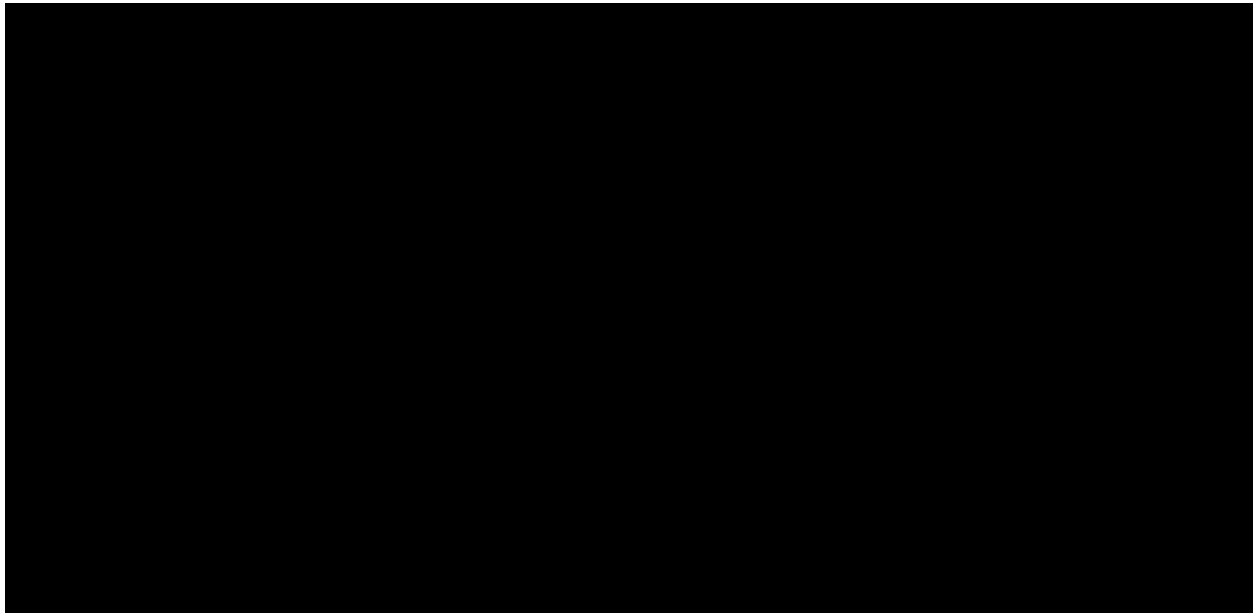


Figure 2-3 – Trapping Mechanisms Summary

2.4 Site Characterization Model

2.4.1 Static (Geocellular) Model Development

This section presents the geocellular model of the Evergreen Hub project, conducted to fulfill the requirement of SWO 29-N-6, **§3615.B.3.a** [40 CFR **§146.84(c)(1)**], which state that the AOR must be delineated using “computational modeling.”

The geocellular 3D model (delineated in Figure 2-4) spans [REDACTED] laterally and is approximately [REDACTED] feet (ft) in average thickness, covering the entire Frio Formation as well as a portion of the sealing upper and lower confining units (Lower Miocene, Anahuac, and Vicksburg/Jackson shales). This model was also constructed using Petrel software.

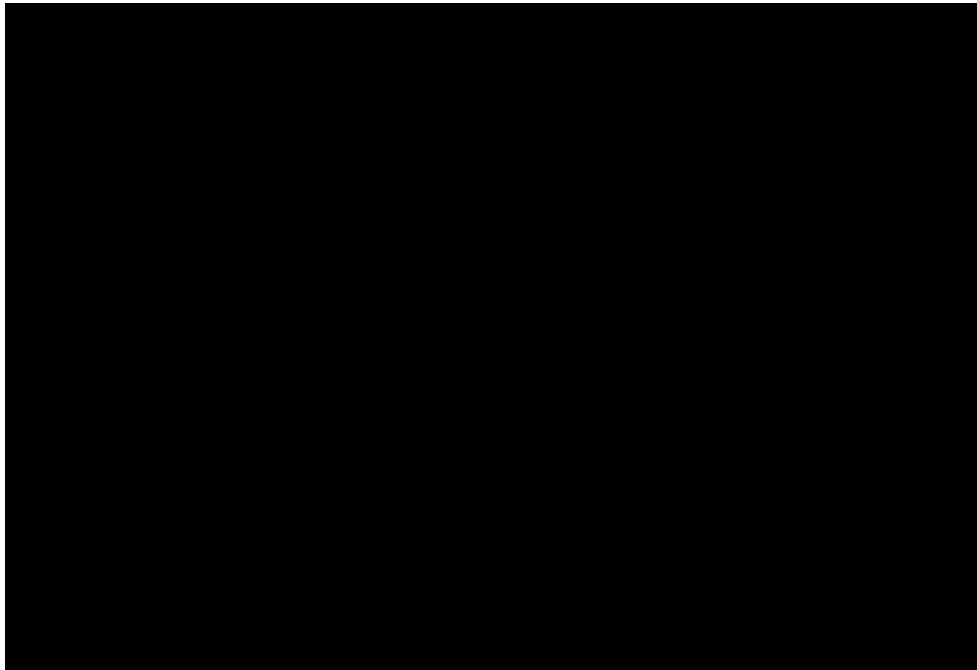
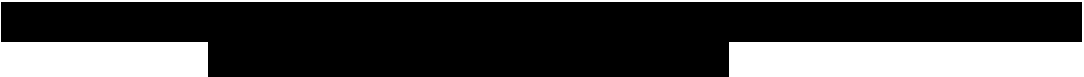


Figure 2-4 –



The 3D model was created in NAD27_LS1702 and included a structural interpretation based on 132 wells. Of those wells, 94 were drilled inside the model boundaries with X, Y, and Z deviations, using logs, datum elevations information, 3D seismic Society of Exploration Geophysicists Y Format (SEG Y), faults, horizon seismic interpretations in time, and public regional shape files. Of the 94 wells, 67 were used for the petrophysical evaluation. The flowchart in Figure 2-5 describes the process followed during the geocellular model construction.

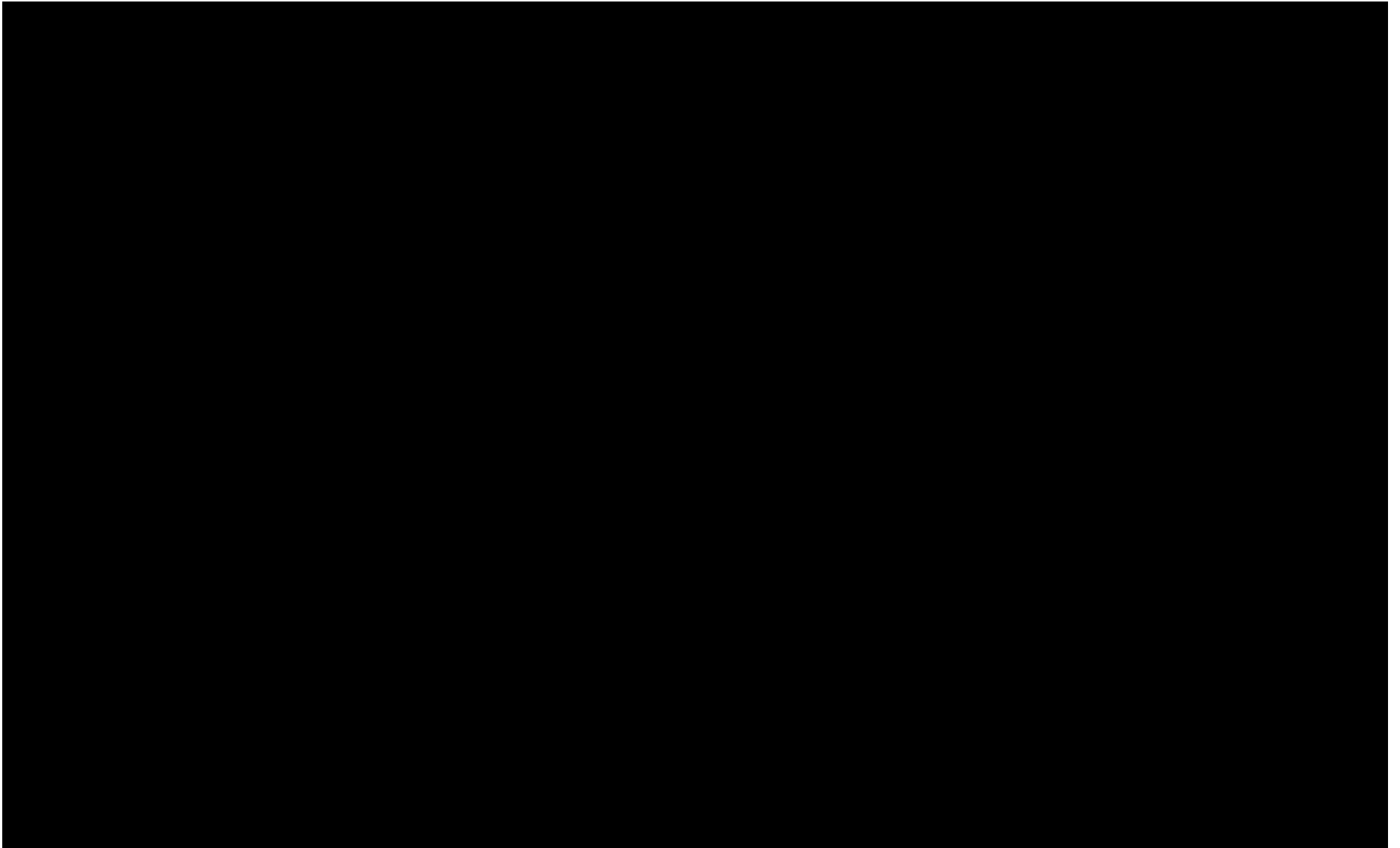


Figure 2-5 – Geocellular Model Workflow

2.4.2 Structural Framework

Then seismic depth conversion, seismic-to-well tie, and 20 sequence stratigraphic markers correlated in 132 wells were used to refine the vertical scale. A salt diapir was interpreted and included in the west part of the model, confirming that the salt diapir is deeper than the lower confining layer. Examination of this diapir indicated that it does not affect the injection or confining zones—and therefore is not included in the dynamic simulation model.

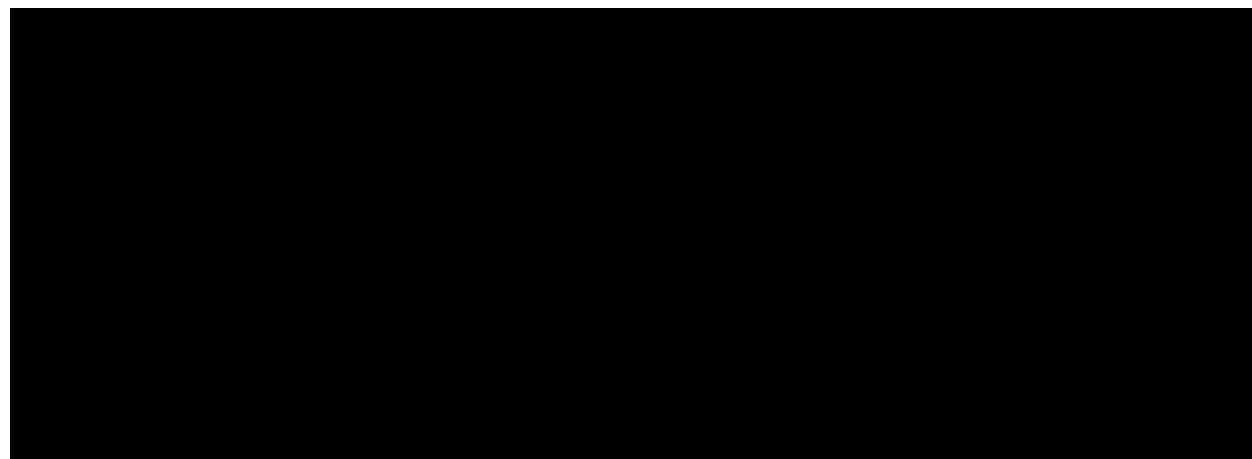


Figure 2-6 – Structural model maps: at left, view of faults at the model base (Jackson Top) in black; at right, view of faults at the modeled top of the injection zone (Frio Top). Both maps show the salt diapir in gray to the west.

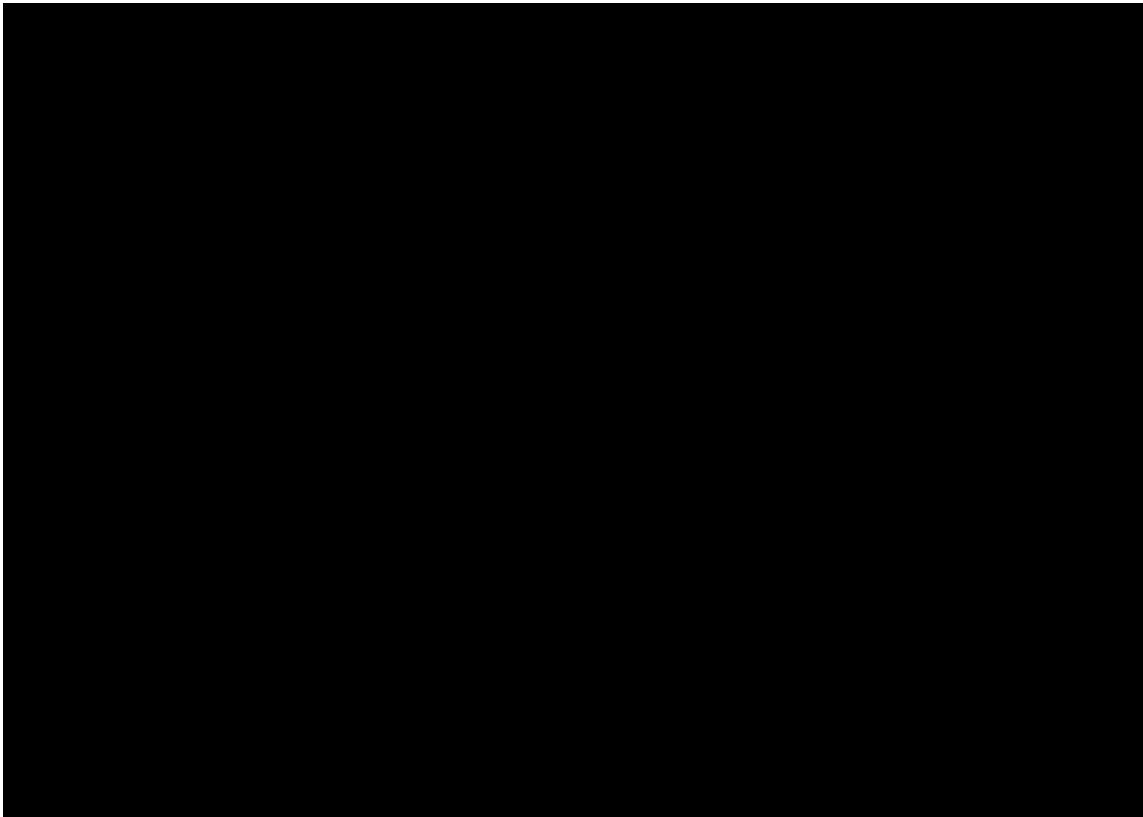
Appendix B-26 illustrates the faults for the top of the upper and lower confining surfaces, the Anahuac Shale and Vicksburg-Jackson shale, respectively. Most faults trend southwest to northeast and dip to the south. The seven seismic time horizons were converted to depth using the corresponding well markers to create the velocity model. These seven seismically mapped horizons are labeled: L_Miocene_100, ANAHUAC TOP_SH, FRIO_TOP, M_Frio_200, Frio_100_Smooth, BASE_FRIO, and TOP JACKSON. In total, 20 formation tops were used to further refine the model vertically.

The Frio Formation in the modeled area was deposited in the Buna aggradational barrier strand-plain environment (Galloway et al., 1982)(Tyler et al., 1985). After running several structural and stratigraphic attributes, the sweetness attribute was used in the lower units of the Frio Formation to guide the continuity of the data in the major and minor directions while matching the well data. The petrophysical properties were distributed (e.g., Vshale, porosity, and permeability) from 67 wells with available information, using the geostatistical modeling tools to preserve the

heterogeneity of the Frio Formation. The anisotropy used in the lower Frio units has an azimuth of roughly [REDACTED], observed in the “sweetness” attribute, shown in Appendix B-27. This corresponds with observed depositional trends described in technical papers of Oligocene-age sediments along the Gulf Coast (Galloway et al., 1982)(Tyler et al., 1985).

Table 2-1 details the geocellular model, which has 19 zones defined between 20 tops, including the entire Frio Formation as well as the confining Anahuac and Vicksburg/Jackson shales. The grid resolution is [REDACTED], with a vertical average of [REDACTED]. The dynamic model has [REDACTED] in the “I” direction, [REDACTED] in “J” direction, and [REDACTED] in the “K” direction for a total of [REDACTED]. An example of well log data is displayed in Figure 2-7, with Vclay, SP, lithofacies, total porosity, effective porosity, and permeability from petrophysical interpretation, and the same properties displayed to the left in the [REDACTED] after modeled.

Table 2-1 – Geocellular Model Construction



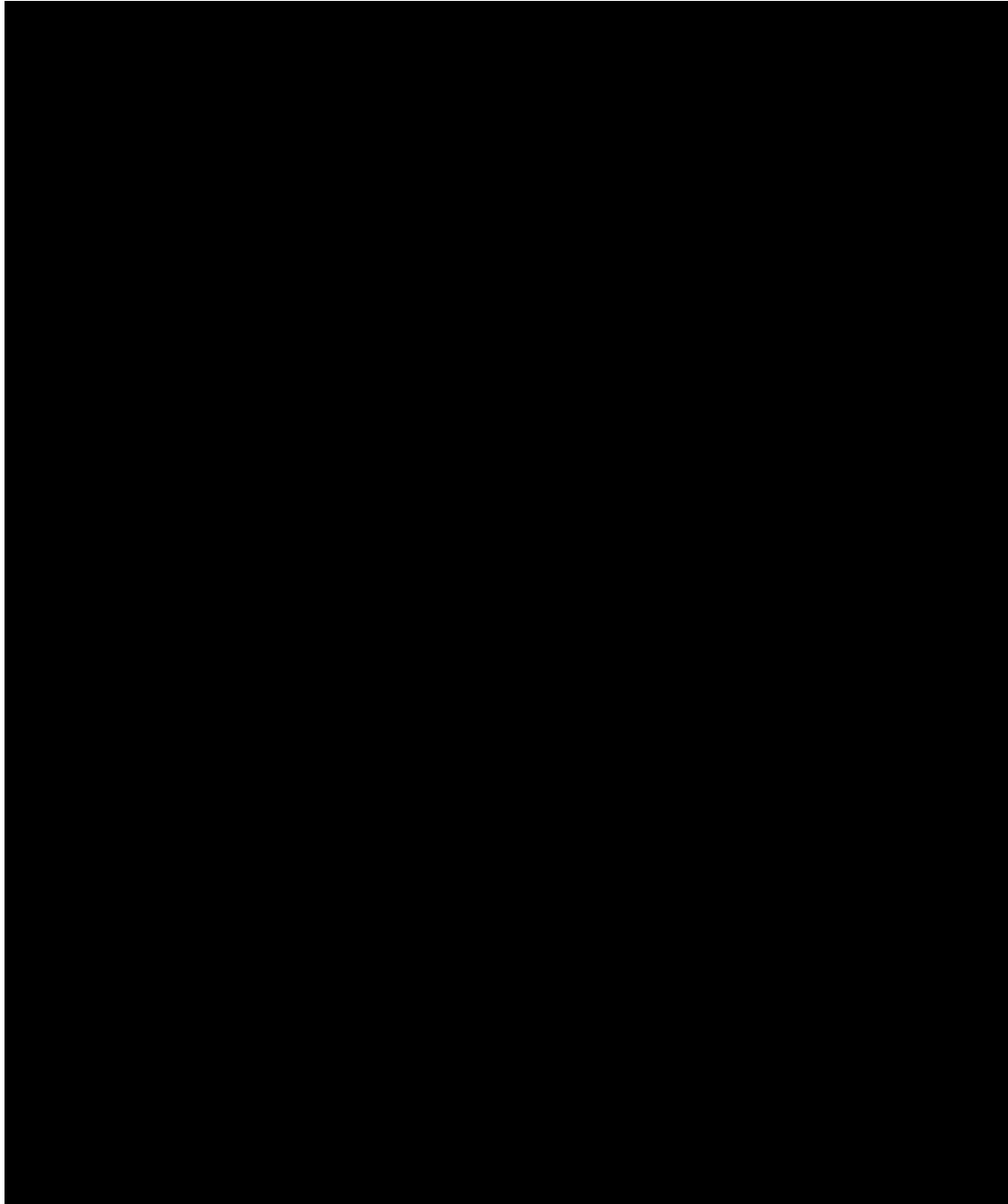


Figure 2-7 – Example Log with Petrophysical Log Data and Corresponding Upscaled Values

2.4.3 Petrophysical Modeling

Petrophysical data was analyzed for 67 wells and 19 zones using geostatistics. These analyses included the use of general statistical information, histograms, and variograms (vertical, major, and minor directions). The petrophysical data analyzed were Vshale, total porosity (ϕ_{Total}), effective porosity ($\phi_{\text{Effective}}$), and permeability (k). Figure 2-8(A) shows the general statistics for the Vshale property from the Frio_60 to Frio_50 interval. Figure 2-8(B) shows a histogram display for the same zone and property, used to compare the raw data (from logs in red) to the upscaled (in green) and populated property (in purple), while Figure 2-8(C) shows the variogram information resulting from the same zone as shown in Figures 2-8(A) and 2-8(B).

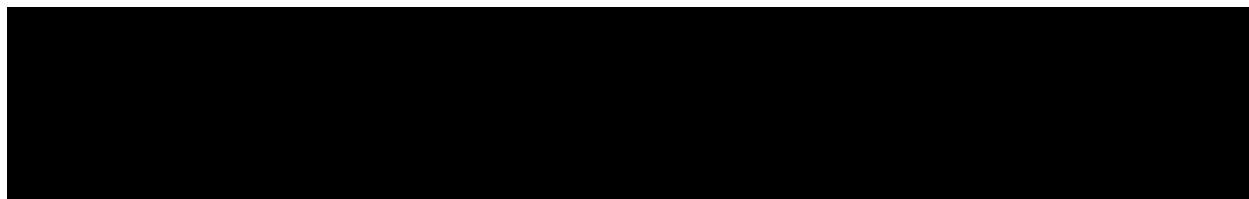


Figure 2-8(A) – General Statistics for the Frio_60 to Frio_50 Zone Within the Vshale Property

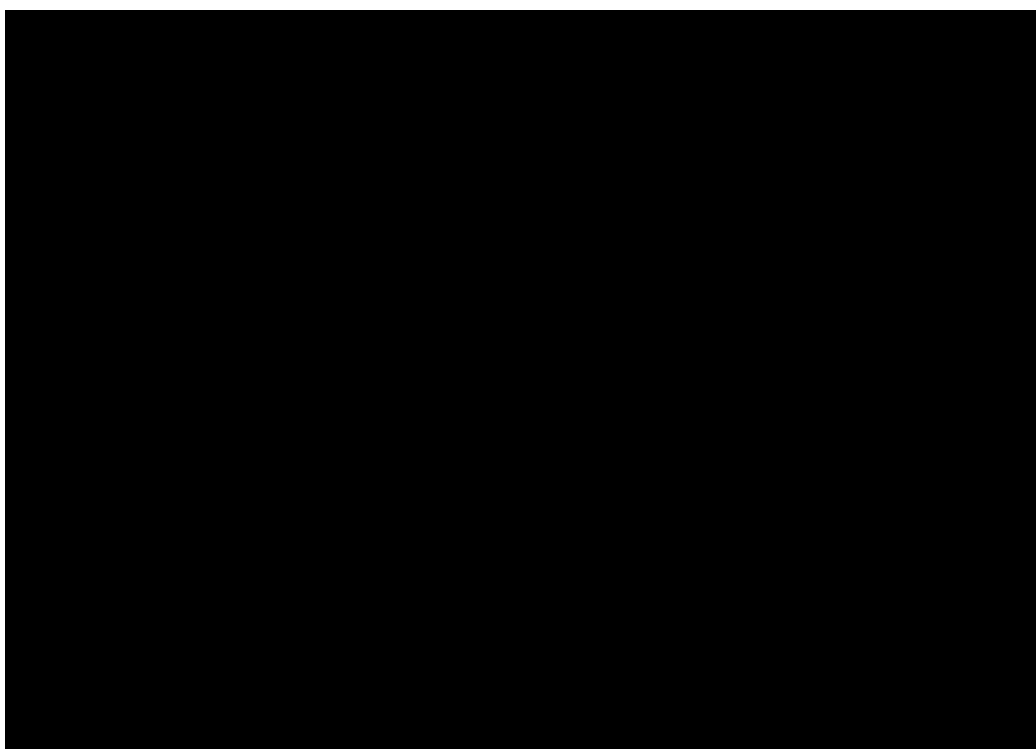


Figure 2-8(B) – Histogram display for the Frio_60 to Frio_50 Zone within the Vshale property. Raw data is shown in red, upscaled cells in green, and populated property in purple.



Figure 2-8(C) – Variogram information resulting from Frio_60 to Frio_50 zone within the Vshale property.

Lithofacies and petrophysical properties of the multilayer model were distributed for each stratigraphic zone using cell-based modeling. The volume of shale (Vshale), total porosity (ϕ_{Total}), effective porosity ($\phi_{\text{Effective}}$), and permeability (k) were scaled up to the 3D grid cell dimensions and distributed stochastically using the [REDACTED]

The [REDACTED] lithofacies [REDACTED] were calculated in every zone from the 67 well logs using a Vshale cut off of [REDACTED]. Lithofacies modeling was conducted in the 19 zones, honoring the well data. The generated lithofacies volume was then used to condition the distribution of the porosity, resulting in the ϕ_{Total} and $\phi_{\text{Effective}}$ modeled volumes. Likewise, permeability (k) was modeled by lithofacies and co-kriged to the porosity model. Figure 2-9 is a display of the three attributes modeled over the Frio_60 to Frio_50 zone.

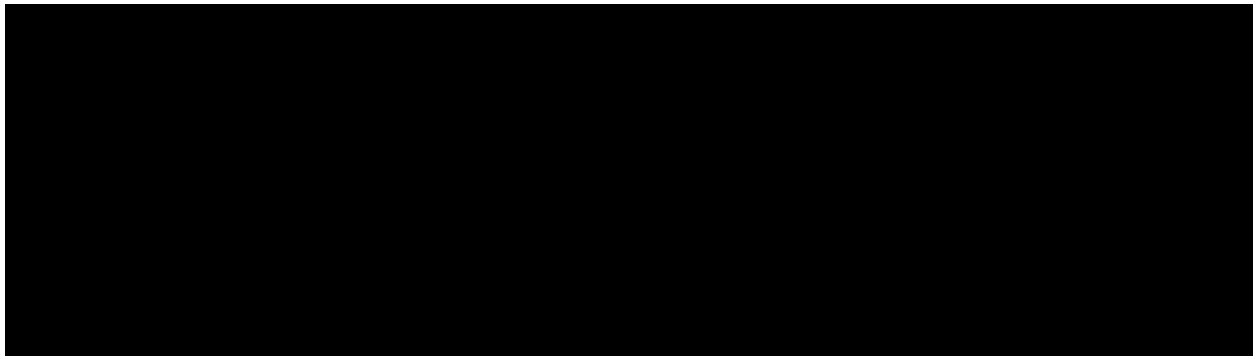


Figure 2-9 – Modeled Frio_60 to Frio_50 Zone: Vshale, $\emptyset_{\text{Effective}}$, and Permeability

The structural and Vshale 3D models were used for the fault slip potential (FSP) analysis, shale gouge ratio (SGR) calculation, and transmissibility analysis of faults in the modeled area. The 3D structural grid with lithofacies, Vshale, $\emptyset_{\text{Total}}$, $\emptyset_{\text{Effective}}$, and k properties distributed across every zone were exported as a RESQMLv2 file, to run the compositional dynamic simulation in GEM.

The location of cross-sectional views is plotted in Figure 2-10 in 3D (from a southwest vantage), with projected lease hold, injection wells, and a proposed stratigraphic test well. The cross-sectional views of lithofacies, effective porosity, and permeability are shown in Figures 2-11, 2-12, and 2-13, respectively.

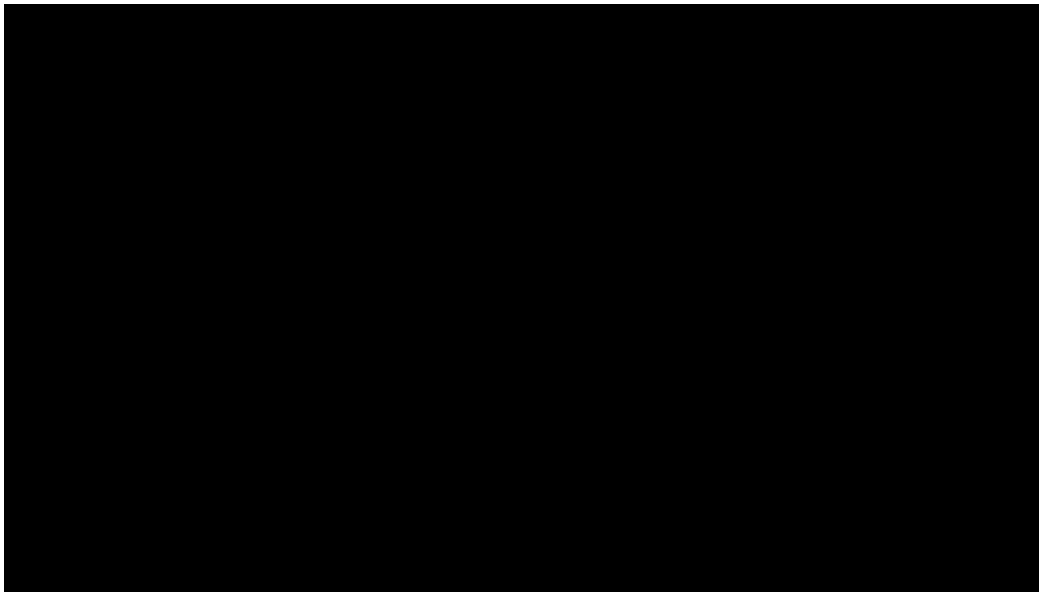


Figure 2-10 – West to east plane depicting cross section location through Injector 1 and Injector 2, well locations (shown in red), and proposed stratigraphic well (green) over the modeled lithofacies volume.

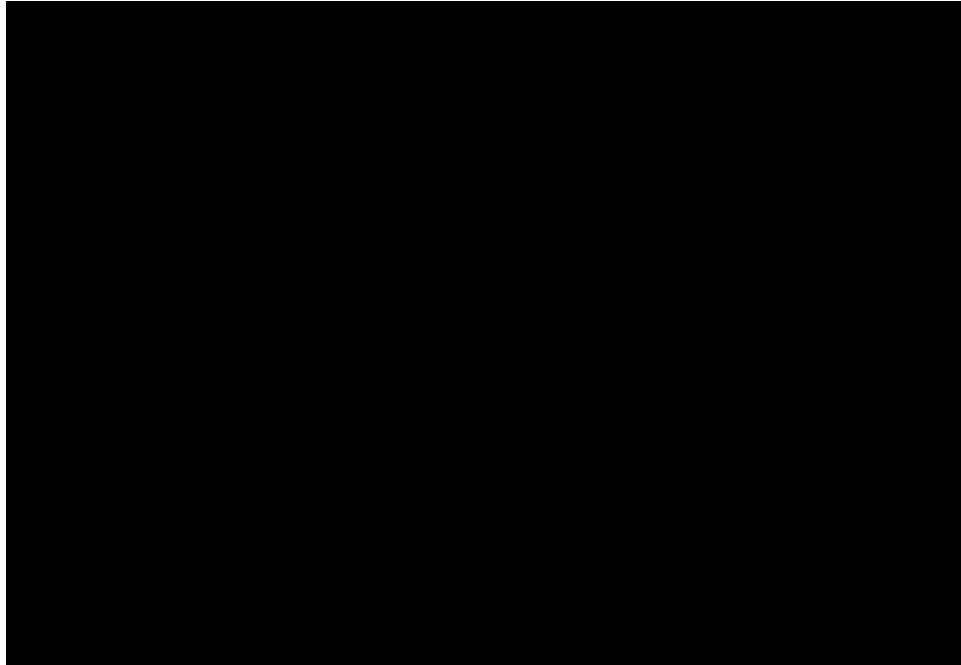


Figure 2-11 – Lithofacies Cross Section

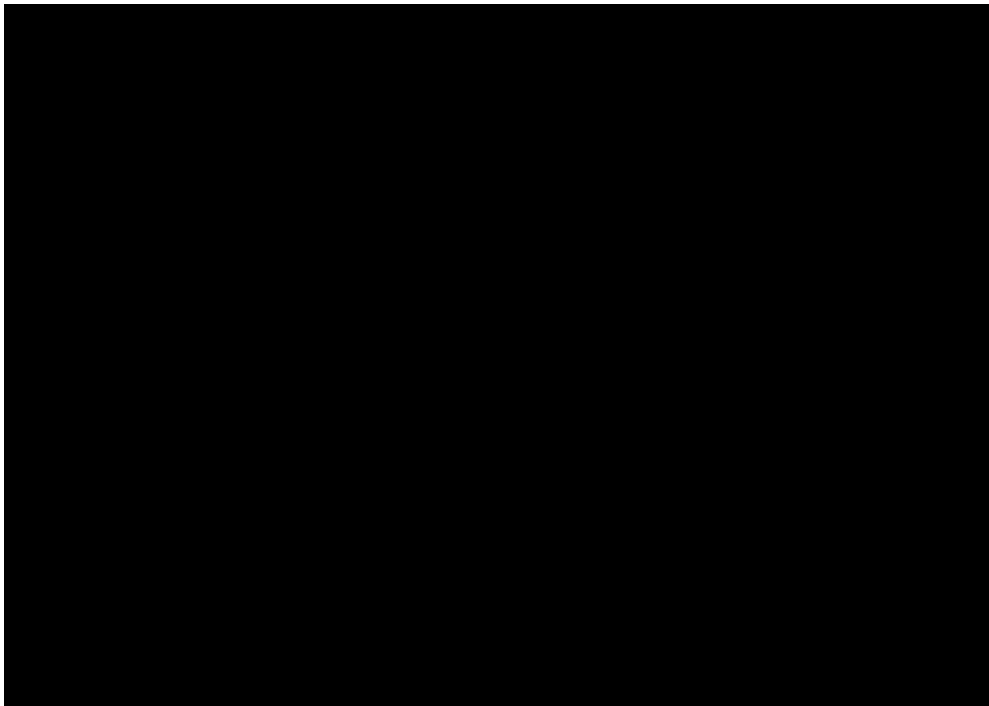


Figure 2-12 – Effective Porosity Cross Section

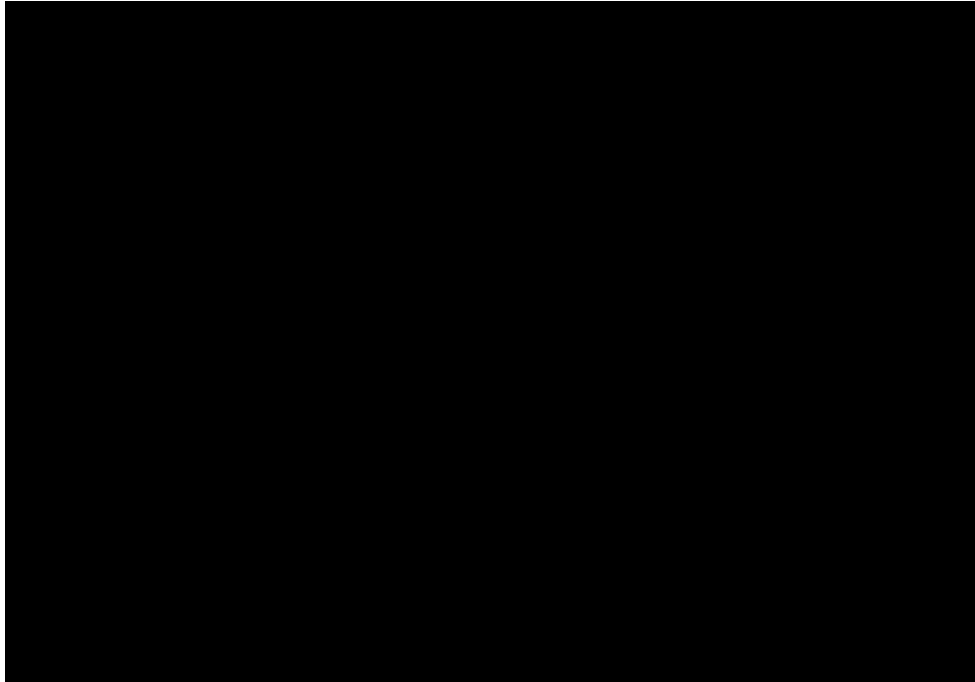


Figure 2-13 – Permeability Cross Section

2.5 Dynamic Plume Model

2.5.1 Model Orientation and Gridding Parameters

2.5.1.1 Spatial Conditions

As discussed earlier, CMG uses the Petrel geologic model as an input. The model maintained its original grid cell dimensions of [REDACTED] without upscaling. To mitigate computational demands, the confining shales were split into fewer layers. The upper shale is split into [REDACTED] layers [REDACTED] and the lower shale is split into [REDACTED] layers [REDACTED]. The model uniformly covers an area of approximately 57,000 acres (around 89 square miles (sq mi)). The grid extends [REDACTED] in the X-direction (east-west), [REDACTED] in the Y-direction (north-south), and [REDACTED] in the Z-direction. Figure 2-14 provides a visual representation of the total area covered by the grid in the project zone.

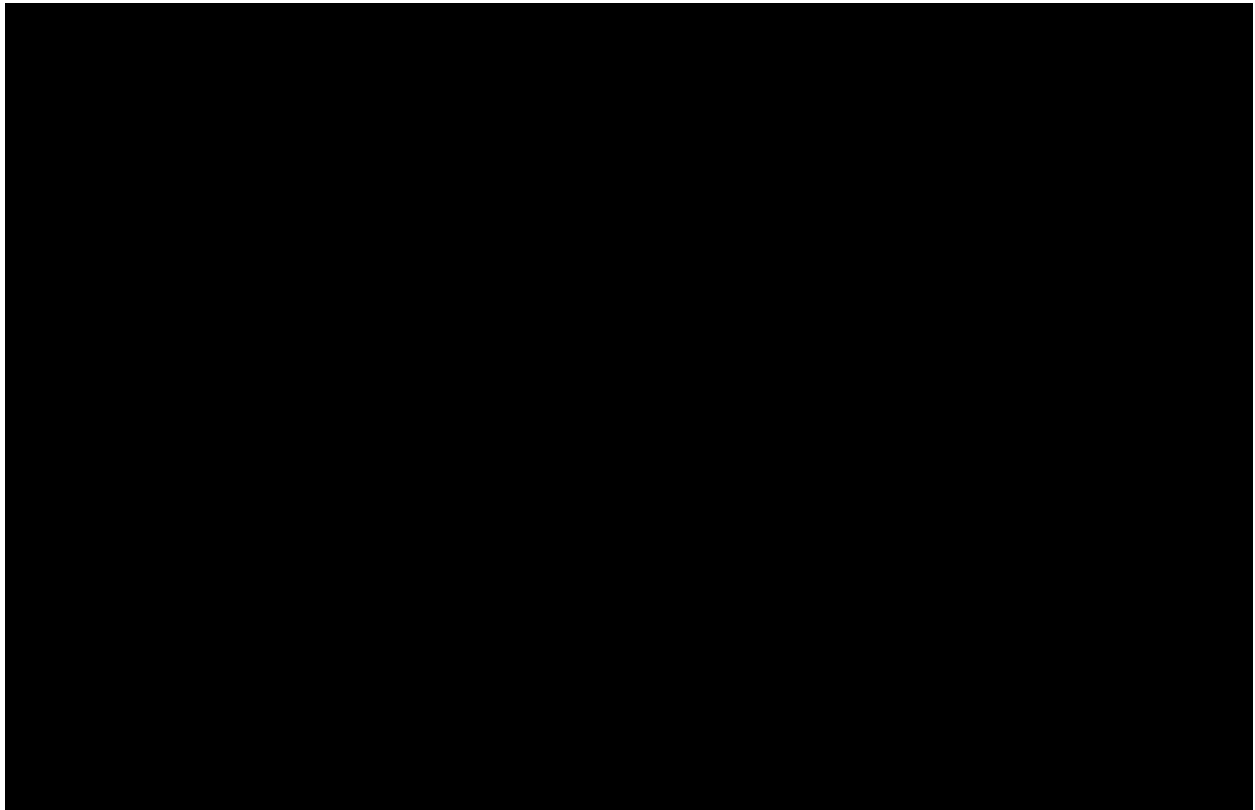


Figure 2-14 – Modeled Area

The model consists of approximately [REDACTED]. No layers were “nulled” or excluded from the model. The simulation ran efficiently, displaying minimal numerical errors.

Multiple distinct sand packages have been identified as prospective candidates for supercritical CO₂ injection. Each package is stratigraphically confined by interbedded shales and shale baffles, serving as potential barriers to impede CO₂ migration. The integration of 3D seismic data has validated the geocellular model, offering a more precise depiction of the sand packages within regions characterized by substantial gaps in well data. Following identification, these sand packages were consolidated into [REDACTED] for Loblolly CCS No. 001 and [REDACTED] for Loblolly CCS No. 002.

2.5.1.2 Boundary Conditions

Boundary conditions were chosen based on geologic research into the depositional environment.

[REDACTED] This method enables the accurate simulation of the pressure response arising from supercritical CO₂ injection. Achieving this specific objective is realized through strategically positioning "volume modifiers" along the grid edges. A value of [REDACTED] is applied uniformly along the edge of the grid, as Figure 2-15 illustrates, to enable [REDACTED] in the dynamic model. The upper and lower confinements serve as sealing boundaries due to their very low permeability.

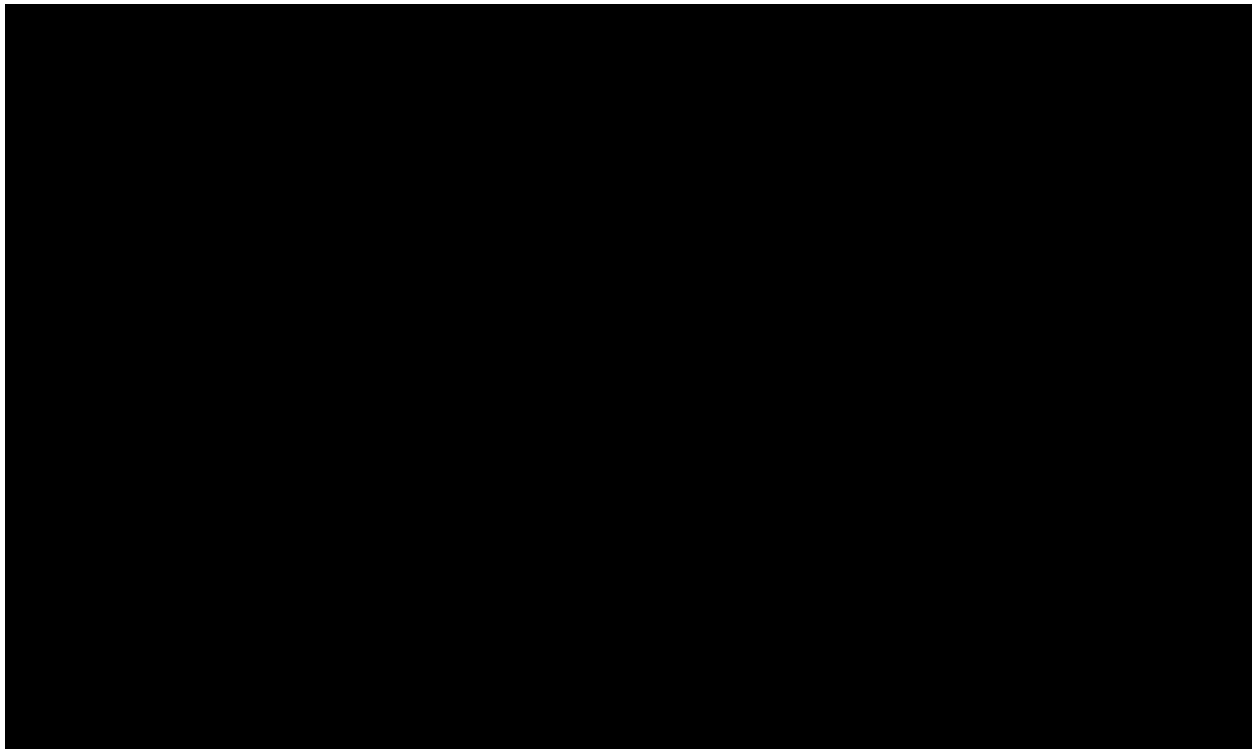


Figure 2-15 – Volume Modifiers as Applied to the Grid (the red line representing the 10,000 value)

The dynamic simulation model was initialized with zero transmissibility for all faults. Under this condition, the simulator will not allow fluids to move between grid blocks that are juxtaposed against a fault face, according to the cross-sectional area through which these blocks are connected. In practical terms, fluid cannot flow across the fault between two grid blocks when both of those grid blocks contain permeable sand. Under this approach, the faults will tend to seal against any and all flow. Sensitivities were run with the default transmissibility where faults would allow flow between grid cells. Since the faults are primarily downdip of the injection wells, there was no significant change in the areal extent of the CO₂ plume. This approach allows for a larger pressure-front extent without reducing the size of the CO₂ plume in the dynamic model—thereby creating the most conservative approach regarding pressure buildup along the faults. In the transmissive case, where the CO₂ is most likely to move towards the southern faults, the injected CO₂ never reaches them.

2.5.1.3 Model Time Frame

The model spans 120 years, comprising 20 years of active injection followed by 100 years of density drift. In this scenario, the model would begin in Year 2025 and end in Year 2145. This time frame is sufficient to capture the migration of the carbon plume until it achieves stabilization. The model results are further discussed in *Section 2.7*.

2.5.2 Initial Conditions

The dynamic model was built using the exported geocellular model and initialized with the following assumptions in Table 2-2. [REDACTED]



Table 2-2 – Initial Conditions Summary

Inputs	Values
Pore Volume Weighted Average Porosity (%)	█
Pore Volume Weighted Average Permeability (mD)	█
Kv/Kh Ratio	█
Pore Pressure Gradient (psi/ft)	█
Fracture Pressure Gradient (psi/ft)	█
Mean Surface Temperature (°F)	█
Temperature Gradient (°F/100 ft)	█
Salinity (ppm)	█

2.5.2.1 Distribution of Porosity and Permeability Discussion

Petrel was utilized to distribute the porosity across the grid. Using 94 well logs as control points, 67 of which were used for the petrophysical evaluation, the software was able to distribute the porosity using █. Distributing these values in such a fashion allowed the model to characterize the injection zone more accurately between large gaps in well data. █



█ In this depositional environment, shales are anticipated to be clay-rich. Clay-rich shales typically exhibit permeability values ranging from 0.1 nano-darcy to 100 nano-darcy, as noted by Backeberg (2017). The model assumes a permeability value of █ in the shale facies. Figures 2-16 and 2-17 highlight the porosity and permeability distributions throughout the model, respectively.

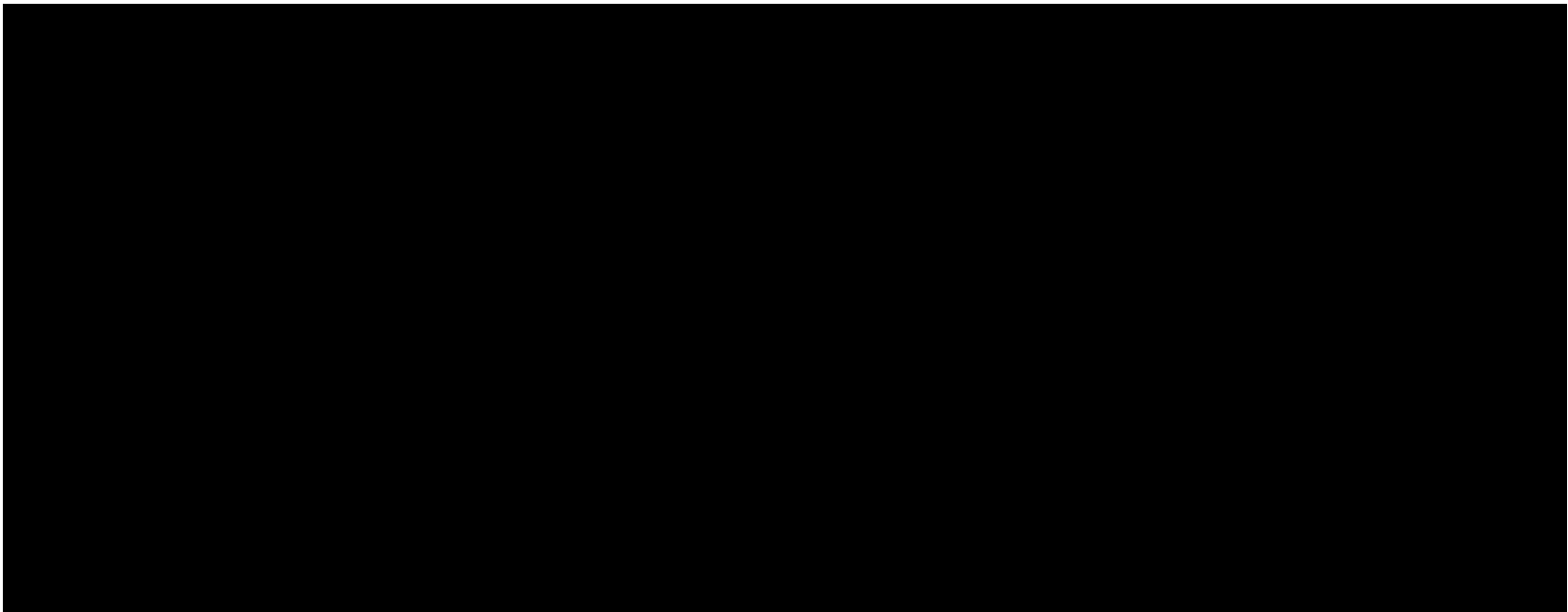


Figure 2-16 – Porosity Cross Section of the Geocellular Model

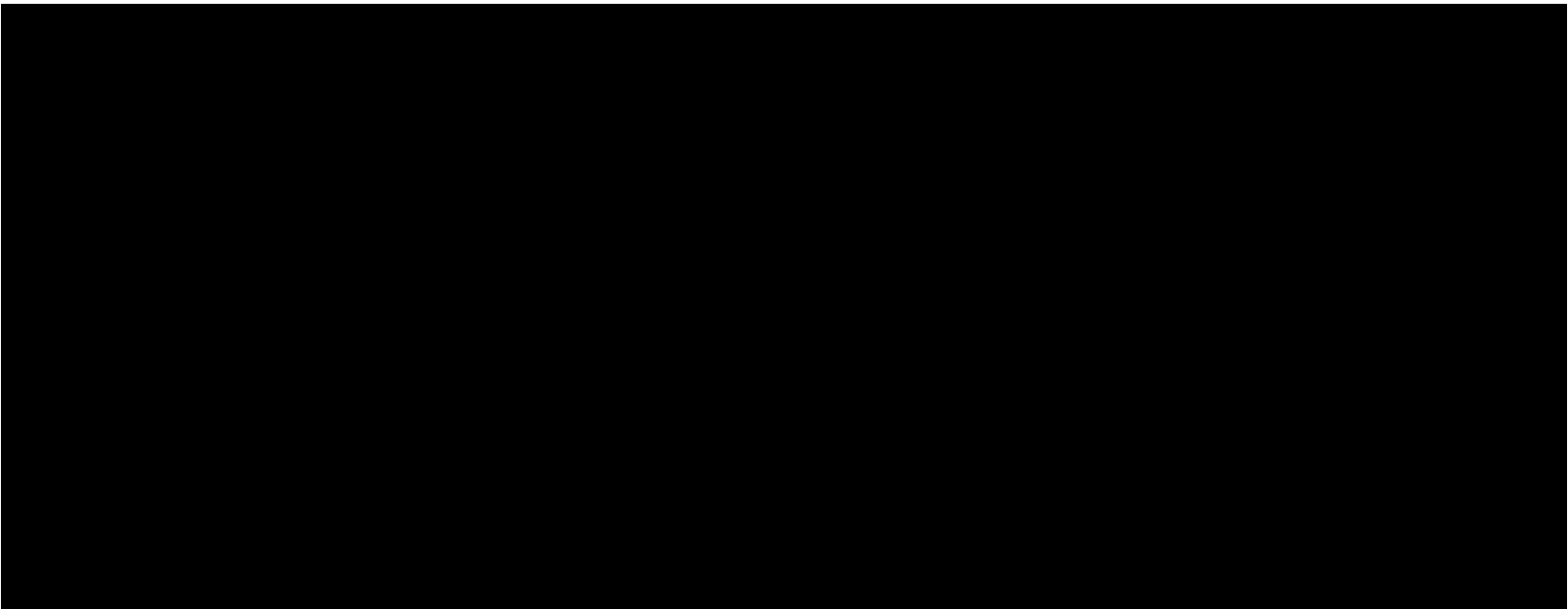


Figure 2-17 – Permeability Cross Section of the Geologic Model

A K_V/K_H ratio of [REDACTED] was used to determine the vertical permeability in the model. In practical terms, the vertical permeability has been established to be [REDACTED] of the horizontal permeability. A study conducted in the Frio sands, an analogous reservoir, suggests that K_V/K_H ratios from core data may have a wide range of values as seen in Figure 2-18 (Hovorka et al., 2003). Core data may indicate K_V/K_H ratios in the range of [REDACTED] at the core plug level. However, the choice of [REDACTED] as a value represents a standard upscaled value when extrapolating to the larger model grid-block scale, especially for intervals with high permeability. When looking at the scales smaller than the grid thickness [REDACTED] there is a high likelihood of permeability variations that would result in a lower K_V/K_H value.

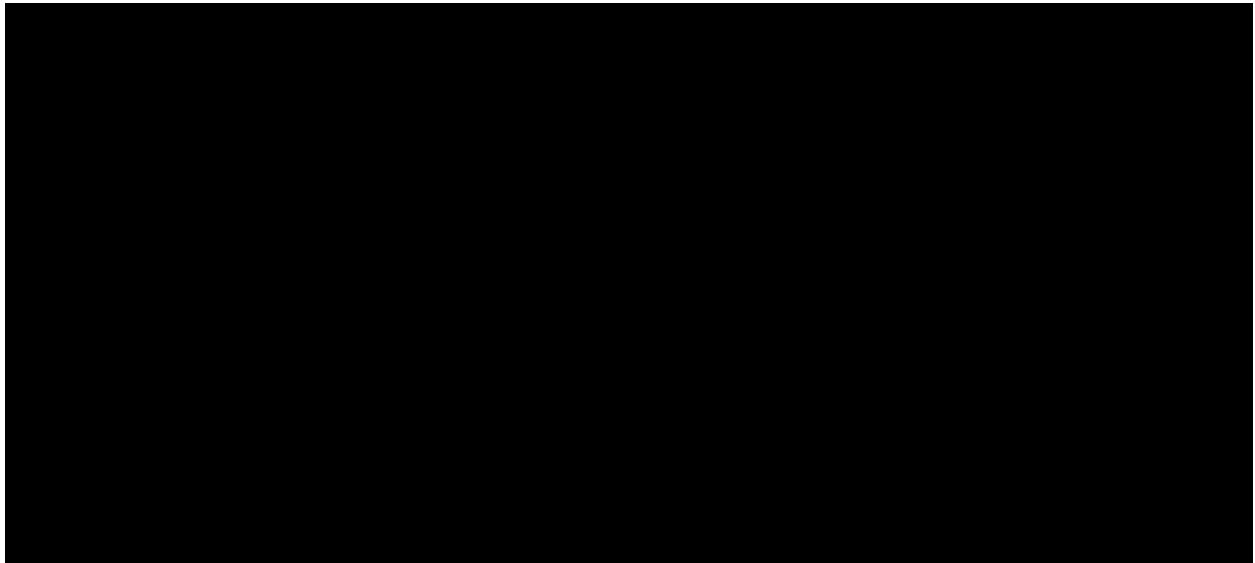


Figure 2-18 – K_V/K_H vs. Porosity Relationship (Hovorka et al., 2003)

For flow perpendicular to the bed boundaries (i.e., vertical flow), the flow will be dominated by the lowest permeability layers and reflected by a harmonic average of permeability data (“flow in series”). Conversely, the flow parallel to bed boundaries will be dominated by the highest permeability layers and reflected by an arithmetic average of permeability.

While perhaps appearing small relative to core data, a K_V/K_H ratio of [REDACTED] being a relatively high value is an important highlight. In a reservoir simulator, the flow between blocks is determined not by permeability but by the transmissibility between two adjacent blocks. The transmissibility between rectangular grid blocks is directly proportional to permeability multiplied by the cross-sectional area through which fluids pass, all divided by the distance separating the centers of the two grid blocks. This relationship can be expressed using the following equation:

$$(Eq. 2) \quad T = k \times A/L$$

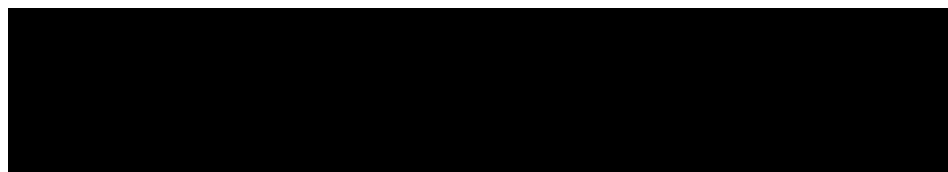
In this context, where A represents the cross-sectional area and L denotes the length of the flow path, there are distinct characteristics for vertical and horizontal flow between grid blocks. In

vertical flow, the cross-sectional area (A) is considerably larger, while the length of the flow path (L) is relatively shorter. Conversely, in the case of horizontal flow between grid blocks, the area (A) is much smaller, and the length (L) is significantly greater. In the context of this simulation model, given a K_v/K_h ratio of [REDACTED], the vertical transmissibility will be [REDACTED] times higher than the horizontal transmissibility.

2.5.2.2 In Situ Reservoir Pressure Gradients Discussion

A 100% brine-filled reservoir is assumed for the dynamic flow model. If hydrostatic conditions are also assumed, then the initial reservoir pressure will be equal to the weight of the fluid column. McCain's correlation (McCain, 1991) was utilized to calculate the density of brine at reservoir conditions. A salinity of [REDACTED] was used in the equation, resulting in a brine density of [REDACTED]. The midpoint of the injection zone was chosen to provide an average value. This pressure was used to initialize the reservoir simulation at the midpoint, where GEM will internally calculate pressure in each grid cell based on salinity and temperature at various points. Equations 3 and 4 provide a step-by-step guide in the brine density calculations.

$$(Eq. 3) \quad \rho_w = 62.368 + (0.4386 \times S) + (0.001600074 \times S^2)$$

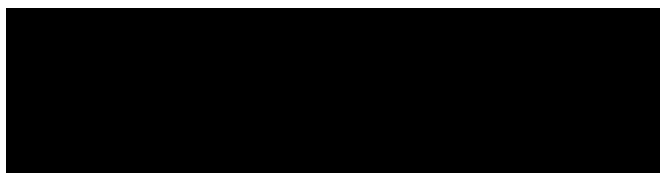


Where:

ρ_w = density of brine

S = total dissolved content of brine, expressed as weight percent

$$(Eq. 4) \quad \rho_w @ Reservoir Conditions = \frac{\rho_w @ Reservoir Conditions}{B_w}$$



Where:

ρ_w = density of brine

B_w = volume formation factor of brine

2.5.2.3 Fracture Gradient Calculation

The fracture pressure has commonly been a function of Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG). Eaton's method (Eaton, 1968) was used to calculate the pressure required to fracture the injectable rock. Primarily developed using data from Gulf Coast sands, this method offers a practical means of estimating the fracture pressure of the rock. Eaton's method is recognized as a standard practice in the industry, contributing to the assessment and

optimization of hydraulic fracturing operations in various geological settings. Table 2-3 provides the values of each input.

Table 2-3 – Fracture Gradient Calculation Assumptions – Eaton’s Method

Inputs	Values
Poisson’s Ratio	0.3
Overburden Gradient (psi/ft)	1.5
Pore Gradient (psi/ft)	0.45

Poisson’s ratio was determined through an extensive literature review on unconsolidated sandstones. Literature suggests that sandstones can have a wide range of potential Poisson’s ratios (0.1–0.4). The review primarily focused on sandstones that closely resemble the unconsolidated nature of the Frio and Miocene sands. Further research shows that soft sandstones can have a range of 0.2–0.35 (Molina, Vilaras, and Zeidouni, 2017). A study conducted by Ben Eaton (1968) also suggests that the Gulf Coast sands will tend to have a Poisson’s ratio greater than 0.3 at the respective depths. A value of 0.3 was chosen to be the most representative of the Frio sands, based on the literature.

Public literature was utilized to determine the OBG of the target formation. Figure 2-19 shows a composite OBG for the Gulf Coast at various depths (Eaton, 1968). A value of 1.5 was chosen to best represent the OBG in this area. A PG of 0.45 was calculated from the salinity estimates as discussed in *Section 2.5.2.2*.

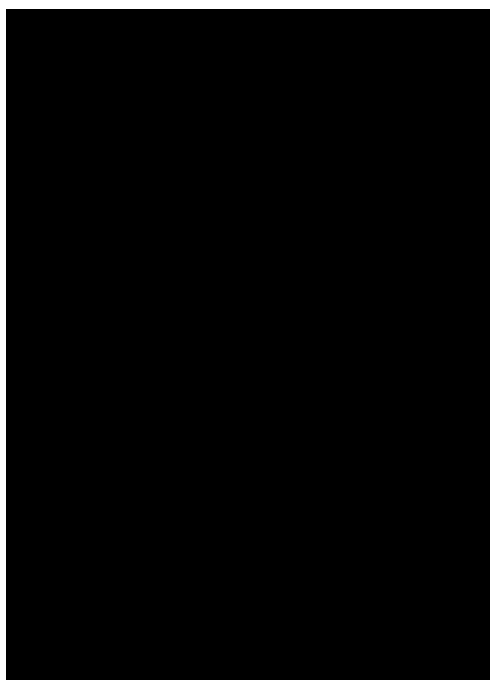
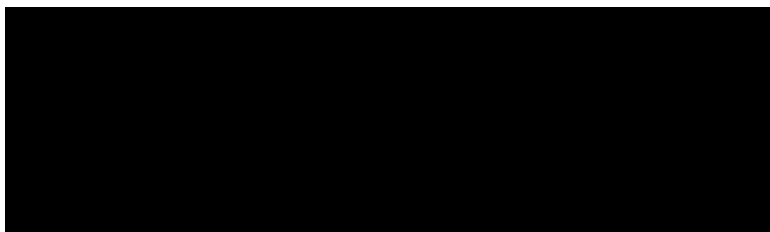


Figure 2-19 – Composite Overburden Stress Gradient for Gulf Coast Formations

The inputs make it possible to calculate a fracture gradient (FG). Equation 5 highlights the necessary steps for calculating the gradient. Per SWO 29-N-6, **§3621.A.1** [40 CFR **§146.88(a)**], the well may not exceed 90% of the fracture gradient during injection operations. Therefore, the model applied a pressure constraint of [REDACTED] to all injectors.

(Eq. 5)
$$FG = \frac{v}{1-v}(OBG - PG) + PG$$



2.5.2.4 Reservoir Fluid Properties

Reservoir Temperature

A review of nearby well logs and regional literature was conducted to estimate the reservoir temperature. First, public literature was used to gain insight into the regional temperature trends. The study showed that the geothermal gradient changes with depth, and data was therefore looked at in 5,000-ft intervals. Loblolly CCS No. 001 and Loblolly CCS No. 002 are situated in [REDACTED]. Figure 2-20 provides a snapshot of the average geothermal gradients in those parishes at the target formation depths.

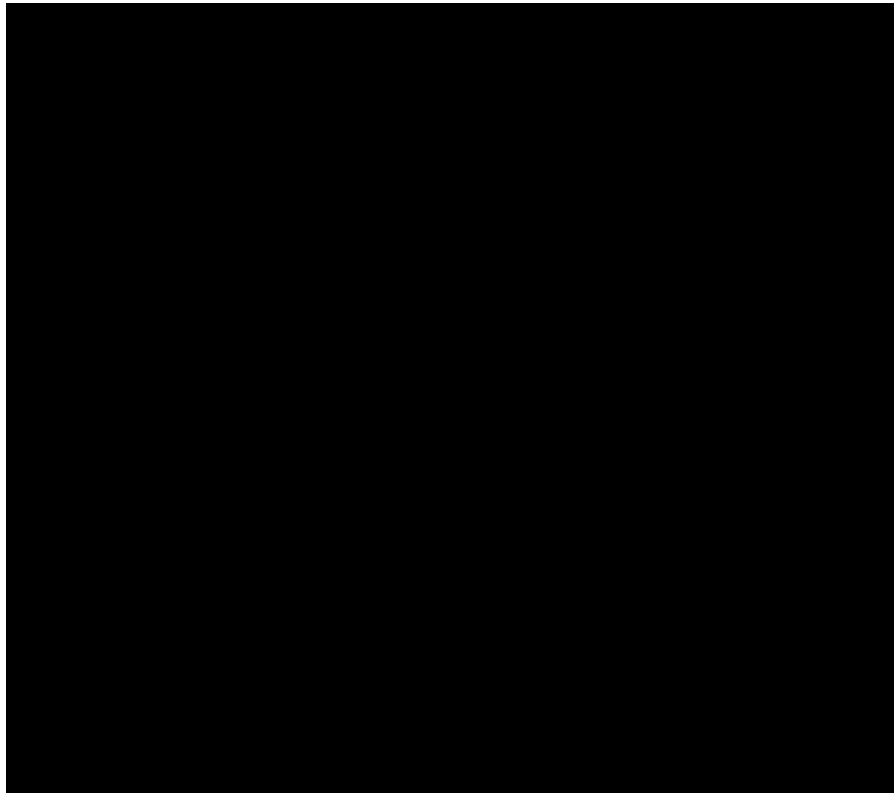


Figure 2-20 – Geothermal Gradients in Louisiana Parishes from Depths of 5,000–10,000 ft (Carlson and McCulloh, 2006)

Well logs were also reviewed near the injection sites to determine site-specific temperature gradients. From this review, the nearest well log was chosen to provide the most analogous data point to the target formation. The reservoir temperature gradient was estimated to be [REDACTED]. This gradient is in line with the regional data, providing an increased confidence interval. That gradient is also added to an assumed surface temperature of [REDACTED], which is the mean annual surface temperature.

Brine Salinity

A regional review of publicly available fluid samples was conducted to identify any trends in salinity estimates for the target reservoir. Information was extracted from the US Geological Survey (USGS) National Produced Waters Geochemical Database (Blonde, 2018), a publicly accessible online repository containing a multitude of water samples aimed at enhancing the understanding of regional hydrogeology. Fluid samples collected in Beauregard and Calcasieu Parishes were analyzed to identify any discernible trends within the injection zone. Figure 2-21 highlights the total dissolved solids (TDS) content for each sample, revealing notable variability in salinity within the injection zone. The brine within the target appears to have a range of [REDACTED].

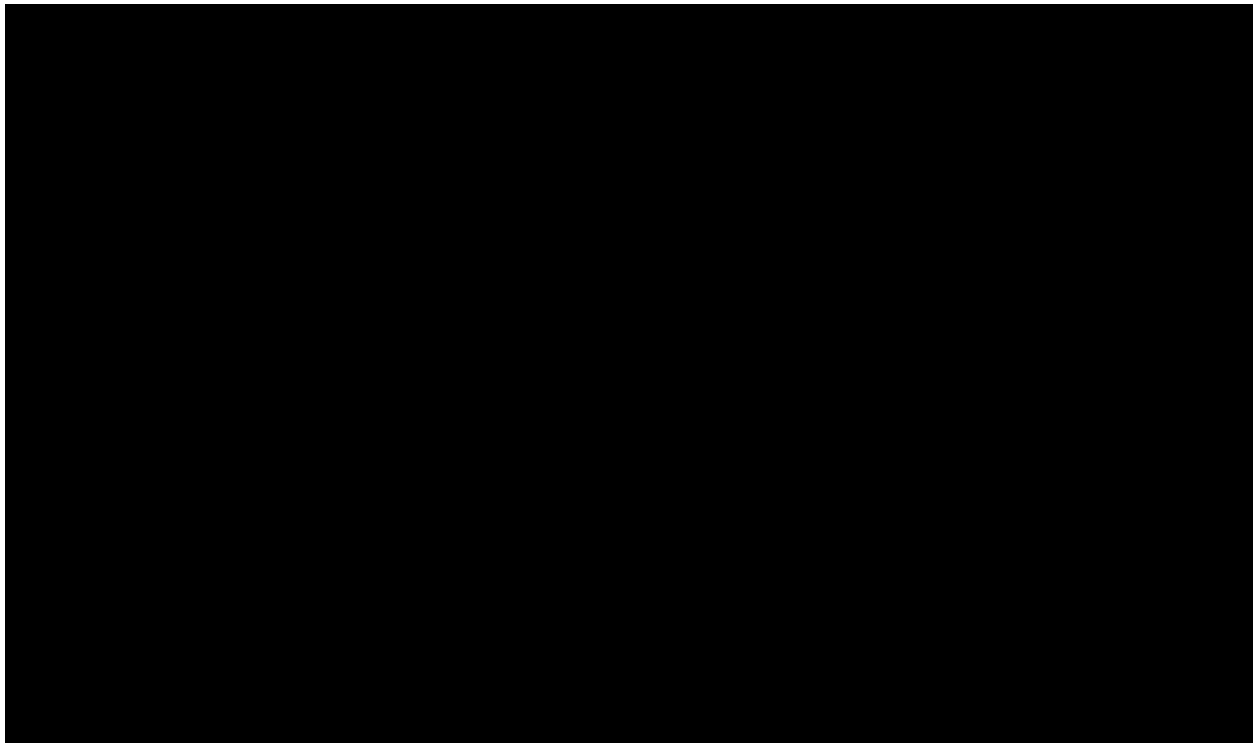


Figure 2-21 – TDS Content from USGS Produced Waters Database (Blonde, 2018)

A site-specific review was also conducted to determine the salinity of the in-situ brine. A nearby offset resistivity log was used to determine the brine salinity. This was done by using Archie's equation on the nearest offset well log to calculate a value of [REDACTED]. This falls within the range seen in the regional samples, further corroborating the data set. The model was initialized with the calculated salinity value of [REDACTED].

2.5.3 Rock Properties Hysteresis Modeling

2.5.3.1 Rock Compressibility

Public literature was utilized to determine the rock compressibility due to lack of any regional or site-specific data. To address this gap, a literature review, targeting unconsolidated, poorly sorted sandstones, was conducted. The gathered research indicates that such formations may exhibit compressibility values ranging from 10–40 microsips, as depicted in Figure 2-22 (Newman, 1973). [REDACTED]

[REDACTED] For the simulation, a representative value of [REDACTED] was selected for the injection interval. This assumption is subject to revision pending the acquisition of data from the stratigraphic test well.



Figure 2-22 – Pore-Volume Compressibility vs. Initial Sample Porosity (Newman, 1973)

2.5.3.2 Residual Gas Saturation



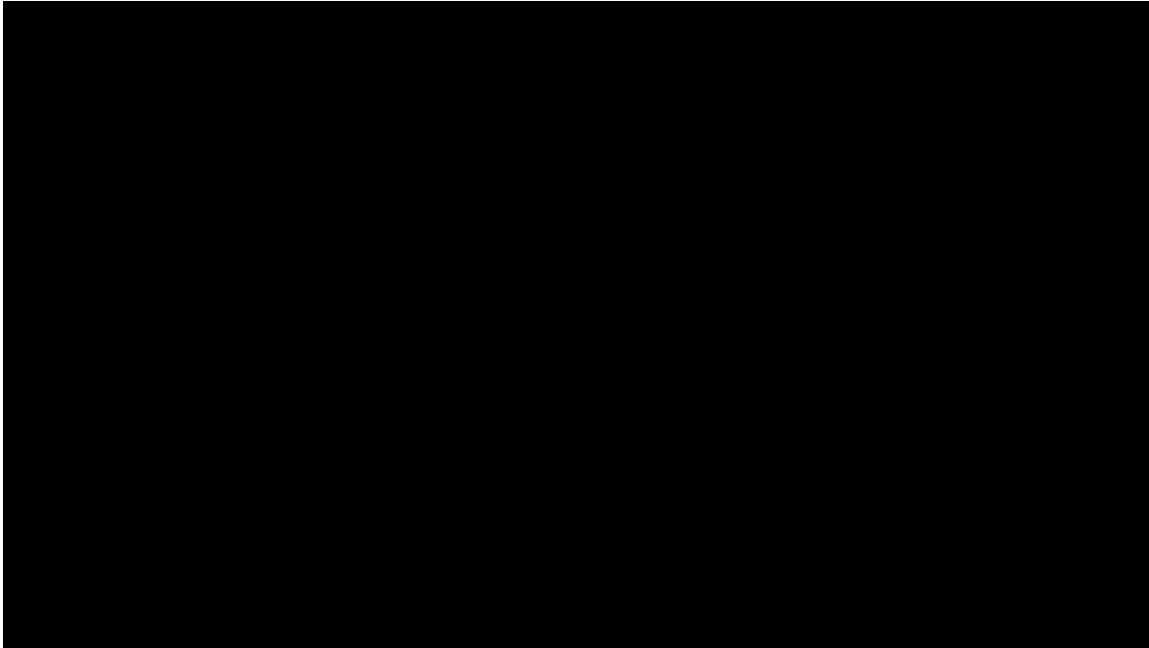


Figure 2-23 – Comparison of S_{gr} Samples taken from the Frio Sands vs. Published Literature (Hovorka et al., 2003)

Site-specific core acquisition and analysis is planned with a stratigraphic test well and upon completion of the subject injection well. The model and subsequent curves will be updated after the core data has been analyzed.

2.5.3.3 Relative Permeability Curves

In the absence of site-specific data, relative permeability curves were generated using research findings from analogous depositional environments. Traditional core testing faces challenges in accurately determining curve endpoints, leading to elevated irreducible water saturations (S_{wirr}) and lower CO_2 endpoints (Benson, 2013). In the drainage CO_2 -brine relative-permeability experiments, as the water saturation decreases, the capillary pressure (P_c) values increase rapidly as P_c approaches the irreducible water saturation. The high mobility ratio limits the necessary capillary pressure required to achieve high saturations of CO_2 during the test. This causes the experimental relative-permeability measurements to end at water saturations higher than the actual irreducible water saturation.

In a recent study conducted by researchers at the University of Texas, a Corey-Brooks function was fitted to experimental data to generate relative permeability curves at a lower irreducible water saturation (Chen et al., 2017). Using similar methodologies and experimental data provided by public literature (Bachu, 2012; Krevor et al., 2012), relative permeability curves were generated.

This further validates using a best-fit Corey-Brooks function to generate relative permeability curves in the model.

Corey-Brooks equations were utilized to generate the drainage curves, and the necessary inputs for solving these equations were determined through a comprehensive review. [REDACTED]

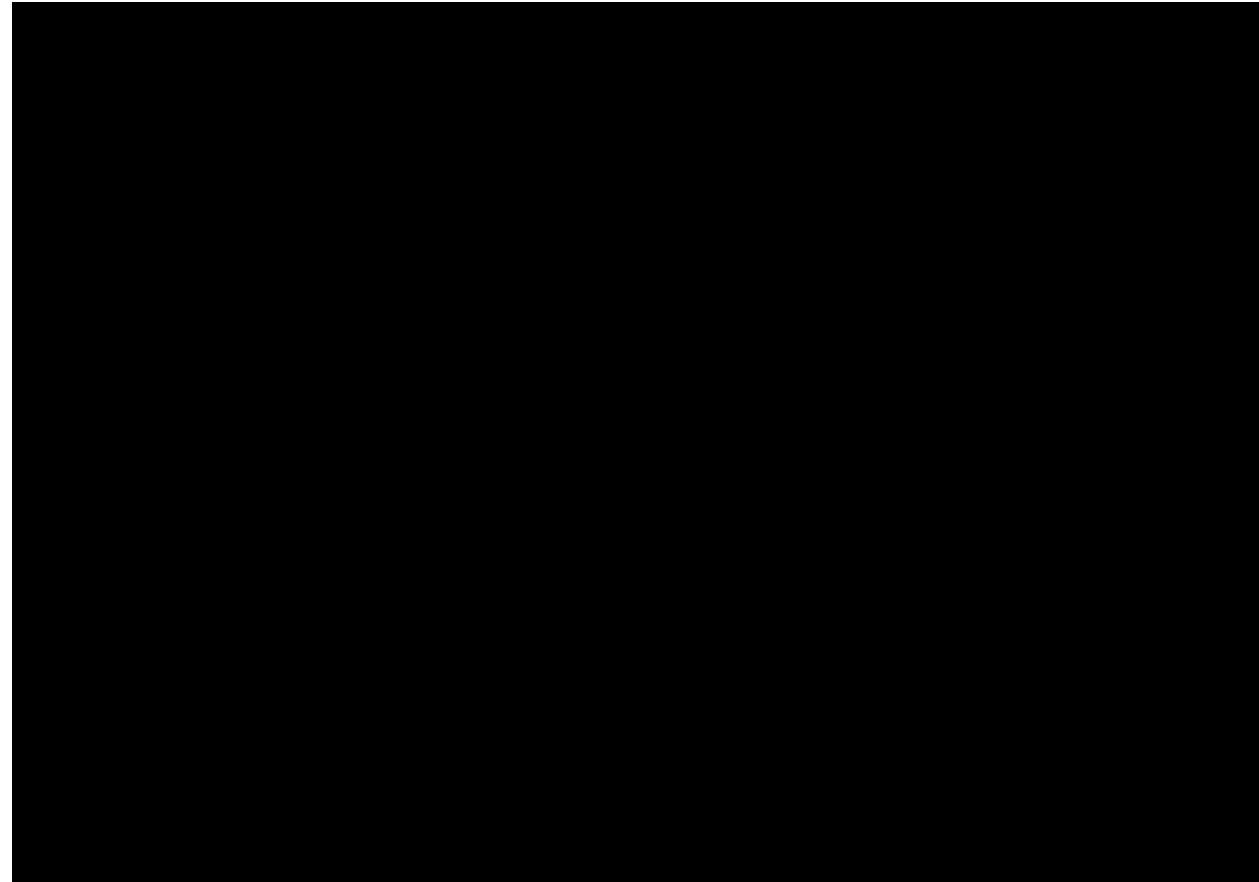
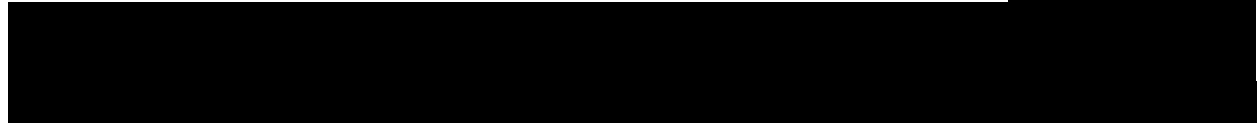


Figure 2-24 – Two-Phase Relative Permeability Curves

Site-specific core acquisition and analysis is planned with a stratigraphic test well and upon completion of the subject injection wells. The model and subsequent curves will be updated after the core data has been analyzed.

2.5.3.4 Capillary Pressure Curves

Site-specific P_c data is scarce in the target injection zone (i.e., Frio sandstone). Therefore, public literature was relied on to provide P_c curves from an analogous formation. [REDACTED]



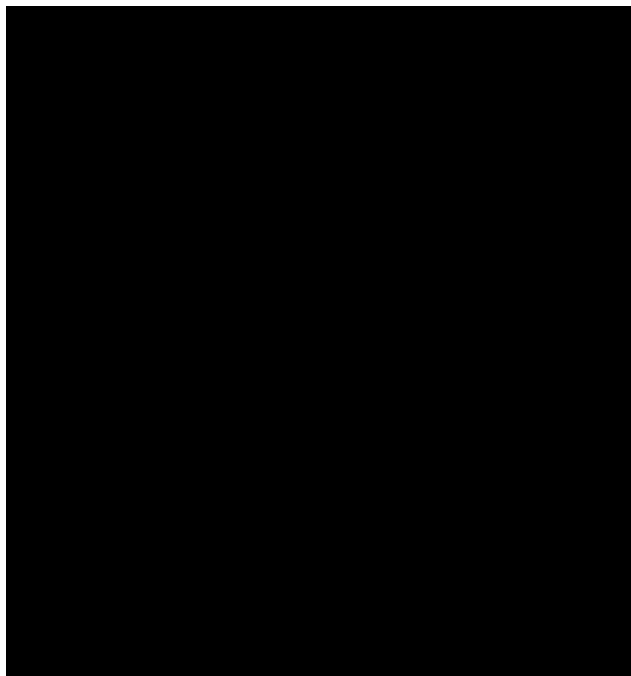
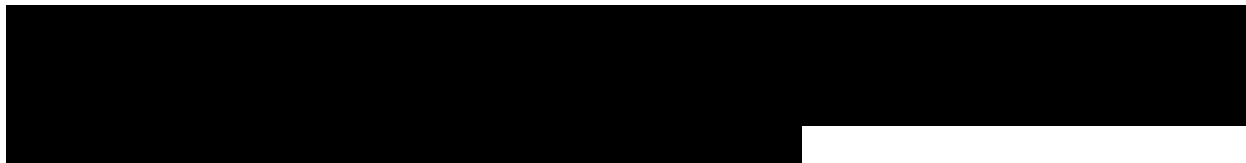


Figure 2-25 – Capillary Pressure Curve of the Frio C Sandstone (Sakurai et al., 2005)



(Eq. 6)
$$P_c = \frac{Max - Min}{1 + \left(\frac{x_{50}}{S_{wn}}\right)^{hill}} + P_{ce}$$

The P_c curves were then converted from a mercury-air system to oil-water and CO₂-brine systems. Published interfacial tension (σ) and contact angles (θ) were used to convert from the mercury-air system. Table 2-4 provides a summary of the values utilized for conversion.

Table 2-4 – Interfacial Tension and Contact Angles for P_c Conversion

Fluids	$\sigma \cos(\theta)$
Mercury-Air	
Oil-Water	
CO ₂ -Brine	



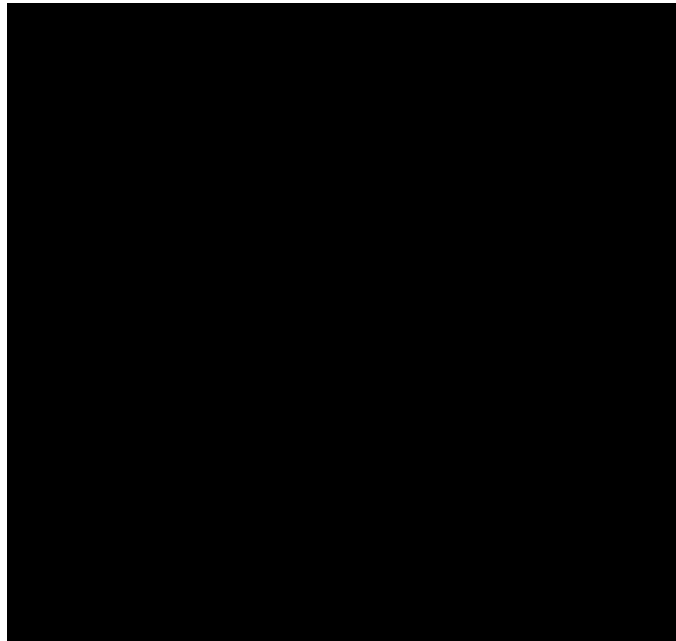


Figure 2-26 – Comparison of P_c Curves Derived from a Single J Function

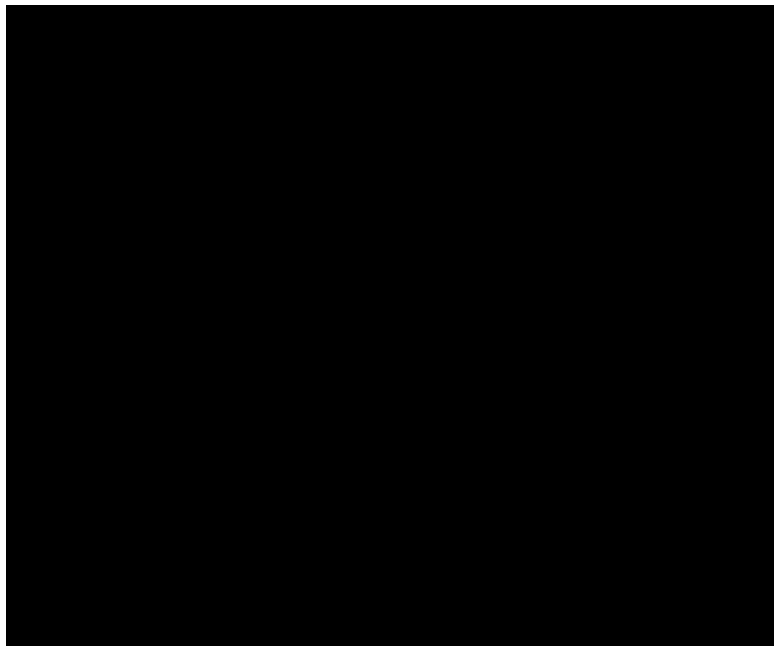


Figure 2-27 – Modeled J-Function Curves

Site-specific core acquisition and analysis is planned with a stratigraphic test well and upon completion of the subject injection wells. The model and subsequent curves will be updated after the core data has been analyzed.

2.6 Wellbore Hydraulics Parameters

The wellbore parameters remained the same for each injector. For Loblolly CCS No. 001 and Loblolly CCS No. 002, the wellbore configuration was set up using the proposed wellbore schematic (WBS) and incorporated additional assumptions specified in Table 2-5. In GEM, three primary constraints were imposed to lessen the supercritical CO₂ front growth and pressure response: (1) a maximum injection rate of [REDACTED], (2) a maximum bottomhole pressure (BHP) gradient of [REDACTED] and (3) an injection duration of [REDACTED], respectively, for the two wells. The maximum injection rate and duration constraints were selected to optimize the largest carbon plume possible on the project acreage. The maximum BHP constraint was determined through calculations discussed in *Section 2.5.2.3*, on the fracture gradient calculation.

Table 2-5 – Wellbore Hydraulics Parameters

Inputs	Loblolly CCS No. 001 Values	Loblolly CCS No. 002 Values
Maximum Injection Rate (MT/yr)	[REDACTED]	[REDACTED]
Pressure Constraint Gradient (psi/ft)	[REDACTED]	[REDACTED]
Injection Duration (yrs)	[REDACTED]	[REDACTED]
Tubing Inner Diameter (in.)	[REDACTED]	[REDACTED]
Upper Perforation Depth (ft)	[REDACTED]	[REDACTED]
Roughness Factor	[REDACTED]	[REDACTED]
Pipeline Outlet Temperature (°F)	[REDACTED]	[REDACTED]
Pipeline Outlet Pressure (psi)	[REDACTED]	[REDACTED]

The Gulf Coast system presents a unique depositional environment where interbedded shales may act as barriers that impede CO₂ migration. To optimize pore space utilization, the injection well is segmented into multiple completion stages. Each stage is dedicated to injecting CO₂ into a specific reservoir section at a designated time. These stages are strategically designed to leverage shale barriers, contributing to the control and mitigation of supercritical CO₂ plume expansion. Figure 2-28 illustrates a generic completion strategy for CCS. Each new completion adjusts the pressure constraint according to the upper perforation depth to prevent the BHP from exceeding the calculated fracture gradient. This measure ensures a safe and effective injection process. Loblolly CCS No. 001 has a total of [REDACTED] completion stages, while Loblolly CCS No. 002 has [REDACTED] completion stages. A summary of each completion stage for each supercritical CO₂ injector is provided in Tables 2-6 and 2-7.

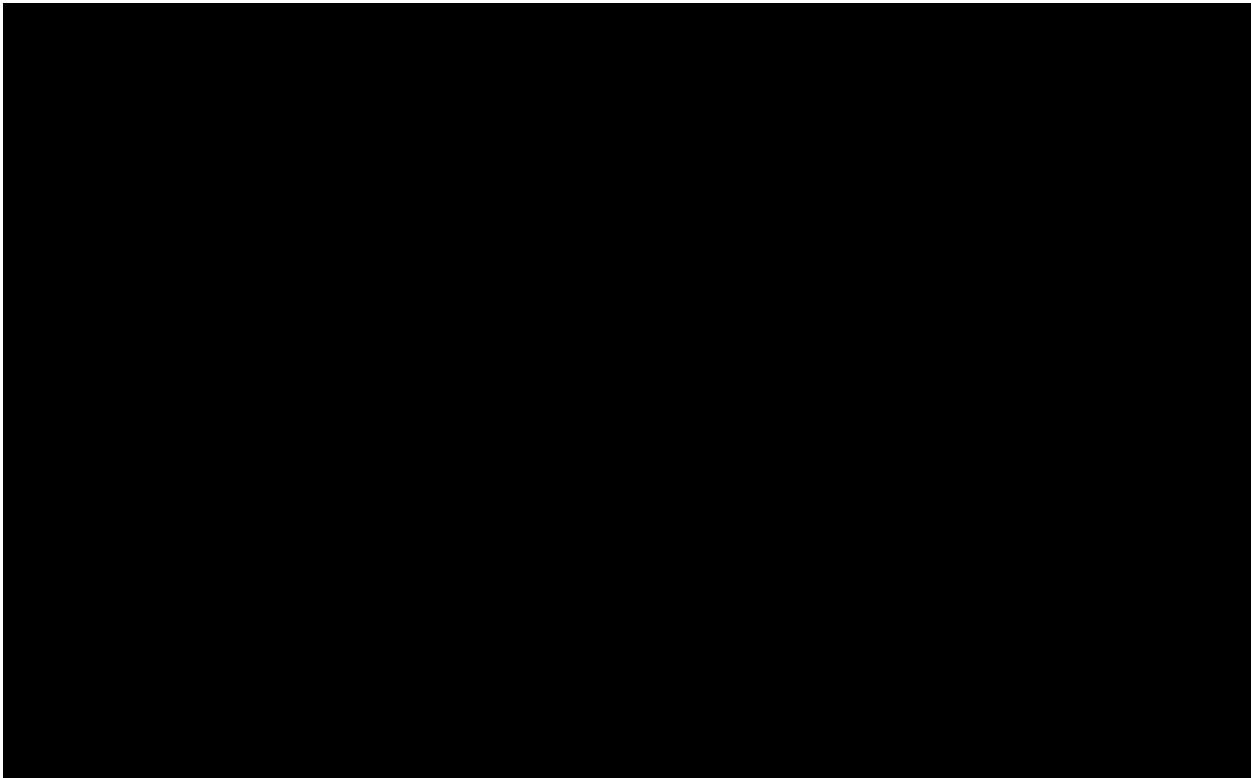


Figure 2-28 – Generic Depiction of Completion Strategy

Table 2-6 – Completion Strategy for Loblolly CCS No. 001

A black rectangular redaction box covering the entire content area of Table 2-6.

Table 2-7 – Completion Strategy for Loblolly CCS No. 002

A black rectangular redaction box covering the entire content area of Table 2-7.

2.7 Model Results

2.7.1 Active Injection Operations of Proposed CO₂ Injector

The injection rate and pressure response due to CO₂ injection are outputs from the dynamic model in GEM. The rate is held at a maximum rate of [REDACTED] throughout the life of the well [REDACTED]. The BHP is calculated internally by GEM and does not exceed the pressure constraint imposed on the model. This constraint prevents the BHP from exceeding 90% of the fracture gradient as required by SWO 29-N-6, §3621.A.1 [40 CFR §146.88(a)]. Figures 2-29 and 2-30 highlight the proposed injection wells' BHP response and injection. [REDACTED]

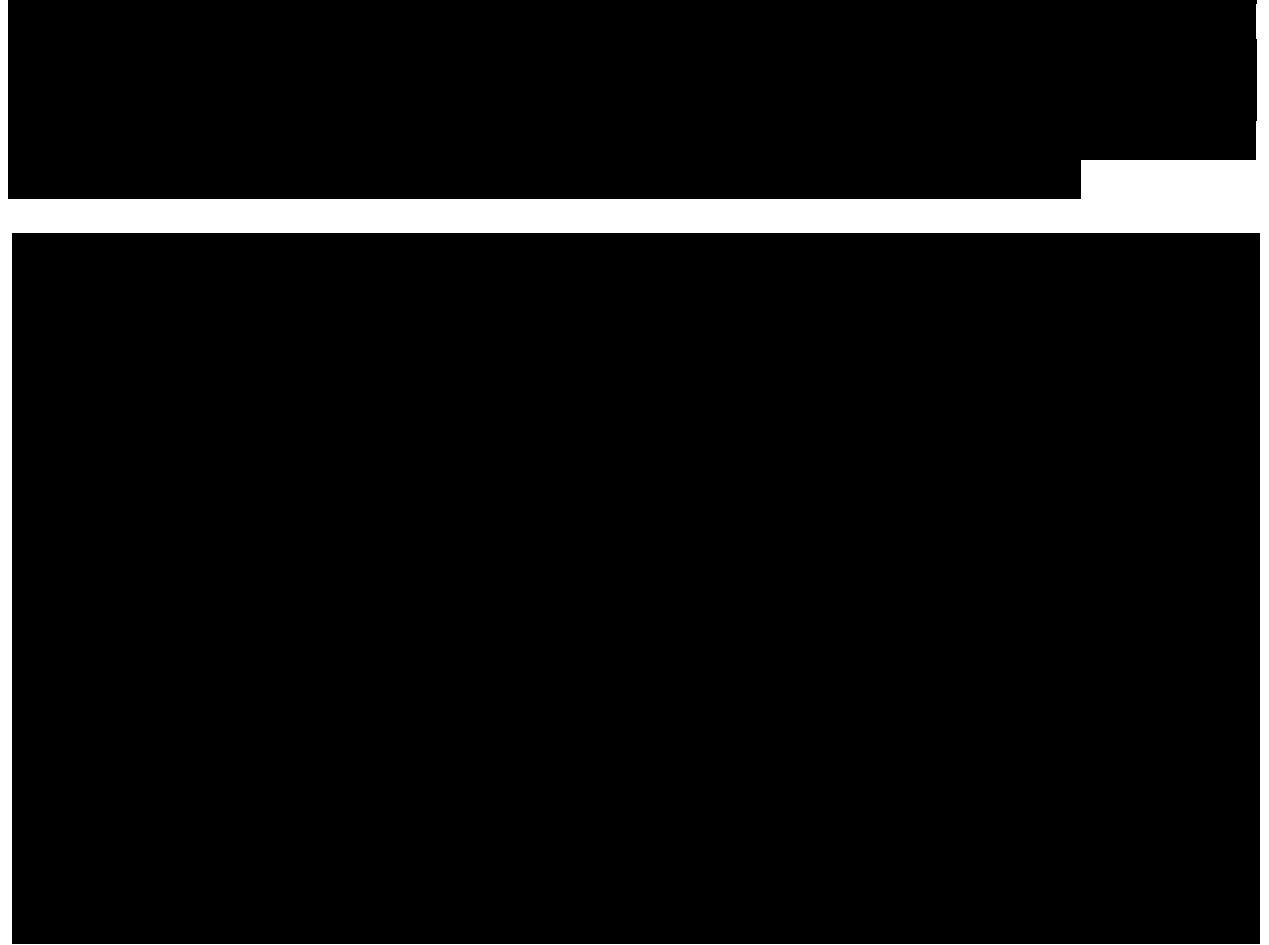


Figure 2-29 – Wellbore Model Outputs During Active Injection Period for Loblolly CCS No. 001

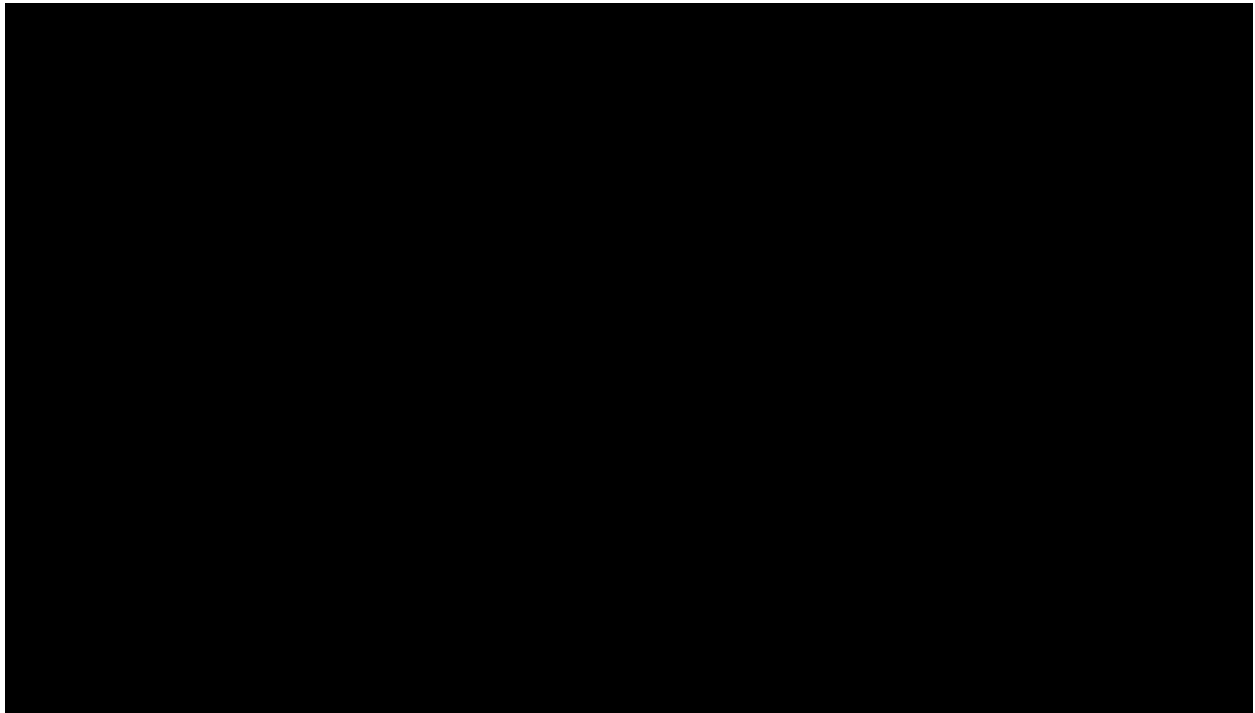


Figure 2-30 – Wellbore Model Outputs During Active Injection Period for Loblolly CCS No. 002

Wellhead pressures were calculated based off of BHP responses using the GEM wellbore modeling option. Wellhead temperature (WHT), bottomhole temperature (BHT), and the wellbore hydraulic parameters in Table 2-5 are utilized by GEM's wellbore model to calculate wellbore pressure traverses. CO₂ density calculations are sensitive to changes in temperature, making WHT and BHT important inputs for the wellhead pressure calculation. BHT input was estimated for each injection stage using a composite of linear heat transfer (vs. depth) and thermodynamic Joule-Thomson (JT) effects for a given bottomhole injection pressure. The JT effects were modeled using CMG's WinProp™ EOS simulation tool to generate temperature data for a constant-enthalpy flash of the injected fluid from the reference condition (pipeline outlet pressure and temperature) to a range of pressures. [REDACTED]

[REDACTED] The WHT was calculated based on JT cooling relative to the pipeline outlet using the constant-enthalpy flash data calculated using WinProp. [REDACTED]

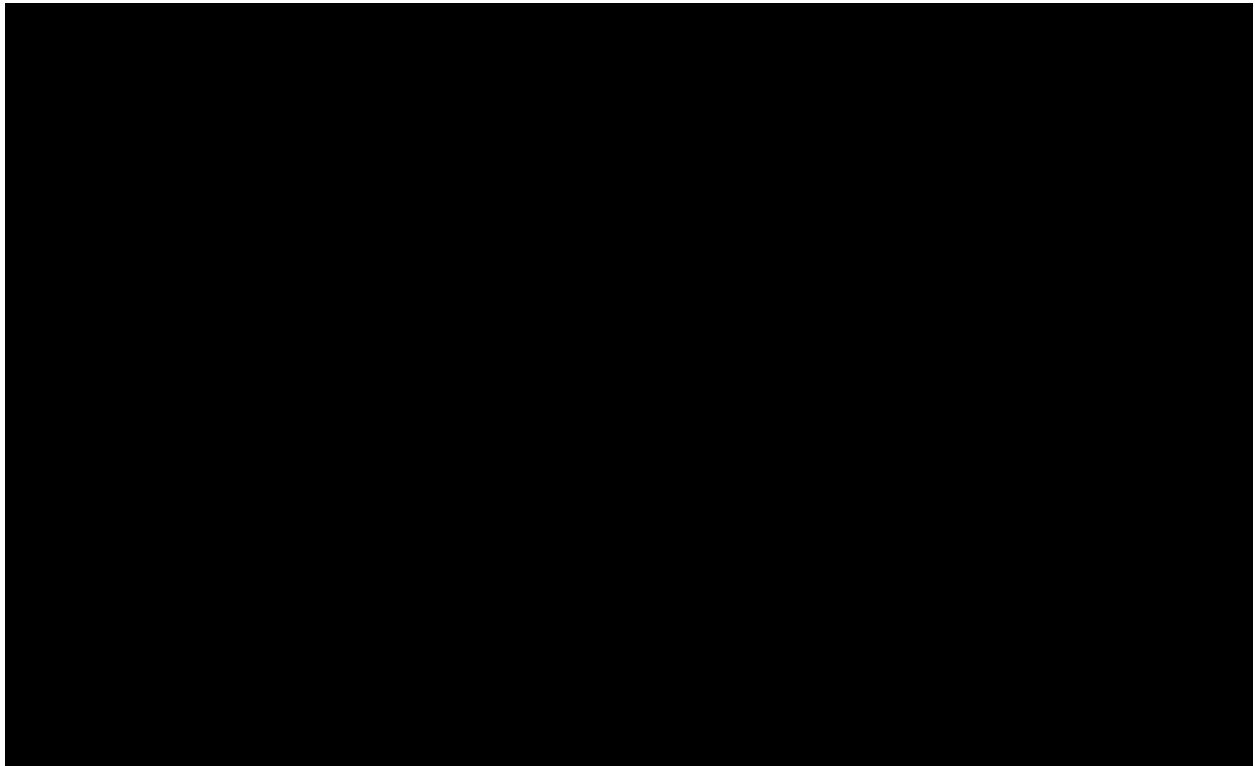


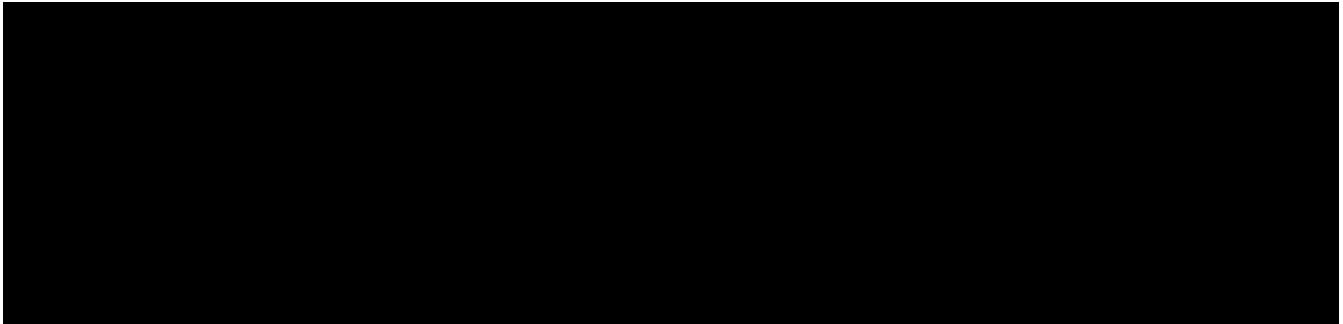
Figure 2-31 – Injected Fluid Temperature vs. Pressure

The maximum expected BHP of Loblolly CCS No. 001 is estimated to be [REDACTED] during the life of the project, evaluated at [REDACTED]. On average, the BHP of the well will be [REDACTED]. The maximum WHP is calculated to be [REDACTED] with an average of approximately [REDACTED]. Table 2-8 highlights the outputs for this injection well as modeled in GEM.

Table 2-8 – Loblolly CCS No. 001 Outputs

The maximum expected BHP of Loblolly CCS No. 002 is estimated to be [REDACTED] during the life of the project, evaluated at [REDACTED]. On average, the BHP of the well will be [REDACTED]. The maximum WHP is calculated to be [REDACTED] with an average of approximately [REDACTED]. Table 2-9 highlights the outputs for this injection well as modeled in GEM.

Table 2-9 – Loblolly CCS No. 002 Outputs

A large black rectangular box redacting the content of Table 2-9.

Injecting supercritical CO₂ into a saline aquifer causes a phenomenon known as “pressure buildup,” characterized by an elevation in reservoir pressure relative to the in situ pressure. The most significant effects will be experienced near the wellbore during the active injection period. The pressure buildup is monitored by the rise of reservoir pressure and its associated gradient based on the top of the perforated interval.

Figures 2-32 and 2-33 illustrate the maximum pressure buildup at each well, calculated based on the BHP results representing the highest pressure observed within the reservoir at any specific time. Furthermore, as these pressure values are obtained at varying depths, the pressure gradient is also computed. The greatest buildup is experienced in the sixth completion stage of Loblolly CCS No. 001, resulting in an [REDACTED] pressure increase. As shown in Figures 2-32 and 2-33, the pressure gradient never exceeds the constraint of [REDACTED] (90% of FG) imposed on the well, to allow for the safe injection of supercritical CO₂.

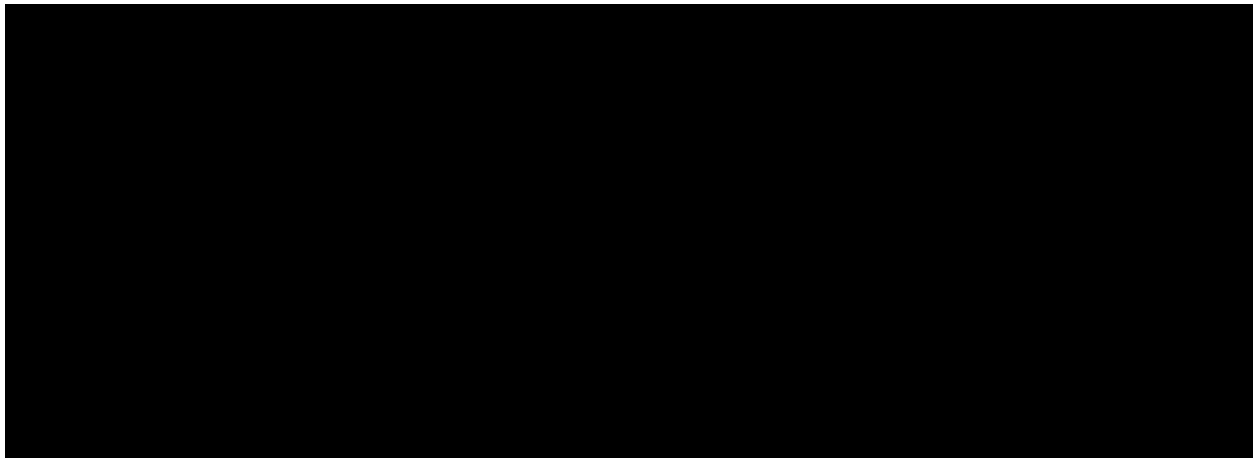


Figure 2-32 – Pressure Buildup During Active Injection Period for Loblolly CCS No. 001

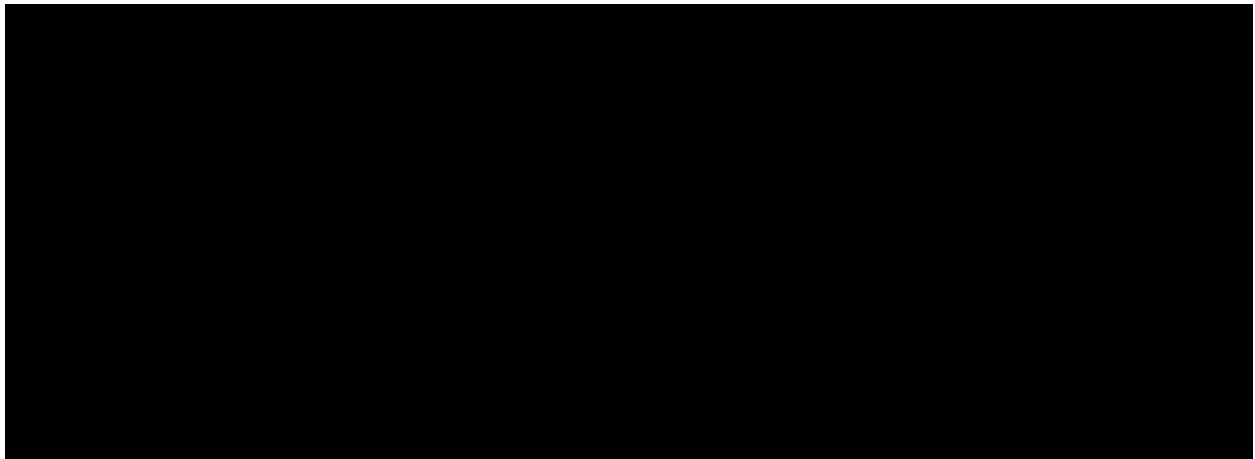


Figure 2-33 – Pressure Buildup During Active Injection Period for Loblolly CCS No. 002

The pressure buildup will begin to sharply decrease back to in situ conditions after injection operations conclude. Pressure buildup falls to a maximum of [REDACTED] once the well is shut in. Within the first year after injection ceases, the reservoir pressure has returned to initial conditions. Figure 2-34 highlights the pressure buildup for the entire life of Loblolly 001.

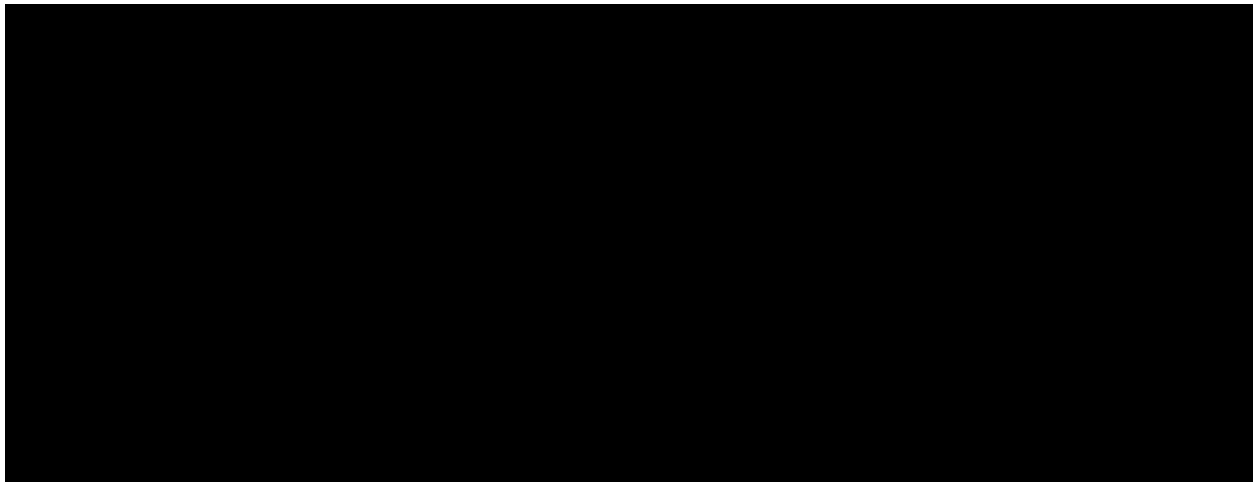


Figure 2-34 – Pressure Buildup During Life of Loblolly CCS No. 001

2.7.2 CO₂ Plume Migration for AOR Delineation

According to SWO 29-N-6 **§3615.B** [40 CFR **§146.84**], the AOR must be determined by the maximum extent of either the supercritical CO₂ front or the critical pressure front—or both. The first review starts with the extent of the CO₂ plume. The dynamic model was used to delineate the maximum carbon front. This section discusses the results of the model as it pertains to the delineation of the carbon front.

The carbon plume tends to migrate in the updip direction due to the buoyant nature of CO₂. However, the structure can vary from layer to layer in the model, resulting in multiple plumes migrating in various directions throughout the injection interval. This variation can be due to

structural changes, sand pinchouts, presence of channels, shale baffles, or other subsurface features. For example, channels are highly permeable sands that can act as “highways” for the CO₂ to preferentially migrate through. Overall, the carbon front migrates to the north from the injection sites. Figure 2-35 helps portray in 3D how the plume migrates through the various sand packages in the injection zone.

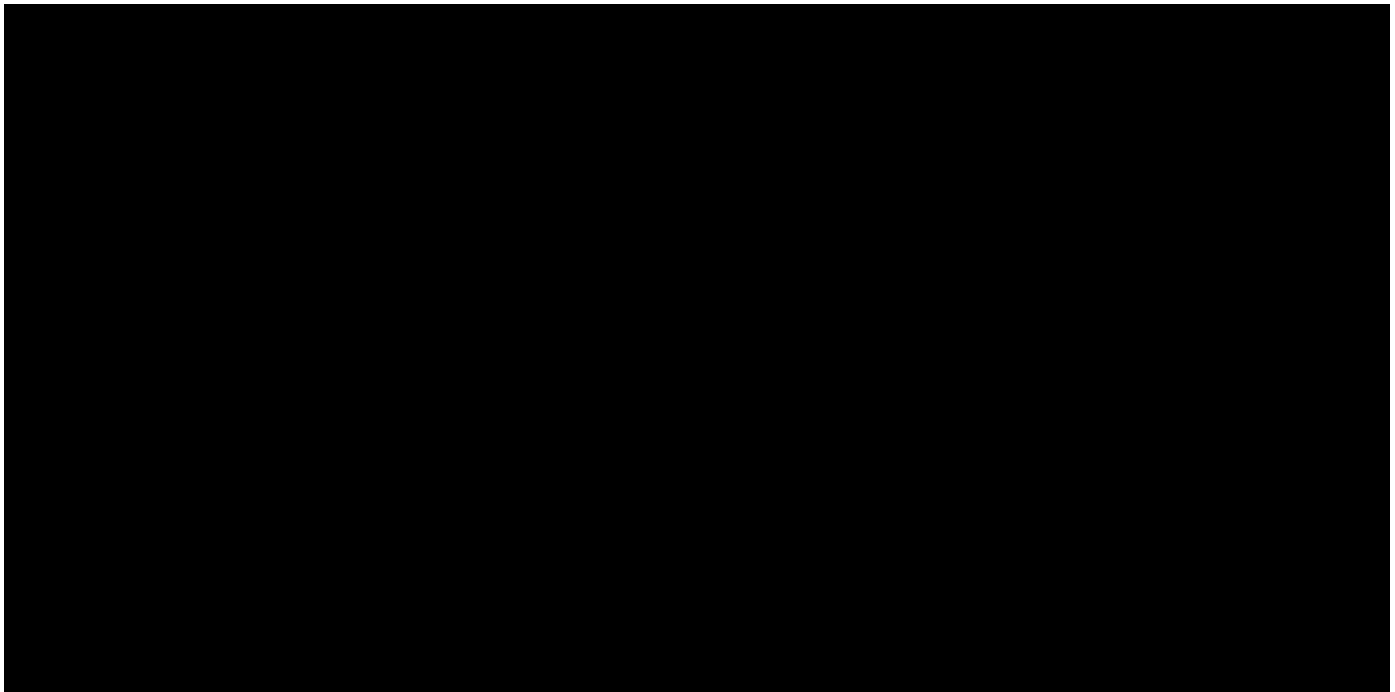


Figure 2-35 – 3D Representation of the CO₂ Plume

Further examination of the cross sections or the plumes at the wellbore helps to provide better insight into how the supercritical CO₂ migrates through the injection zone. As CO₂ is injected into each sand package, the subsequent plumes vary in size and shape. Between each sand package, interbedded clay-rich shales exist that help structurally trap CO₂ and inhibit vertical migration. The existing completion strategy is tailored to leverage these interbedded shales to help permanently sequester the CO₂ between completion intervals, while limiting the spatial extent of the plume. Figures 2-36 and 2-37 show the west-to-east and south-to-north cross sections of the carbon plume, respectively.

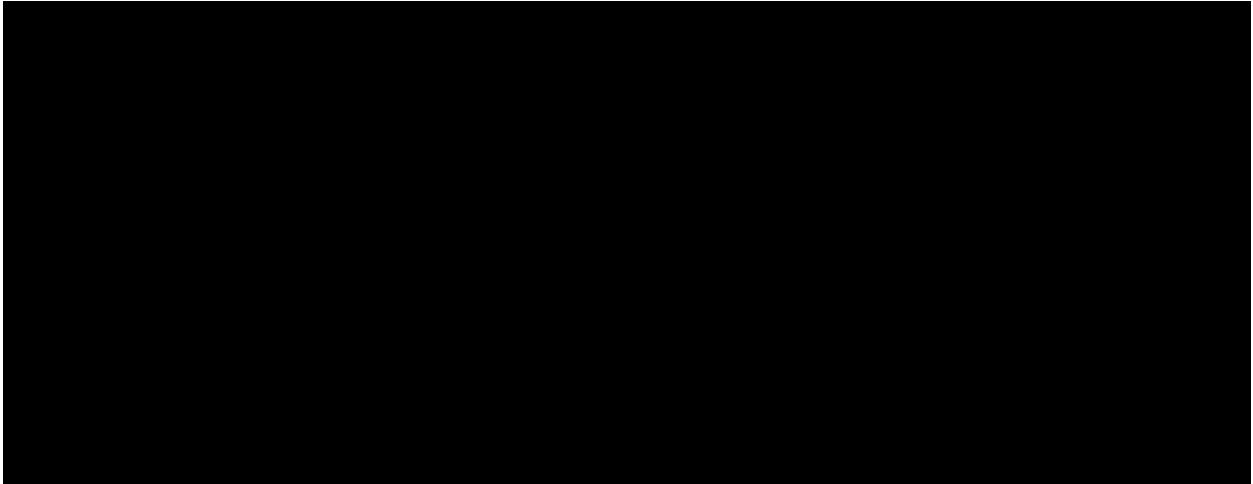


Figure 2-36 – West-East Cross Sections of Stabilized Carbon Plume, Loblolly CCS No. 001 (Left) and Loblolly CCS No. 002 (Right)

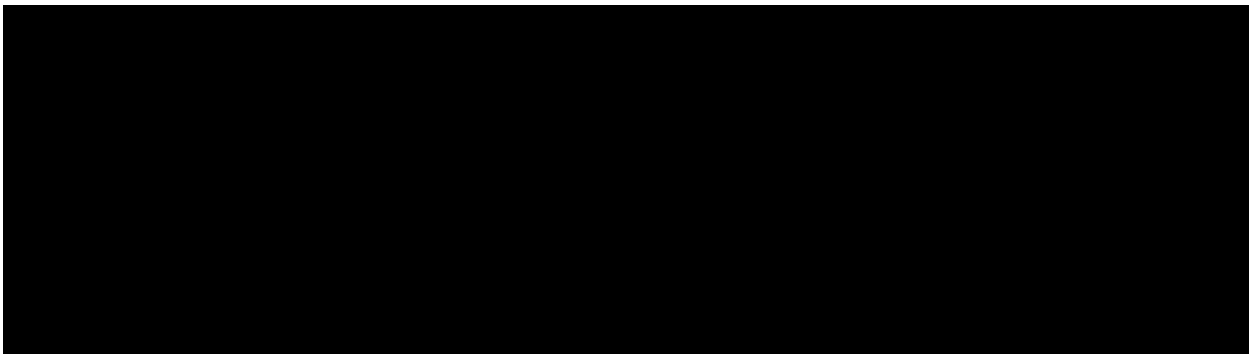


Figure 2-37 – South-North Cross Sections of Stabilized Carbon Plume, Loblolly CCS No. 001 (Left) and Loblolly CCS No. 002 (Right)

The carbon front is delineated from the most significant plume, or a combination of plumes from each completion. In the current dynamic model, the carbon front encompasses an area of [REDACTED]. The carbon front primarily extends to the north of the injection sites, reaching a maximum of [REDACTED] in diameter. Figure 2-38 provides a visual representation of the maximum extent of the carbon front.



Figure 2-38 – Maximum Carbon Front

2.7.2.1 Stabilized Plume Growth Analysis

Plume stabilization occurs when the growth rate or positional change has slowed to a nearly imperceptible change per year. At that point in time, the CO₂ plume is considered hydrodynamically trapped within the pore space.

[Redacted text block]

[Redacted text block]

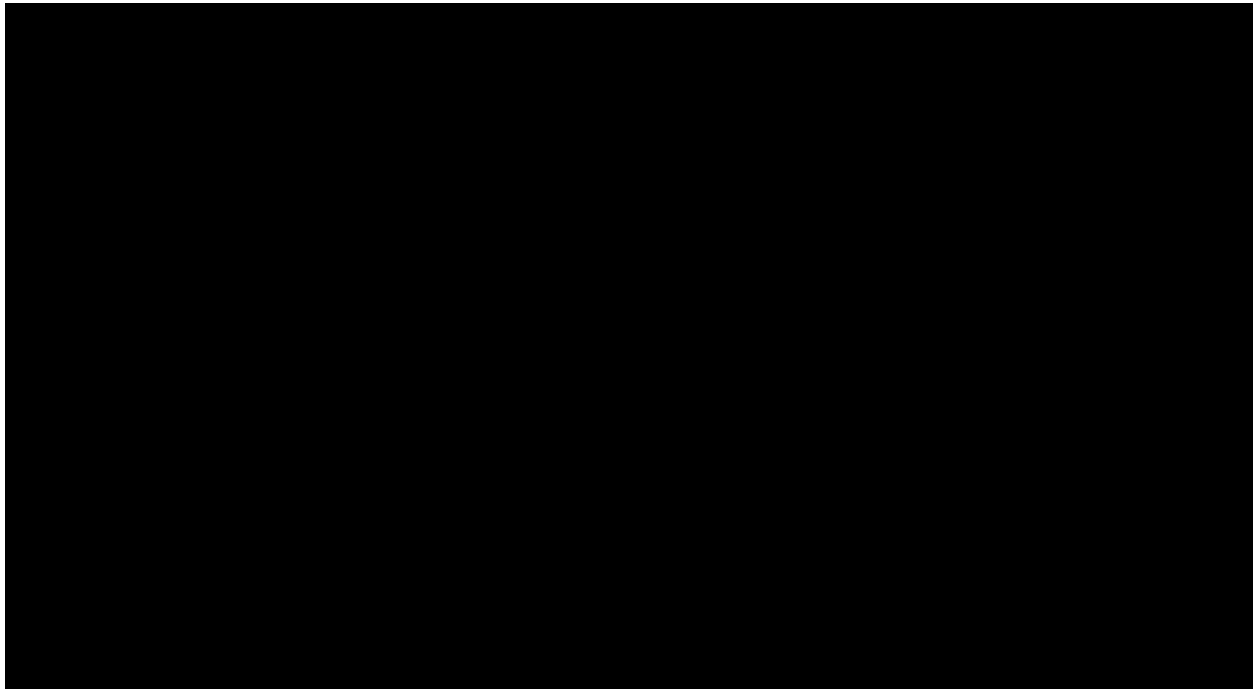
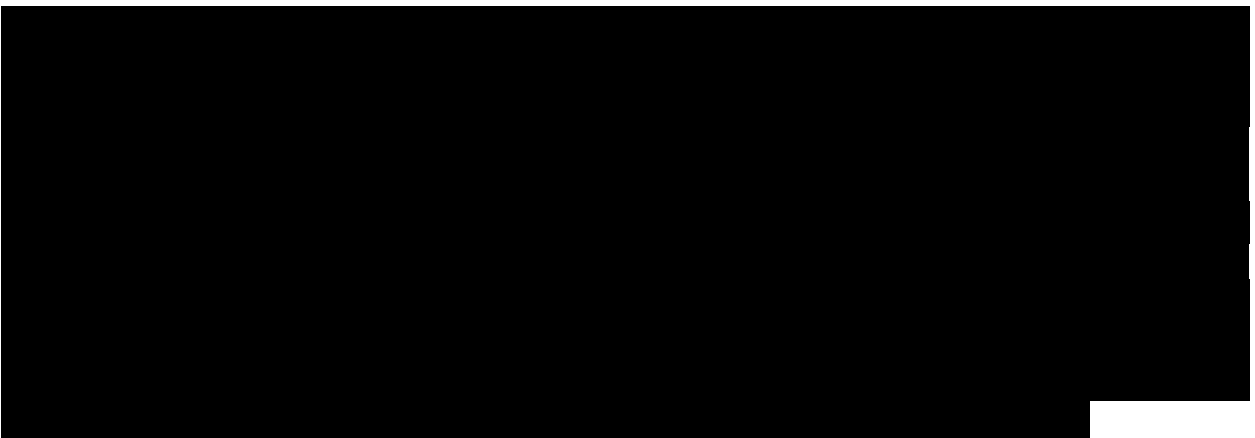


Figure 2-39 – Plume Growth Analysis

2.7.3 Critical Pressure Front for AOR Delineation

In accordance with SWO 29-N-6 **§3615.B** [40 CFR **§146.84**], the AOR was delineated by the critical pressure front created by injecting supercritical CO₂ into a saline aquifer. Critical pressure is the increase in reservoir pressure that may push in situ fluids out of the injection zone and into the lowermost USDW, in the presence of a bridging conduit such as an unplugged borehole. The initial step in predicting the pressure front involves calculating the critical threshold pressure for each completion stage. Subsequently, a numerical simulation is used to forecast the size and configuration of the critical pressure front.



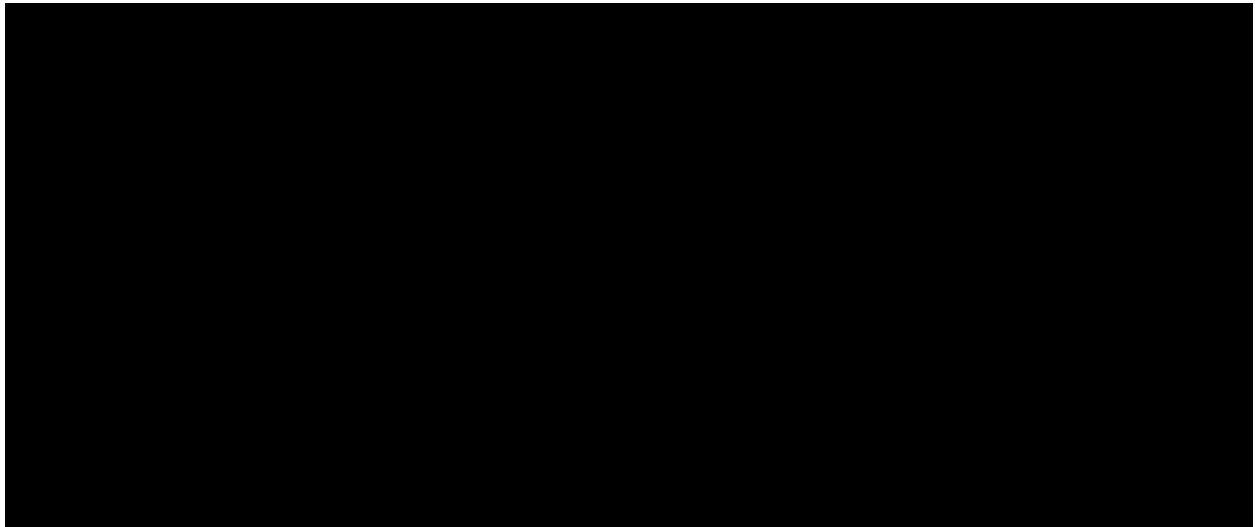


Figure 2-40 – Step-by-Step Process for Calculating Critical Pressure

The resulting critical pressure rise for the uppermost stage is a positive value. This suggests that the reservoir pressure may be safely increased by approximately [REDACTED] without risk of fluid migration to the USDW. Table 2-10 provides the critical pressure for each stage at the injection wells.

Table 2-10 – Critical Pressure by Completion Stage for the Injection Wells

The critical pressure front is delineated based on the completion stage with the most significant pressure front, or a combination of pressure fronts from each completion. In practical terms, the critical pressure front is based on the greatest possible extent experienced in the model. The end result is a pressure front that encompasses an area of [REDACTED] of land. The pressure front predominantly extends in the northwest-southeast orientation, reaching a

maximum of [REDACTED] in diameter. Figure 2-41 shows a visual representation of the maximum extent of the critical pressure.

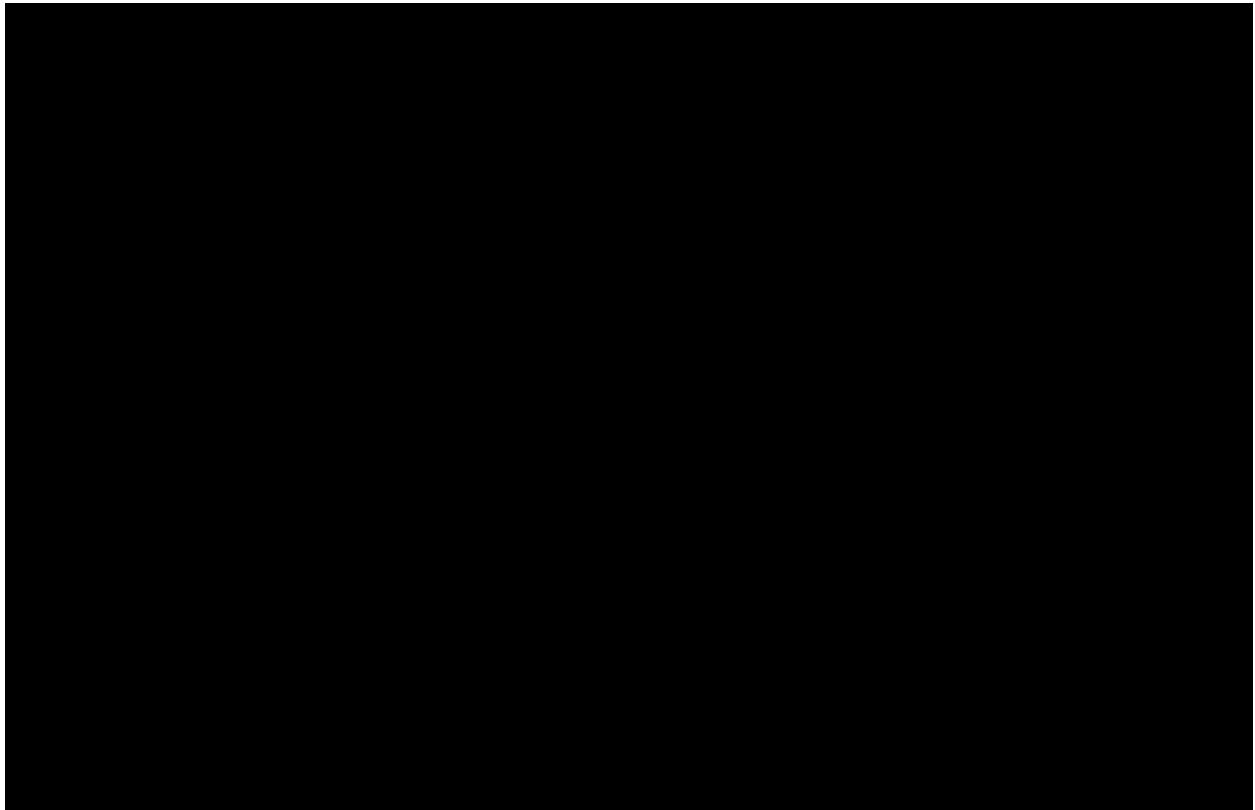


Figure 2-41 – Maximum Critical Pressure Front

2.8 Final AOR

The final AOR, [REDACTED], encompasses both the carbon and critical pressure fronts. Defining the monitoring requirements and potential corrective action plan for offset wells heavily depends on this designated AOR. As the AOR involves two distinct fronts, it is essential to consider specific monitoring and corrective action measures for each front, to ensure a thorough approach in managing the carbon sequestration project.

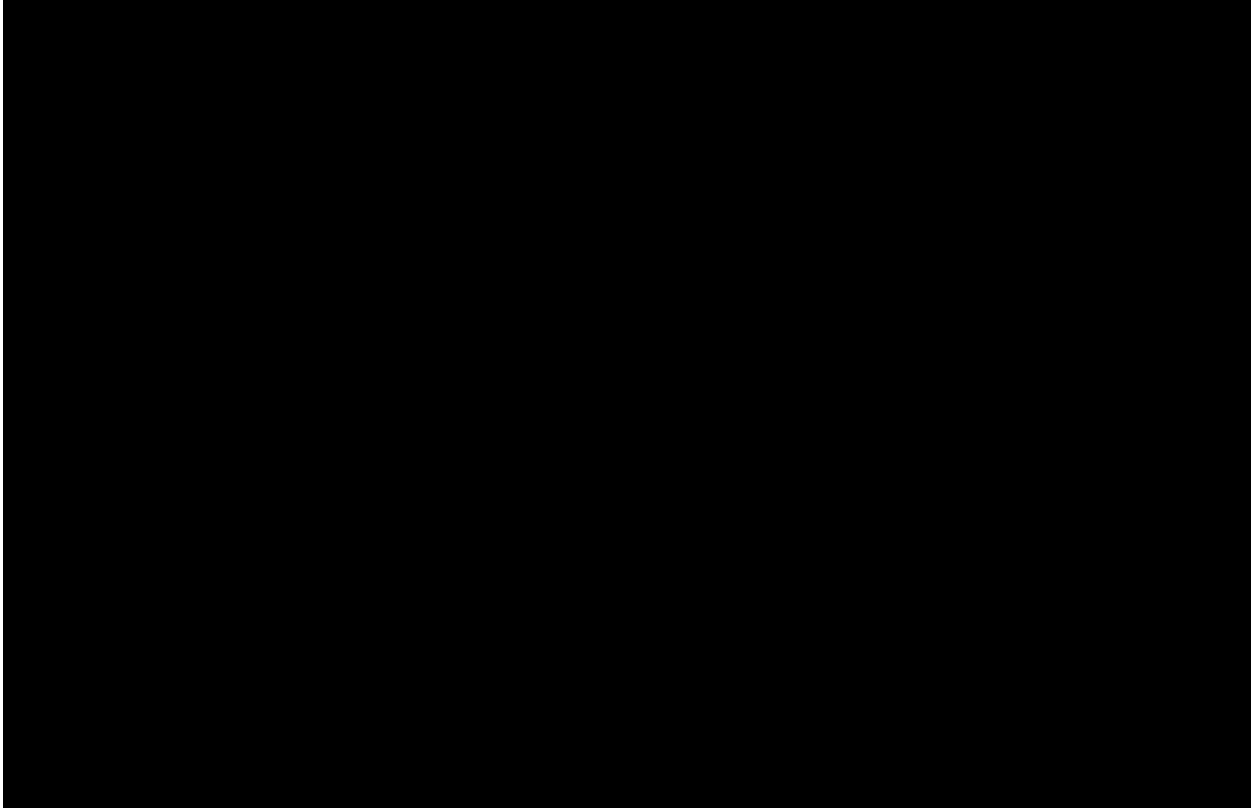


Figure 2-42 – Final AOR with Carbon and Critical Pressure Fronts

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Appendices

Appendix B-26	Structural Model 3D
Appendix B-27	Sweetness Attribute



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

February 2024



SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.1 Facility Information

Facility name: Evergreen Sequestration Hub

Injection Well Information:

Well Name and Number Loblolly CCS No. 001

Parish Beauregard

Location [REDACTED]

Latitude and Longitude [REDACTED]

Well Name and Number Loblolly CCS No. 002

Parish Beauregard

Location [REDACTED]

Latitude and Longitude [REDACTED]

*CCS – carbon capture and sequestration

3.2 Computational Modeling

Model Name: GEM (Version No. 2022.30)

Model Authors/Institution: Computer Modelling Group (CMG), Ltd.

Description of Model: Equation-of-state (EOS) reservoir simulator for compositional, chemical, and unconventional reservoir modeling

Model Inputs and Assumptions: The parameters for CMG’s GEM are summarized in Table 3-1.

Table 3-1 – Model Input Parameters and Assumptions

Input	Value
Per-Well Injection Rate (MT/yr)	[REDACTED]
Average Porosity (%)	[REDACTED]
Average Permeability (mD)	[REDACTED]
Temperature Gradient (°F/100 ft)	[REDACTED]
Fracture Gradient (psi/ft)	[REDACTED]
Brine Salinity (ppm)	[REDACTED]
Injected Fluid Composition	[REDACTED]

*MT/yr – metric tons per year

mD – millidarcy

psi – pounds per square inch
ppm – parts per million

3.3 Area of Review Discussion

Statewide Order (SWO) 29-N-6, **§3615.B** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**] requires that an area of review (AOR) investigation be conducted for a Class VI carbon sequestration well application. SWO 29-N-6 defines the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity, and is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set forth in §3615.B. and §3615.C. The Evergreen Sequestration Hub (Evergreen) Project AOR was determined utilizing the detailed site characterization and plume modeling effort discussed in Section 1 and 2 respectively.

3.3.1 Area of Review: Pore Occupancy Plume

The pore occupancy plume is delineated through computational modeling that accounts for the physical and chemical properties of every phase of the injected CO₂ stream. The data required for this modeling process is derived from site characterization, monitoring, operational records, and literature. A comprehensive overview of the modeling effort to establish the extent of the pore occupancy plume is included in *Section 2 – Plume Model*.

The AOR for the pore occupancy plume was investigated to identify and assess artificial penetrations, subsurface features, and pore space rights.

The artificial penetrations (e.g., wellbores) located within the AOR have been assessed to ensure proper completion, plugging, and construction using suitable materials. Class VI regulations require these wellbores to be constructed or plugged using materials capable of facilitating the long-term storage of carbon dioxides and protection of the USDW. Any wellbore found within this AOR that penetrated the gross injection zone was evaluated to determine its effect on the integrity of the containment of CO₂. Wellbores that were deemed to be insufficiently constructed or plugged are included in the corrective action plan.

The AOR is also evaluated for subsurface characteristics to determine their influence or lack thereof on the primary injection zone. These characteristics may include faults, mapped fractures, folds, steeply dipping formations, and salt diapirs, among others. These features may assist in the confinement of CO₂ by acting as impermeable barriers to flow. They may also, however, facilitate fluid movement out of the injection zone. It has been established that any such identified feature should not be allowed to facilitate the escape of CO₂ to the surface.

The reservoir modeling simulations indicate that the resultant CO₂ plume extent will remain on the acreage that is subject to the sequestration agreement between Evergreen Sequestration Hub, LLC (Evergreen) and MWF Madison, LLC for the Evergreen Project.

3.3.2 Area of Review: Pressure Front

The second AOR to be evaluated is the pressure front formed during the injection of fluids into a reservoir previously in equilibrium. This pressure front AOR is determined through both calculation and simulation. The AOR defines the pressure buildup that could potentially result in fluid migration out of the primary injection zone. That buildup is determined for inadequately plugged and abandoned artificial penetrations or subsurface features that extend into the upper confining zone (UCZ) of the gross injection interval.

A wellbore that is open or insufficiently plugged and abandoned, and that is open at both the top of the injection interval and the base of the USDW, has the ability to facilitate fluid migration to the USDW. The *critical pressure* is the pressure at which this migration can occur. [REDACTED]

[REDACTED]

[REDACTED]

The base of the USDW is expected to be at [REDACTED] feet (ft) as observed on an offset log from the closest well, further discussed in *Section 1.8.1*. The base of the USDW was conservatively assumed to be [REDACTED] ft for the critical pressure calculation—the deeper depth allowing for a more conservative critical pressure value to be calculated. Figure 3-1 displays a map of the location of the wells used to determine the USDW.

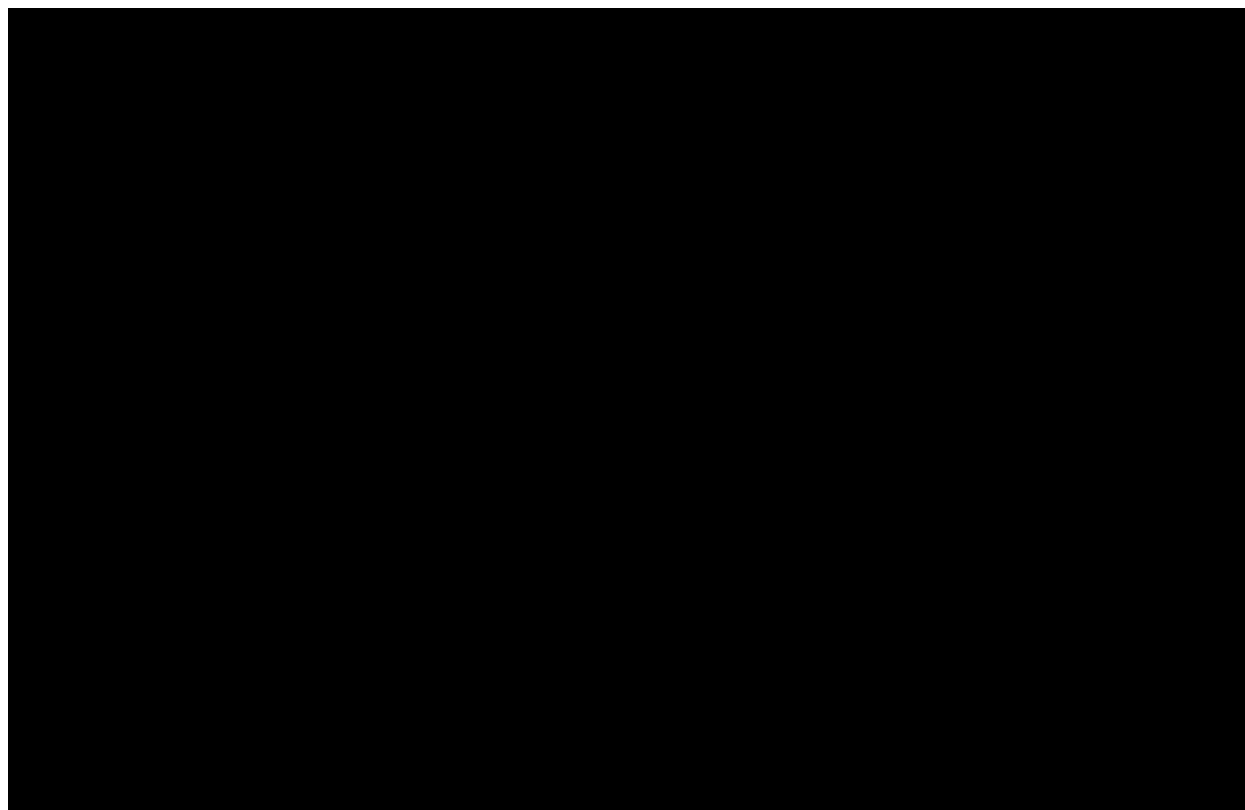


Figure 3-1 – USDW Determination Map

A hypothetical worst-case scenario for moving reservoir fluids to the USDW would be through an incorrectly plugged and abandoned wellbore that is open at both the top of the injection interval and the base of the USDW. [REDACTED]

[REDACTED]

[REDACTED] The equations and inputs are provided in Figure 3-2.

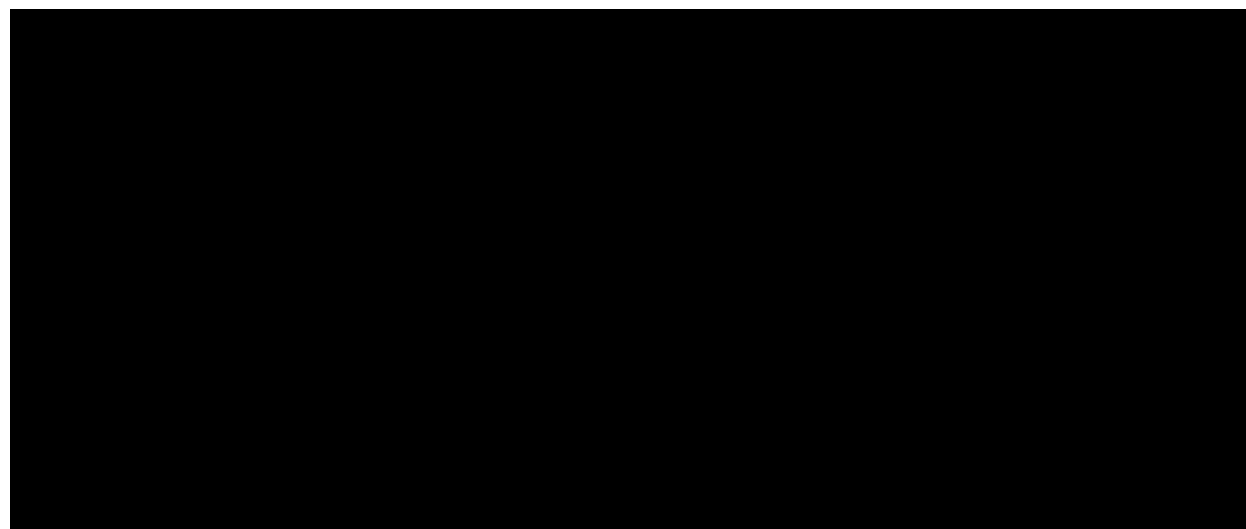


Figure 3-2 – Step-by-Step Calculation of the Critical Threshold Pressure

The critical threshold pressure is evaluated for each completion stage for each injection well. These values will delineate the pressure front for each stage based on the simulation results. The final pressure front will be on the completion stage with the most significant pressure, or a combination of fronts from each stage. Tables 3-2 and 3-3 provide the calculated values for each stage of the proposed Loblolly CCS No. 001 and Loblolly CCS No. 002 injection wells for the Evergreen Project.

Table 3-2 – Loblolly CCS No. 001 Critical Threshold Pressure for Each Completion Stage

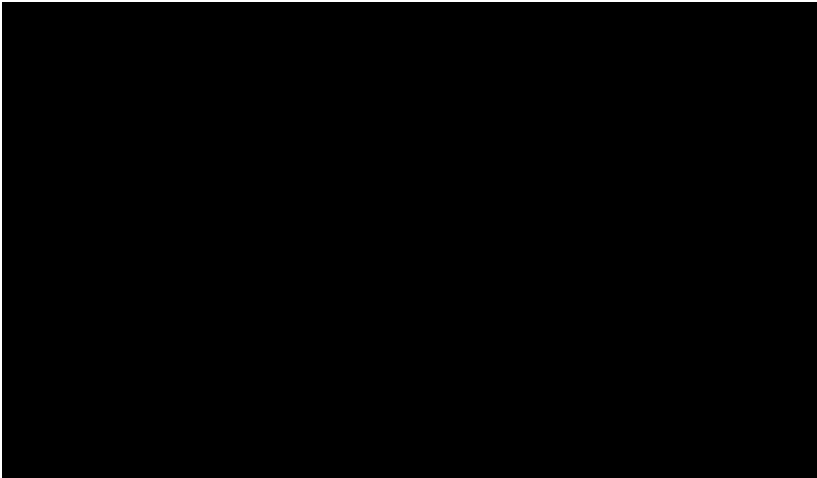
A large black rectangular box redacting the content of Table 3-2.

Table 3-3 – Loblolly CCS No. 002 Critical Threshold Pressure for Each Completion Stage

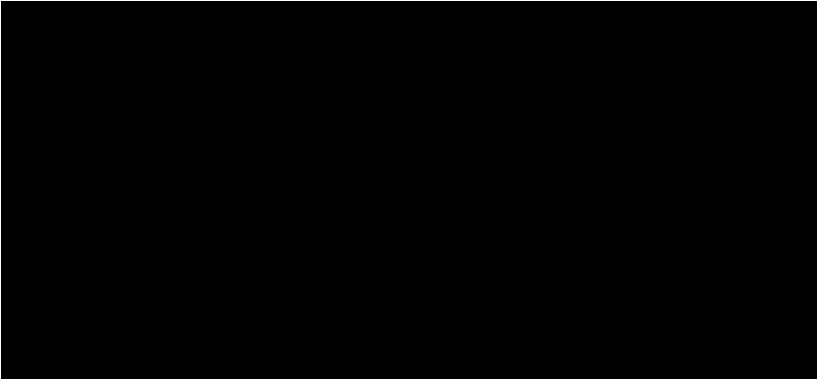
A large black rectangular box redacting the content of Table 3-3.

Figure 3-3 depicts the shape and lateral extent of the pressure front area. The comprehensive AOR for the Evergreen Project includes both the pore space and pressure front areas. Any identified feature within either of these zones was evaluated to ensure the proper containment of CO₂ in safeguarding the USDW. Any feature found to have inadequate protection was included in the corrective action plan discussed in *Section 3.4*.

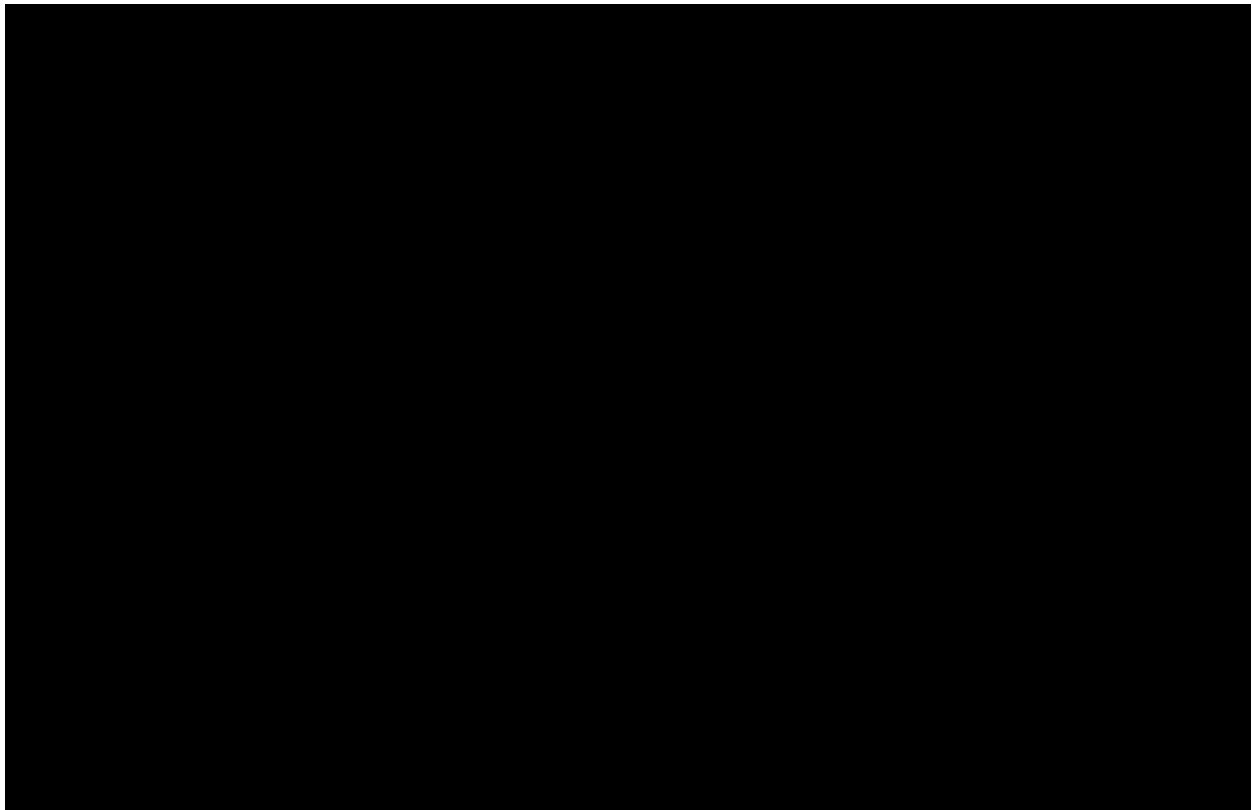


Figure 3-3 – Critical Pressure Front

The delineation of the AOR was established with three primary objectives:

1. Identification of artificial penetrations or man-made structures that may have an impact on the safe storage of sequestered CO₂ for an indefinite period while safeguarding the USDW
2. Identification of subsurface geological features that may have an impact on the safe storage of sequestered CO₂ for an indefinite period while protecting the USDW
3. Identification of pore space rights affected by the expansion of the CO₂ plume over the modeled time period

In accordance with SWO and EPA requirements, Evergreen will reevaluate the AOR at each of the following intervals:

- Minimum frequency of 5 years
- Detection of a significant change in the plume
- As otherwise warranted by routine monitoring or operational conditions

During reevaluation, wells identified as requiring corrective action will be addressed with an amended AOR and corrective action plan, to be submitted to the Commissioner of Conservation

(Comissioner) for approval. All amendments and corrective action plans will be approved, incorporated into the permit, and subject to permit modification requirements per SWO 29-N-6 § 3613.

Upon reevaluation, if no additional wells are identified, Evergreen will provide to the Comissioner evidence backed by monitoring data and modeling results, indicating that no additions are necessary. All modeling inputs and data used to substantiate AOR reevaluations will be retained for 10 years.

3.3.3 Operating Strategies Influencing Reservoir Modeling Results

To limit plume growth and reduce the number of artificial penetrations and subsurface features encountered, a staged completion strategy will be implemented. [REDACTED]

[REDACTED] Each stage will target a specific package of Frio sands in the Gulf Coast depositional environment, thereby optimizing the usage of available pore space.

The Evergreen Project targets approximately [REDACTED] of porous, permeable sand formations for injection in Loblolly CCS No. 001 and approximately [REDACTED] of the same for injection in Loblolly CCS No. 002. Discrete intervals will be used to target these sands in the Frio Formation and spaced to span the life of the project. Impermeable layers of shale isolate these sand packages, allowing for the secure containment of injected CO₂ within each injection interval.

The use of this completion strategy will create multiple stacked plumes, separated by shale beds, thereby limiting the lateral extent of the overall plume while increasing the maximum injection-volume potential. As a result, the plume will be contained to the controlled pore space. The GEM model outputs featured in Figures 3-4 and 3-5 show the cross sections of the resultant plume, and Figure 3-6 displays the oblique cross section of the stacked plume layers.

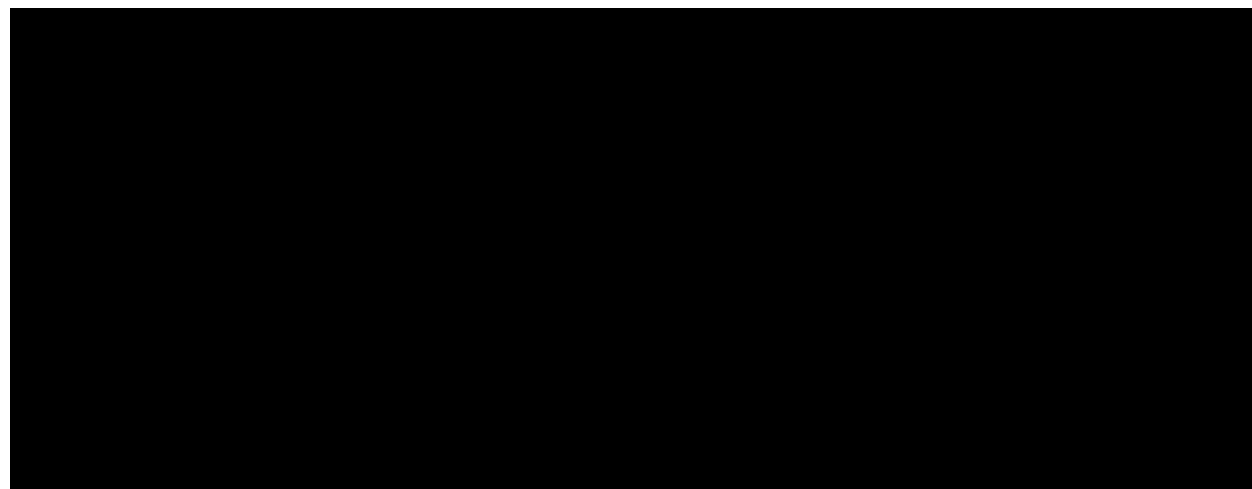


Figure 3-4 – West-East Cross-Sectional View, Loblolly CCS No. 001 (Left) and No. 002 (Right)



Figure 3-5 – South-North Cross-Sectional View, Loblolly CCS No. 001 (Left) and No. 002 (Right)

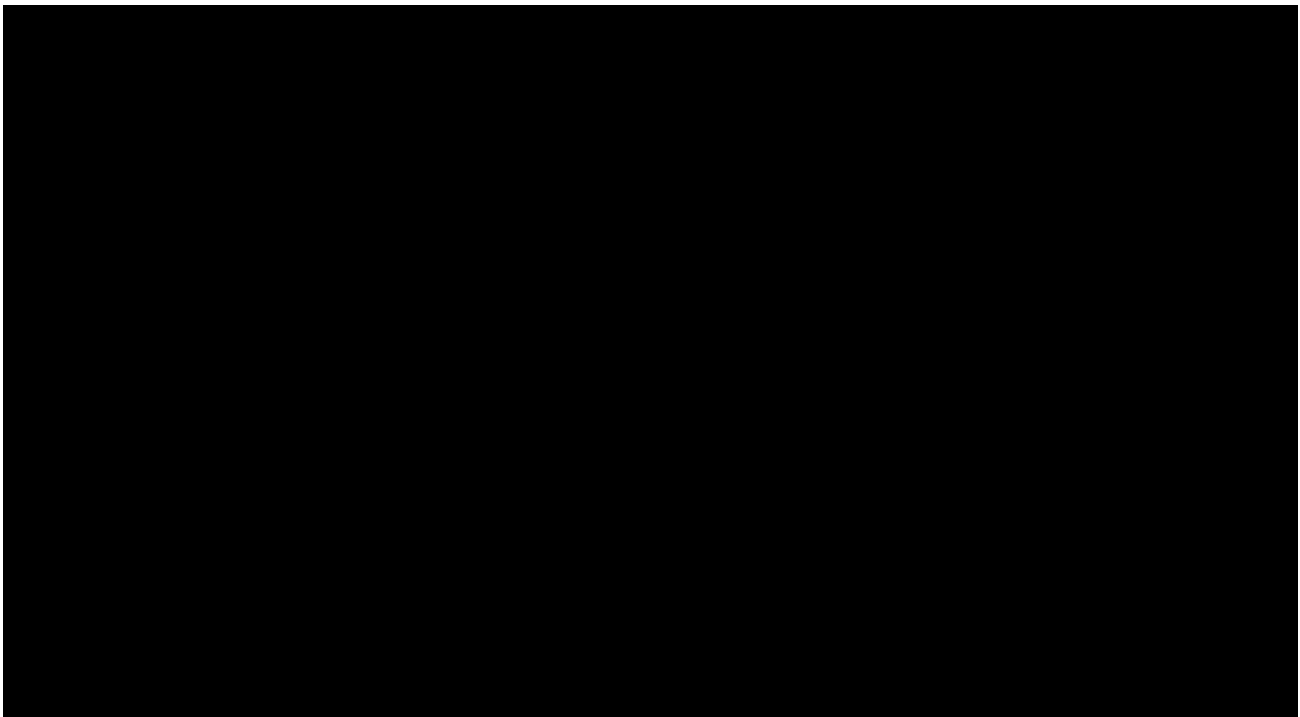


Figure 3-6 – GEM Plume Model Results – Oblique Cross Section Views

Figure 3-7 depicts the shape and lateral extent of the largest of the stacked injection plumes. This extent, in addition to the critical pressure area, was used to define the initial AOR for the proposed well.

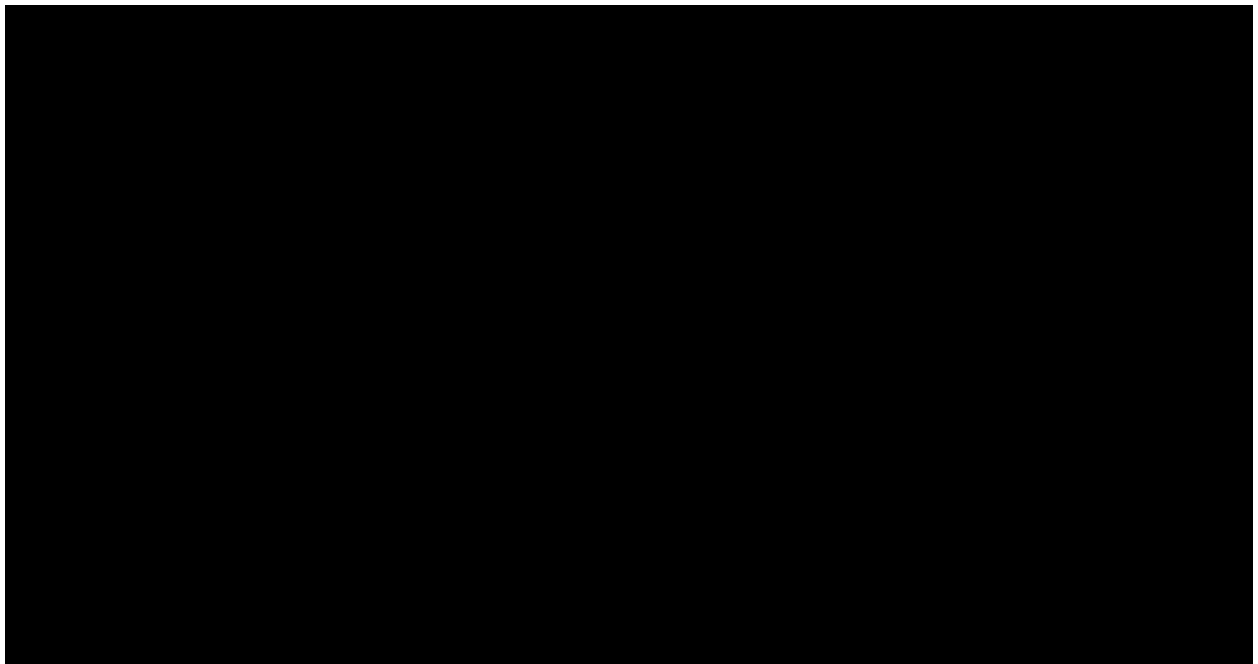


Figure 3-7 – GEM Plume Model Results – Plan View Maximum Extents

This plume extent was digitized from the GEM output and imported into ArcGIS to define the AOR for the Evergreen Project. Per SWO §3615.B.1 [40 CFR §146.84], a thorough investigation was conducted to identify artificial penetrations or any other features that pose a threat to the lowermost USDW during injection activities or operational processes. During this review, maps were created to illustrate the AOR and the man-made structures found within its boundaries. Subsequently, these artificial penetrations and other man-made elements were evaluated based on their depth of completion, construction specifications, and adequacy of plugging and abandonment (P&A) procedures. The goal of this assessment was to identify any penetrations that could potentially compromise the integrity of the storage intervals or the USDW.

The maps and associated lists generated during this effort are contained in *Appendix C*. Figure 3-8 identifies the AOR for the project.

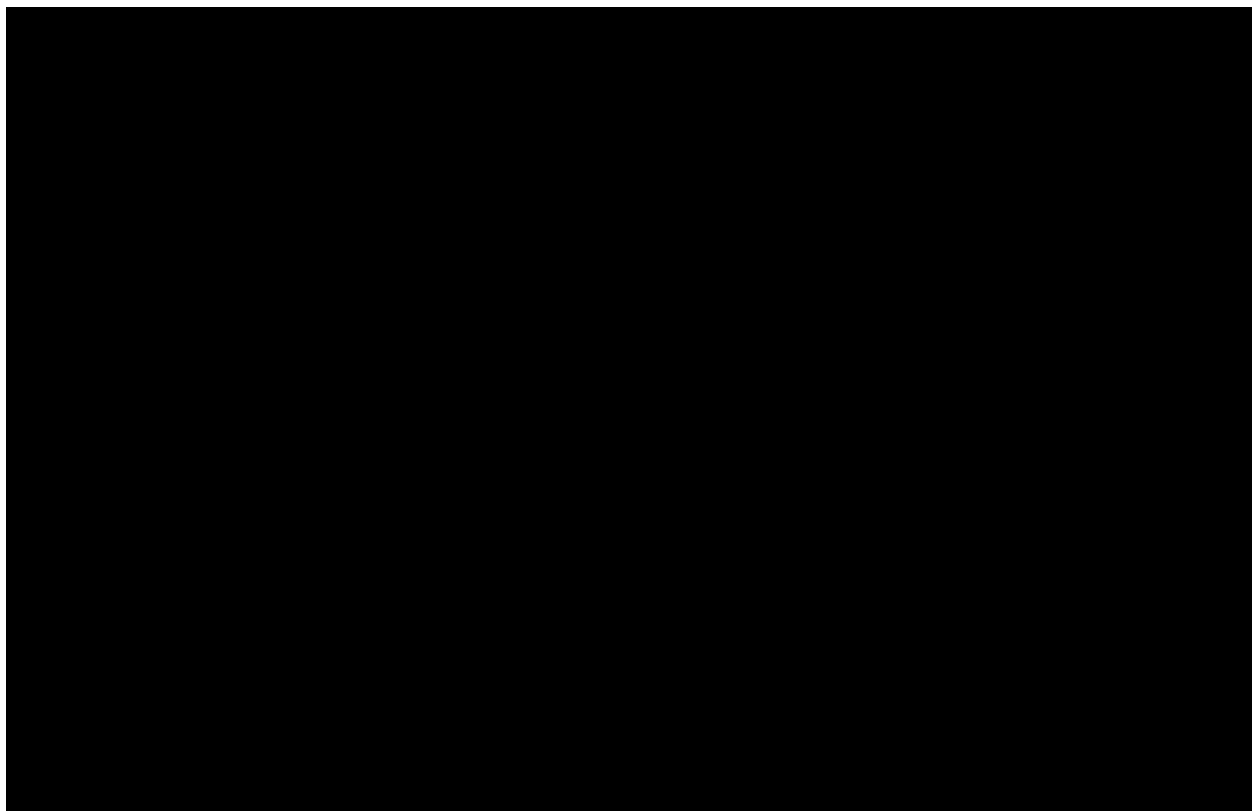


Figure 3-8 – Final AOR Map for the Evergreen Project

3.3.4 Area of Review Results

A comprehensive multi-database analysis was performed to identify all artificial penetrations into the injection interval within the AOR.

Well data for the AOR was gathered primarily from the Louisiana Department of Natural Resources (LDNR) Strategic Online Natural Resources Information System (SONRIS).

Supplemental data was then obtained from other databases, including Enverus and IHS, to limit inaccuracies in the data and provide additional information. Water well data was accessed from the LDNR water-well registration database.

As stated in *Section 0 – Introduction*, the proposed locations of Loblolly CCS No. 001 and No. 002 are ideally suited for carbon sequestration. [REDACTED]

[REDACTED] pressure front AOR evaluation yielded no additional penetrations. No subsurface geologic features were determined to exist within the AOR, that may compromise the long-term storage of injected CO₂. A map showing the offset oil and gas wells is shown in Figure 3-9, and Table 3-4 details these wells.

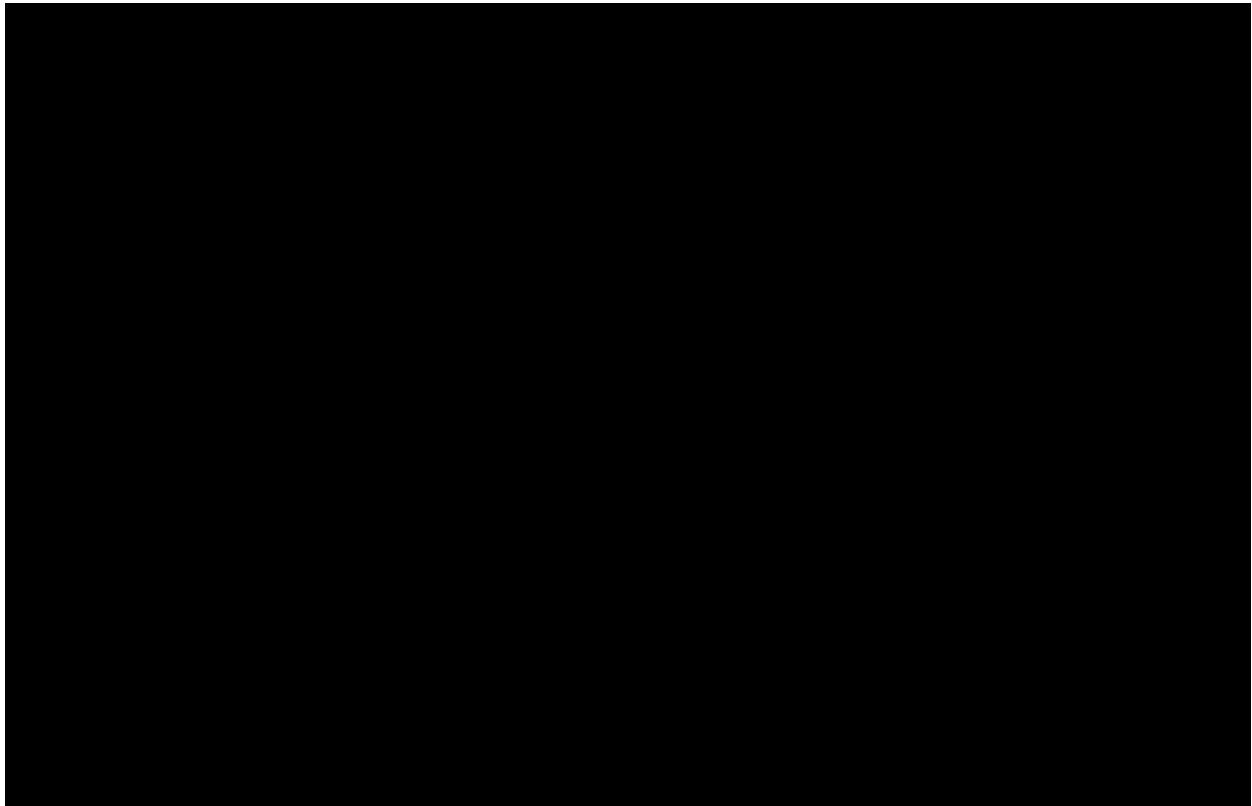
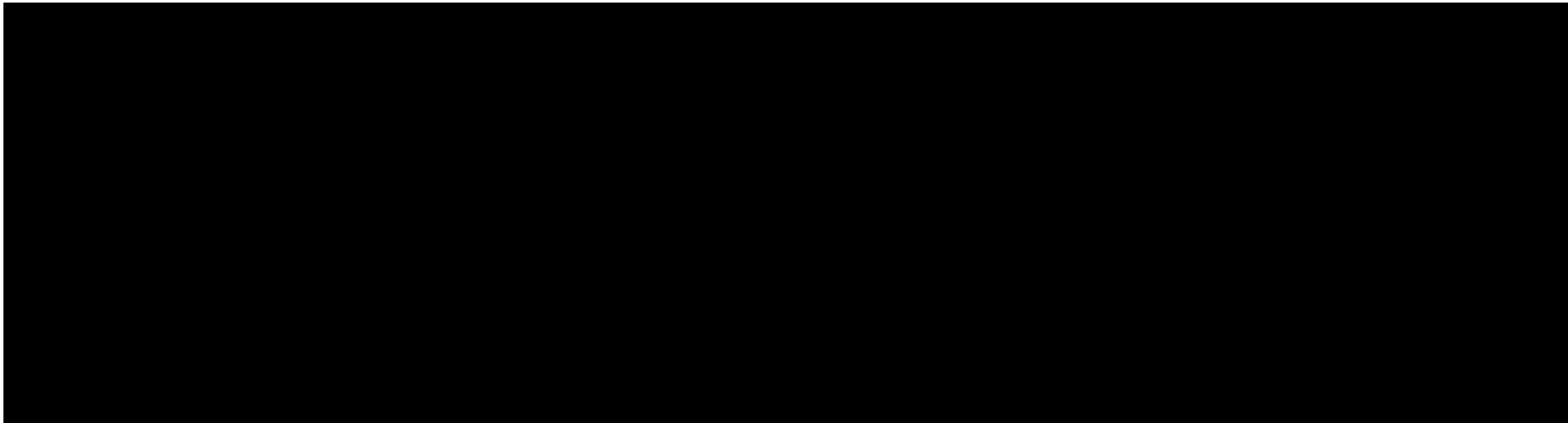


Figure 3-9 – Map of Oil and Gas Wells within the AOR

Table 3-4 – Oil and Gas Well Penetration List



Existing water wells within the AOR have been evaluated to ensure their safeguarding during CO₂ injection operations. The depths of these water wells range from [REDACTED] ft to [REDACTED] ft, which is at least [REDACTED] ft shallower than the base of the USDW. A map showing the offset water wells is featured in Figure 3-10.

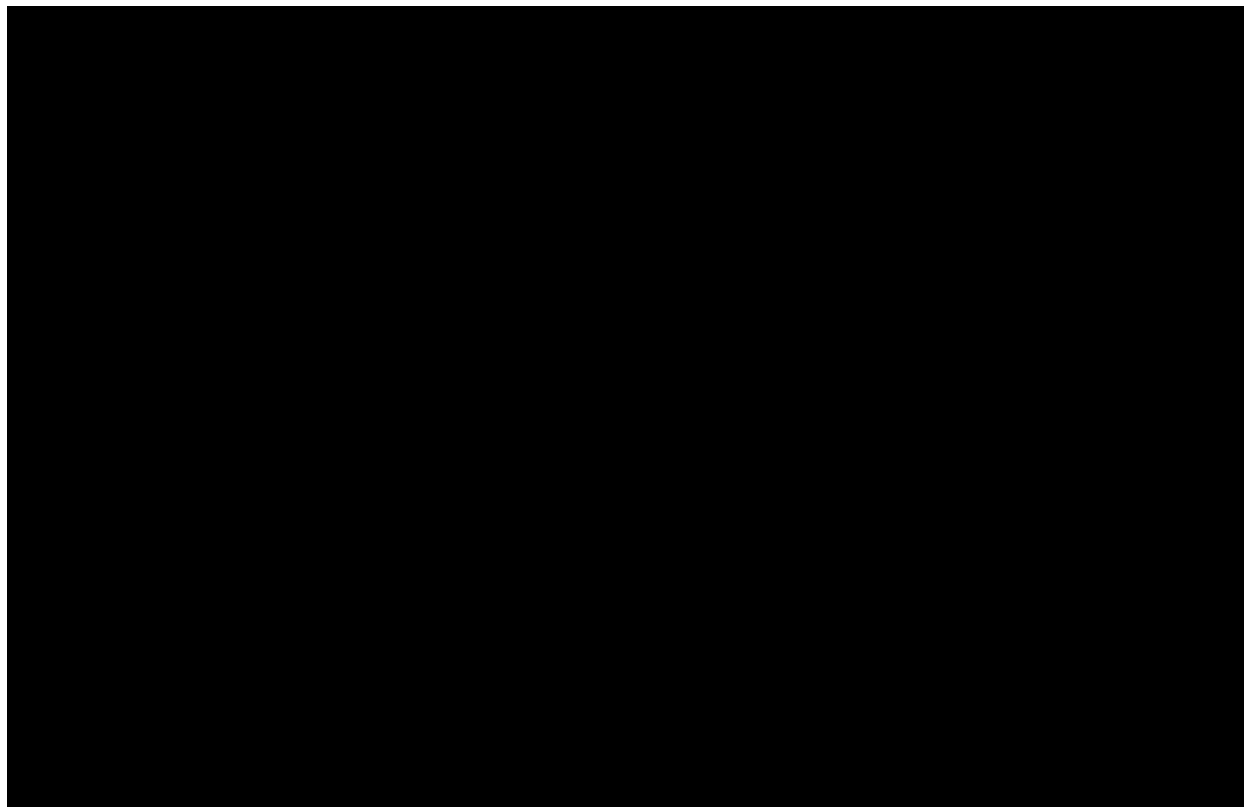


Figure 3-10 – Freshwater Wells AOR Map

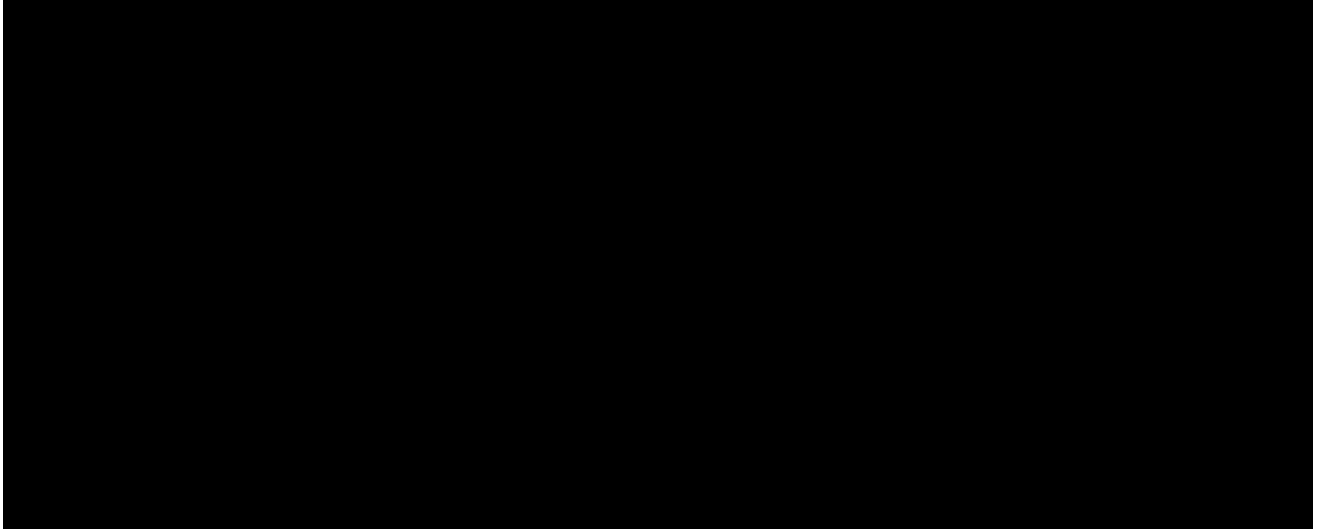
3.4 Corrective Action Plan and Schedule

This corrective action plan is designed to guarantee the effective long-term containment of CO₂ and other fluids, while emphasizing the safety of the USDW. To secure that safety, the plan will ensure that neither CO₂ nor any other formation fluids are allowed to migrate out of the injection interval and reach beyond the UCZ.

[REDACTED]

The wells requiring reentry or recompletion are shown in Table 3-5. The wells listed in Table 3-4 that are not identified in Table 3-5 as needing corrective action have been plugged in a manner to prevent the movement of carbon dioxide and other reservoir fluids, thereby safeguarding the USDW.

Table 3-5 – Corrective Action Well List



The growth and extent of the CO₂ plume will be monitored and periodically evaluated. A reassessment will occur every 5 years and, if necessary, amendments will be made to the corrective action plan to include these additional wells.

3.4.1 General Reentry Process

Using documented coordinates from public data, historical wells were located and operational plans developed based on the available information, including casing specifications, cementing records, and P&A activities.



Wireline logging tools will be utilized during the reentry process to verify the quality and tops of cemented casings. Each well needing corrective action will be logged to evaluate casing integrity and cement quality. The intervals logged for each well will be determined based on the casing integrity necessary to maintain sufficient barriers for abandonment. The data acquired during

logging will be used to identify both the depths at which casing needs to be pulled and the depths that require cementing.

Each historical well in the pore occupancy plume requiring reentry to plug and abandon will have multiple barriers installed during P&A to meet Class VI standards. Barriers will be established at the surface casing shoe, base of the USDW, base of the UCZ, and surface.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

3.4.2 In-Depth Review of Wells Needing Corrective Action

Well Name: [REDACTED]

Serial Number: [REDACTED]

API Number: [REDACTED]

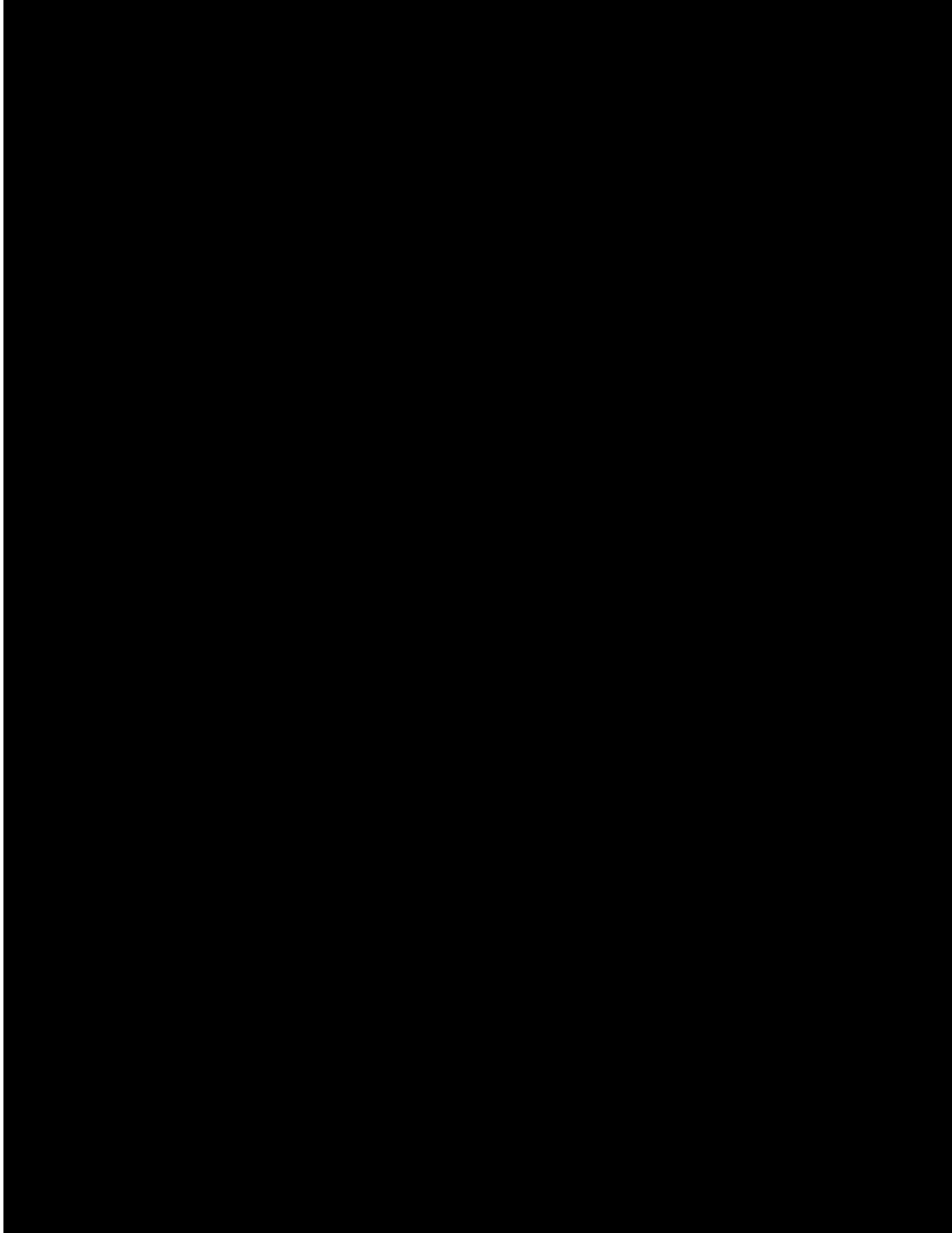


Figure 3-11 – [REDACTED]

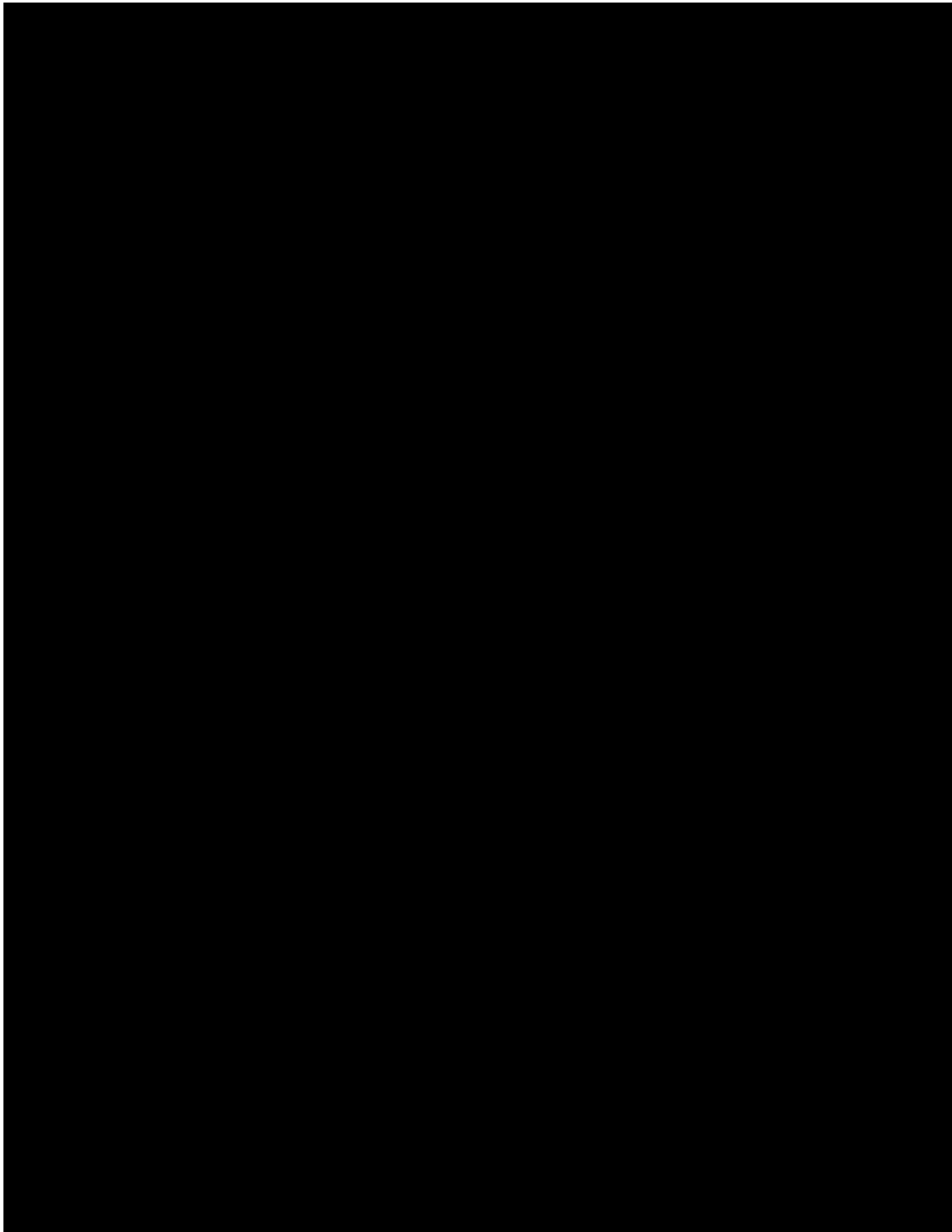


Figure 3-12 – [REDACTED]

Well Name: [REDACTED]

Serial Number: [REDACTED]

API Number: [REDACTED]

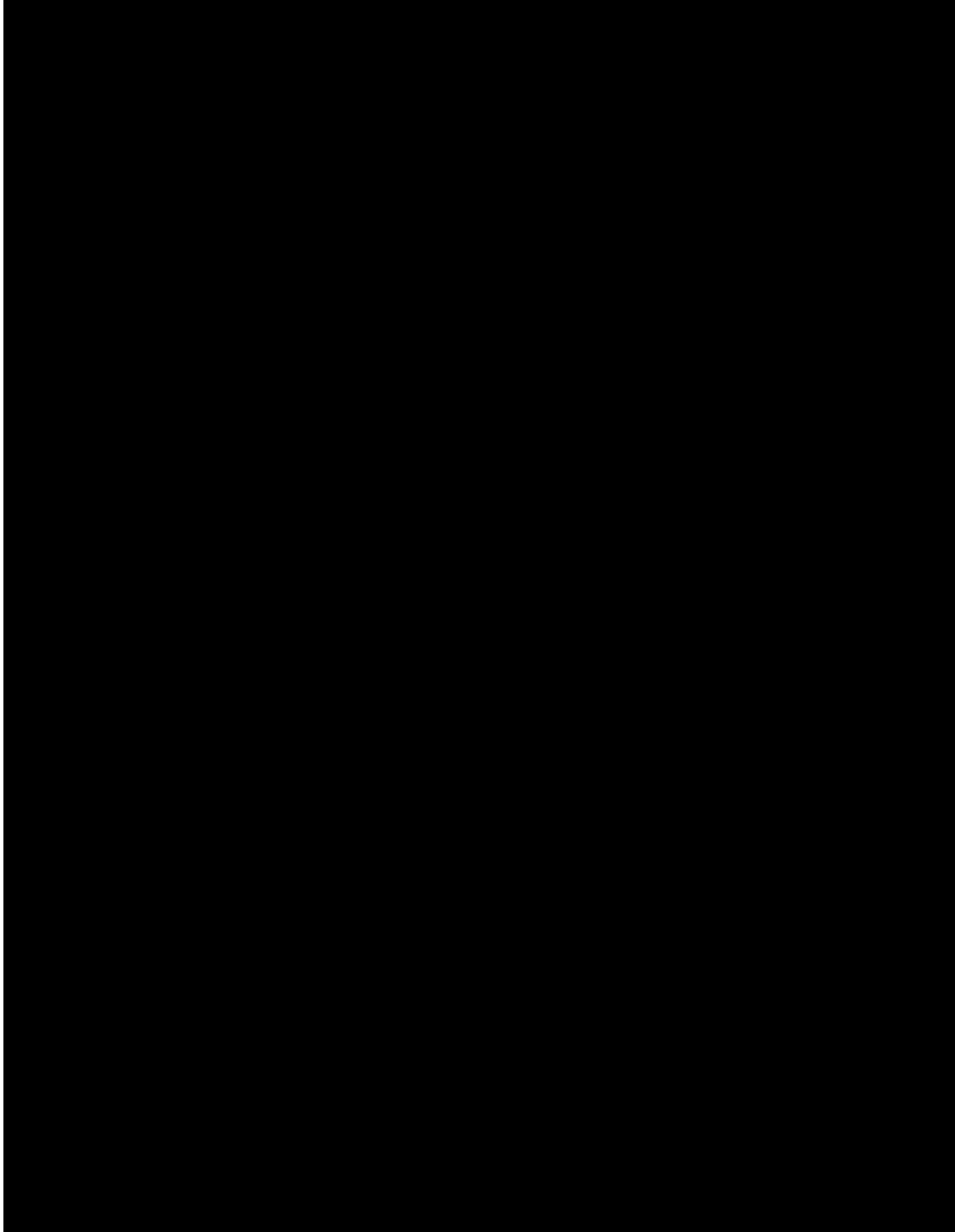


Figure 3-13 – [REDACTED]

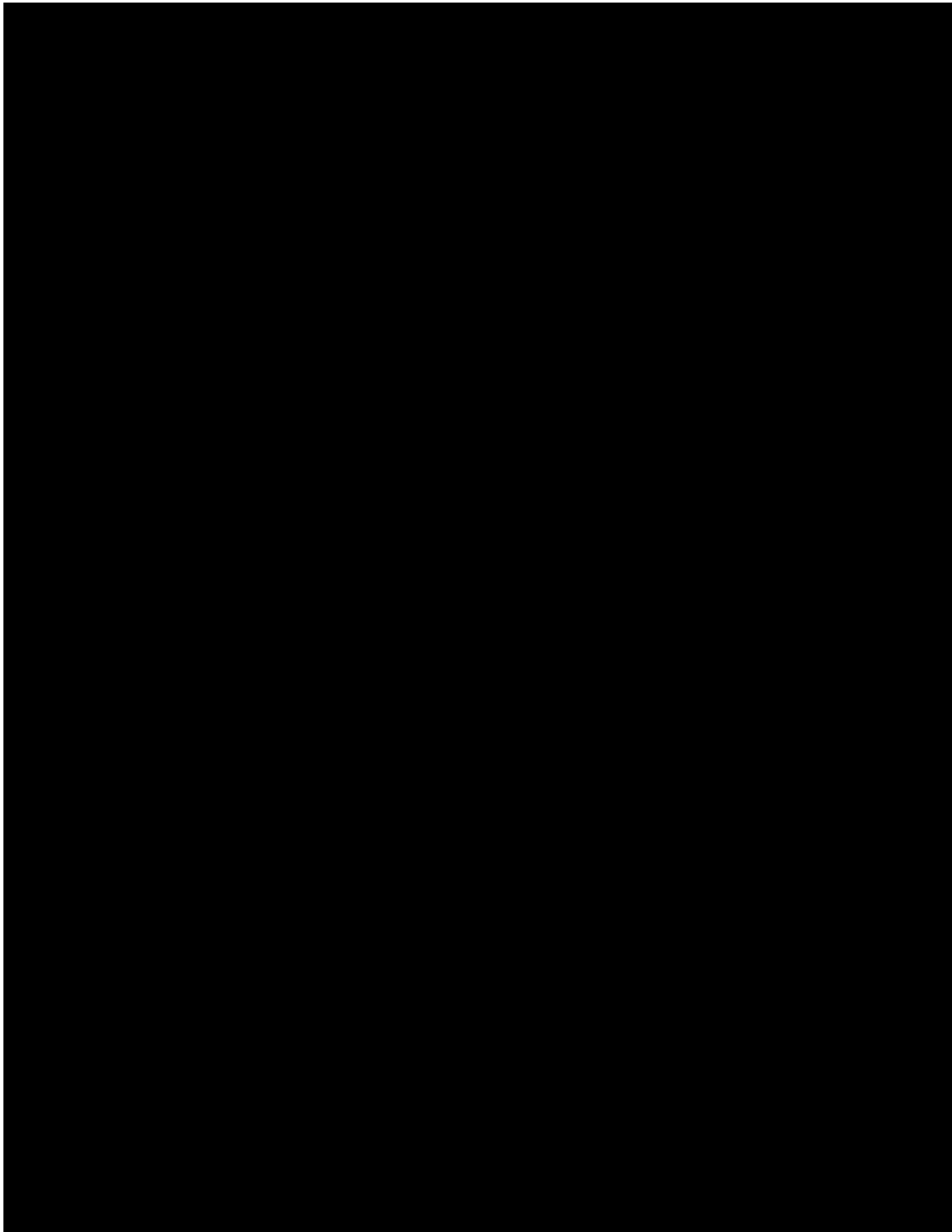


Figure 3-14 – [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]

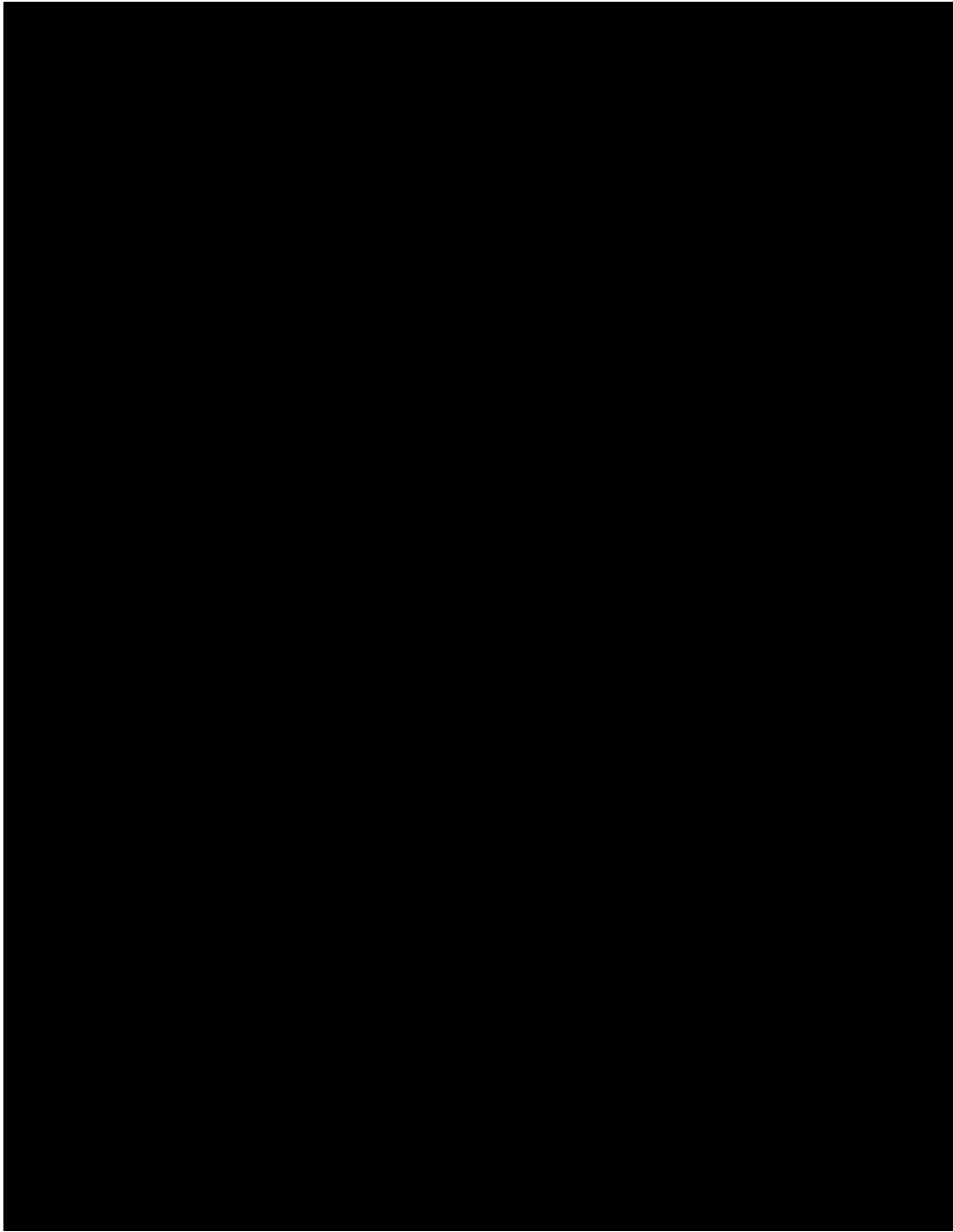


Figure 3-15 – [REDACTED]

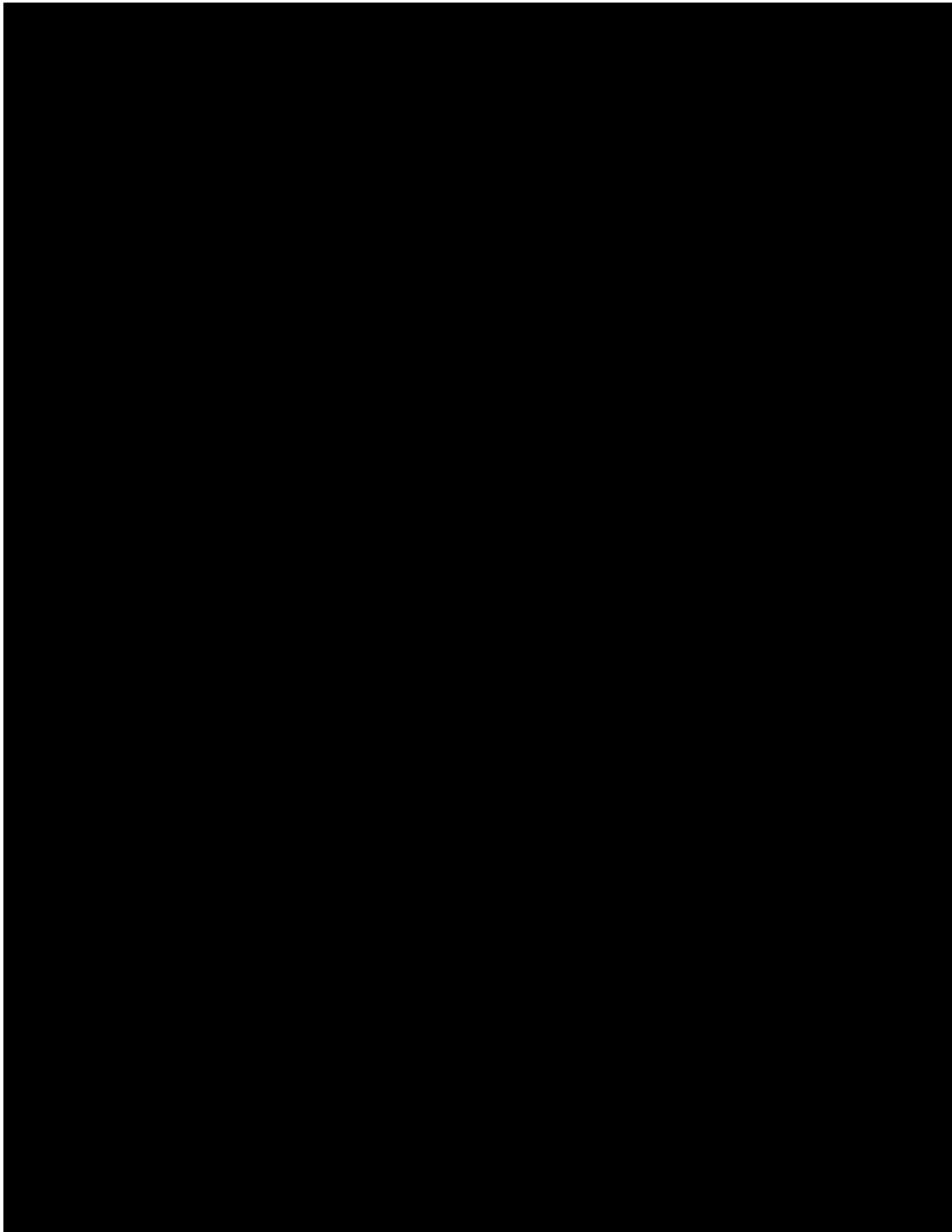


Figure 3-16 – [REDACTED]

Well Name: [REDACTED]

Serial Number: [REDACTED]

API Number: [REDACTED]

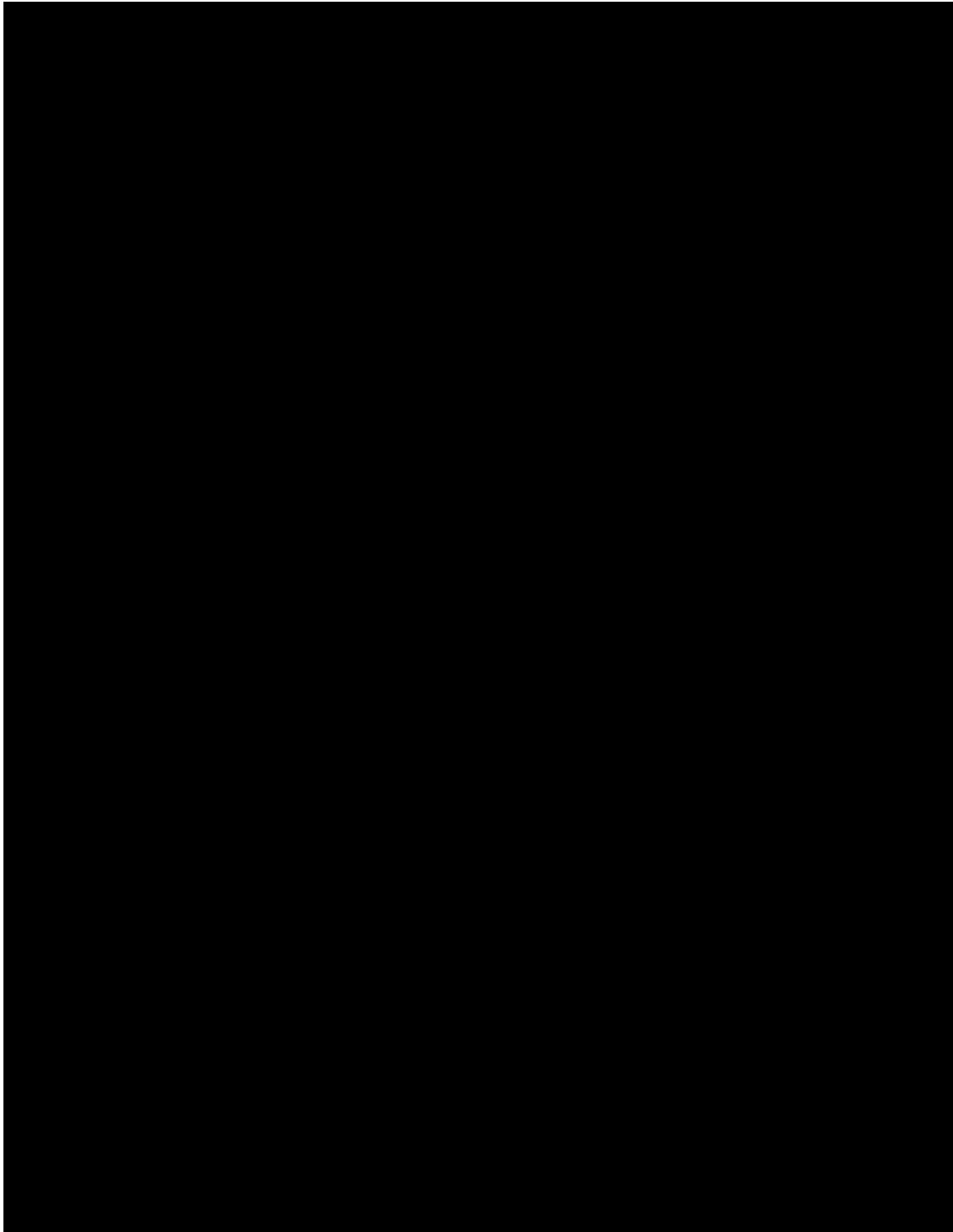


Figure 3-17 – [REDACTED]

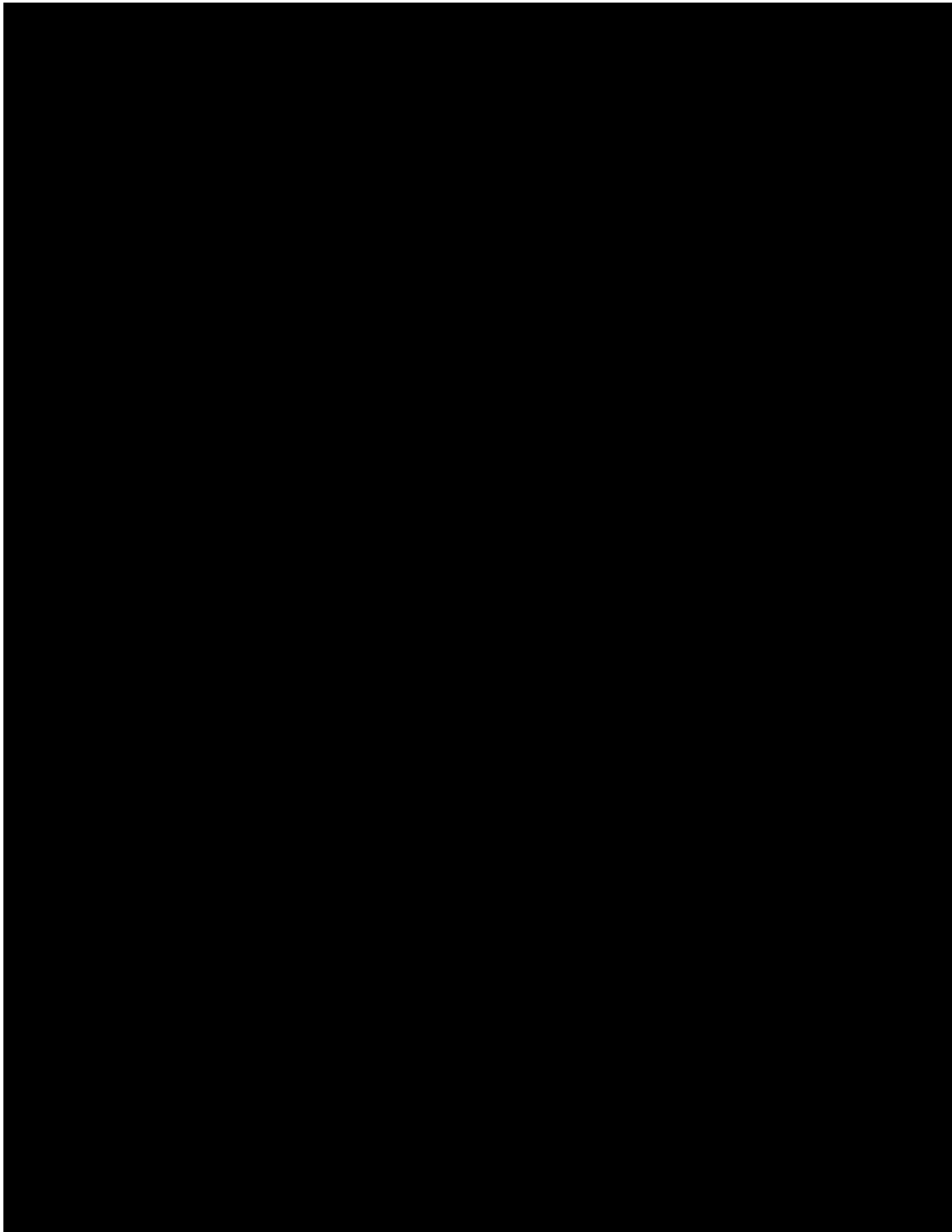


Figure 3-18 – [REDACTED]

Well Name: [REDACTED]

Serial Number: [REDACTED]

API Number: [REDACTED]

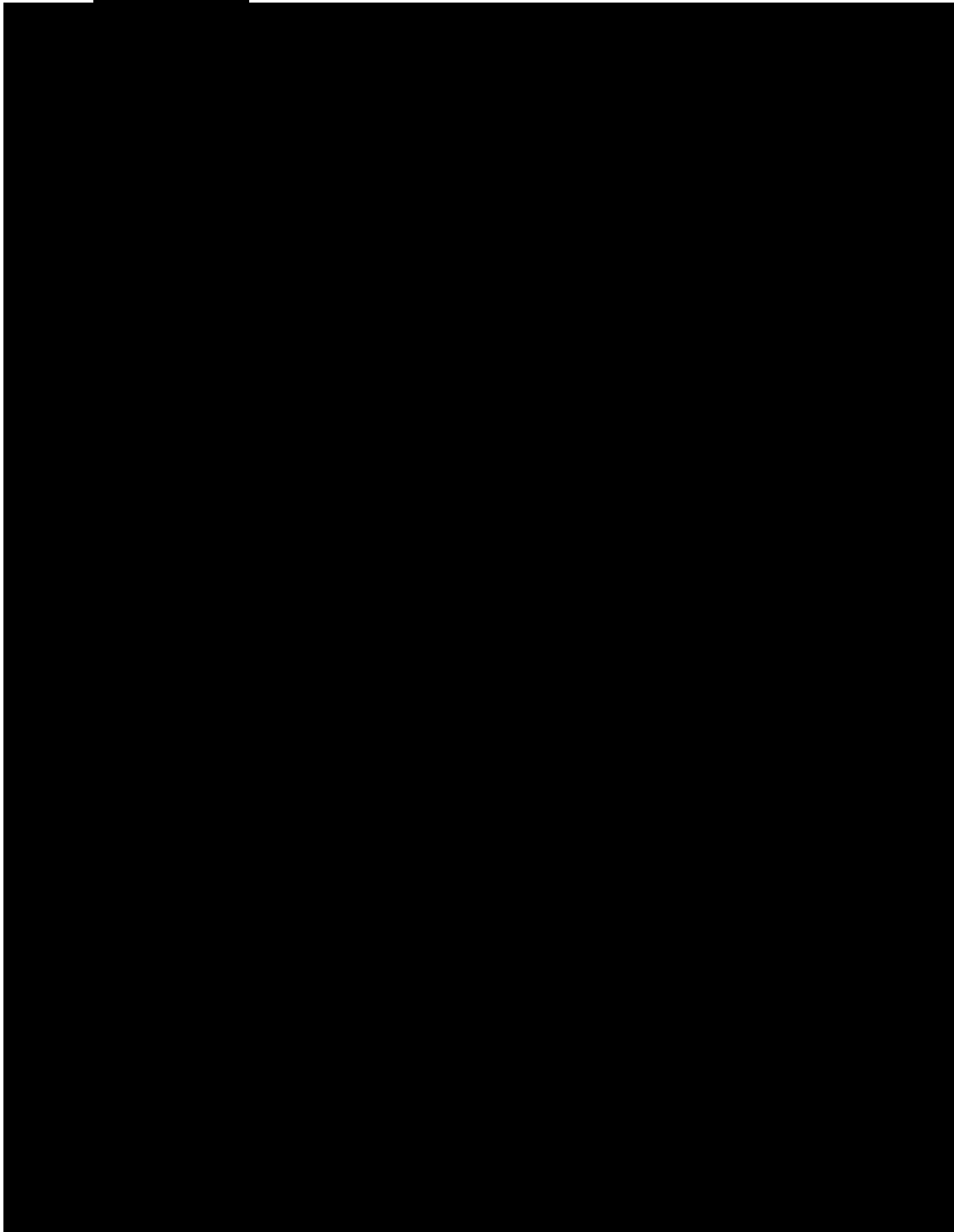


Figure 3-19 – [REDACTED]

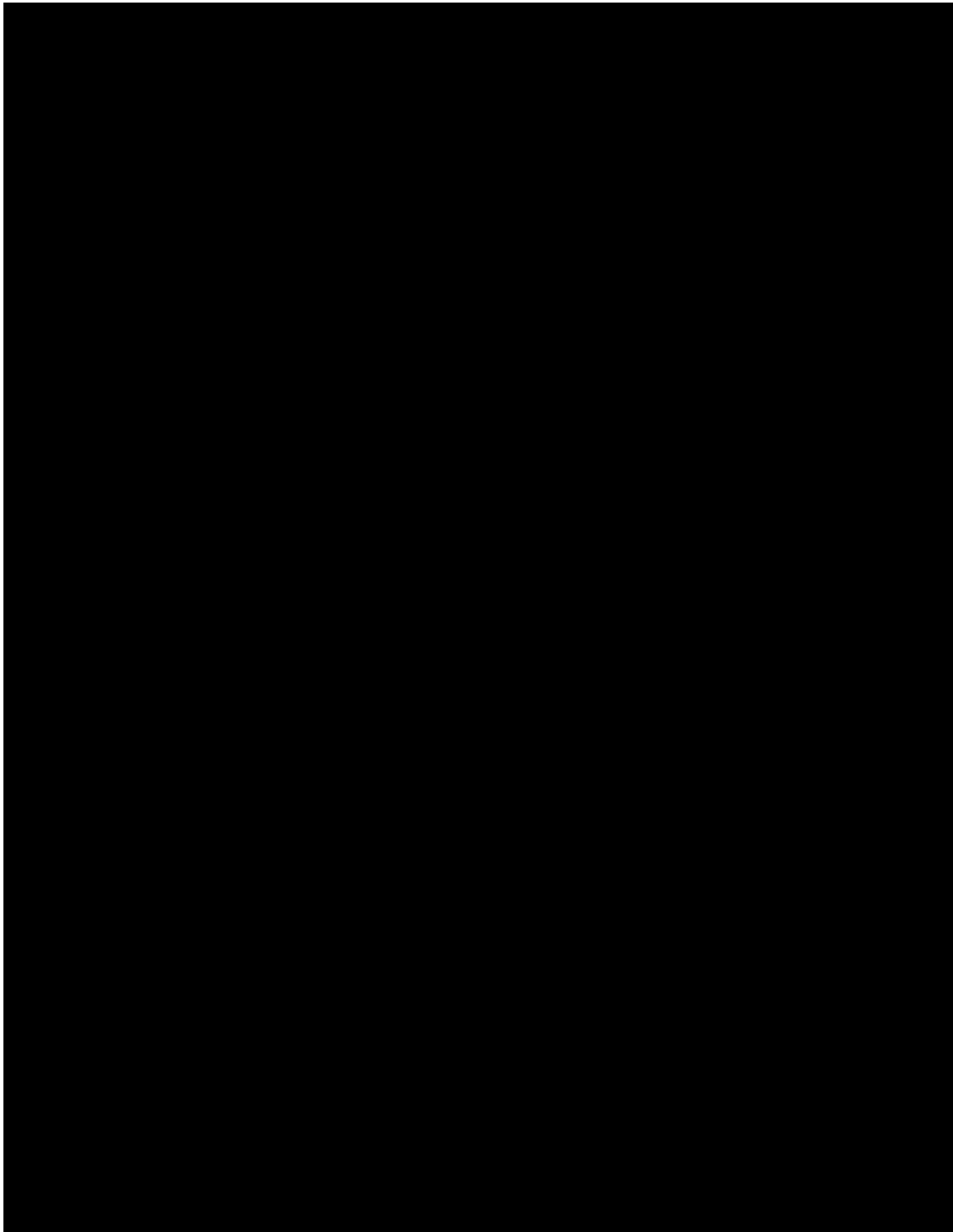


Figure 3-20 – [REDACTED]

3.5 Area of Review Reevaluation Plan and Schedule

3.5.1 Proposed Reevaluation Cycle

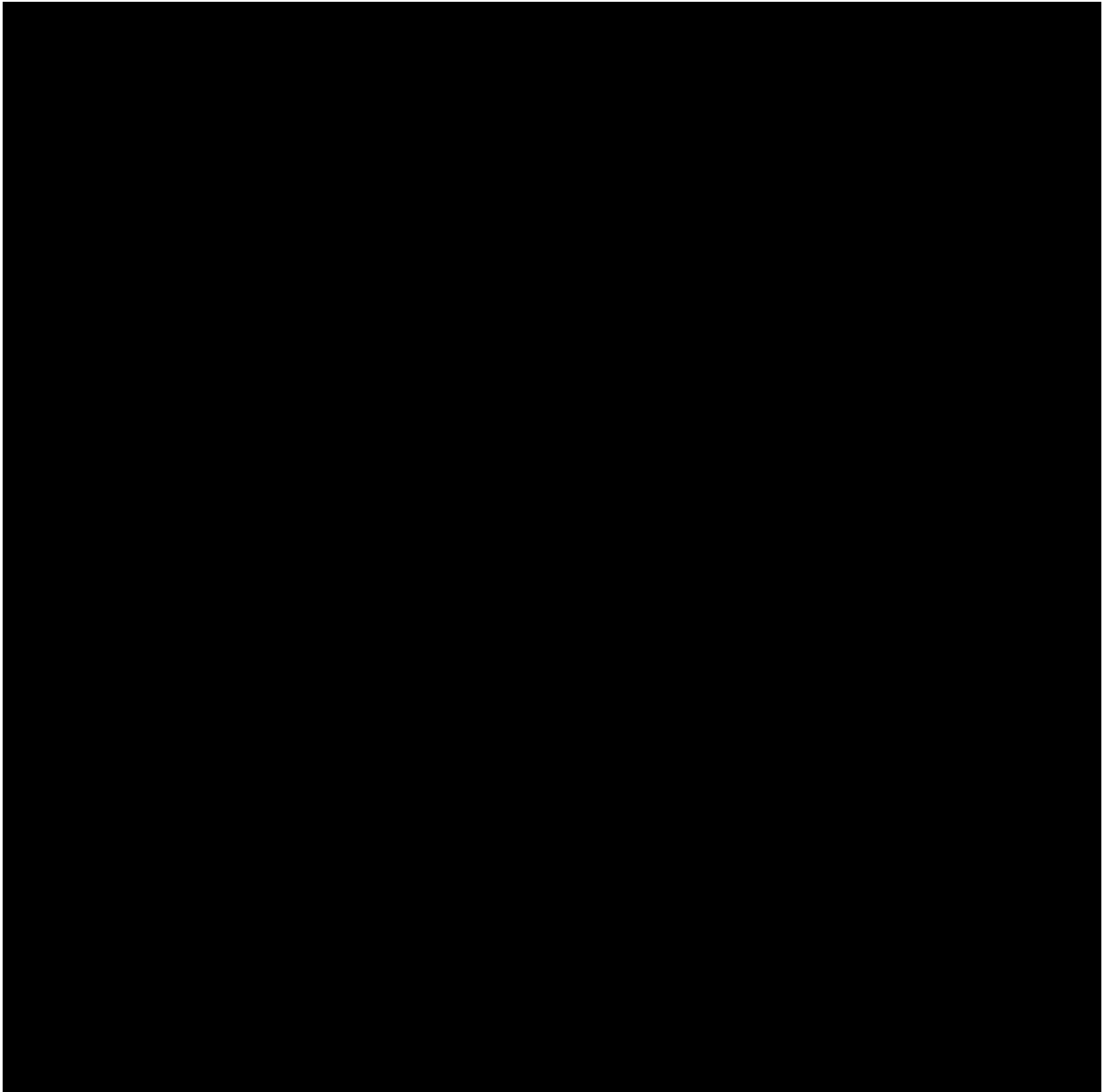
Evergreen will reevaluate the AOR at least every 5 years, per SWO 29-N-6 **§3615.B.2.b.i** [40 CFR **§146.84(b)(2)(i)**]. Reevaluation of the AOR will occur more frequently than every 5 years if the monitoring of the plume growth and migration suggest it is necessary, following discussion with the regulators. Triggers for reevaluation are discussed in Table 3-6.

[REDACTED]

[REDACTED] This will allow adjustments to be made to the development of the plume throughout the injection life of each well. It is expected that, over time, the modeled plume and the measured plume survey will coincide, allowing for a decrease in the frequency of surveying. This will be especially true after injection has ended and plume movement slows considerably, stabilizing the plume. The surveys will be performed at least once every 5 years from the commencement of injection operations.

If injection rates are less than the modeled capacity, plume migration could be less than the modeled extent. If this occurs, the life of each discrete completion zone could be extended without impacting the AOR. However, if the measured plume behavior extends beyond the modeled limits, the model will be updated, triggering the AOR reevaluation. Table 3-6 lists some of the possible triggers.

Table 3-6 – Triggers for AOR Reevaluations



The following AOR maps and resultant tables are included in *Appendix C* in large-scale format for ease of detailed review.

Appendix C – AOR and Corrective Action:

- Appendix C-1 USDW Determination AOR Map
- Appendix C-2 Oil and Gas Wells AOR Map
- Appendix C-3 Oil and Gas Wells AOR List
- Appendix C-4 Freshwater Wells AOR Map

- Appendix C-5 Freshwater Wells AOR List
- Appendix C-6 Site Review AOR Map
- Appendix C-7 [REDACTED]
- Appendix C-8 [REDACTED]
- Appendix C-9 [REDACTED]
- Appendix C-10 [REDACTED]
- Appendix C-11 [REDACTED]
- Appendix C-12 [REDACTED]
- Appendix C-13 [REDACTED]
- Appendix C-14 [REDACTED]
- Appendix C-15 [REDACTED]
- Appendix C-16 [REDACTED]



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

February 2024



5SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

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4.1 Introduction

The following section describes the engineering design details and operational strategies employed during the planning of the proposed Loblolly Carbon Capture and Sequestration (CCS) No. 001 and Loblolly CCS No. 002 injection wells. All engineering design details for the Evergreen Sequestration Hub (Evergreen) Project meet the requirements of Statewide Order (SWO) 29-N-6 §3617 and Title 40, U.S. Code of Federal Regulations (40 CFR) §146.86.

The design, construction, and operation of Class VI injection wells is governed by the Environmental Protection Agency (EPA), under the jurisdiction of the Underground Injection Control (UIC) program. The purpose of Class VI CCS projects is to develop and implement a safe method of injecting and storing CO₂ within the targeted injection zone and to ensure containment within that zone for the protection of Underground Sources of Drinking Water (USDWs).

Evergreen Sequestration Hub, LLC (Evergreen) plans to inject CO₂ within the sandstone intervals of the Frio Formation. The reservoir characteristics of the Frio offer optimal transmissibility and storage capacity for sequestering CO₂ for the life of the project. Characteristics of this group include a high porosity, a high permeability, and a saline-filled zone that contains approximately [REDACTED] of gross vertical thickness of sands interbedded with shale beds, [REDACTED]

The specific requirements implemented for the design and operation of Loblolly CCS No. 001 and No. 002 are described in the following sections.

4.2 Engineering Design

The objective in the design of Loblolly CCS No. 001 and Loblolly CCS No. 002 is to sequester CO₂ and ensure protection of the USDW from any CO₂ injectate contamination. Design parameters such as injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid were considered.

The proposed CO₂ sequestration wells were engineered to withstand a corrosive environment that results from the combination of CO₂ mixed with formation fluids. The well components selected are designed to withstand exposure to the corrosive environment and include casing, tubing, wellhead equipment, and downhole tools. The engineering design also considers the cement used in the wells, including products designed to provide a good bond between the casing and formations and withstand the nature of corrosive fluids across the upper confining zone (UCZ). The downhole wellbore components, including production casing, cement, tubing, and packer, were designed to prevent the migration of CO₂ above the UCZ.

The CO₂ injectate will be stored in the Frio sands and bound by the upper and lower confining zones, as discussed in *Section 1 – Site Characterization*. Intermittent shale layers within the Frio injection zone will aid in confining the injectate by providing additional vertical barriers and isolating the completion stages predefined for injection. The top of the Frio Formation for the Loblolly CCS No. 001 and No. 002 location is located at approximately 4,800 ft true vertical depth (TVD) and is

approximately 1,867 ft and 1,923 ft thick, respectively. The Frio sand stages are characterized as porous, permeable, and unconsolidated, which make them favorable for CO₂ injection and storage.

[REDACTED]

The CO₂ injectate plume will be monitored during each injection period and over the life of the project, to ensure that the plume growth follows the modeled projection. The extensive monitoring program is included in *Section 5 – Testing and Monitoring Plan*.

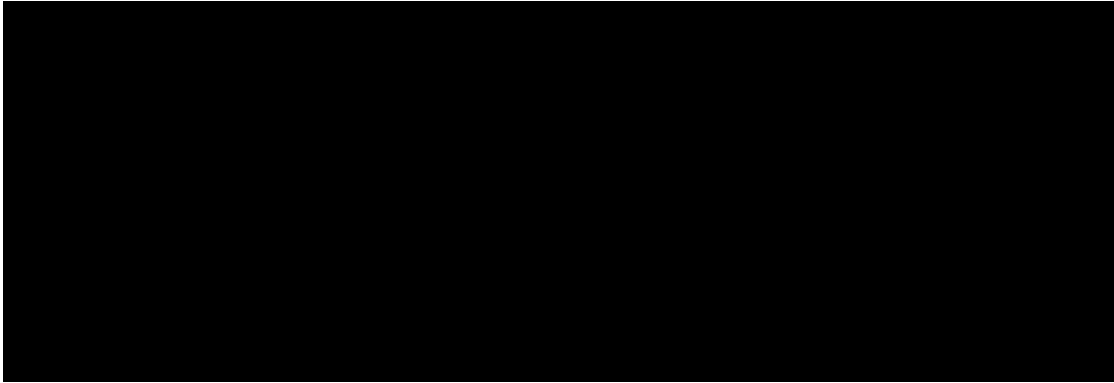
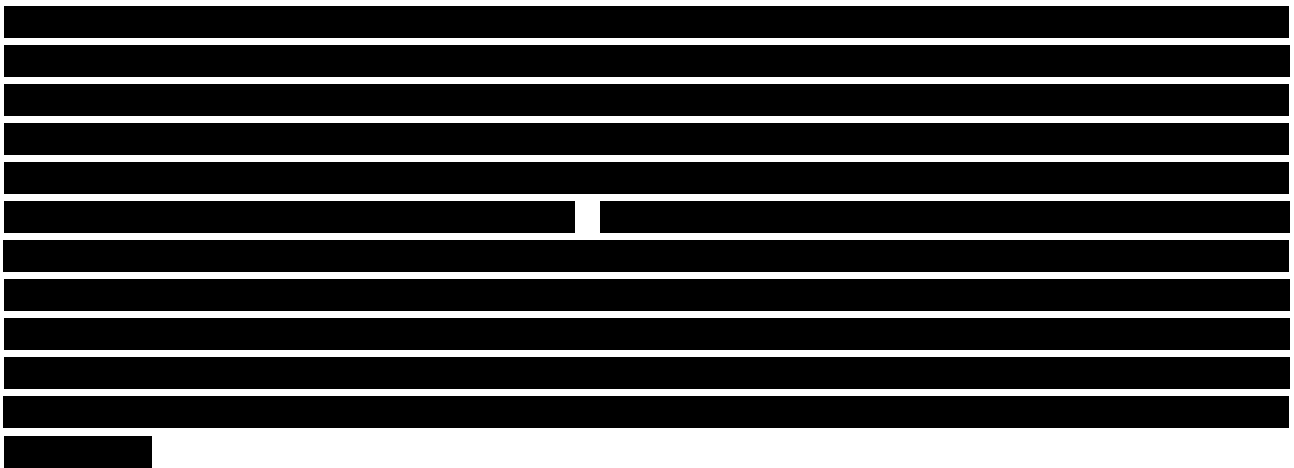
[REDACTED]

Injection into the completion stage will be initiated and the injectate sequestered into the stage until the end of the injection period for each respective stage. This process will be repeated until the uppermost completion stage below the UCZ is reached, as shown in Tables 4-1 and 4-2 for Loblolly CCS No. 001 and No. 002, respectively.

Table 4-1 – Loblolly CCS No. 001 Operational Strategy

[REDACTED]

Table 4-2 – Loblolly CCS No. 002 Operational Strategy

A large rectangular area that has been completely redacted with a solid black fill, obscuring the operational strategy details for Loblolly CCS No. 002.A table structure consisting of 12 horizontal rows. The first 11 rows are fully redacted with black bars. The 12th row contains two segments of redacted text separated by a small gap, indicating a table with at least two columns.

Figures 4-1 and 4-2 show the proposed wellbore designs for Loblolly CCS No. 001 and No. 002, respectively.

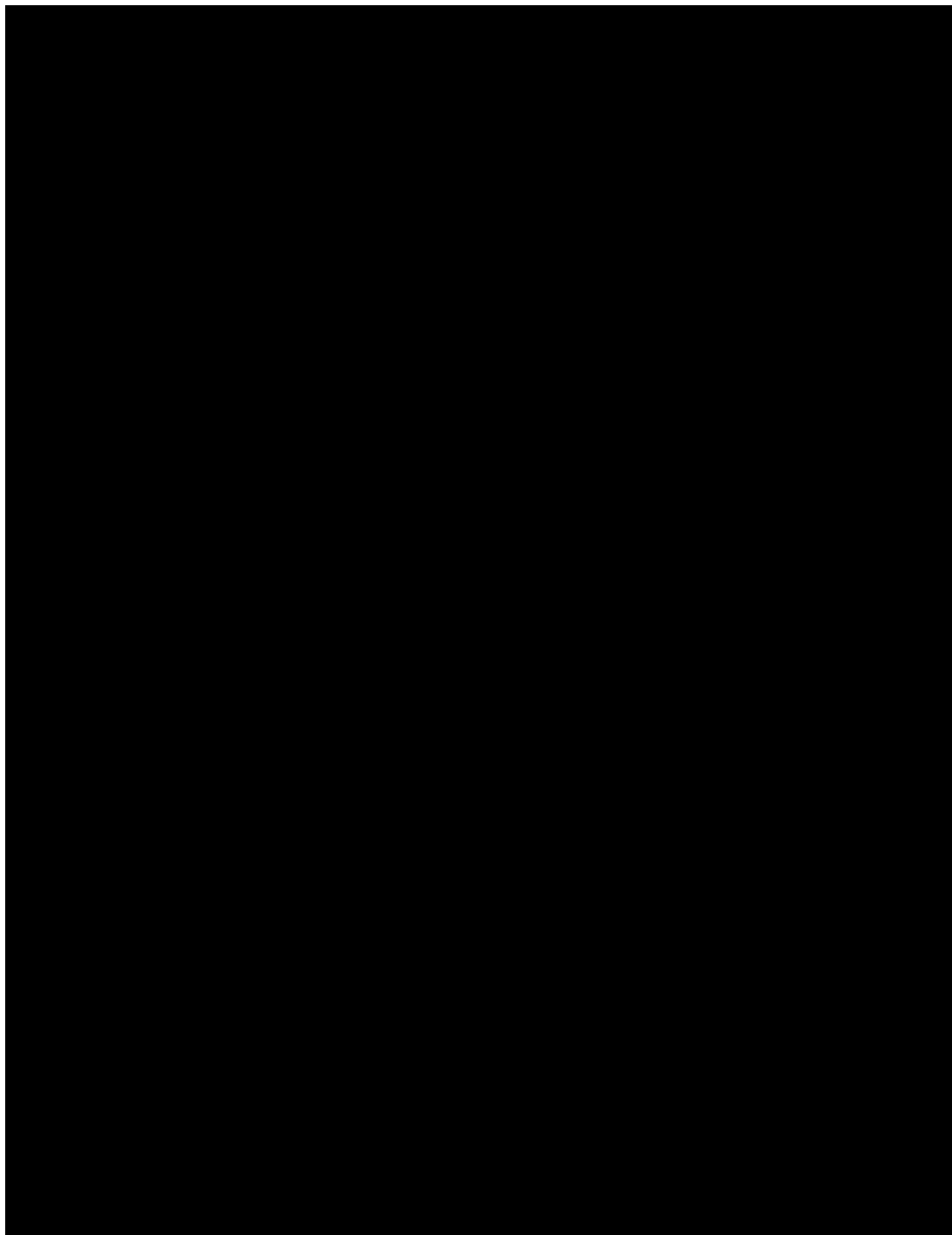


Figure 4-1 – Loblolly CCS No. 001 Wellbore Schematic

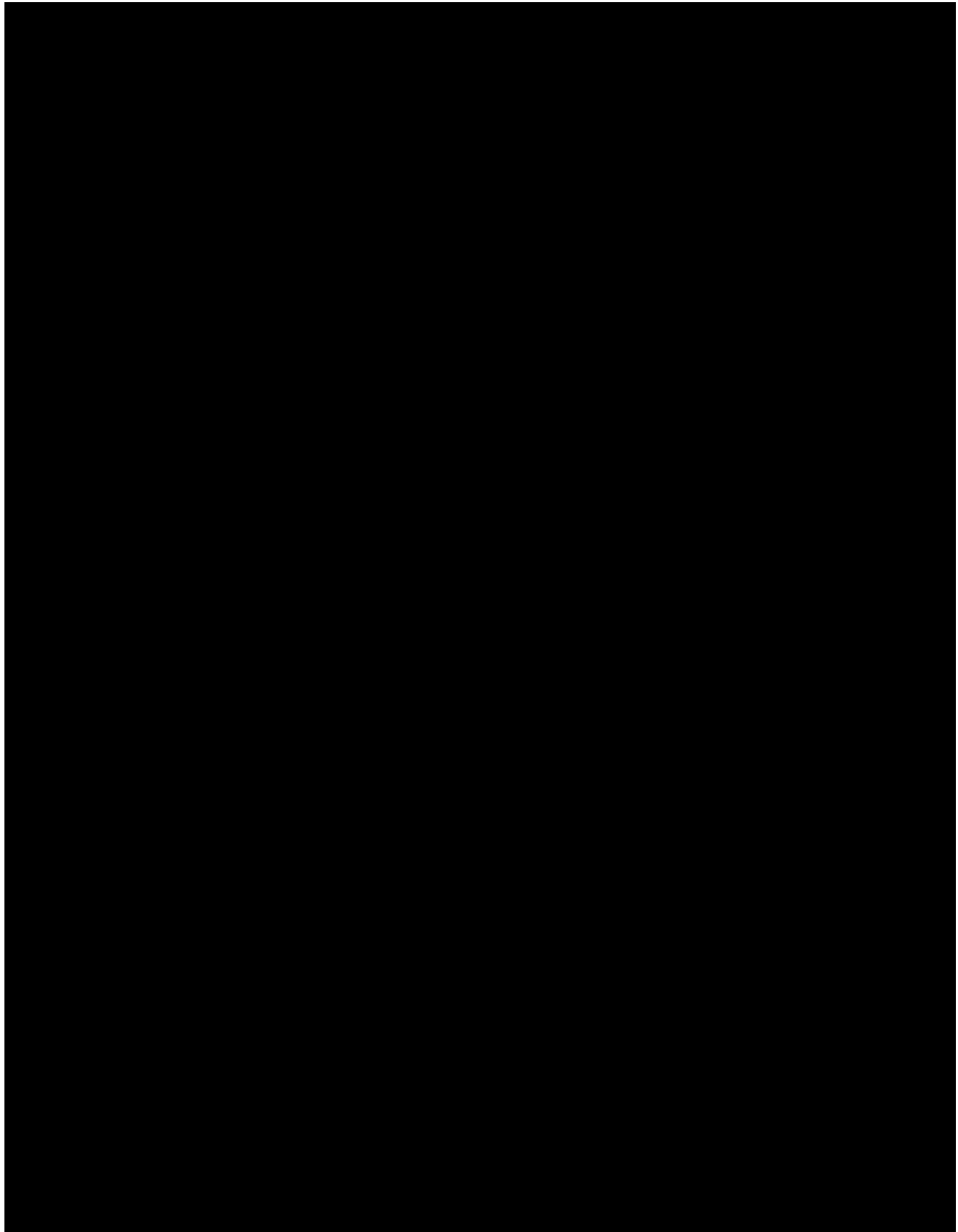


Figure 4-2 – Loblolly CCS No. 002 Wellbore Schematic

The drilling and completion design for Loblolly CCS No. 001 is as follows:

- Drive Pipe
 - [REDACTED]
- Surface Casing
 - To be set below the lowermost USDW
 - The USDW will be determined by means of openhole logging during drilling of the well. If necessary, the final setting depth will be adjusted.
 - The current estimated setting depth is [REDACTED] ft TVD.
 - [REDACTED] hole size
 - [REDACTED] outer diameter (OD) casing
 - Cemented to surface
- Production Casing
 - [REDACTED] hole size
 - [REDACTED] casing set to TD of well
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - Cemented to surface
 - Cement to be comprised of:
 - Corrosion-resistant cement across the UCZ, designed to be from [REDACTED]
 - [REDACTED]
 - [REDACTED]
- Completion Assembly
 - Subsurface safety valve [REDACTED]
 - [REDACTED] tubing from surface to [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - Tubing annulus will be filled with a noncorrosive fluid.
- Wellhead
 - Casing head assembly
 - [REDACTED]

- [REDACTED]
 - Tubing spool assembly
 - [REDACTED]
 - [REDACTED]
 - Production tree assembly
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]

The drilling and completion design for Loblolly CCS No. 002 is as follows:

- Drive Pipe
 - [REDACTED]
- Surface Casing
 - To be set below the lowermost USDW
 - The USDW will be determined by means of openhole logging during drilling of the well. If necessary, the final setting depth will be adjusted.
 - The current estimated setting depth is [REDACTED] ft TVD.
 - [REDACTED] hole size
 - [REDACTED] OD casing
 - Cemented to surface
- Production Casing
 - [REDACTED] hole size
 - [REDACTED] casing set to TD of well
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
 - Cemented to surface
 - Cement to be comprised of:
 - Corrosion-resistant cement across the UCZ, designed to be from [REDACTED]
 - [REDACTED]

- Completion Assembly
 - Subsurface safety valve
 - tubing from surface to
 -
 -
 -
 -
 -
 - Tubing annulus will be filled with a noncorrosive fluid.
- Wellhead
 - Casing head assembly
 -
 -
 -
 - Tubing spool assembly
 -
 -
 - Production tree assembly
 -
 -
 -
 -
 -
 -
 -
 -

A detailed drilling-and-completion prognosis is included in *Appendix D*.

4.2.1 Detailed Discussion of Injection Well Design

Evergreen plans to inject a maximum volume of CO₂ injectate of per year (MMT/yr) into the proposed Frio sand stages. The well designs consider the properties of the injectate, rate of injection, and injection pressures determined during the reservoir modeling and were factored into the selection of the production and tubing size, weight, and grades. Table 4-3 shows the standard conditions of CO₂ used in the modeling and flow calculations.

Table 4-3 – Estimated CO₂ Pipeline Conditions

*psia – pounds per square inch absolute
lbm – pound mass | ft³ – cubic foot

A sensitivity analysis was run for the tubing design that considered calculated pipe-friction losses, exit velocities, compression requirements, and economic evaluations. The reservoir-engineering model runs were used to calculate the bottomhole pressures (BHPs), as shown in Figures 4-3 and 4-4 for Loblolly CCS No. 001 and No. 002, respectively. The model outputs identified when the maximum BHP will occur during the life of the project and the resulting maximum flowing pressure at surface—allowing for proper design of the casing, tubing, and wellhead configurations.

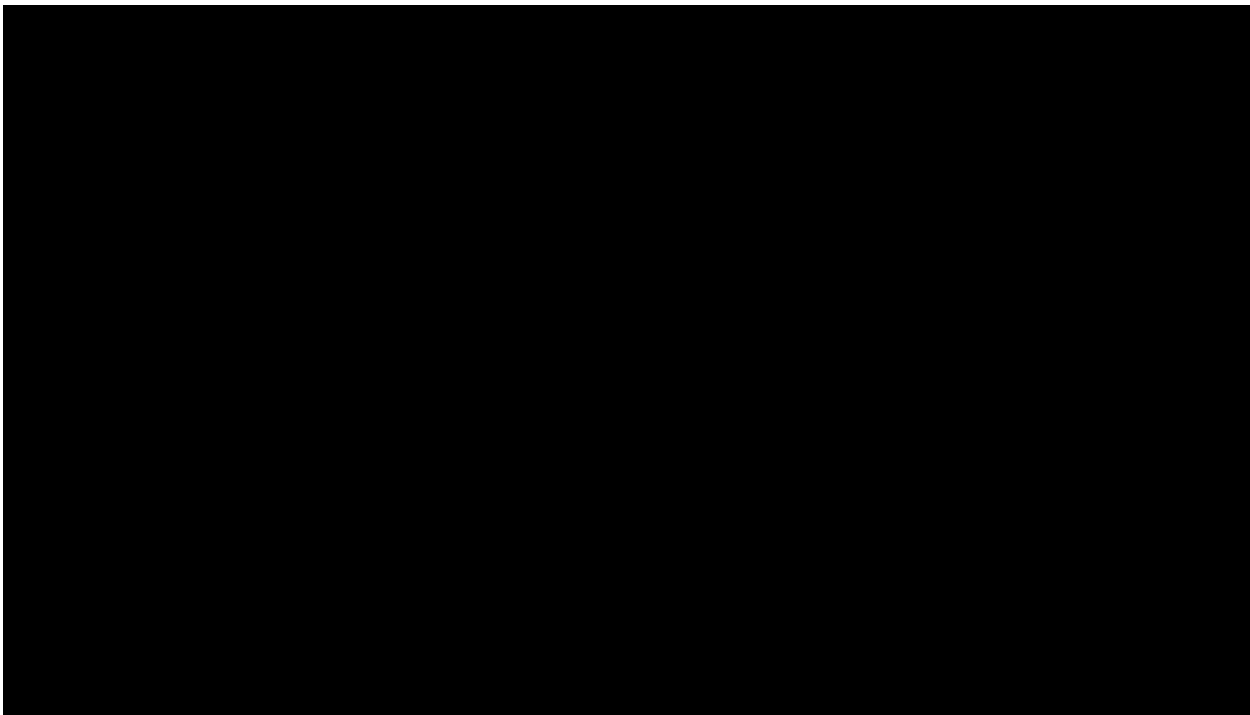


Figure 4-3 – Injection Pressure Plot for Loblolly CCS No. 001

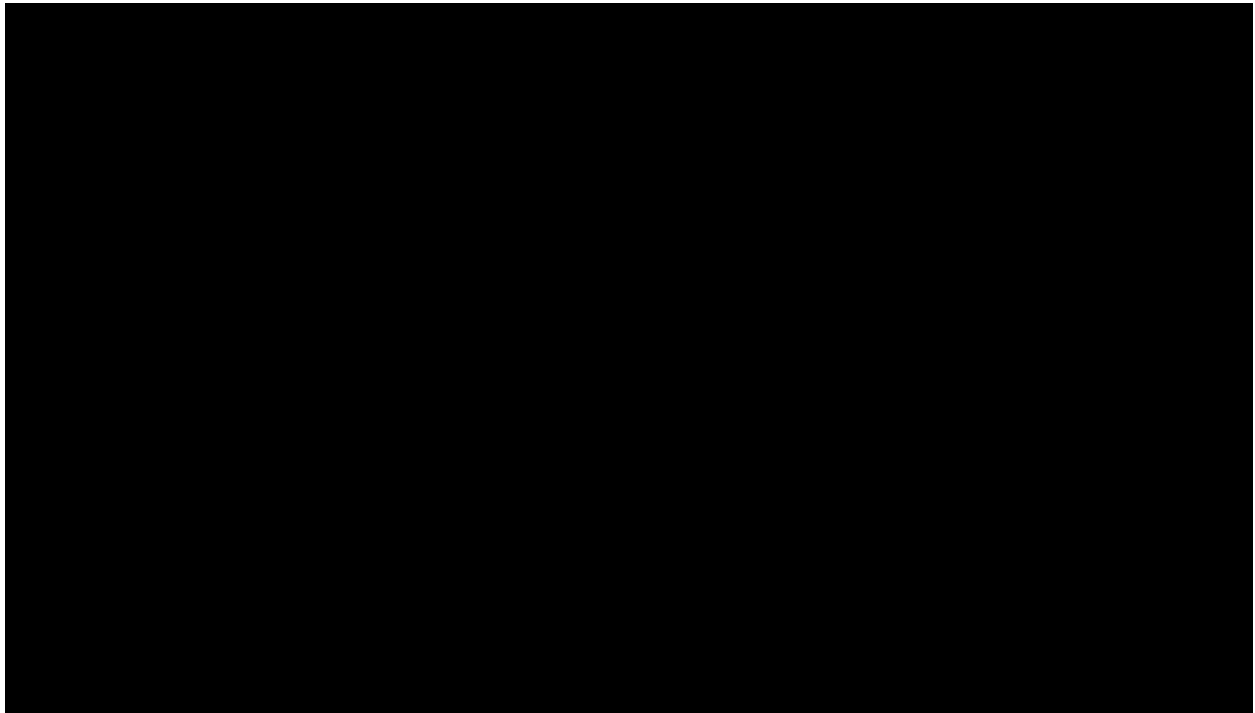


Figure 4-4 – Injection Pressure Plot for Loblolly CCS No. 002

[REDACTED]

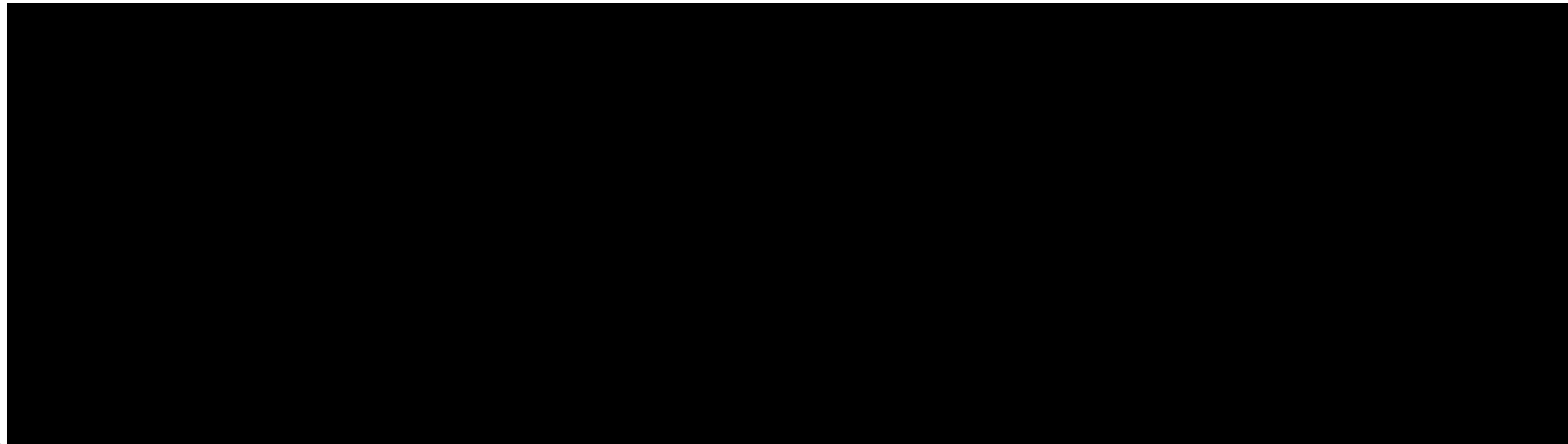
The input injection parameters from the model for both injection wells are shown in Table 4-4. The calculated injection parameters are then shown in Tables 4-5 and 4-6 for Loblolly CCS No. 001 and No. 002, respectively.

Table 4-4 – Input Injection Parameters for Loblolly CCS No. 001 and No. 002

Inputs	Loblolly CCS No. 001	Loblolly CCS No. 002
Max Injection Rate (MMT/yr)	[REDACTED]	
Pressure Constraint Gradient (psi/ft)	[REDACTED]	
Injection Duration (yrs)	[REDACTED]	[REDACTED]
[REDACTED] Tubing Inner Diameter (ID) (in.)	[REDACTED]	
Absolute Roughness Factor	[REDACTED]	
Wellhead Temperature (°F)	[REDACTED]	

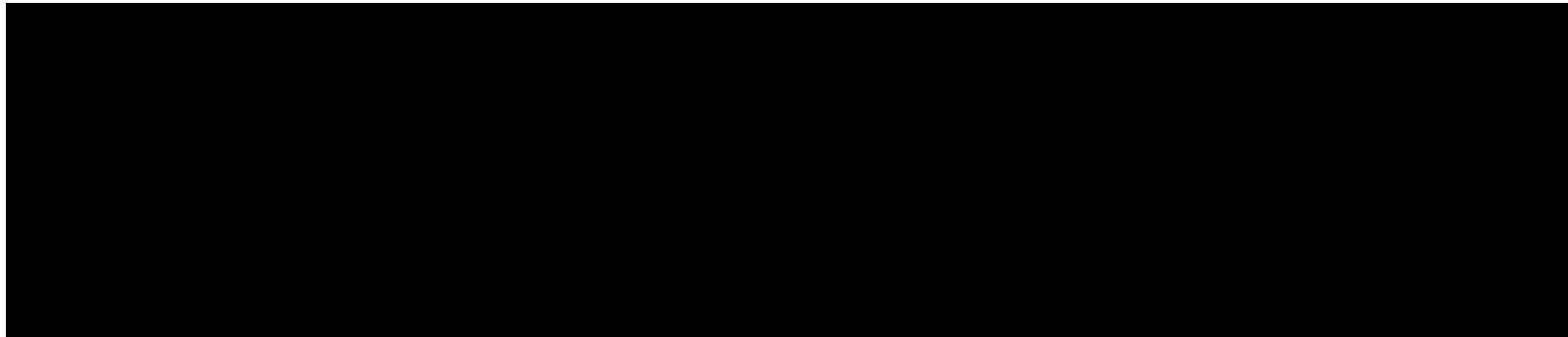
*psi/ft – pounds per square inch per foot

Table 4-5 – Calculated Injection Parameters for Loblolly CCS No. 001

A large black rectangular box redacting the content of Table 4-5.

*WHP – wellhead pressure

Table 4-6 – Calculated Injection Parameters for Loblolly CCS No. 002

A large black rectangular box redacting the content of Table 4-6.

Based on the inputs and results from the model, a [REDACTED] for both Loblolly CCS No. 001 and No. 002 is the appropriate size to move the desired volumes [REDACTED] into the formation. [REDACTED]

Based on the appropriate selection of bit size, pipe-clearance requirements, and recommended annular spacing for assurance of proper cementing, the following casing sizes were selected to accommodate the [REDACTED] design:

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

4.2.1.1 Conductor Pipe

Due to the loose, unconsolidated nature of sediment near the surface, a conductor pipe will be required to maintain the integrity of the hole during the initial drilling phase of Loblolly CCS No. 001 and No. 002. A [REDACTED] conductor pipe will be used for this purpose.

The criteria for the conductor pipe is based on the required clearance for the surface casing borehole. With the conductor pipe having an ID of [REDACTED], a [REDACTED] bit can be used to clean out the conductor pipe and drill the following section of the well to a depth of [REDACTED] ft for Loblolly CCS No. 001 and [REDACTED] ft for Loblolly CCS No. 002.

The engineering and design parameters for the selected conductor pipe are summarized in Table 4-7:

Table 4-7 – Parameters for the Selected Conductor Pipe – Loblolly CCS No. 001 and No. 002

Conductor Pipe								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			

*ppf – pounds per foot
 bbl/ft – barrels per foot
 ppg – pounds per gallon

4.2.1.2 Surface Casing

The surface hole for Loblolly CCS No. 001 and No. 002 will be drilled to below the USDW at +/- [REDACTED] ft and +/- [REDACTED] ft, respectively, at a minimum of [REDACTED] ft below the base defined for the USDW. The holes will be drilled and completed using a [REDACTED] in. bit and a [REDACTED] in. casing to allow sufficient annular space for consistent thickness of cement between the surface casing hole and the open hole. A series of centralizers will be installed on the surface casing strings for Loblolly CCS No. 001 and No. 002 to ensure cement will be circulated to surface and, if necessary, a top job performed—should the top-of-cement level fall after the cement is circulated. This will provide a cement barrier along the surface casing from the shoe to surface and protect the critical USDW. Following cementing operations, a cement bond log will be run to evaluate and verify bonding throughout the surface holes.

The engineering and design parameters for the surface casing of the two Loblolly injection wells are summarized in Tables 4-8 through 4-17:

Table 4-8 – Surface Casing Engineering Calculations – Loblolly CCS No. 001

Surface Casing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)

Table 4-9 – Surface Casing Engineering Calculations – Loblolly CCS No. 002

Surface Casing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)

Table 4-10 – Surface Casing Annular Geometry – Loblolly CCS No. 001

Annular Geometry			
Section	ID	MD	TVD
	(in.)	(ft)	(ft)
Drive Pipe			
Open Hole			

Table 4-11 – Surface Casing Annular Geometry – Loblolly CCS No. 002

Annular Geometry			
Section	ID	MD	TVD
	(in.)	(ft)	(ft)
Drive Pipe	■	■	■
Open Hole	■	■	■

Table 4-12 – Surface Casing Specifications – Loblolly CCS No. 001

Casing					
Section	OD	ID	Weight	MD	TVD
	(in.)	(in.)	(lb/ft)	(ft)	(ft)
Surface	■	■	■	■	■

Table 4-13 – Surface Casing Specifications – Loblolly CCS No. 002

Casing					
Section	OD	ID	Weight	MD	TVD
	(in.)	(in.)	(lb/ft)	(ft)	(ft)
Surface	■	■	■	■	■

Table 4-14 – Surface Casing Cement – Loblolly CCS No. 001

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Lead	█	██	██
Tail	██	██	██

*cf – cubic foot

Table 4-15 – Surface Casing Cement – Loblolly CCS No. 002

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Lead	█	██	██
Tail	██	██	██

Table 4-16 – Surface Casing Detail Cement – Loblolly CCS No. 001

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Drive Pipe/Casing Annulus Lead Cement	██	██	█	██
Open Hole/Casing Annulus Lead Cement	██	██	██	██
Open Hole/Casing Annulus Tail Cement	██	██	██	██
Shoe Track	█	██	█	█

*cf/ft – cubic feet / foot

Table 4-17 – Surface Casing Detail Cement – Loblolly CCS No. 002

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Drive Pipe/Casing Annulus Lead Cement	██	██	█	██
Open Hole/Casing Annulus Lead Cement	██	██	██	██
Open Hole/Casing Annulus Tail Cement	██	██	██	██
Shoe Track	█	██	█	█

To ensure cement is circulated to surface, 100% excess relative to the gauge hole is used in the openhole cement volume calculations. Excess cement volumes may be adjusted based on the openhole caliper log.

4.2.1.3 Production Casing

The production casing, or long-string casing, is the final, permanently cemented string of casing installed in the well. The production casing will be run from the surface to TD and cemented back to surface. The key design criteria for the production casing string includes the following:

- The use of [REDACTED] across the UCZ
- The use of downhole tools, including centralizers, float equipment, a PBR, and galvanic crossovers
- [REDACTED]
- [REDACTED]
- [REDACTED]
- The use of corrosion-resistant cement or equivalent across the UCZ

A detailed metallurgical analysis, which incorporates the detailed composition of the CO₂ injectate at downhole conditions, was performed and is included in *Appendix D*. Based on the analysis of the injectate stream and downhole conditions, the production casing will be [REDACTED] material across the UCZ to prevent corrosion and downhole failures at the base and across the confining zone.

To prevent CO₂ migration above the injection zone, corrosion-resistant cement will be run from the base of the UCZ to the top of the UCZ. By using corrosion-resistant material, the cement barrier is resistant to carbonic acid, thereby maintaining the integrity of the confinement zone throughout the life of the project. Figures 4-1 and 4-2 (*Section 4.2*) illustrate the production casing design.

The gross formation thickness of the injection zone at Loblolly CCS No. 001 and No. 002 is approximately [REDACTED] thick, respectively. The sands within the Frio Formation are interbedded with layers of shale that will provide intermediate traps for the CO₂ injectate below the UCZ. [REDACTED]

[REDACTED] The CO₂ injectate will be injected for a predetermined amount of time or volume, derived from the reservoir-injection plume model.

[REDACTED] This strategy allows for efficient and economic recompletion operations, as a workover rig will not be necessary to remove and reset completion equipment. The process will be repeated throughout the life of the well until the uppermost sand completion stage is completed.

Throughout the life of the project, a continuous monitoring system will be in place. [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED] To ensure the integrity of the monitoring equipment, perforations will be oriented away from the monitoring equipment placed on the backside of the casing.

The engineering and design parameters for the production casing are summarized in Tables 4-18 through 4-27.

Table 4-18 – Production Casing Engineering Calculations – Loblolly CCS No. 001

Production Casing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			

Table 4-19 – Production Casing Engineering Calculations – Loblolly CCS No. 002

Production Casing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			
[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]			

Table 4-20 – Production Casing Annular Geometry – Loblolly CCS No. 001

Annular Geometry			
Section	ID	MD	TVD
	(in.)	(ft)	(ft)
Surface Casing	████	████	████
Open Hole	████	████	████
Open Hole	████	████	████

Table 4-21 – Production Casing Annular Geometry – Loblolly CCS No. 002

Annular Geometry			
Section	ID	MD	TVD
	(in.)	(ft)	(ft)
Surface Casing	████	████	████
Open Hole	████	████	████
Open Hole	████	████	████

Table 4-22 – Production Casing Specifications – Loblolly CCS No. 001

Casing					
Section	OD	ID	Weight	MD	TVD
	(in.)	(in.)	(lb/ft)	(ft)	(ft)
████	████	████	████	████	████
████	█	████	█	████	████

Table 4-23 – Production Casing Specifications – Loblolly CCS No. 002

Casing					
Section	OD	ID	Weight	MD	TVD
	(in.)	(in.)	(lb/ft)	(ft)	(ft)

Table 4-24 – Production Casing Cement – Loblolly CCS No. 001

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Stage 2 Lead			
Stage 2 Tail			
Stage 1			

Table 4-25 – Production Casing Cement – Loblolly CCS No. 002

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Stage 2 Lead			
Stage 2 Tail			
Stage 1			

Table 4-26 – Production Casing Detail Cement – Loblolly CCS No. 001

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Section 1	100	1.5	15	1500
Section 2	120	1.8	18	2160
Section 3	150	2.2	22	3300
Section 4	180	2.5	25	4500
Section 5	200	3.0	30	6000

Table 4-27 – Production Casing Detail Cement – Loblolly CCS No. 002

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Section 1	100	1.5	15	1500
Section 2	120	1.8	18	2160
Section 3	80	1.2	12	960
Section 4	90	1.4	14	1260
Section 5	110	1.6	16	1760

To ensure cement is circulated to surface, 30% excess relative to the gauge hole is used in the openhole cement volume calculations. Excess cement volumes may be adjusted based on the openhole caliper log.

4.2.1.4 Centralizers

Centralizer selection and installation for Loblolly CCS No. 001 and No. 002 provide proper centralization of the casing in the borehole. [REDACTED]

[REDACTED] The recommended centralizer placement is as follows:

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

The centralizer design for the [REDACTED] production casing [REDACTED] is planned to ensure that a continuous, uniform cement column is set from TD to surface. The centralizers and [REDACTED] will be utilized as follows for Loblolly CCS No. 001 and No. 002, [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

4.2.1.5 Injection Tubing

The [REDACTED] injection tubing size and material for Loblolly CCS No. 001 and 002 were selected based on injection volume, injection rate, and injectate composition. The conditions that result from the combination of the injectate and formation fluids are important to consider for tubing selection. An [REDACTED] tubing string will be installed. The [REDACTED] corrosion resistance, and the tubing casing annulus will be continuously monitored during operation. [REDACTED]

Tables 4-28 and 4-29 provide the tubing design and calculations for Loblolly CCS No. 001 and No. 002.

Table 4-28 – Tubing Engineering Design Calculations – Loblolly CCS No. 001

Tubing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)

Table 4-29 – Tubing Engineering Design Calculations – Loblolly CCS No. 002

Tubing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)

4.2.1.6 Packer Assembly [REDACTED]

A [REDACTED] will be installed in the production casing at the [REDACTED] [REDACTED] at the base of the UCZ. The packer [REDACTED] will be run on a work string, [REDACTED] [REDACTED] Prior to engaging the packer seal assembly, the tubing annulus will be filled with noncorrosive fluid.

The proposed packer for Loblolly CCS No. 001 and No. 002 will be installed in the [REDACTED] casing. The flow-wetted components were selected to ensure the material is compatible with the expected CO₂ injection stream and formation fluids at downhole conditions.

Figure 4-5 provides a schematic of the packer [REDACTED]

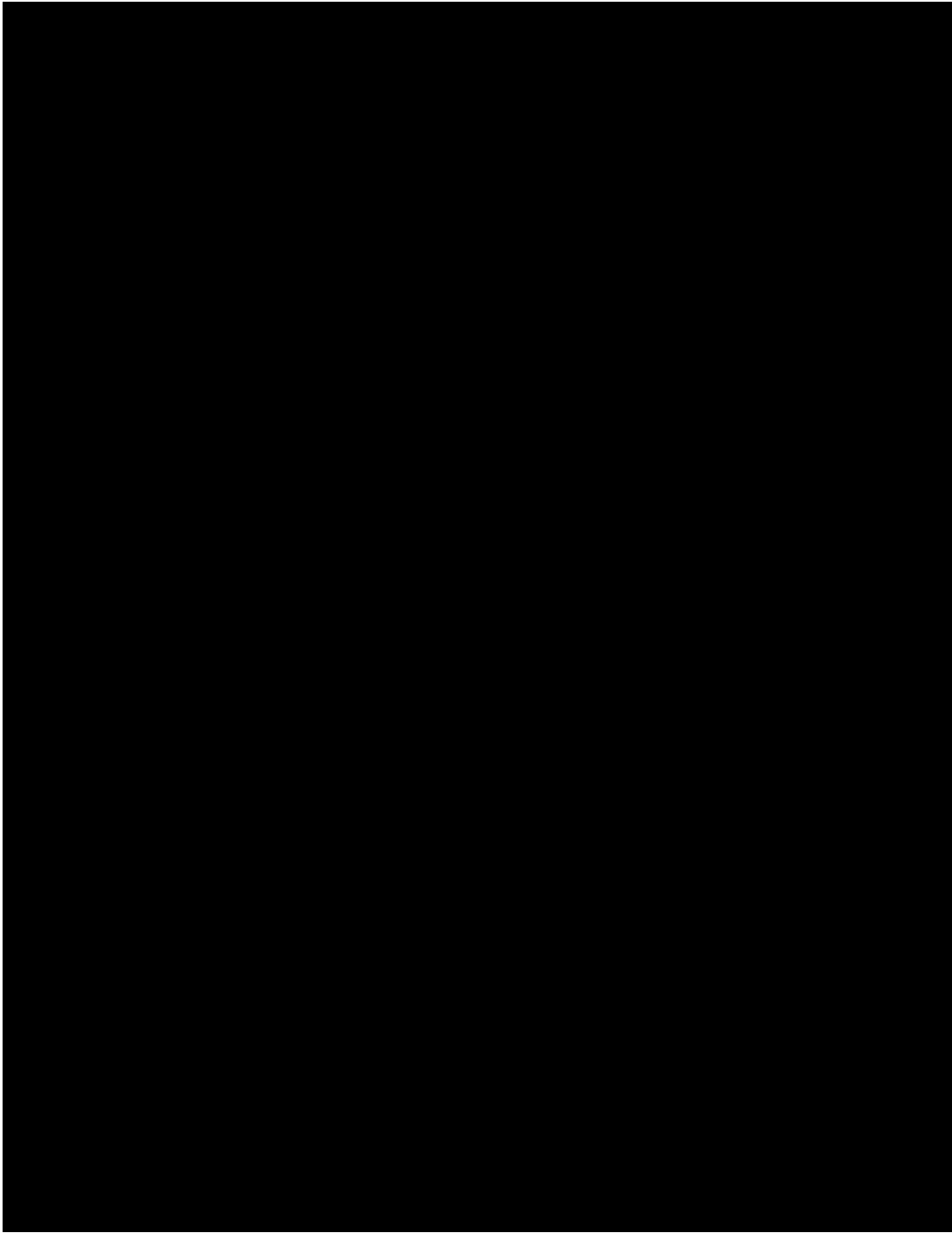


Figure 4-5 – Packer Assembly [REDACTED]

4.2.1.7 [REDACTED]

[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

4.2.1.8 Wellhead Discussion

The wellhead is designed to withstand working pressures and corrosion complications. The wellhead equipment will be manufactured with a combination of stainless steel and Inconel components across the tubing hanger, adapter spool and wellhead tree. Inconel lining will be placed across trims, stems, gates, valves, etc. The wellhead will be configured as illustrated in Figure 4-7.

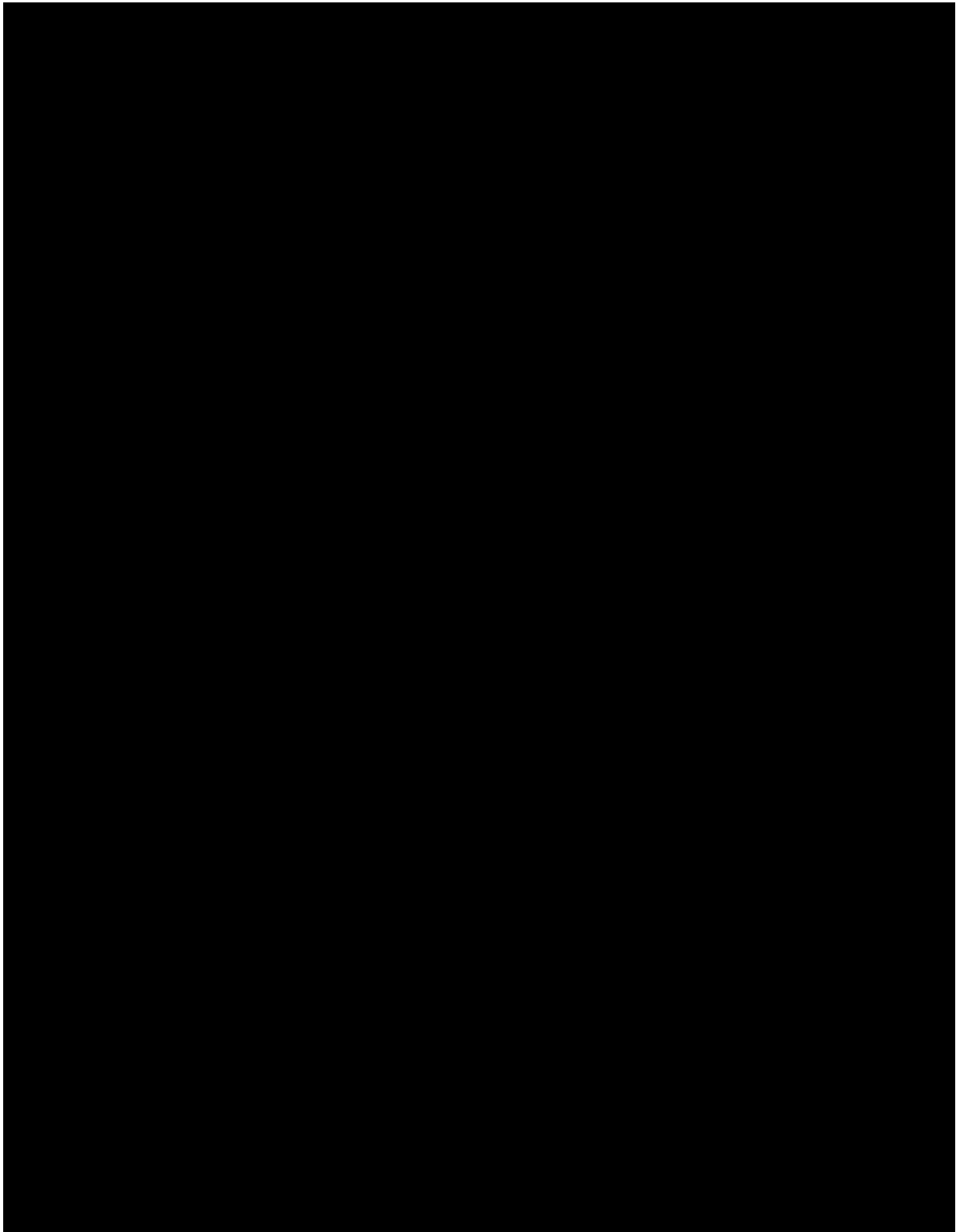


Figure 4-6 – Preliminary Wellhead Design – Loblolly CCS No. 001 and No. 002

4.3 Testing and Logging During Drilling and Completion Operations

4.3.1 Coring Plan



4.3.2 Logging Plan

An extensive suite of electric logs will be run in the openhole sections and in each string of casing. The openhole logging plan is detailed in Tables 4-30 and 4-32 for Loblolly CCS No. 001 and Loblolly CCS No. 002, respectively. The cased-hole logging plan for both injection wells is detailed in Tables 4-31 and 4-33, respectively.

Table 4-30 – Openhole Logging Plan – Loblolly CCS No. 001

CARBON SEQUESTRATION / INJECTION WELL
Loblolly CCS No. 001
OPENHOLE LOGGING PLAN

Trip	Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	Depths of Survey
1	Surface Casing				
2					
3					
4	Production Casing				
5					

6		[REDACTED] [REDACTED] [REDACTED] [REDACTED]	[REDACTED] [REDACTED] [REDACTED]		
7		[REDACTED] [REDACTED] [REDACTED] [REDACTED]	[REDACTED] [REDACTED] [REDACTED]		
8		[REDACTED] [REDACTED] [REDACTED] [REDACTED]	[REDACTED] [REDACTED] [REDACTED]	[REDACTED] [REDACTED]	[REDACTED] [REDACTED]
9		[REDACTED]	[REDACTED]		
10		[REDACTED]			
11		[REDACTED]			

[REDACTED]
[REDACTED]
[REDACTED]

Table 4-31 – Cased-Hole Logging Plan – Loblolly CCS No. 001

CARBON SEQUESTRATION / INJECTION WELL**Loblolly CCS No. 001****CASED-HOLE LOGGING PLAN**

Trip	Hole Section	Logging Suite	Target Data Acquisition	Casing Dimension	Depths of Survey
1	Surface Casing	██████████ ██████████ ██████████ ██████████	████████████████████	████████	████████ ████████
2	Production Casing	██████████ ██████████ ██████████ ██████████ ██████████	████████████████████	██████████ ██████████	████████ ████████
3		████████	████████████████		
4		████████████████	████████████████ ██████████ ████████████████		
5		████████████████	████████████████ ████████████████		
6		██████████	████████████████		
7	Tubing and Packer	████████████ ████████	████████████████ ████████████	████	████████ ████████

Table 4-32 – Openhole Logging Plan – Loblolly CCS No. 002

CARBON SEQUESTRATION / INJECTION WELL
Loblolly CCS No. 002
OPENHOLE LOGGING PLAN

Trip	Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	Depths of Survey
1	Surface Casing				
2					
3					
4	Production Casing				
5					

6		[REDACTED]	[REDACTED]				
		[REDACTED]	[REDACTED]				
		[REDACTED]	[REDACTED]				
		[REDACTED]	[REDACTED]				
7		[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]		
		[REDACTED]	[REDACTED]				
		[REDACTED]	[REDACTED]				
		[REDACTED]	[REDACTED]				
8		[REDACTED]	[REDACTED]			[REDACTED]	[REDACTED]
		[REDACTED]	[REDACTED]			[REDACTED]	[REDACTED]
		[REDACTED]	[REDACTED]				
	[REDACTED]	[REDACTED]					
9	[REDACTED]	[REDACTED]					
10	[REDACTED]						
11	[REDACTED]						

Table 4-33 – Cased-Hole Logging Plan – Loblolly CCS No. 002

CARBON SEQUESTRATION / INJECTION WELL**Loblolly CCS No. 002****CASED-HOLE LOGGING PLAN**

Trip	Hole Section	Logging Suite	Target Data Acquisition	Casing Dimension	Depths of Survey
1	Surface Casing	██████████ ██████████ ██████████ ██████████ ██████████	████████████████████	████████	████████ ████████
2	Production Casing	██████████ ████████ ████████ ██████████ ████████ ██████████	████████████████████	████████████████ ████████████████	████████ ████████
3		████████	████████████████		
4		████████████████	████████████████ ██████████ ████████████████		
5		████████████████	████████████████ ████████████████		
6		██████████	████████████████		
7	Tubing and Packer	████████████████ ████████	████████████████ ████████████████	████	████████ ████████

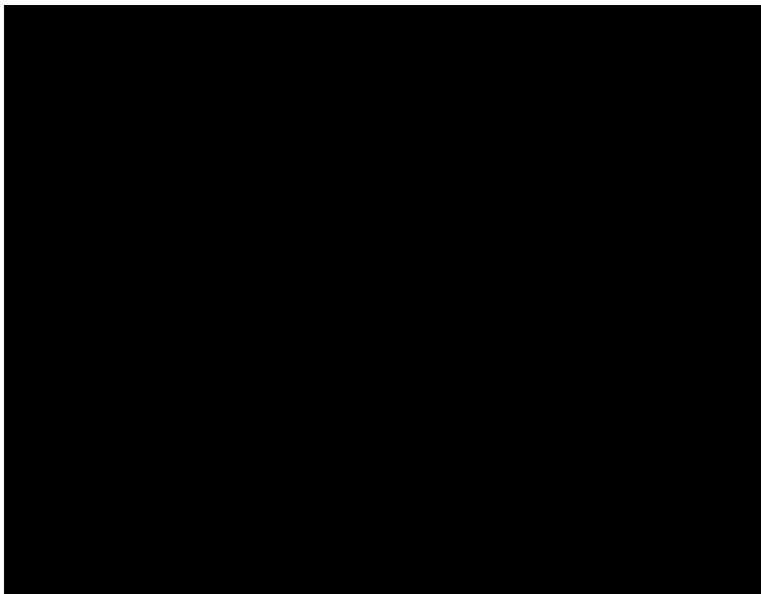
4.3.3 Formation Fluid Testing

Prior to setting the production casing, formation fluid samples will be collected from the injection zone. The fluid will be obtained through an openhole fluid recovery tool, and the sample intervals will be determined based on the openhole log evaluation.

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
[REDACTED]
[REDACTED]
 - [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
 - [REDACTED]
[REDACTED]
 - [REDACTED]
[REDACTED]
 - [REDACTED]
[REDACTED]

[REDACTED]

[REDACTED]



[REDACTED]

[REDACTED]

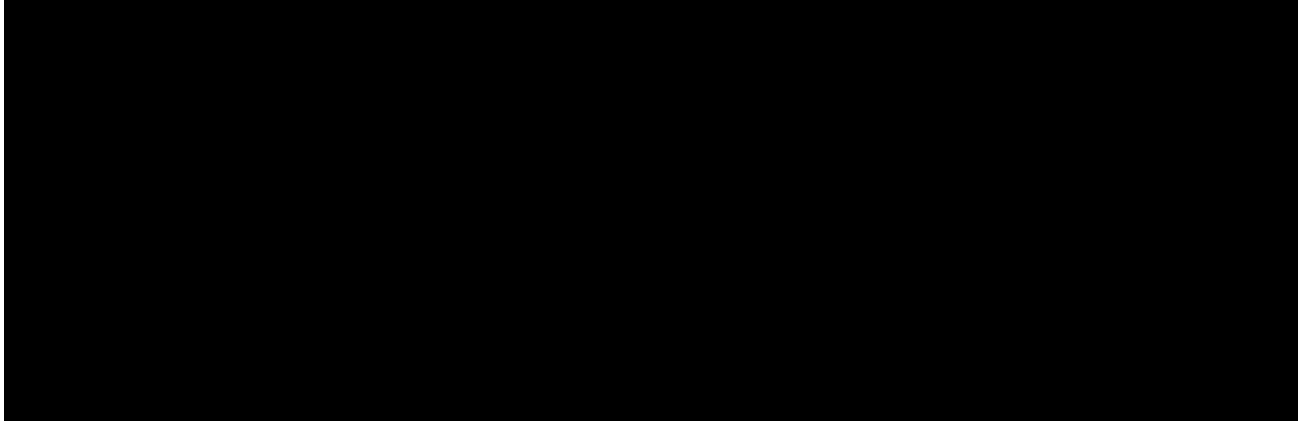
Evergreen plans to inject [REDACTED] of CO₂ in Loblolly CCS No. 001 and Loblolly CCS No. 002. The CO₂ injectate will remain in the supercritical state in the injection zone. The Frio Formation reservoir characteristics of high porosity and permeability will allow the pressure induced by the injection to be absorbed and dissipated within the reservoir. The surface and bottomhole injection pressures are provided in Table 4-35.

Parameter	Loblolly CCS No. 001	Loblolly CCS No. 002
Gross Injection Zone		
Maximum Injection Volume		
Average Injection Volume		
Maximum Increase in BHP		
Maximum Allowed Surface Pressure (90% of Estimated Fracture Gradient)		
Modeled Maximum Surface Pressure Injection		
Maximum Annular Pressure		

Table 4-36 – Injection Pressures and Volumes by Stage – Loblolly CCS No. 001

[illegible]

Table 4-37 – Injection Pressures and Volumes by Stage – Loblolly CCS No. 002

A large black rectangular box redacting the content of Table 4-37.

The wells will be completed in multiple completion stages to occupy the available pore space most effectively. The pre-defined completion stages were selected to maximize storage capacity and the use of the acreage position for the project. A summary table of the planned injection strategy for both Loblolly CCS No. 001 and No. 002 is displayed in Tables 4-38 and 4-39, respectively.

Table 4-38 – Completion Stages – Loblolly CCS No. 001

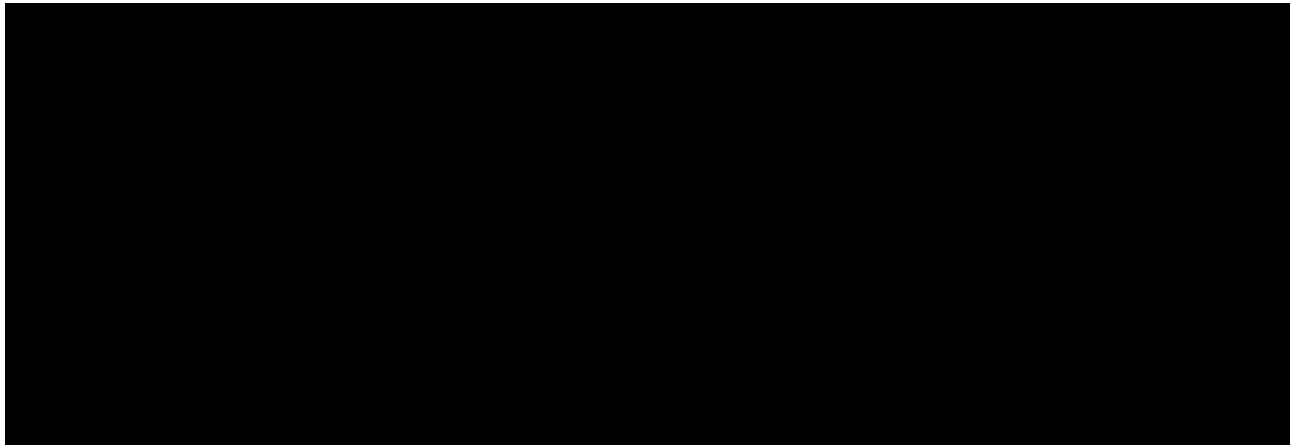
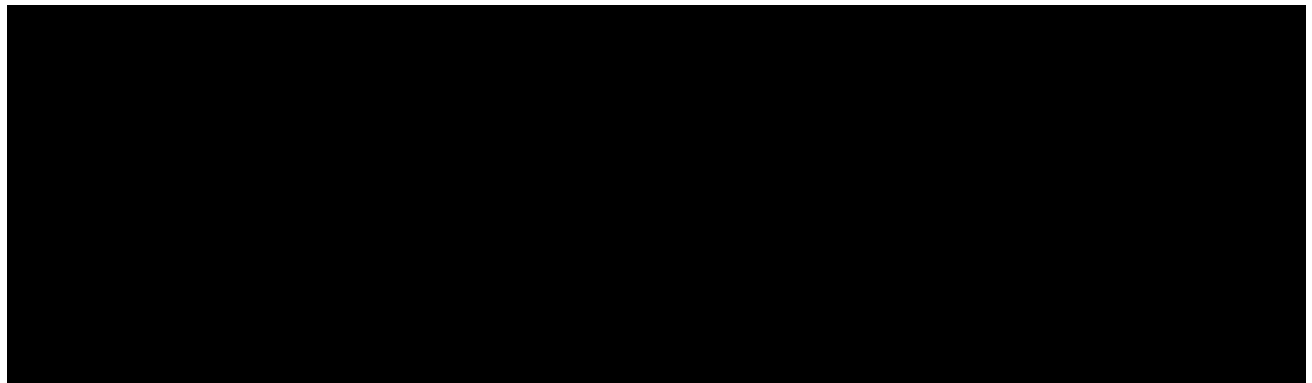
A large black rectangular box redacting the content of Table 4-38.

Table 4-39 – Completion Stages – Loblolly CCS No. 002

A large black rectangular box redacting the content of Table 4-39.

Typical densities for the injectate range from [REDACTED] in the shallowest completion stage to [REDACTED] in the deepest completion stage. This is compared to approximately [REDACTED] for the connate brine in the same formations. This density difference and the high vertical permeability in the Frio sands allow the CO₂ to migrate vertically to the top of each discrete completion stage—and laterally under the confining layer of that completion stage.

In a simplified homogeneous model, this results in a significant “mushroom cap” effect, with the top of the mushroom expanding outwardly from the injection well. This effect is generally depicted in Figure 4-8. Site-specific data will be collected from a stratigraphic test well that will provide greater insight into the heterogeneity of the rock and vertical migration of the CO₂.

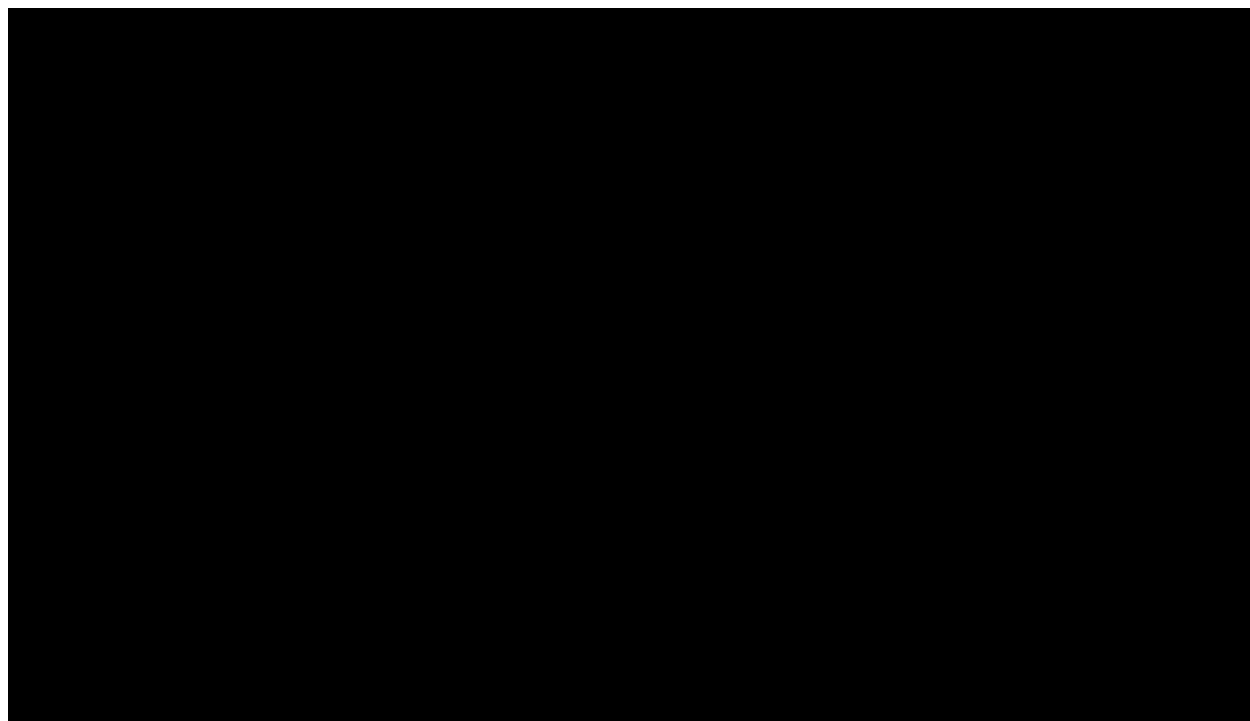


Figure 4-7 – Typical Plume Profile in High Permeability Formations

To maximize the utilization of pore space, discrete completion stages must be identified. Through modeling of injection in the reservoir, a CO₂ plume model was built based on the well-specific completion strategy. From that strategy, a plume map and pressure front map were generated and used to determine the lateral extent of the plume, which were then used to confirm the ownership of the pore space that will be impacted by the CO₂ plume.

[REDACTED]

4.5 Injection Well Construction and Operation Summary

The Loblolly CCS No. 001 and Loblolly CCS No. 002 wells were engineered to meet UIC standards and to protect the USDW and mitigate the risks associated with Class VI wells. The well design, casing, set points, materials, and cement meet the requirements for this classification of injection well, and offer efficient use of pore space and time associated with operating the wells.

The proximity to CO₂ emitters in the Gulf Coast region, available reservoir storage, and plume orientation in relation to acreage boundaries make the location of Loblolly CCS No. 001 and No. 002 ideal for carbon sequestration purposes. Combining the best engineering practices in design of the well with a state-of-the-art monitoring system and extensive reservoir management strategy, these wells will safely serve the state of Louisiana for years to come.

Appendix D – Well Construction Schematics and Procedures:

- Appendix D-1 Drilling and Completion Prognosis – Loblolly CCS No. 001
- Appendix D-2 Drilling and Completion Prognosis – Loblolly CCS No. 002
- Appendix D-3 Drilling and Completion Wellbore Schematic – Loblolly CCS No. 001
- Appendix D-4 Drilling and Completion Wellbore Schematic – Loblolly CCS No. 002
- Appendix D-5 Recompletion Wellbore Schematic – Loblolly CCS No. 001
- Appendix D-6 Recompletion Wellbore Schematic – Loblolly CCS No. 002
- Appendix D-7 Cement Program – Loblolly CCS No. 001
- Appendix D-8 Cement Program – Loblolly CCS No. 002
- Appendix D-9 [REDACTED]
- Appendix D-10 [REDACTED]



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 5 – TESTING AND MONITORING PLAN

February 2024



SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

This section includes the proposed Testing and Monitoring Plan for the Evergreen Sequestration Hub, LLC (Evergreen) Loblolly CCS No. 001 and No. 002 wells. The plan includes robust testing and monitoring programs that satisfy the requirements of Statewide Order (SWO) 29-N-6 **§3625.A** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**]. This plan will start before the injection of CO₂ commences. Monitoring strategies are designed to ensure and verify protection of the Underground Sources of Drinking Water (USDWs). These strategies consider, but are not limited to, the injection-stream composition, wellhead conditions, bottomhole operating parameters, seismic imaging for plume evolution, well integrity, and the above-zone confinement conditions. The location and information for all new monitoring wells are included, as are the parameters to be measured at each location. [REDACTED]

[REDACTED] The monitoring activities described in this plan will be carried out during the entirety of the life of the injection wells, including the post-injection site care (PISC) phase. These activities will follow a predetermined timeline tailored toward verifying that the observed plume development is according to modeling expectations, as well as demonstrating that the injected CO₂ is not endangering a USDW.

5.2 Reporting Requirements

In compliance with SWO 29-N-6 **§3629.A** [40 CFR **§146.91**], Evergreen will provide routine reports to the Commissioner of Conservation (Commissioner). The report contents and submittal frequencies are described below:

- Any noncompliance with a permit condition, or malfunction of the injection system that may cause fluid migration into or between USDWs
 - Verbal Notification – Reported within 24 hours of event
- Any evidence that the injected CO₂ stream or associated pressure front may cause an endangerment to a USDW
 - Verbal Notification – Reported within 24 hours of event
- Any failure to maintain mechanical integrity
 - Verbal Notification – Reported within 24 hours of event
- Any changes to the physical, chemical, and other relevant characteristics of the CO₂ stream from what has been described in the proposed operating data
 - Written Notification – Reported within 72 hours of composition change
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
 - Verbal Notification – Reported within 24 hours of event
 - Written Notification – Reported within 72 hours of event
- Description of any event that triggers a shut-off device either downhole or at the surface and the response taken
 - Verbal Notification – Reported within 24 hours of event

- Written Notification – Reported within 72 hours of event

Reports will include all contents and situations listed above, in addition to the following:

Semiannual Reports

- Monthly annulus fluid volume added
- Raw operating data from the continuous recording devices, submitted in digital format
- Results of any monitoring as described here, throughout *Section 5*

Quarterly Reports

- Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure
- Monthly volume and/or mass of the CO₂ stream injected over the reporting period, and the volume injected cumulatively over the life of the project

Reports to be submitted within 30 days after the following events:

- Any well workover
- Any periodic tests of mechanical integrity
- Any test of the injection well conducted, if required by the Commissioner.

Notification to the Commissioner, in writing, 30 days in advance of:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of an injection well

Evergreen will submit all reports, submittals, and notifications to both the Environmental Protection Agency (EPA) and the Louisiana Department of Natural Resources (LDNR) and ensure that all records are retained throughout the life of the project. In accordance with SWO 29-N-6 **§3629.A.4.c** [40 CFR **§146.91(f)**], records for 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 SWO 29-N-6 **§3625.A.10** [40 CFR **§146.90(j)**], the Testing and Monitoring Plan will be reviewed and revised as necessary, at a minimum of every 5 years to incorporate collected monitoring data, operational data, and most recent area of review reevaluation. Plan amendments will also be submitted within 1 year of an area of review (AOR) reevaluation.

Amendments to the Testing and Monitoring Plan will further be submitted following any significant facility changes, such as the development of offset monitoring wells or newly-permitted injection wells within the AOR, on a schedule determined by the Commissioner. Finally, Plan amendments will be submitted as otherwise required by the Commissioner.

5.4 Testing Strategies

5.4.1 Initial Step-Rate Injectivity Test

Prior to the commencement of CO₂ injection, Evergreen will conduct a mini-fracture (“mini-frac”) injection test to verify the fracture pressure estimated during the formation evaluation process. This test will be performed [REDACTED] of Loblolly CCS No. 001 and No. 002 in compliance with SWO 29-N-6 §3617.B.4.a [40 CFR §146.87(d)(1)] and SWO 29-N-6 §3617.B.5.c [40 CFR §146.87(e)(3)]. The details of the step-rate test are provided in *Section 4.3.4*.

5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with SWO 29-N-6 §3627.A.2 [40 CFR §146.89(b)], Evergreen will ensure the mechanical integrity of the injection wells by performing an annulus pressure test after each well has been completed, prior to injection, and annually afterwards. An annulus pressure test will also be conducted after performing any well remedial work that involves unseating the tubing or packer. This pressure test specifically verifies the integrity of the annulus between the casing and tubing above the packer. During well construction and prior to completion, the casing will also be pressure tested to the maximum anticipated annulus-surface pressure, to verify its integrity. An agent of the Louisiana Office of Conservation must witness the annual pressure tests.

The annulus pressure tests are designed to demonstrate the mechanical integrity of the casing, tubing, and packer. These tests are conducted by pressuring the annulus to a minimum of 500 pounds per square inch gauge (psig) surface pressure. A block valve is then used to isolate the test-pressure source from the test-pressure gauge upon test initiation, with all ports into the casing annulus closed except the one monitored by the test-pressure gauge. [REDACTED]

[REDACTED]

[REDACTED]

All annulus pressure test results will be submitted to the LDNR Injection and Mining Division (IMD) on Form UIC-5 within 30 days of completion.

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times. More details regarding continuous monitoring are described in *Sections 5.5.1* and *5.5.2*.

5.4.3 External Mechanical Integrity Testing

Following the requirements of SWO 29-N-6 §3627.A.3 [40 CFR §146.89(c)], Evergreen will perform an annual external mechanical integrity test (MIT). [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] The proposed primary method has minimal environmental impact because the measurements are conducted remotely, using permanently available interrogators. This method avoids the need for an annual wireline mobilization in the sensitive wetlands of the project area.

[REDACTED]

All logs recorded during the external MIT will be submitted to the Commissioner within 30 days of log-run completion.

5.4.4 Pressure Falloff Testing

[REDACTED]

Evergreen will perform a required pressure falloff test [REDACTED] every 5 years, [REDACTED], to meet the requirements of SWO 29-N-6 §3625.A.6 [40 CFR §146.90(f)]. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] This test will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

5.4.4.1 Testing Method

The CO₂ injection rate and pressure will be held as constant as possible prior to the beginning of the falloff test, and data will be continuously recorded during testing. After the well is shut in, continuous pressure measurements will be taken with a downhole pressure gauge [REDACTED]

[REDACTED] The falloff period will end once the pressure-decay data plotted on a semi-log plot is a straight line, indicating that radial-flow conditions have been reached.

5.4.4.2 Analytical Methods

Near-wellbore conditions, such as the prevailing flow regimes, well skin, and hydraulic property and boundary conditions, will be determined through standard diagnostic plotting. This determination is 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 can be exposed by comparing pressure falloff tests performed prior to initial injection with later tests. The effects of two-phase flow effects will also be considered. 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.

All pressure falloff test results will be submitted to the IMD within 30 days of test completion.

5.4.4.3 Quality Assurance/Quality Control

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

5.4.5 **Cement Evaluation and Casing Inspection Logs**

A cement bond log will be run after the casing installation and the required cement-hardening time, to understand the cement's quality. [REDACTED]

[REDACTED] of the production casing after it is cemented. [REDACTED]

[REDACTED] The CIL will serve as the baseline survey for potential future repeat

surveys, [REDACTED] These repeat electromagnetic CILs will only be performed if one of the following occurs:

- Other monitoring measurements create concern about the integrity of the well's casing, and the technical determination is made that a repeat CIL is most suitable to address those concerns. [REDACTED]
[REDACTED]
- The Commissioner requests it.

Changes in the recorded [REDACTED] in such a repeat CIL can be analyzed to identify [REDACTED] addressing SWO 29-N-6 §3627.A.4 [40 CFR §146.89(d)].

5.5 Monitoring Programs

5.5.1 Continuous Injection Stream Physical Monitoring

Evergreen will ensure continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with SWO 29-N-6 §3625.A.2 [40 CFR §146.90(b)]. A Supervisory Control and Data Acquisition (SCADA) system facilitates the operational data collection and monitoring for the full sequestration site, consisting of the pipeline, the injection wells, and the above-zone monitoring interval (AZMI) monitoring wells.

The injected CO₂ stream pressure will be continuously monitored in the CO₂ piping near the pipeline-wellhead interface. The annulus pressure will also be continuously recorded at the wellhead. [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED] A highly accurate [REDACTED] will measure the mass flow rate in the pipeline that connects to the injection wells. Each of the injection wells will also have its own [REDACTED] to quantify the partitioning of the flow between the two injectors.

5.5.1.1 Analytical Methods

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

5.5.2 Continuous Injection Stream Composition Monitoring

Under SWO 29-N-6 **§3625.A.1** [40 CFR **§146.90(a)**], Evergreen will determine the chemical composition of the injection stream with the objective of understanding potential interactions between CO₂ and other injectate components, as well as with the wellbore materials. This determination is accomplished by quarterly sampling of the injection stream and subsequent laboratory analysis.

5.5.2.1 Sampling Methods

The quarterly measurements are obtained by extracting samples from the injection stream at a location where the composition is representative for the injection well. The samples are subsequently sent to a laboratory for analysis.

5.5.2.2 Parameters Measured

Table 5-1 lists the injection stream parameters that will be measured, plus the frequency and methods used.

Table 5-1 – Injection Stream Measurements

Parameter/Analyte	Frequency	Method
Pressure	Continuous	Pressure gauges at wellhead (downstream of choke) and downhole
Temperature	Continuous	Temperature gauges in pipeline and downhole
pH	Quarterly	Lab analysis
Water (lb/MMscf)	Quarterly	Lab analysis
Oxygen (%)	Quarterly	Lab analysis
Methane (%)	Quarterly	Lab analysis
Other Hydrocarbons (%)	Quarterly	Lab analysis
Hydrogen Sulfide (ppm)	Quarterly	Lab analysis

*MMscf – million standard cubic feet

ppm – parts per million

5.5.3 Corrosion Coupon Monitoring

Monitoring of potential corrosion to the well tubing and casing materials will be conducted in adherence to SWO 29-N-6 **§3625.A.3** [40 CFR **§146.90(c)**]. A quarterly evaluation of a corrosion coupon monitoring system, implemented by Evergreen, will be performed to meet this requirement. A corrosion coupon station or rack is provided as part of monitoring well-materials integrity. Multiple coupons will be exposed to the stream composition to provide ongoing

evaluation of materials compatibility. Results will be reported to the Commissioner semiannually.

5.5.3.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection tubing and production casing, will be exposed to the conditions of the pipeline's CO₂ flow. The coupons will be removed on a quarterly schedule and examined for corrosion per American Society for Testing and Materials (ASTM) standards for corrosion testing evaluation. The coupons, once removed, will be visually inspected for signs of corrosion, including pitting, and measured for weight and size each time they are removed. The corrosion rate will be estimated by applying a weight-loss calculation method that divides the weight loss recorded during the exposure period by the period duration.

5.5.4 Fluid Quality Monitoring

Fluid samples will be taken periodically from the USDW and AZMI monitoring wells.

The USDW monitoring wells will target the deepest USDW formation with [REDACTED]. This sampling frequency is for the pre-injection phase and will characterize any potential seasonal fluctuation in the USDW. After the initial phase, the sampling will become annual, with the optimal season of data collection determined by analysis of the [REDACTED].

The AZMI monitoring wells will provide complementary leakage-detecting monitoring measurements with fluid sampling in the first permeable formation above the upper confining zone (UCZ). This formation is referred to as the AZMI. This interval has no expected seasonal variation. Therefore, sampling this formation—only if required from the start of the project—will provide sufficient resolution for analysis.

Table 5-2 summarizes the parameters analyzed and the planned sampling frequency, which apply to all USDW and AZMI wells. Anomalous measurements will initiate further studies, including a more detailed analysis of existing data to understand the potential cause of the variation. This analysis could take the form of geochemical modeling and review of trends observed in samples collected from all wells prior to the anomalous measurement.

These studies could also include integration with other measurements, such as time-lapse seismic and AZMI pressure measurements, as described in *Sections 5.5.8* and *5.5.6*, respectively. If this study does not satisfactorily rule out the leakage scenario, further acquisition of contingency data will be considered. The options include acquiring another fluid sample to verify the original measurement, or taking complementary measurements, such as a repeat cased-hole wireline log in the injector. Details of the USDW and AZMI sample-collection strategies are discussed in *Sections 5.5.5* and *5.5.6*, respectively.

Table 5-2 – USDW and AZMI Monitoring Well Sampling Program During the Injection Phase

Parameter/Analyte	USDW Well Frequency	AZMI Well Frequency
Total dissolved solids, alkalinity, electrical conductivity, temperature, pH	Pre-injection: Quarterly After injection initiation: Annually	Only if required by the Commissioner, or if warranted by a material change in other monitored parameters
Gas composition (CO ₂ , CH ₄ , C ₂₊ , O ₂ , N ₂)		
Dissolved cations (i.e., Ba, Ca, Fe, Mg, Mn, Na, other relevant metals)		
Dissolved anions (i.e., HCO ₃ Br, Cl, F, SO ₄)		

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

5.5.4.1 Analytical Methods

Evergreen will test the fluid samples and maintain results for the parameters listed in Table 5-2. If results indicate the existence of impurities in the injection stream, the diagnostic power of these constituents 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.

Potential geochemical signs that fluid may be leaking from the injection interval may be detected upon observation of the following trends:

- Material change in total dissolved solids (TDS)
- Material change in signature of major cations and anions
- Material increase in carbon dioxide concentration
- Material decrease in pH
- Material increase in concentration of injectate impurities
- Material increase in concentration of leached constituents

5.5.4.2 Laboratory to Be Used/Chain of Custody Procedures

The analysis of the fluid samples will be submitted to the IMD through a state-approved laboratory. Evergreen will observe standard chain-of-custody procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including any problems encountered.

5.5.4.3 Quality Assurance and Surveillance Measures

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

5.5.4.4 Plan for Guaranteeing Access to All Monitoring Locations

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

5.5.5 USDW Monitoring Wells

To comply with SWO 29-N-6 §3625.A.4 [40 CFR §146.90(d)], [REDACTED] USDW monitoring well will be drilled into the deepest USDW sand, and [REDACTED] monitor the deepest USDW sand to support the Evergreen Project. The deepest USDW formation is defined by [REDACTED] feet (ft) at the Evergreen Sequestration Hub. When the injection wells and USDW monitoring well are drilled, the USDW depth will be confirmed in each well through the collection of openhole wireline-resistivity logs.

These [REDACTED] USDW monitoring wells surround the injection wells and provide USDW-quality verification for the sequestration project. [REDACTED]

[REDACTED] Water samples will be collected from the USDW monitoring wells to monitor for signs of CO₂ or brine leakage. Figure 5-1 (*Section 5.5.5.1*) displays the monitoring well locations, which are also listed in Table 5-3 (also in *Section 5.5.5.1*).

The USDW monitoring wells are positioned to maximize the value of the information collected, using knowledge of the local hydrology and subsurface features that could potentially act as leakage pathways. [REDACTED] is positioned to the [REDACTED] of the injection wells,

[REDACTED] will be located in the preferential growth direction (i.e., updip) of the injected CO₂. These monitoring wells are therefore more likely to encounter CO₂ or its effects on the USDW chemistry if a leak does occur. [REDACTED]

5.5.5.1 Fluid Sampling Methods

Water samples will be collected from the USDW monitoring wells at the surface. Two well volumes will be purged to collect a pristine sample that represents the USDW water rather than water that has resided for a significant time in the wellbore. These water samples will be analyzed in the field for a variety of physical parameters, including temperature, pH, alkalinity, dissolved oxygen, and electrical conductivity, as these parameters are sensitive to alteration over time. Additional analyses include TDS, concentrations of cations, anions, CO₂, and CH₄. Samples for cations and anions will be collected in appropriate acid-washed bottles to eliminate possible contamination.

The fluid-sampling parameters and frequencies for the groundwater monitoring wells are shown in Table 5-2. Details regarding sampling techniques and processes are explained in *Section 5.5.4*.

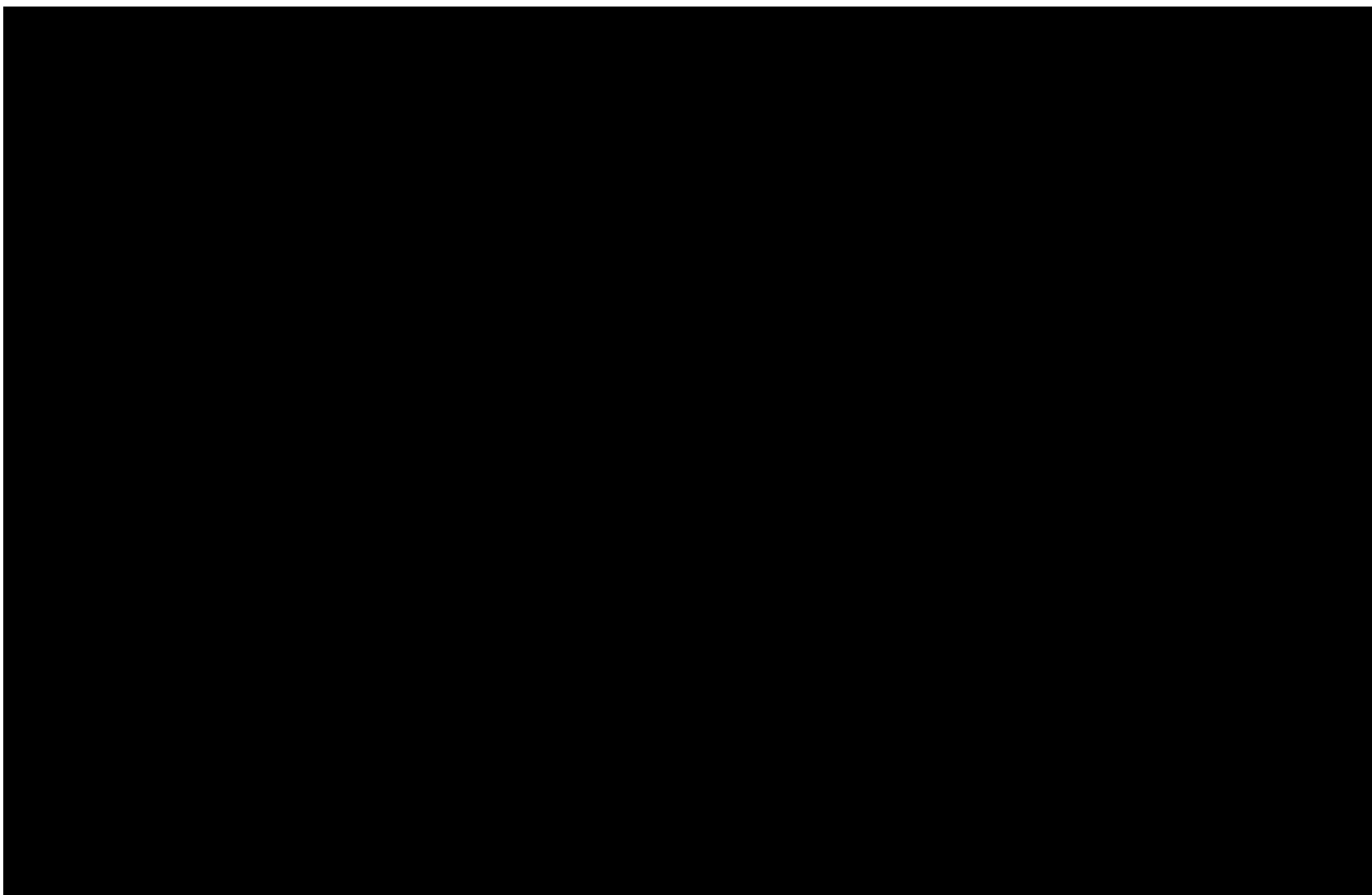
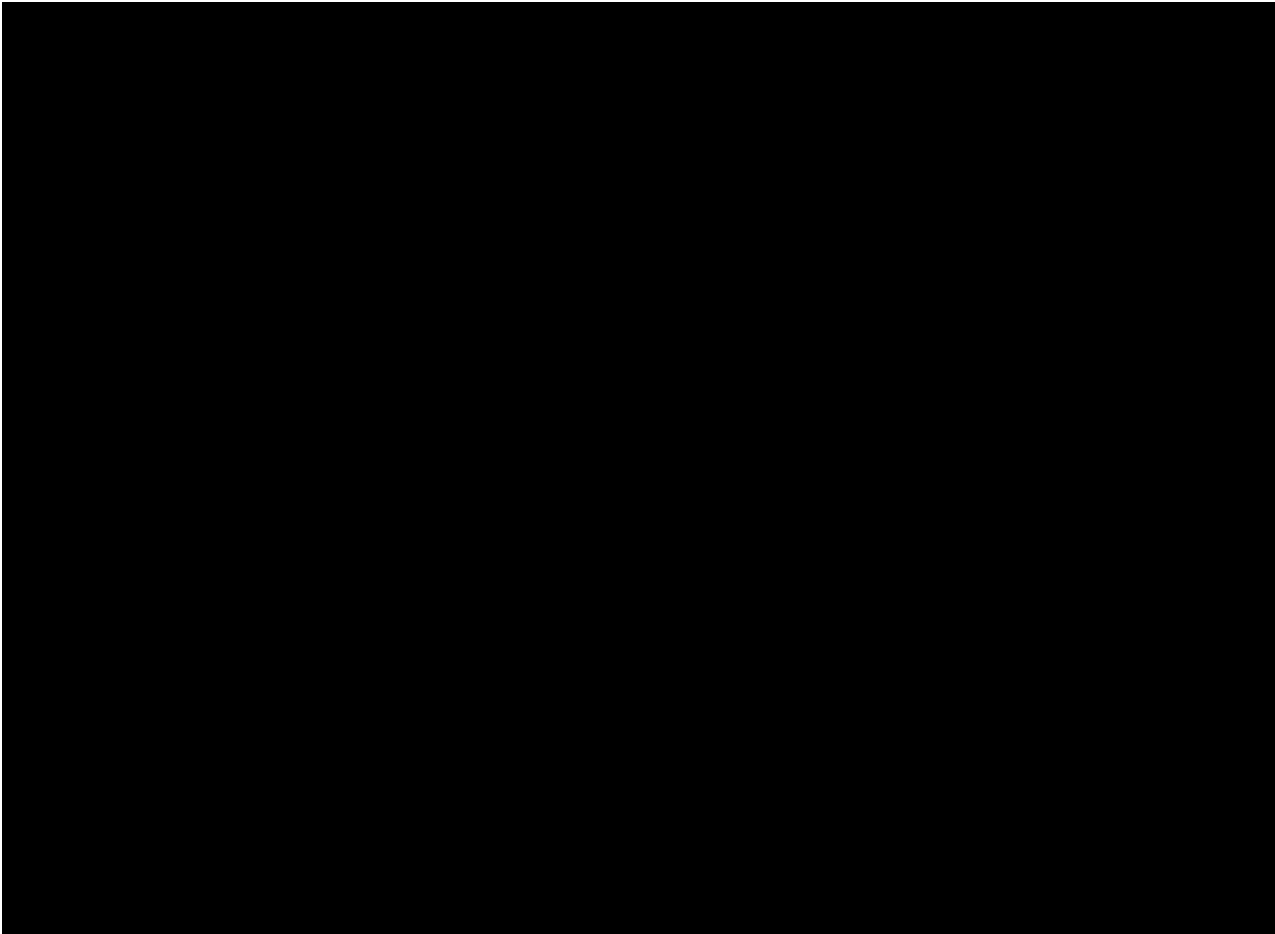


Figure 5-1 – Location of USDW Monitoring Wells

Table 5-3 – USDW Monitoring Well Details



Detailed wellbore schematics for all [REDACTED] USDWM wells are shown in [REDACTED] [REDACTED] respectively. Wellbore schematics of all [REDACTED] USDWM wells are also provided in *Appendix F*.

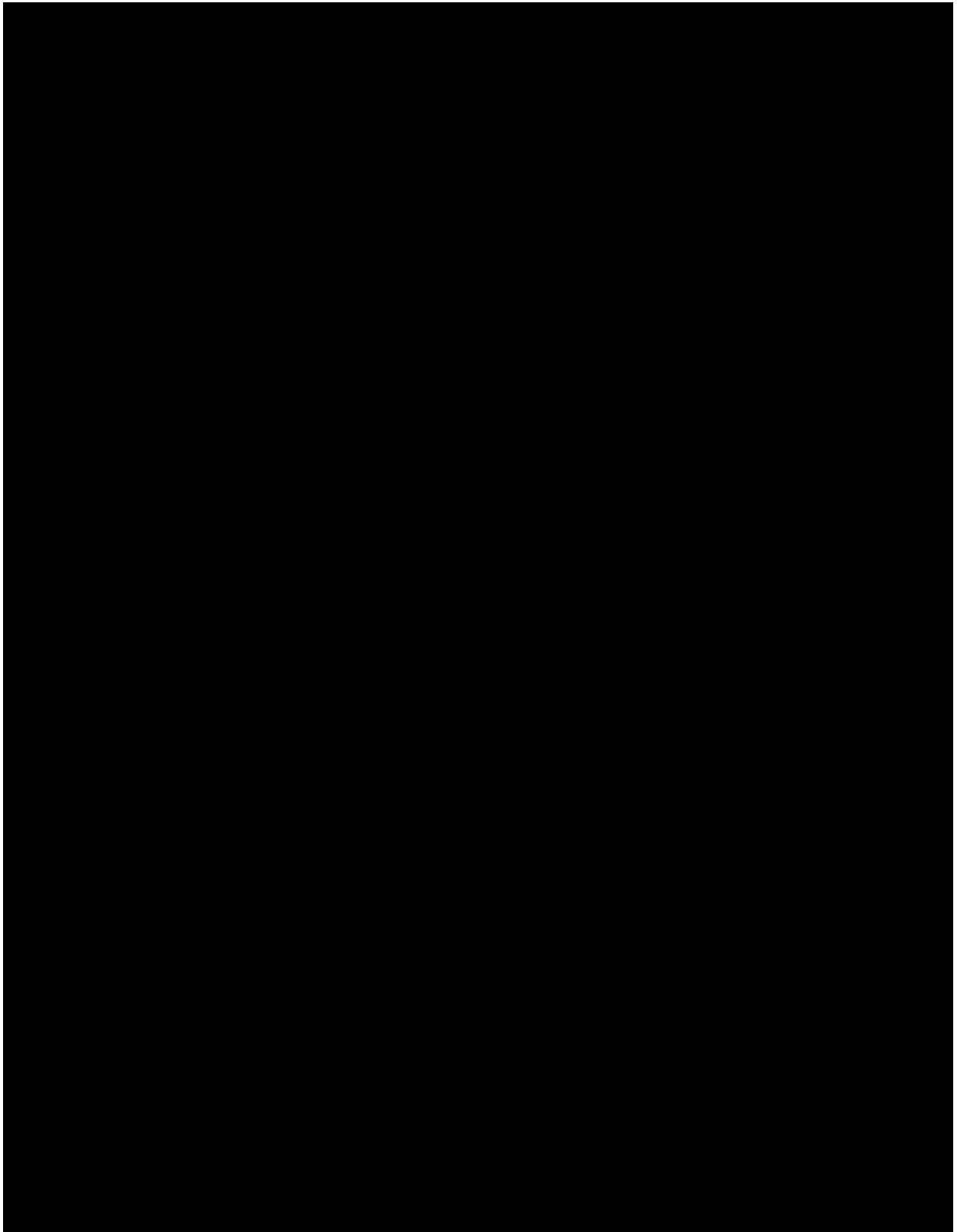


Figure 5-2 – [REDACTED] Schematic

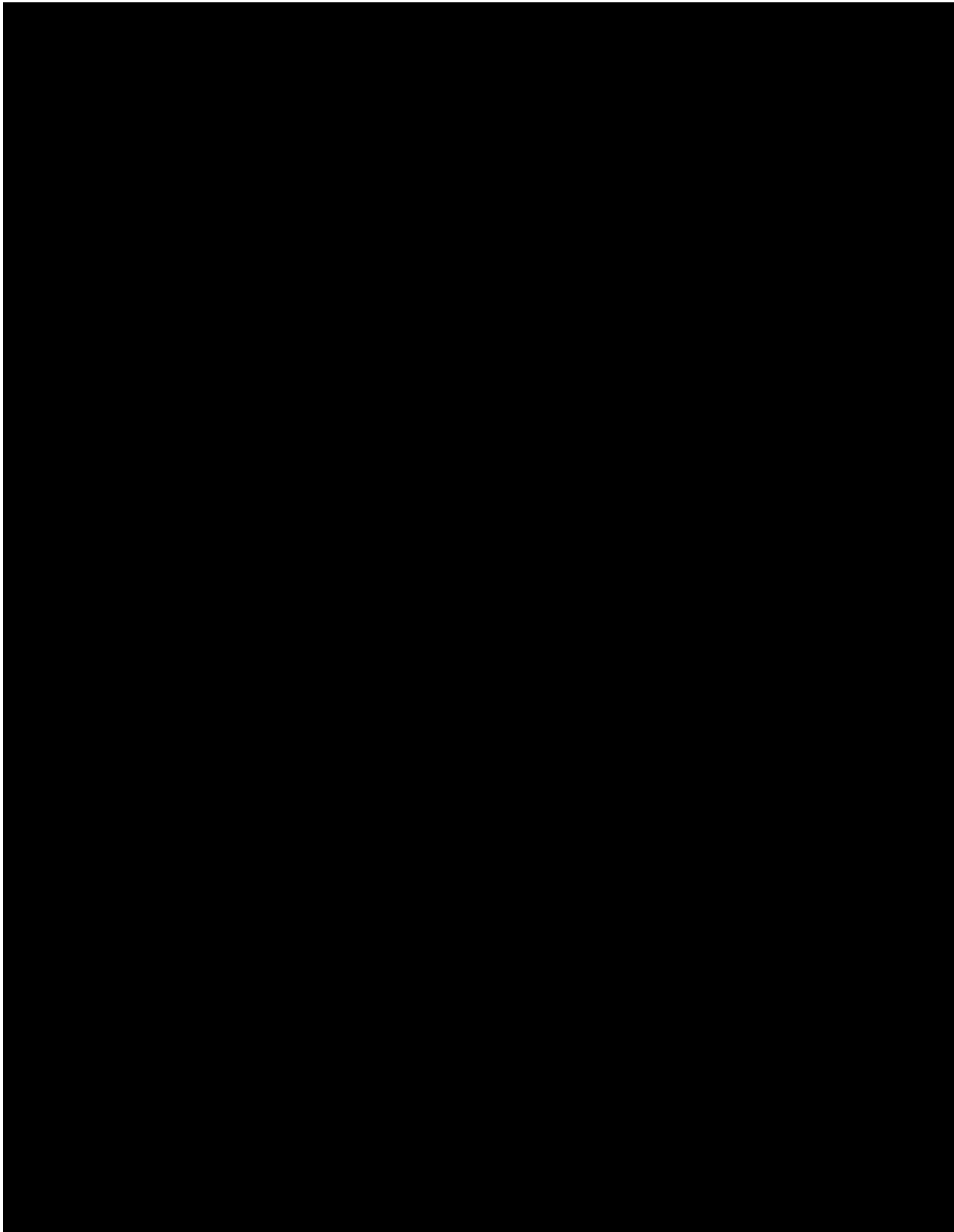


Figure 5-3 – [REDACTED] Schematic

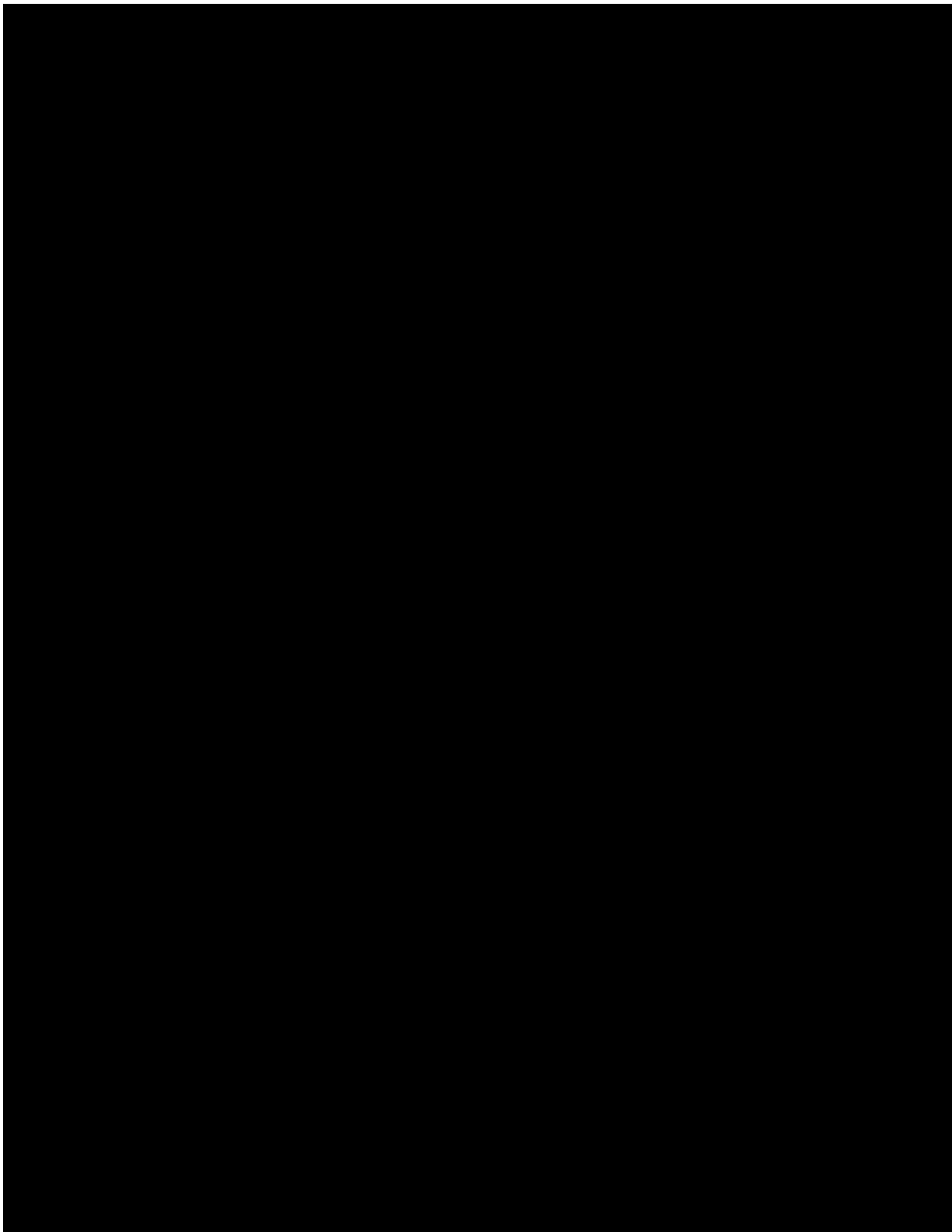


Figure 5-4 – [REDACTED] Schematic

well will be a monitoring well at a depth corresponding to the AZMI (i.e., the first permeable formation above the UCZ). Additionally, to monitor the AZMI to support the Evergreen Project. These wells monitor both injection wells in this project. is positioned to the of the injection wells, will be located in the preferential growth direction (i.e., updip) of the injected CO₂. These monitoring wells are located on Evergreen's property as shown in Figure 5-5, with the location details provided in Table 5-4.

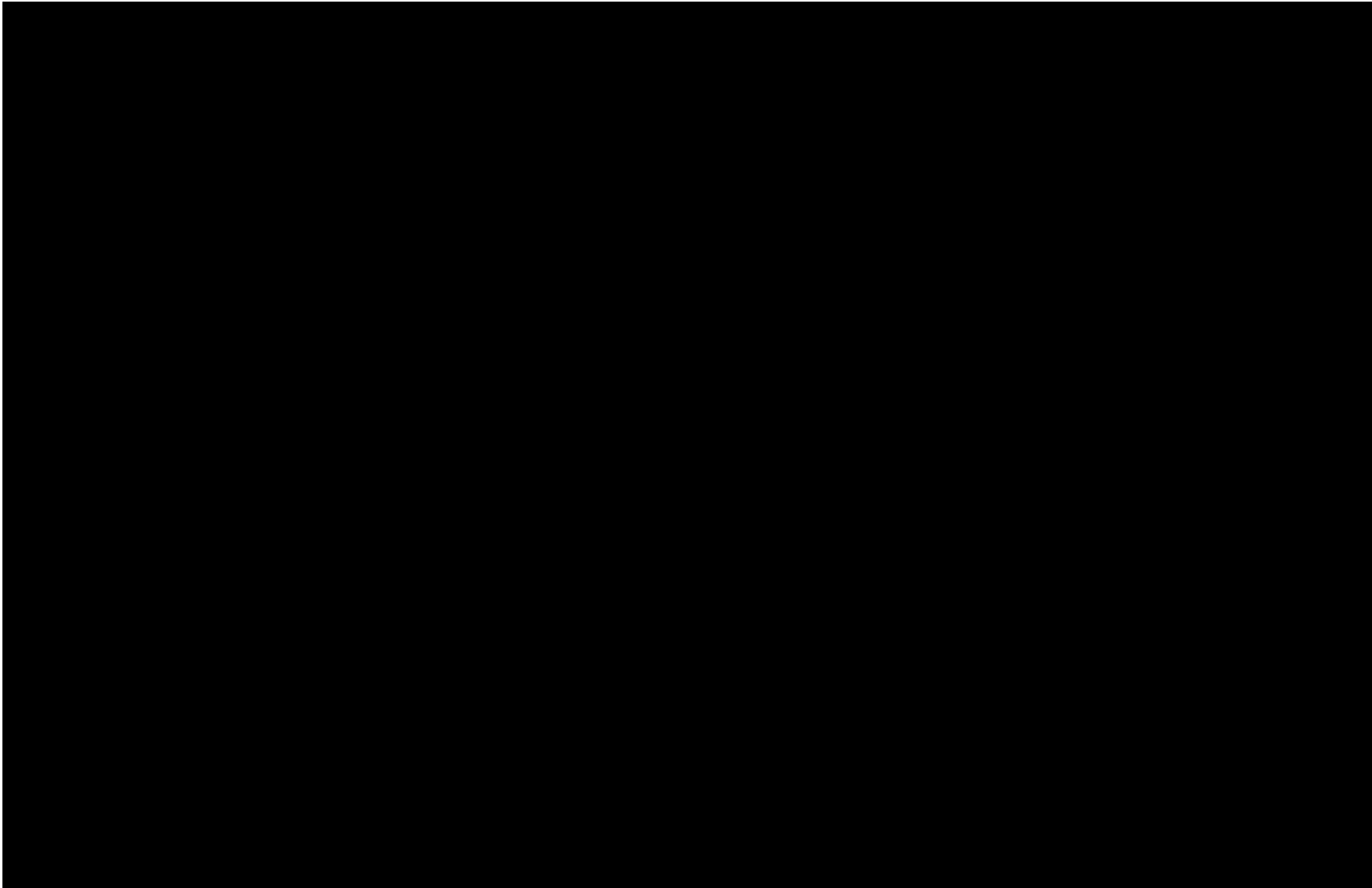
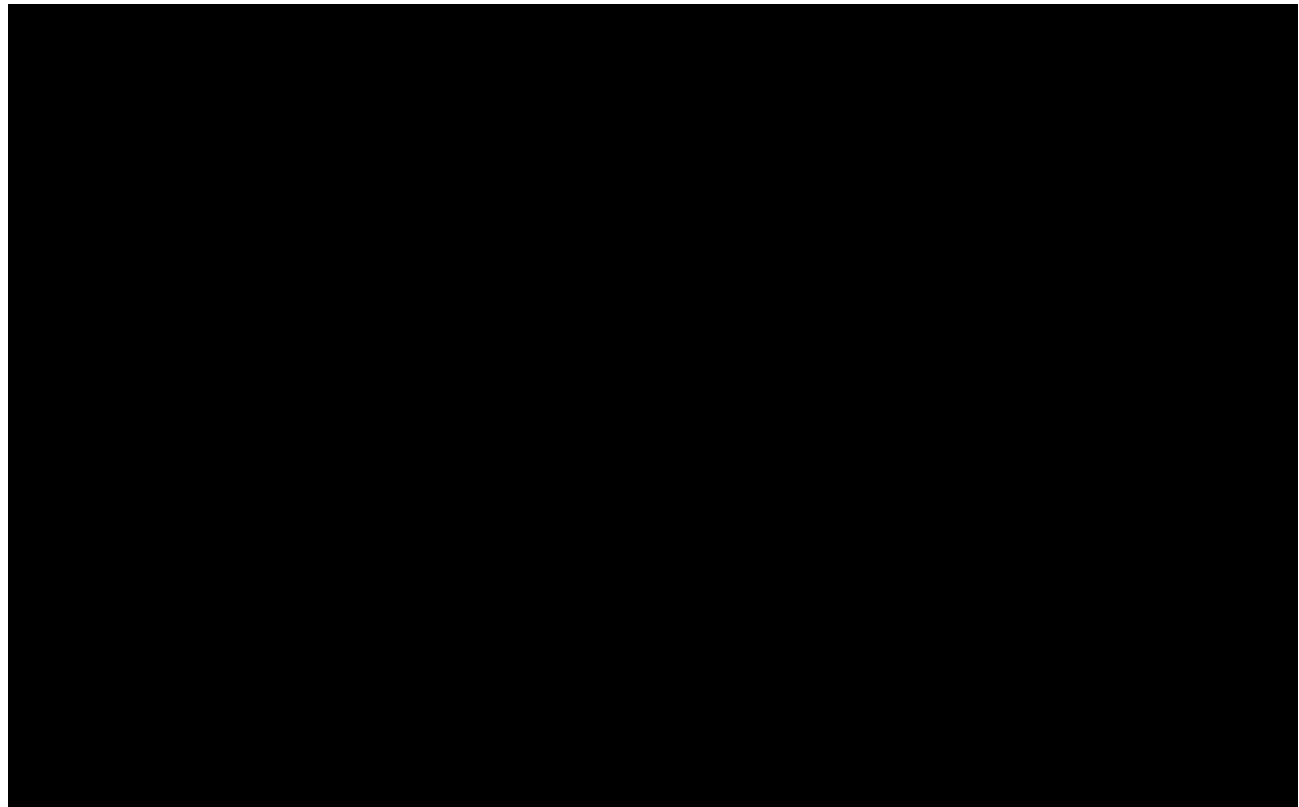


Figure 5-5 – Evergreen Project AZMI Well Locations

Table 5-4 – Location of AZMI Wells



5.5.6.1 Pressure Monitoring

Although not required by Class VI regulations, Evergreen will continuously monitor the pressure of the first permeable formation identified above the UCZ in the AZMI wells using a downhole pressure gauge. Material deviations from baseline pressures after the start of injection will initiate further review in the area. This review will include a study to rule out any minor poro-elastic pressure responses caused by compression from physical expansion of the injection interval. This benign response can occur without a physical leak path being present.

5.5.6.2 Fluid Sampling Methods

The AZMI wells will be designed to allow fluid samples to be obtained if necessary. The fluid will be analyzed for the physical parameter and geochemical species provided in Table 5-2.

Sample collection will occur before the start of injection, to characterize the original chemical composition of the formation fluids. As discussed in *Section 5.5.4*, unexpected changes in the fluid chemistry in the AZMI may be caused by a leakage or other processes and would result in further studies to determine if a leak is present.

5.5.6.3



[REDACTED]

Detailed wellbore schematics for all [REDACTED] AZMI wells are shown in [REDACTED]
[REDACTED] Wellbore schematics of all [REDACTED] AZMI wells are also displayed in *Appendix F*.

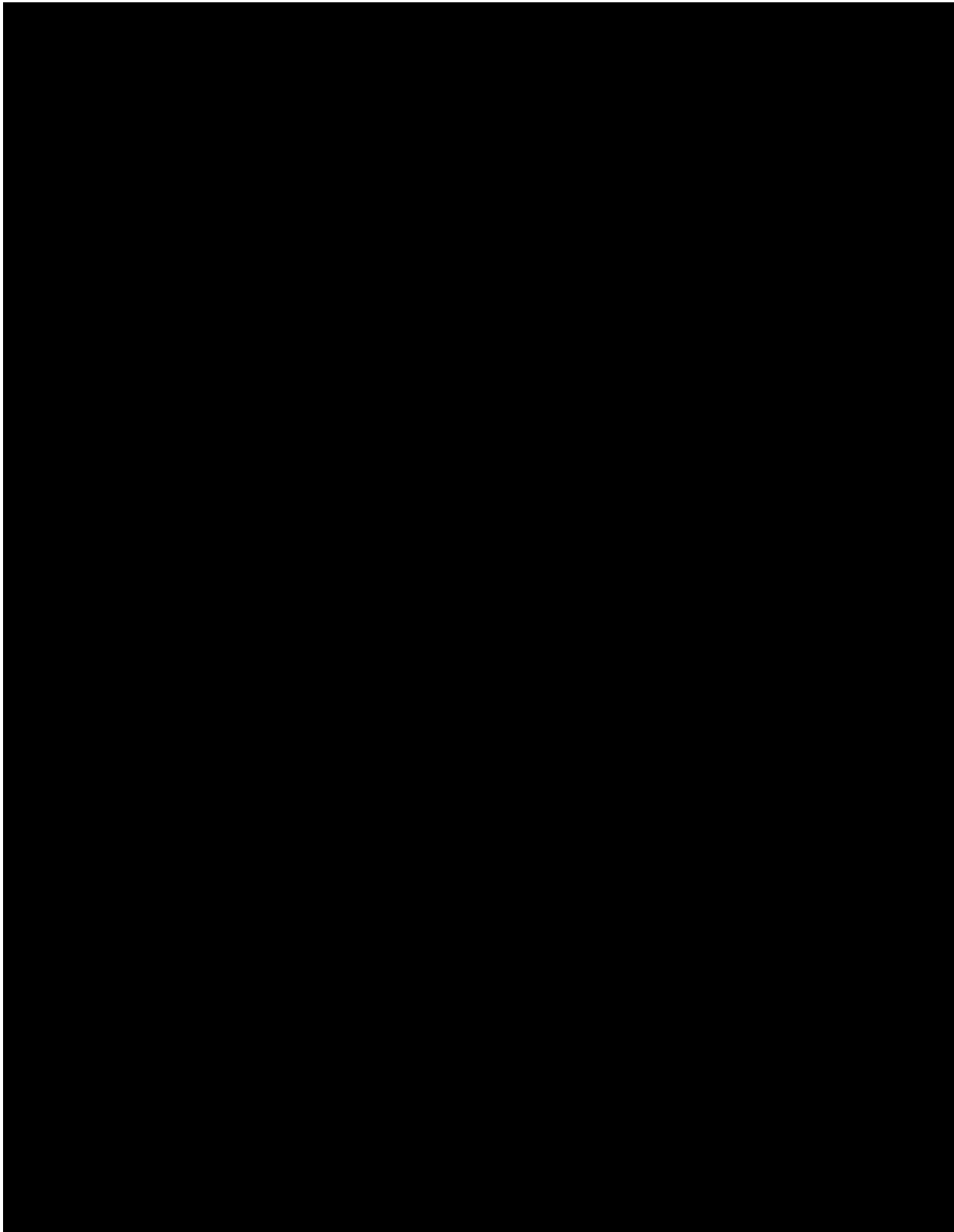


Figure 5-6 – [REDACTED] Schematic

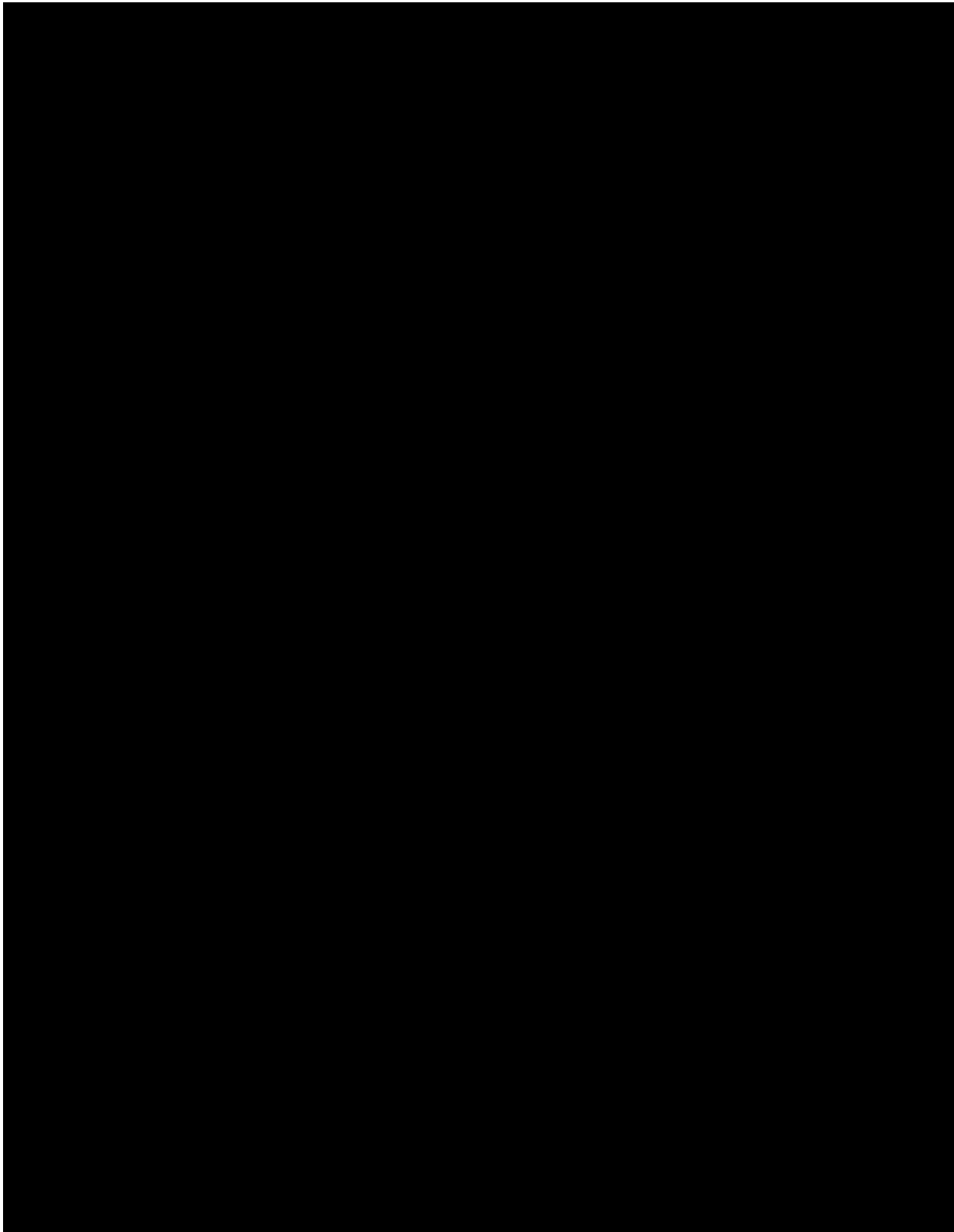


Figure 5-7 – [REDACTED] Schematic

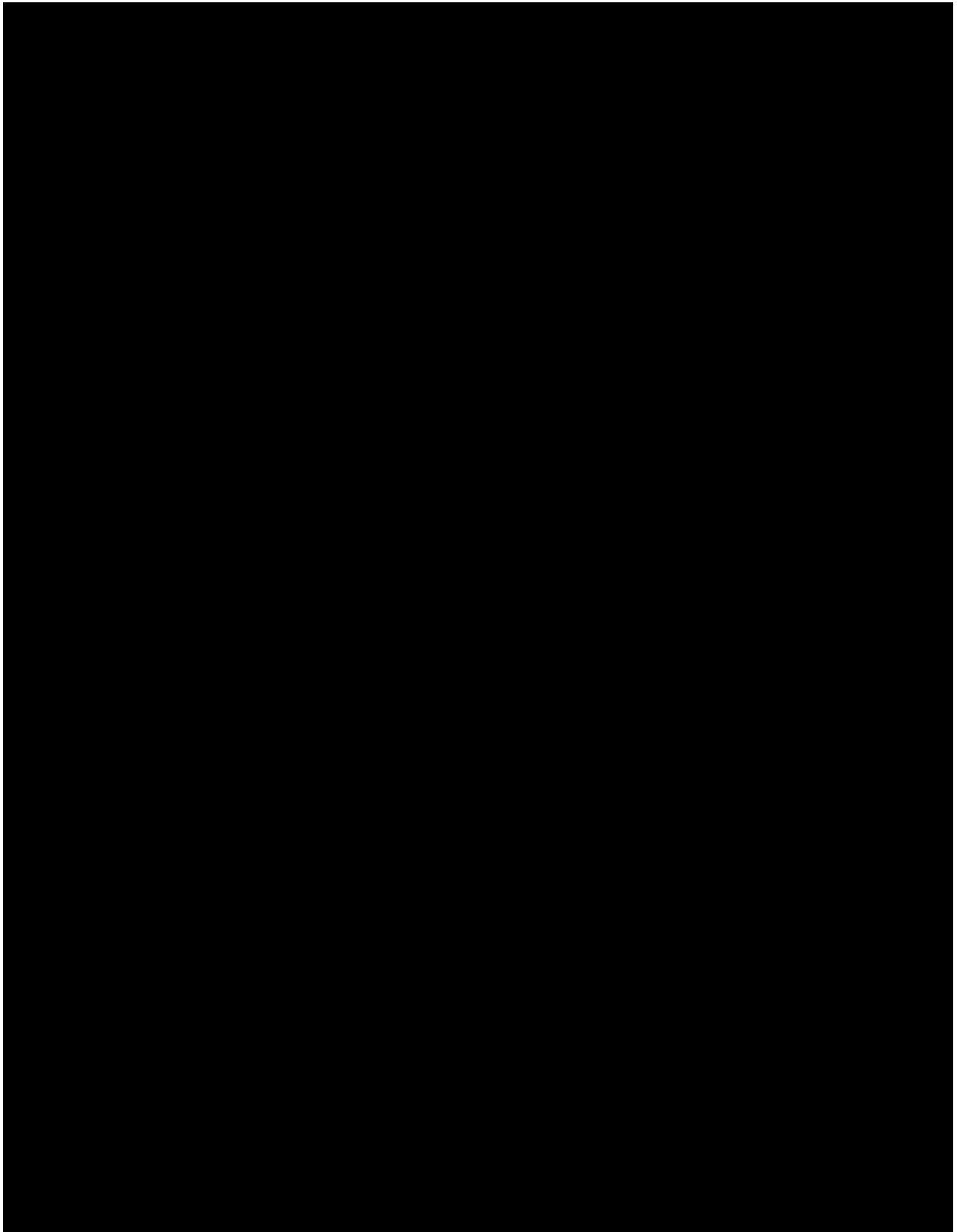


Figure 5-8 – [REDACTED] Schematic

5.5.7 Injection Interval Monitoring

The injection interval will be monitored through measurements taken from the injection wells themselves. Each well will continuously monitor pressure and temperature in all injection stages of the injection interval, including previously injected-into stages. These stages will continue to be monitored for the life of the well.

This project includes two injection wells targeting the same sand formations. The pressure measurements taken from the two wells will allow the wells to monitor each other within the injection interval. [REDACTED]

5.5.8 Injection Plume Monitoring

Evergreen proposes the following two-tiered system for plume and pressure-front tracking per the operational monitoring requirements of SWO 29-N-6 §3625.A.7 [40 CFR §146.90(g)]. [REDACTED]

- [REDACTED]

- [REDACTED]

5.5.8.1 Direct Monitoring: Pressure

The injection wells will be instrumented with multiple downhole pressure gauges to continuously monitor the pressure in the multiple injection sands. The pressure response recorded by any gauge would not only be a representation of the injection through that well, but would also be affected by the far-field pressure response from the other injection well. This response effectively empowers one injection well to function as the in-zone pressure monitoring well of the other. These recorded time series provide insight into the reservoir connectivity between the two injectors. Such measurements are sufficient for pressure monitoring when both injection

wells inject into the same sands of an injection stage, and also in those occasions when the injectors may target separate injection stages. In the latter case, the absence of simultaneous injection in a stage means that the recorded pressure response is exclusively the far-field pressure response of the other injector. This case corresponds to the most conventional understanding of a pressure monitoring well.

The reservoir model built during the site-evaluation phase may be used to predictively monitor the reservoir conditions during injection operations. Continual monitoring of bottomhole pressures and temperatures, combined with known reservoir parameters, will be used to derive reservoir conditions throughout the injection stages and allow the two wells to work in conjunction with each other to monitor both plumes.

Any periods of shut-in of the well can 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 continual measurements obtained during regular operating conditions, will aid in updating models and forecasts.

5.5.8.2 [REDACTED]

[REDACTED]

[REDACTED]

Reservoir monitoring using time-lapse seismic has an extensive history of use in tertiary oil and gas recovery. The methodology has undergone thorough testing in saline aquifers with the presence of CO₂ (Bacci, 2017). The time-lapse effect is primarily driven by the change in acoustic impedance resulting from compressional changes in velocity between high CO₂ concentrations and formation fluids. As such fluids are displaced by CO₂, the change in acoustic impedance during plume growth can be analyzed.

[REDACTED]

[REDACTED]

[REDACTED]

- [REDACTED]

- [REDACTED]

- [REDACTED]

- [REDACTED]

[REDACTED]

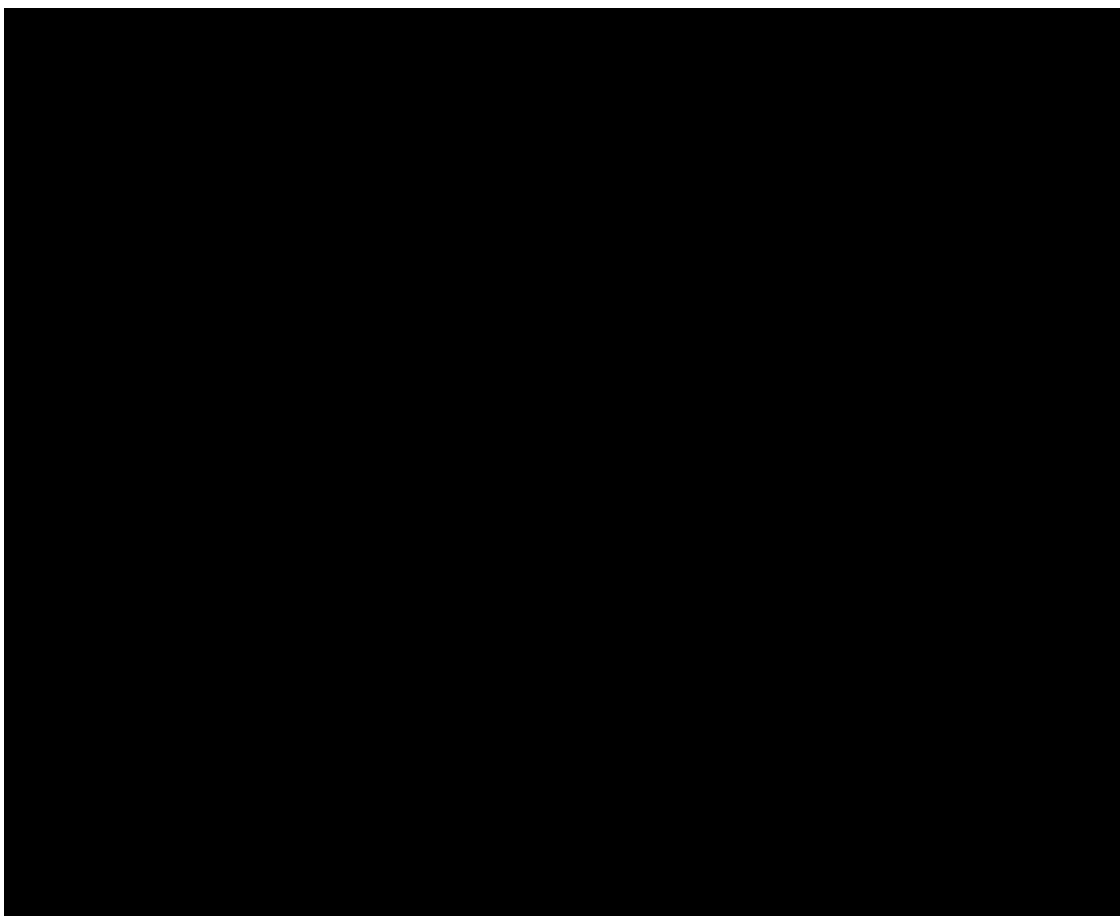


Figure 5-9 – [Redacted]

[Redacted]

- [Redacted]
- [Redacted]
- [Redacted]
- [Redacted]
- [Redacted]
- [Redacted]

The following subsections discuss key portions of these work steps.

Rock Physics Model

A rock physics model is critical to time-lapse interpretation. This model establishes a relationship between fluid substitution and the change in acoustic impedance—and can be produced with high confidence, provided that the reservoir characterization data is accurate. Changes in seismic response can be projected with a synthetic survey design and reservoir model, relying on the rock physics model to calculate the impact of the formation fluid on acoustic impedance. This model

determines if the monitoring program can facilitate the detection of expected formation-fluid substitutions.

Deterministic petrophysical-analysis estimations can be used to forecast the dry mineral rock components before any saturation modeling. The model accounts for the following rock properties:

- Total porosity
- Effective porosity
- Water saturation
- Clay (type)
- Quartz
- Mineral content
- Oil/gas residual (if any)

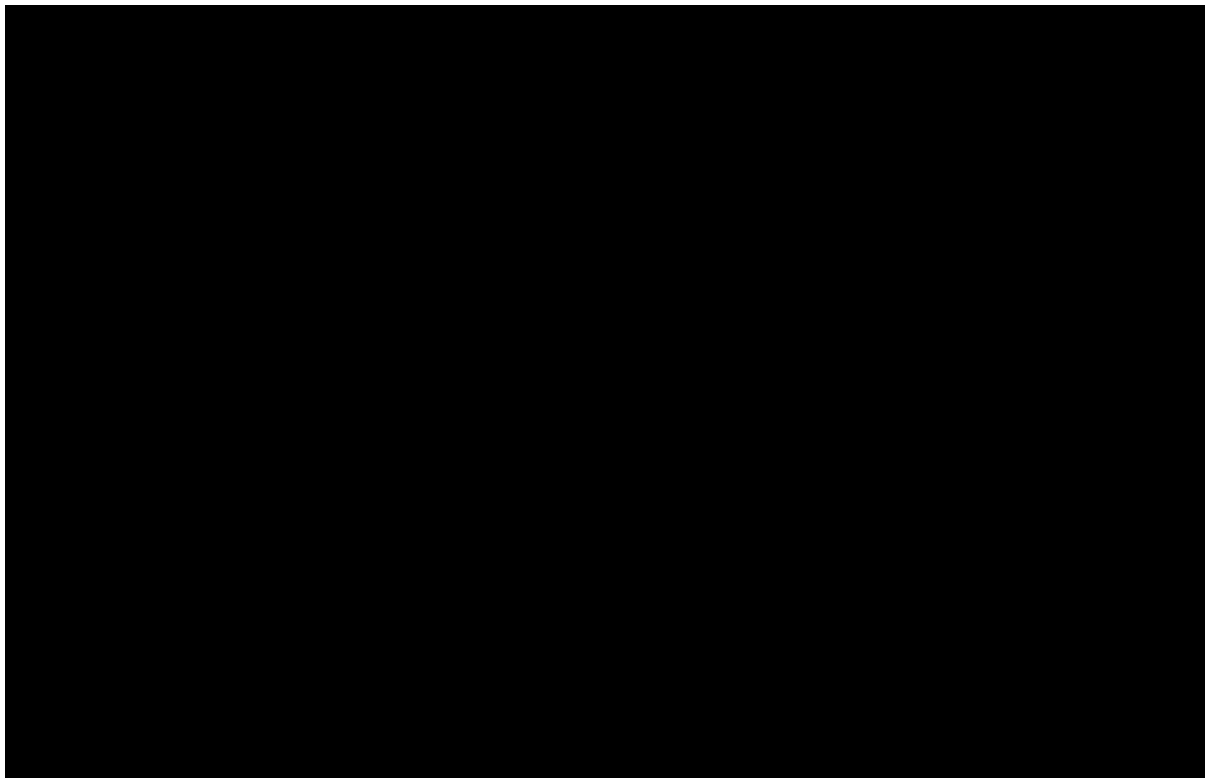


Figure 5-10 – [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

Petro-Elastic Model

The rock physics model will generate a zero-order dry rock model, which is then used to establish a petro-elastic model by perturbing the elastic parameters for varying degrees of saturation.

Figure 5-11 illustrates the combination of the rock physics model (shown in red) and the petro-elastic model at [REDACTED] (blue). Changes in saturation result in changes primarily to the compressional wave velocity for this type of rock. The effect of gas replacement of the reservoir fluid can be estimated using the fluid saturation and fluid replacement from the rock physics model.

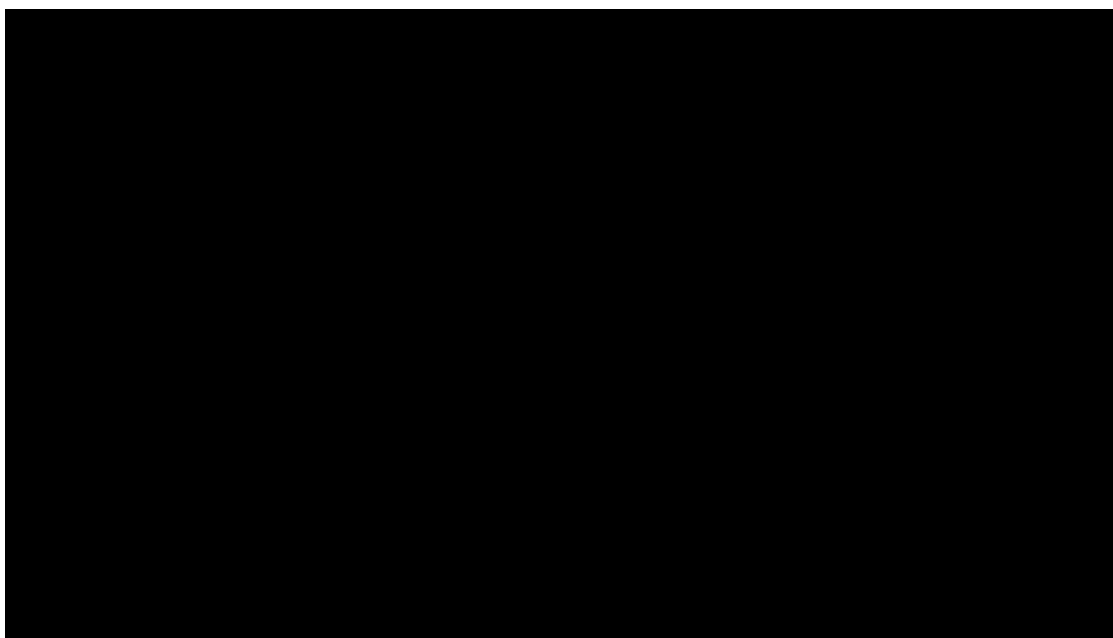


Figure 5-11 – [REDACTED]

Predicting velocity and density as functions of injectate saturation is the result of the petro-elastic model (Figure [REDACTED]). [REDACTED]

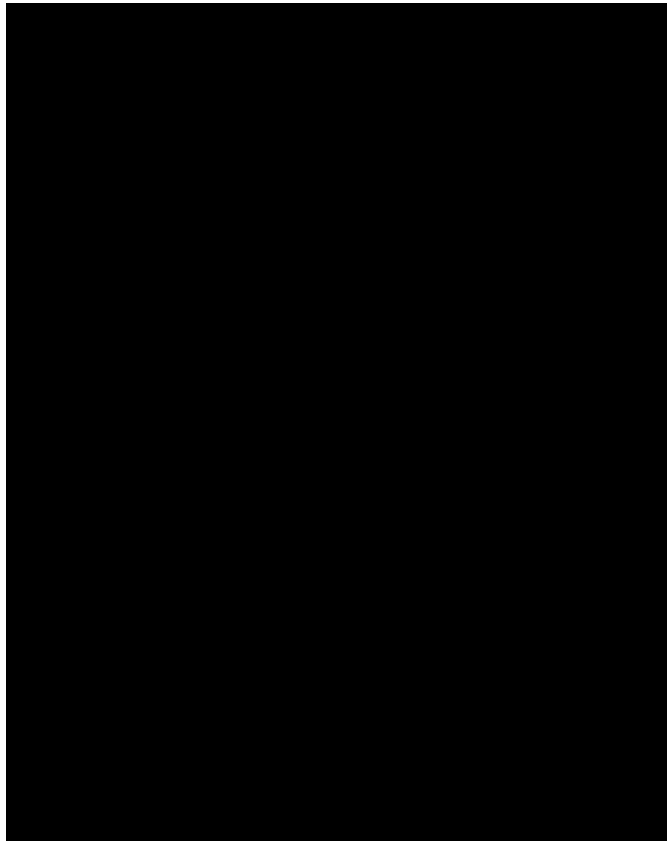


Figure 5-12 –

A feasibility study will be designed to determine if the petro-elastic model could detect connate fluids replaced with CO₂. This study will be conducted after recovering core material from the injection well. The CO₂ properties will be input into the model as replacement variables for openhole log readings that will be taken while drilling the stratigraphic test well for this project.

1D and 2D Models

Changes in the magnitude of the CO₂ plume are measured for different scenarios using 1D and 2D models. This section will detail the methodology used to generate these models.

Seismic waves that travel through the earth are created with seismic surveys, and geophones listen for the waves that are subsequently reflected. The seismic waves can be made with a “shot,” referring to explosives or other mechanical sources—most commonly a vibrator, which generates seismic waves by pounding a steel plate against the earth. Geophones are recorders that detect sound waves reflected to the surface, and the data sent by geophones is then stored using seismographs. The geophones enable geophysicists to calculate the time it takes for seismic waves to reflect off transition zones between formations. Geoscientists can use the variation in sonar velocities to understand subsurface lithology.

[REDACTED]

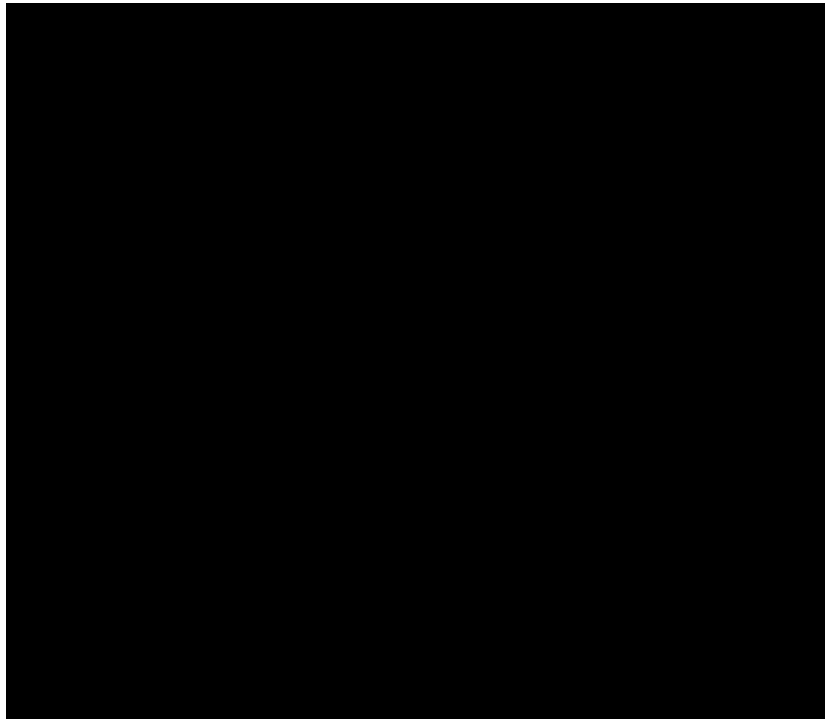


Figure 5-13 – [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
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[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]



2D Model

A geologic model can be built once the results of a 1D model have been interpreted. The model reflects two saturation scenarios: one with connate formation fluid and the other with CO₂-replaced fluid.

Applying the same principles discussed in the previous section, 2D seismic surveys can provide a snapshot of a thin layer of the crust of the Earth. The geophones for this survey are placed in a line along the surface and record reflected seismic waves from each formation. For best results, 2D surveys require setting multiple lines, ideally parallel to the structure dip and orthogonal to the geologic strike. The surveys provide subsurface information on various formations, faults, and other characteristics. Geologists can interpret contour lines and produce geologic maps using the intersection of numerous 2D surveys, which cost less and have less environmental impact than 3D surveys. Therefore, 2D surveys are commonly used to explore new areas and allow geologists to visualize the formations lying beneath the surface.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]



Figure 5-16 – [REDACTED]

[REDACTED]

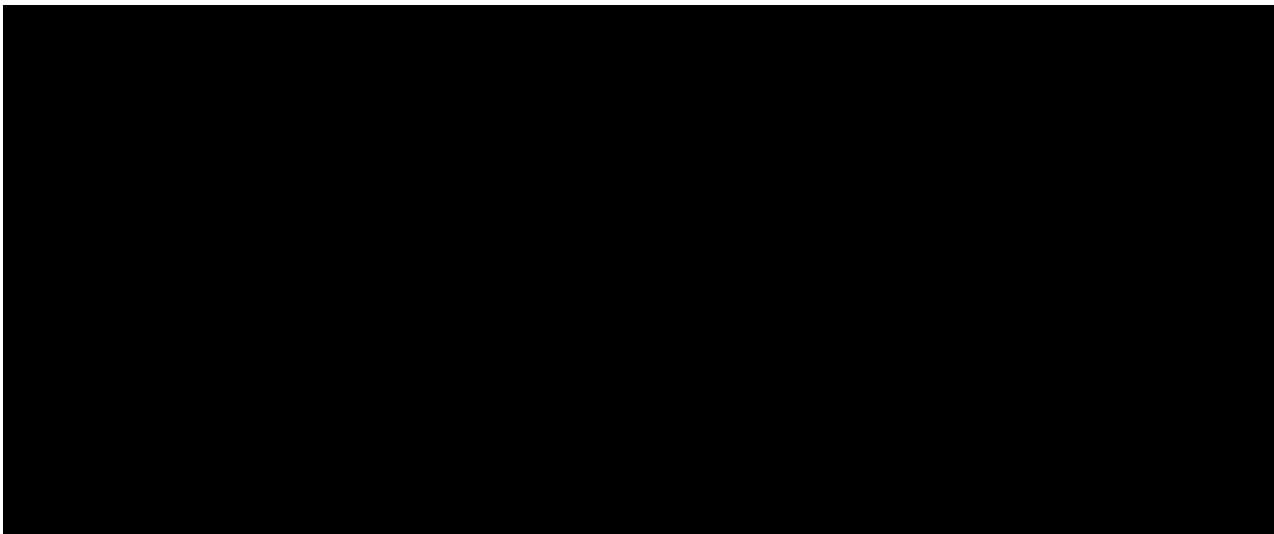


Figure 5-17 – [REDACTED]
[REDACTED]

[REDACTED]
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[REDACTED] [REDACTED]
[REDACTED]
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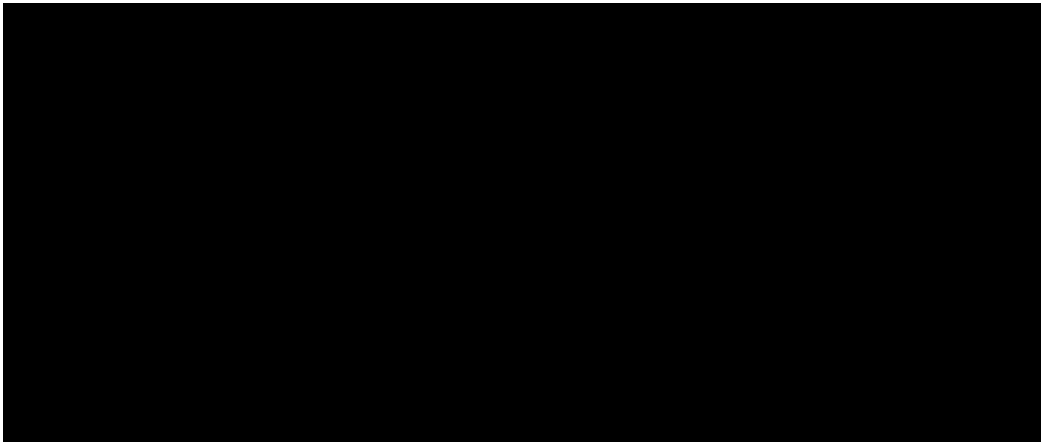
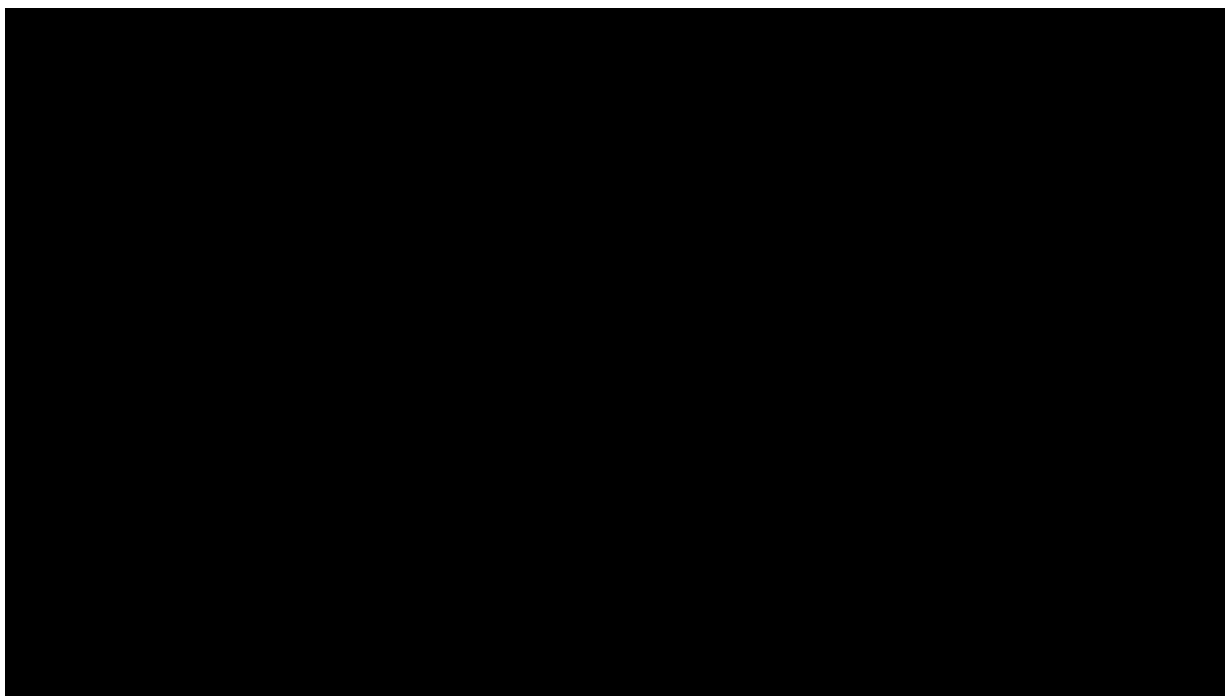


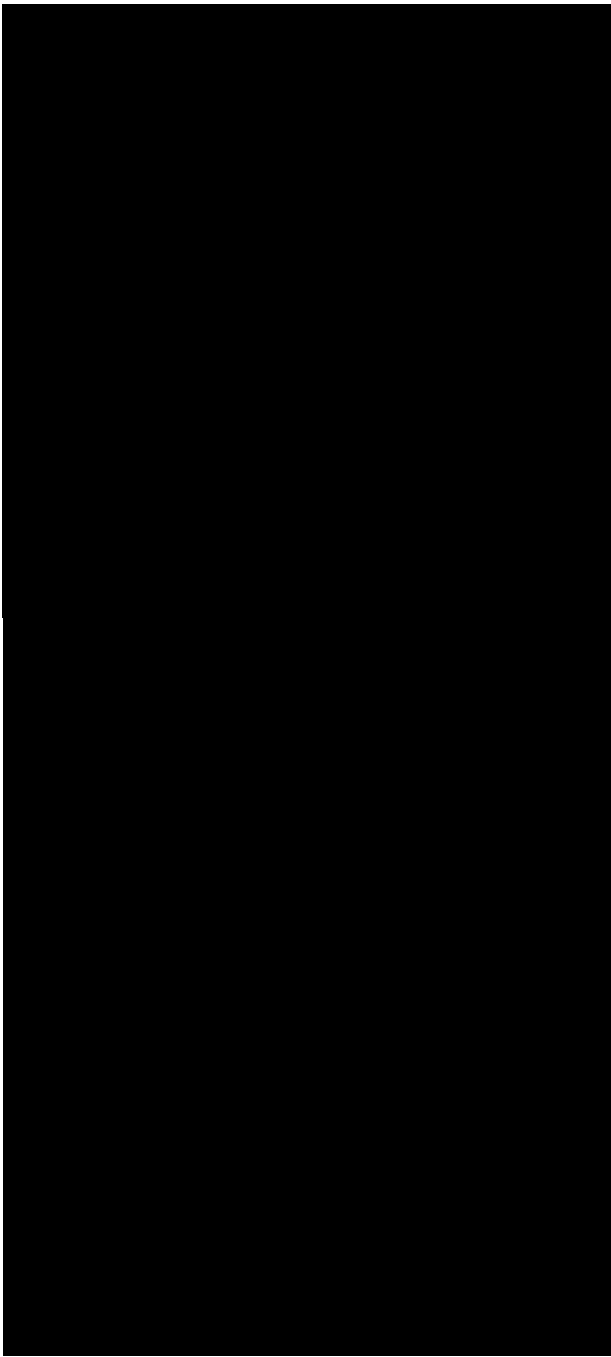
Figure 5-18 – [REDACTED]

Table 5-5 – [REDACTED]



[REDACTED]
[REDACTED]
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[REDACTED]

Table 5-6 – [REDACTED]



[REDACTED]

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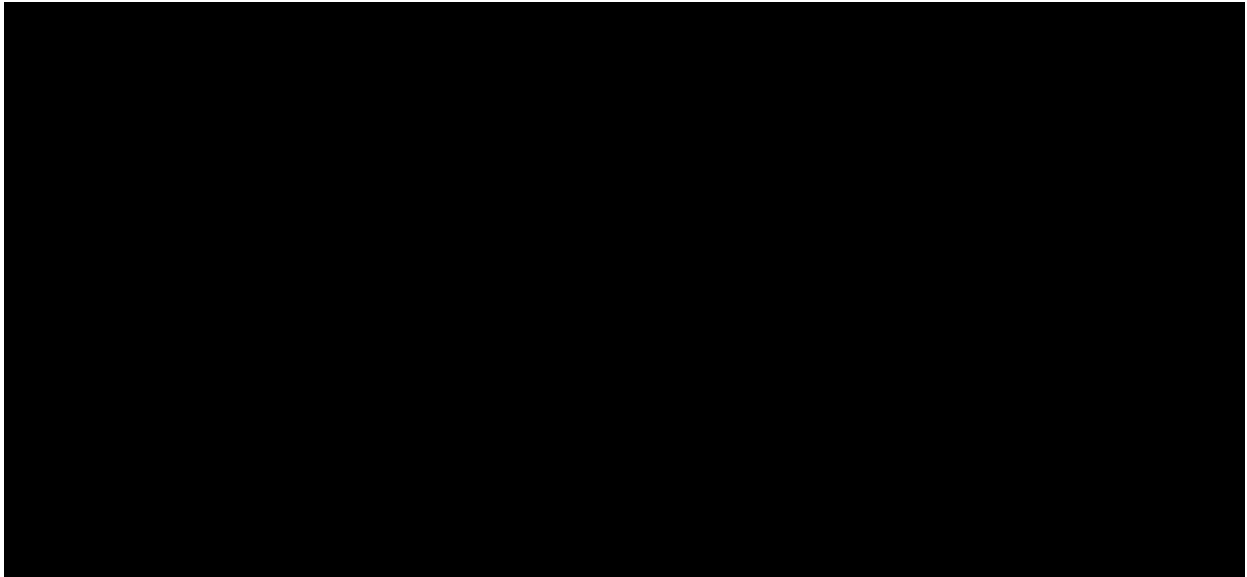
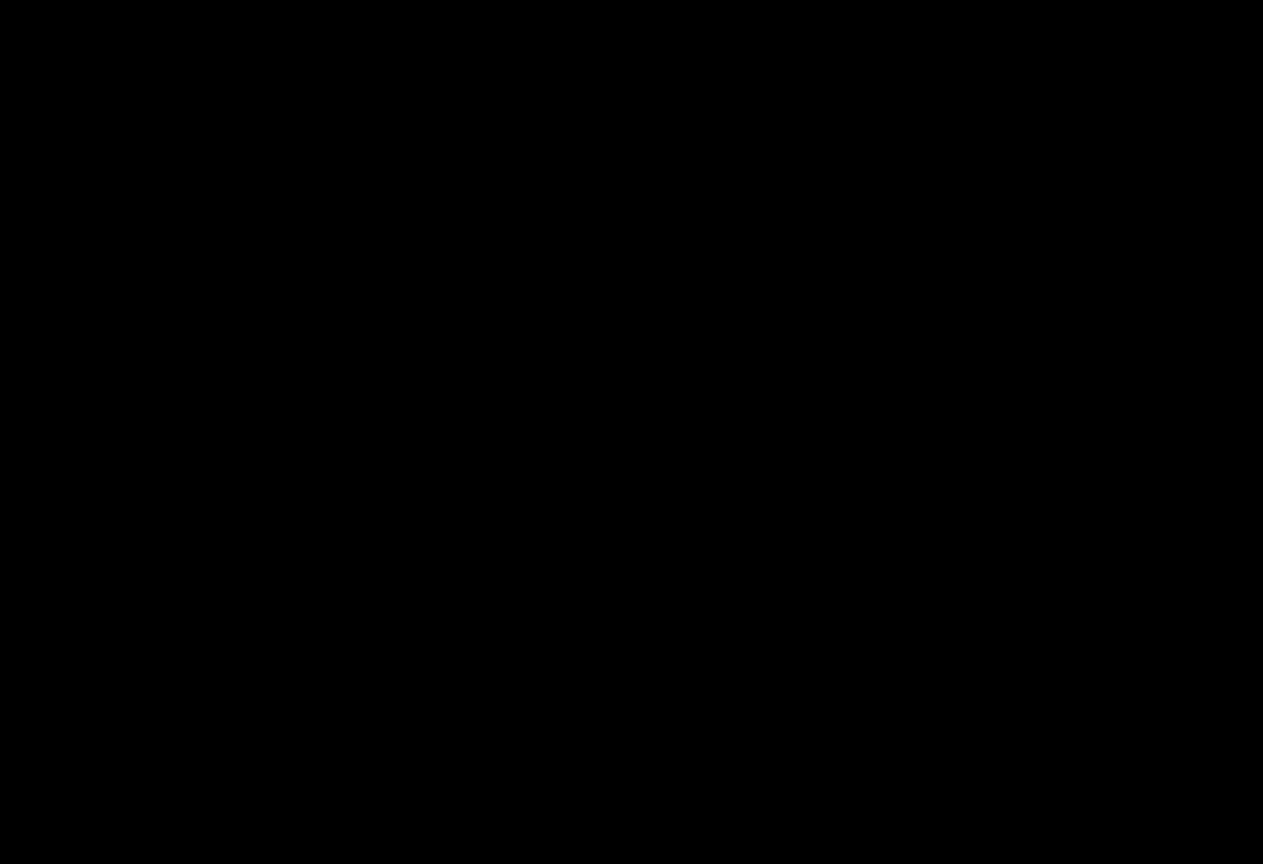


Figure 5-19 – [REDACTED]

[illegible]

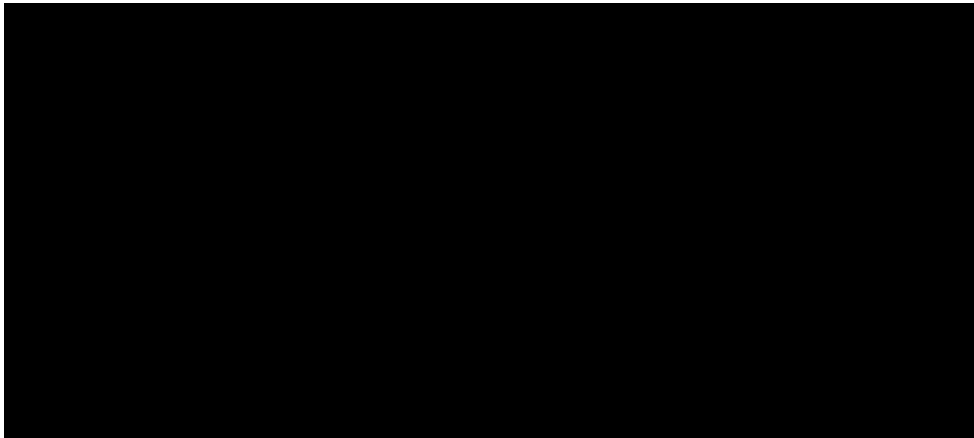


Figure 5-20 – [REDACTED]

Table 5-8 – [REDACTED]

[REDACTED]

Table 5-9 – [REDACTED]

[REDACTED]

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Figure 5-21 – [Redacted]

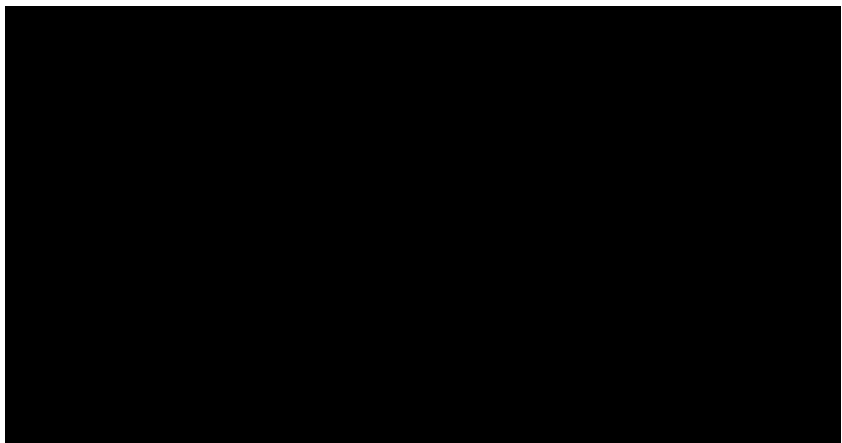


Figure 5-22 – [Redacted]

Table 5-10 – [REDACTED]

[REDACTED]	

[REDACTED]	
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[REDACTED]	
[REDACTED]	
[REDACTED]	



Figure 5-23 – [REDACTED]



5.5.9 Monitoring Conclusion

The contents of this Testing and Monitoring Plan have been designed to satisfy SWO 29-N-6 **§3625.A** [40 CFR **§146.90**]. Reporting and reevaluation requirements will be executed by Evergreen for the life of the project, including post-injection. Monitoring strategies are included for the injection stream composition and wellhead CO₂ conditions using pressure and temperature gauges, as well as mass flowmeters, to allow for continuous reading of data. Bottomhole operating parameters are monitored by the pressure gauges array that extends the full length of the injection interval. Well integrity is confirmed by the execution of annual tests. Above-zone confinement is monitored by multiple new wells equipped with pressure sensors and periodic fluid sampling. USDW safety is ensured by monitoring multiple groundwater wells that are distributed in a manner that allow for effective sampling of the bottomhole fluids. The appropriate well equipment and its related use are explained within the respective subsections of this application.

The individual injection stages of the injection wells are also instrumented with pressure and temperature gauges, which enable direct monitoring of the formation pressure. Furthermore, these pressure gauges verify the pressure decay toward pre-injection levels after injection in each stage is finished.



[REDACTED]

This method eliminates the need for additional penetrations within the injection formations for monitoring purposes beyond what is proposed in this plan. This approach minimizes the risk of inadvertently forming a leakage path through the upper confining zone.

The contents of this plan will be carried out during the entirety of the life of the injection wells, including post-injection monitoring following a predetermined timeline, based on both updated plume growth and observed well conditions at the time of planned injection cessation.

Table 5-11 summarizes the various measurements discussed in the Testing and Monitoring Plan.

Table 5-11 – Testing and Monitoring Plan Measurements

Equipment / Measurement	Regulation	Comment	Frequency
██████████	§3625.A.2 §146.90(b)	Measures mass flow rate	Continuously
Corrosion Coupon	§3625.A.3 §146.90(c)	Measures corrosion levels on the types of metal used in the project	Quarterly
Injection Stream Sampling	§3625.A.1 §146.90(a)	Provides more detailed analysis via periodic lab analysis of injection stream	Quarterly
Injector Wellhead Tubing Pressure Gauge	§3625.A.1 §146.90(a)	Verifies surface injection pressure	Continuously
Injector Wellhead Annulus Pressure Gauge	§3625.A.2 §146.90(b)	Verifies annulus pressure maintained	Continuously
Injector Annulus Pressure Test	§3627.A.2 §146.89(b)	Verifies absence of leak in annulus	Annually
██████████ ██████████ ██████████ ██████████	██████████ ██████████	██████████ ██████████ ██████████ ██████████ ██████████	██████████
	██████████ ██████████	██████████ ██████████ ██████████ ██████████	██████████ ██████████ ██████████ ██████████ ██████████
██████████ ██████████ ██████████ ██████████	██████████ ██████████	██████████	██████████ ██████████
	██████████ ██████████	██████████ ██████████	██████████ ██████████ ██████████ ██████████
	██████████ ██████████ ██████████	██████████ ██████████	██████████
Injector Casing-Inspection Log	§3625.A.5 §146.90(e)	██████████ log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey only in case there is a concern about leakage or if regulator requests

Above-Zone Monitoring Well Downhole Pressure/ Temperature Gauge	Redundant measurement, no direct regulatory link	Potential to detect pressure anomaly in AZMI in case of leakage; will require careful analysis due to false positive potential from sensor drift, geomechanical effects, and preexisting pressure trends due to potential far-field activities	Continuously
██████████ ██████████ ██████████ ██████████ ██████████	██████████ ██████████	████████████████████	████████████████████ ██████████
Above-Zone Monitoring Well Fluid Sampling	§3625.A.4 §146.90(d)	Above upper confining zone fluid collection is possible if other trends justify reasonability.	Only if required
USDW Fluid Sampling	§3625.A.4 §146.90(d)	Sample fluids from the deepest USDW, as recommended by guidelines, and analyze composition	At least once every 5 years

Appendix F – Testing and Monitoring:

- Appendix F-1 USDWM Well Plan Map
- Appendix F-2 AZMI Well Plan Map
- Appendix F-3 [REDACTED]
- Appendix F-4 [REDACTED]
- Appendix F-5 [REDACTED]
- Appendix F-6 [REDACTED]
- Appendix F-7 [REDACTED]
- Appendix F-8 [REDACTED]

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Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 6 – INJECTION WELL PLUGGING PLAN

February 2024



SECTION 6 – INJECTION WELL PLUGGING PLAN

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6.1 Introduction

The plugging plans for the Loblolly Carbon Capture and Sequestration (CCS) No. 001 and Loblolly CCS No. 002 injection wells are designed to satisfy the requirements of Statewide Order (SWO) 29-N-6, **§3631** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.92**]. This section outlines the completion and plugback plan for each completion stage for the two injection wells as well as their plugging and abandonment (P&A) plans and operations. This section also specifies the P&A plans and procedures for the Underground Source of Drinking Water (USDW) monitoring and above-zone monitoring interval (AZMI) wells.

6.2 Injection Well Zonal Isolation and Final Plugging and Abandonment

As discussed in *Section 4 – Engineering Design and Operating Strategy*, the injection wells are planned to be completed [REDACTED]

[REDACTED] CO₂ will be injected into each completion stage for a discrete period of time, which will be defined by the plume model or the plume boundary within the extent of pore space ownership.

[REDACTED] At the end of the injection period for the final stage, the perforations will be isolated with a plug, and monitoring of the gross injection zone will continue.

Once the monitoring phase is complete, and the regulator approves project cessation, Loblolly CCS No. 001 and No. 002 and the monitoring wells will be permanently plugged and abandoned. The plugging operations for the injection and monitoring wells will be performed according to the procedures and designs that prevent CO₂ or formation fluids in the injection zone from migrating to USDWs.

The following details outline the plugging procedures for the injection and monitoring wells. For the Evergreen Sequestration Hub (Evergreen) Project, two types of plugs will be used:

- [REDACTED]
- [REDACTED]

6.2.1 Zonal Isolation of Completion Stages

[REDACTED] The general procedure for zonal isolation includes the following:

6.2.1.1 Pre-zonal Isolation Activities

1. Evergreen Sequestration Hub, LLC (Evergreen) will comply with all reporting and notification provisions.
 - a. Notice of Intent to Plug will be communicated to the Louisiana Department of Natural Resources (LDNR) by submitting Form UIC-17 with detailed plans. (SWO 29-N-6 **§3631.A.4**). No actual well-plugging operations will commence until written approval from the Commissioner of Conservation (Commissioner) is received.

2. [REDACTED]
[REDACTED]
[REDACTED]

(SWO 29-N-6 **§3631.A.2** [40 CFR **§146.92(a)**])

- a. External mechanical integrity will be demonstrated through the approved monitoring methods described in *Section 5*. (SWO 29-N-6 **§3631.A.2** [40 CFR **§146.92(a)**])
- b. Figures 6-1 and 6-2 show the zonal isolation of the first completion stage in Loblolly CCS No. 001 and No. 002, respectively.

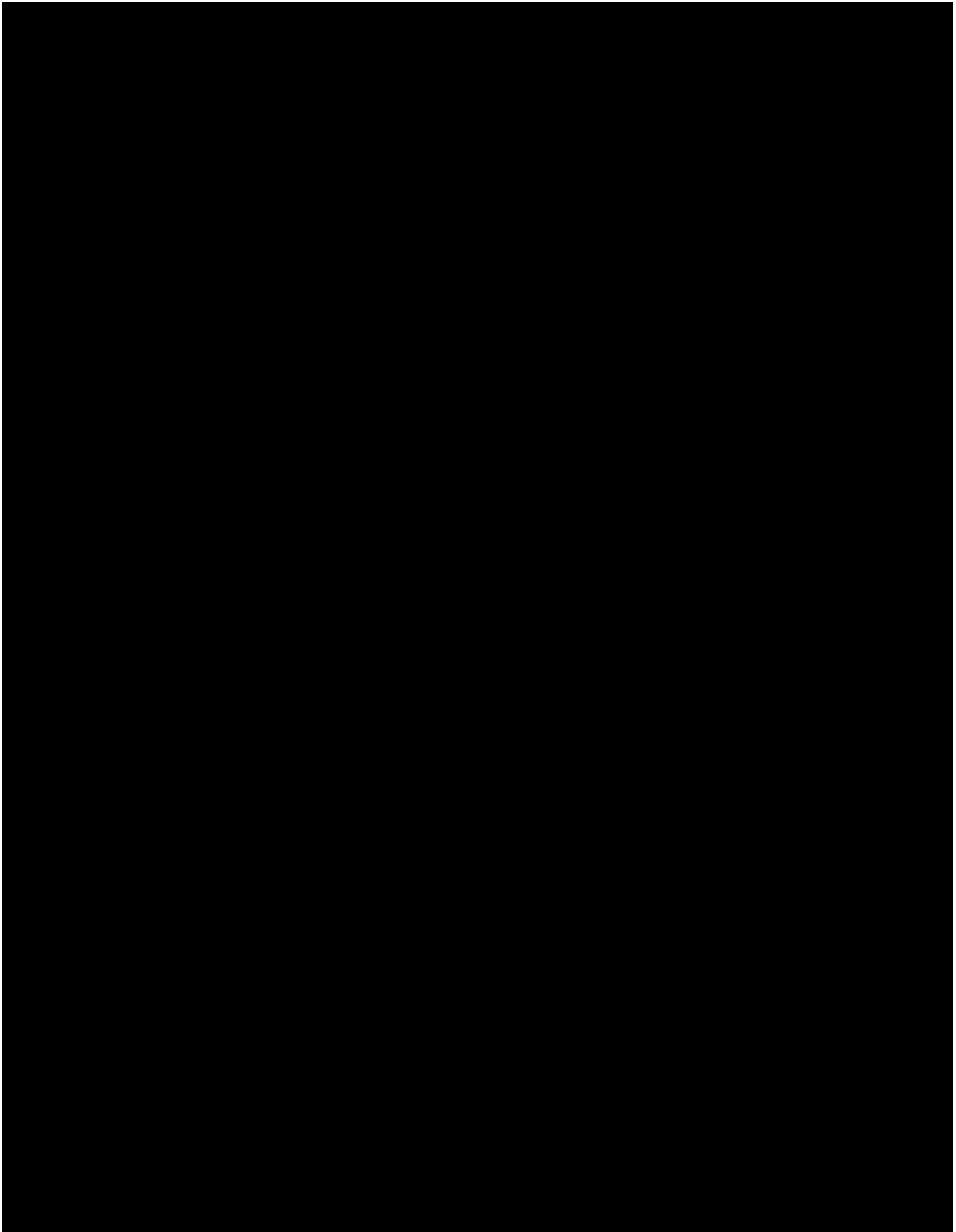


Figure 6-1 – Zonal Isolation Schematic for Loblolly CCS No. 001

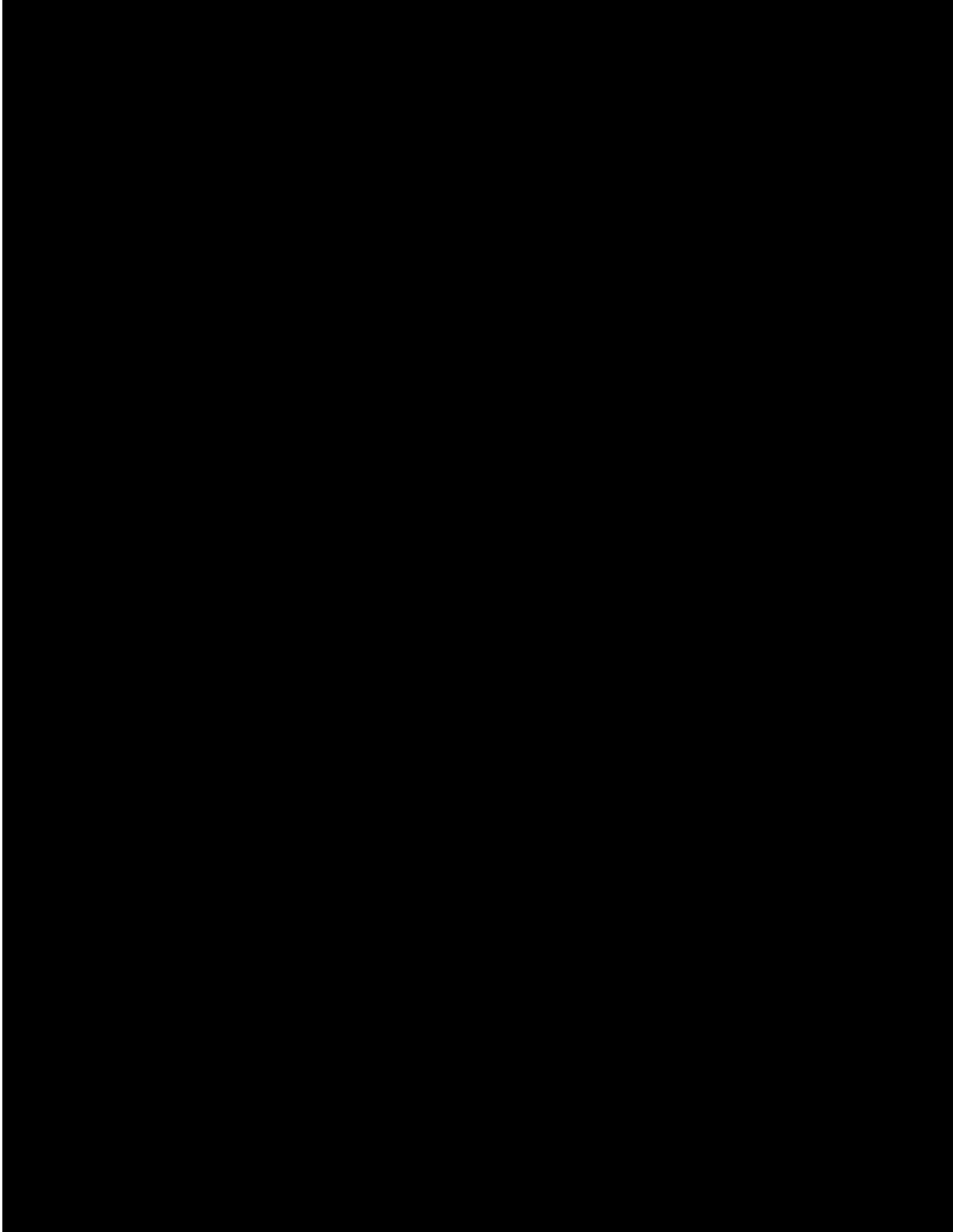


Figure 6-2 – Zonal Isolation Schematic for Loblolly CCS No. 002

6.2.1.2 Zonal Isolation Activities

1. A [REDACTED] will be placed above the active completion stage.
2. A pressure test will be conducted to confirm the plug is properly set.
3. To provide pressure monitoring of each completion stage for the life of the storage project, the perforations will not be squeezed.

The injection well designs allow for zonal isolation operations to be conducted without removing any well components. All zonal isolation activities can be conducted with wireline operations, resulting in an efficient and safe recompletion process.

6.2.2 **Final Plugging and Abandonment**

After injection operations are complete and the pore space of the formation has been utilized, the injection wells will be prepared for final P&A. The general procedure includes the following.

6.2.2.1 Pre-plugging Activities for Loblolly CCS No. 001 and No. 002

1. Notice of Intent to Plug will be communicated to the Louisiana Department of Natural Resources (LDNR) by submitting Form UIC-17 with detailed plans. (SWO 29-N-6 **§3631.A.4**). No actual well-plugging operations will commence until written approval from the Commissioner is received.
2. Downhole pressure gauges, permanently installed on the backside of the casing, will be used to measure the bottomhole reservoir pressure.
3. Mechanical integrity of the tubing-casing annulus will be demonstrated by pressure testing, as described in *Section 5 – Testing and Monitoring Plan*. (SWO 29-N-6 **§3631.A.2** [40 CFR **§146.92(a)**])
4. Casing inspection and cement bond logs will be performed prior to final plugging. Log evaluation will determine if the plugging procedure needs to be revised.

6.2.2.2 Plugging Activities for Loblolly CCS No. 001

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Tables 6-1 and 6-2 provide the details for well-construction materials to be removed for Loblolly CCS No. 001 and No. 002, respectively.

Table 6-1 – Description of Tubing and Other Well-Construction Materials to Be Removed, Loblolly CCS No. 001

Well Component	Size	Amount	Notes / Comments
Injection Tubing and Packer Seal Assembly	4	1	4
Injection Packer	4	1	4
Tail Pipe and PBR Seal Assembly	4	1	4

Table 6-2 – Description of Tubing and Other Well-Construction Materials to Be Removed, Loblolly CCS No. 002

Well Component	Size	Amount	Notes / Comments
Injection Tubing and Packer Seal Assembly	4	1	4
Injection Packer	4	1	4
Tail Pipe and PBR Seal Assembly	4	1	4

Tables 6-3 and 6-4 provide the plugging details for zonal isolation plugs for Loblolly CCS No. 001 and No. 002, respectively; Tables 6-5 and 6-6 provide the same for cement plugs for the two injection wells, respectively.

Table 6-3 – Plugging Details for Zonal Isolation Plugs, Loblolly CCS No. 001

Class VI Permit Application, Section 6 – Loblolly CCS No. 001 and No. 002

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Table 6-5 – Plugging Details for Cement Plugs, Loblolly CCS No. 001

Plug Description	UCZ Plug	Surface Casing Shoe and USDW Plug	Surface Plug
Plug Number	1	2	3
Diameter of Boring in Which Plug Will Be Placed	██████	██████	██████
Depth to Bottom of Tubing or Drill Pipe (MD)	██████	██████	████
Sacks of Cement to Be Used (each plug)	██	██	██
Slurry Volume to be Pumped (cf)	██	██	██
Slurry Weight (lb/gal)	████	████	████
Top of Plug (MD)	██████	██████	████
Bottom of Plug (MD)	██████	██████	████
Type of Cement or Other Material	██████ ██████	██████ ██████	██████ ██████
Method of Emplacement	██████	██████	██████
New Plug?	██	██	██

*UCZ – upper confining zone

Table 6-6 – Plugging Details for Cement Plugs, Loblolly CCS No. 002

Plug Description	UCZ Plug	Surface Casing Shoe and USDW Plug	Surface Plug
Plug Number	1	2	3
Diameter of Boring in Which Plug Will Be Placed	██████ ██████	██████	██████
Depth to Bottom of Tubing or Drill Pipe (MD)	██████	██████	████
Sacks of Cement to Be Used (each plug)	██	██	██
Slurry Volume to be Pumped (cf)	██	██	██
Slurry Weight (lb/gal)	████	████	████
Top of Plug (MD)	██████	██████	████
Bottom of Plug (MD)	██████	██████	████
Type of Cement or Other Material	██████ ██████	██████ ██████	██████ ██████
Method of Emplacement	████████	████████	████████
New Plug?	██	██	██

Figures 6-3 and 6-4 show the final plugging schematics for Loblolly CCS No. 001 and No. 002, respectively.

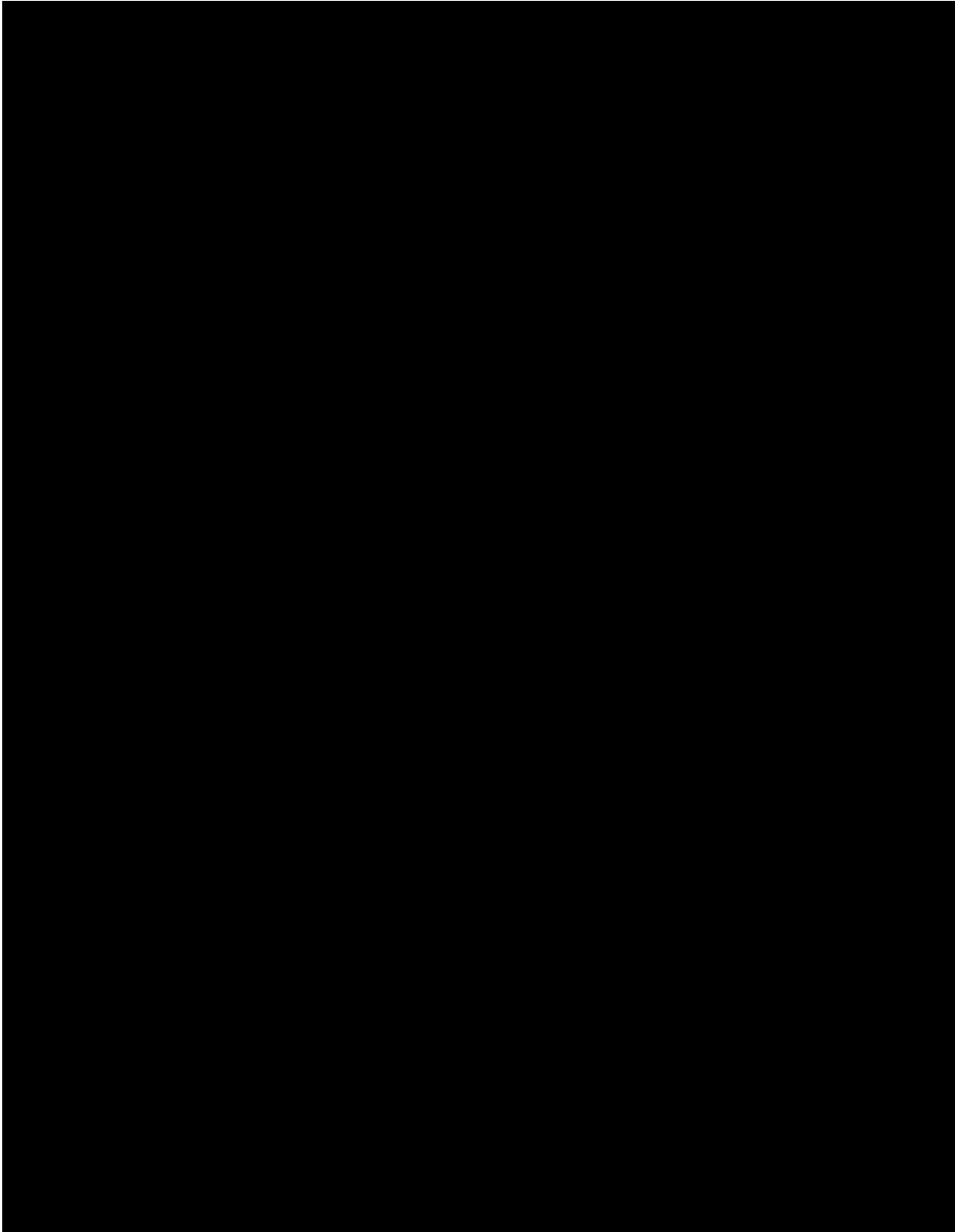


Figure 6-3 – Final Plugging Schematic for Loblolly CCS No. 001

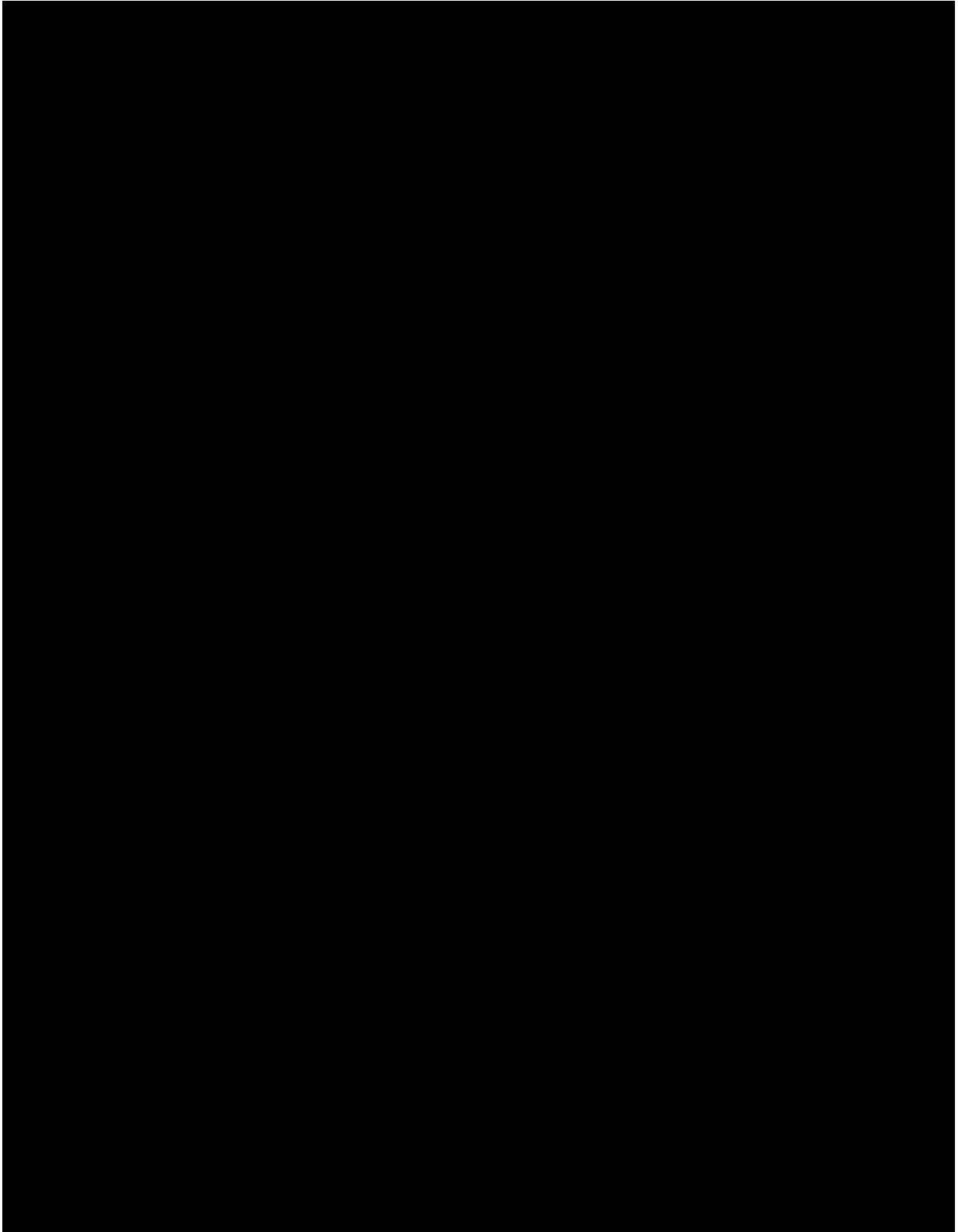


Figure 6-4 – Final Plugging Schematic for Loblolly CCS No. 002

6.3 Monitoring Well Plugging and Abandonment Plans

The following sections detail the P&A of the USDW and AZMI monitoring wells associated with the project.

6.3.1 Pre-plugging Activities for All Wells

Evergreen will comply with all reporting and notification provisions, including the following.

1. Notice of Intent to Plug will be communicated to LDNR by submitting Form UIC-17 with detailed plans. (SWO 29-N-1 **§109.D.4**) No actual well-plugging operations will commence until written approval from the Commissioner is received.

6.3.2 Plugging Procedure for

Response	Percentage
Yes, the U.S. should take action to address climate change	85%
No, the U.S. should not take action to address climate change	15%

6.3.2.1 Final P&A Wellbore Schematic –

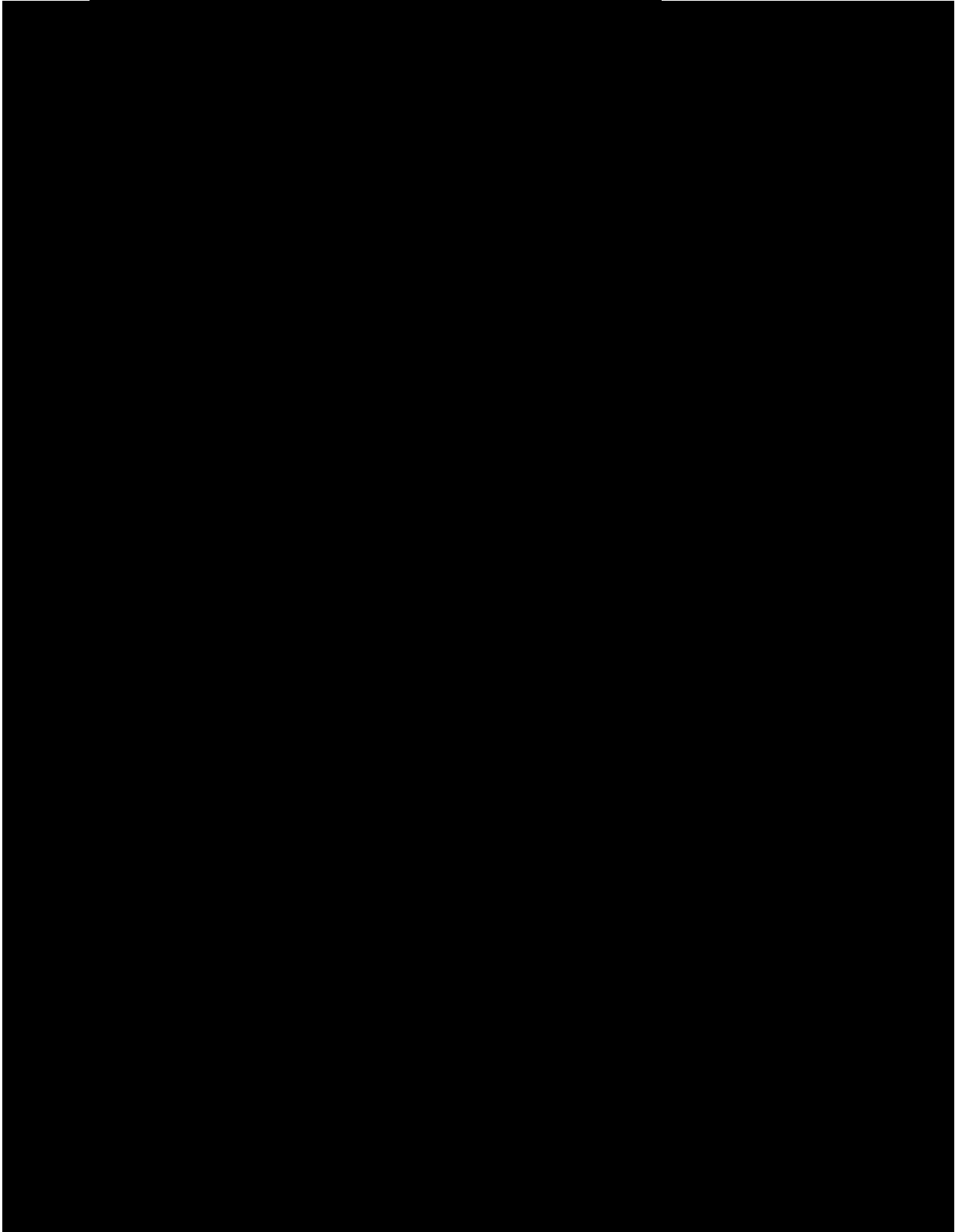


Figure 6-5 – Final Plugging Schematic for

6.3.3 Plugging Procedure for Loblolly

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

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[REDACTED]

[REDACTED]

6.3.3.1 Final P&A Wellbore Schematic –

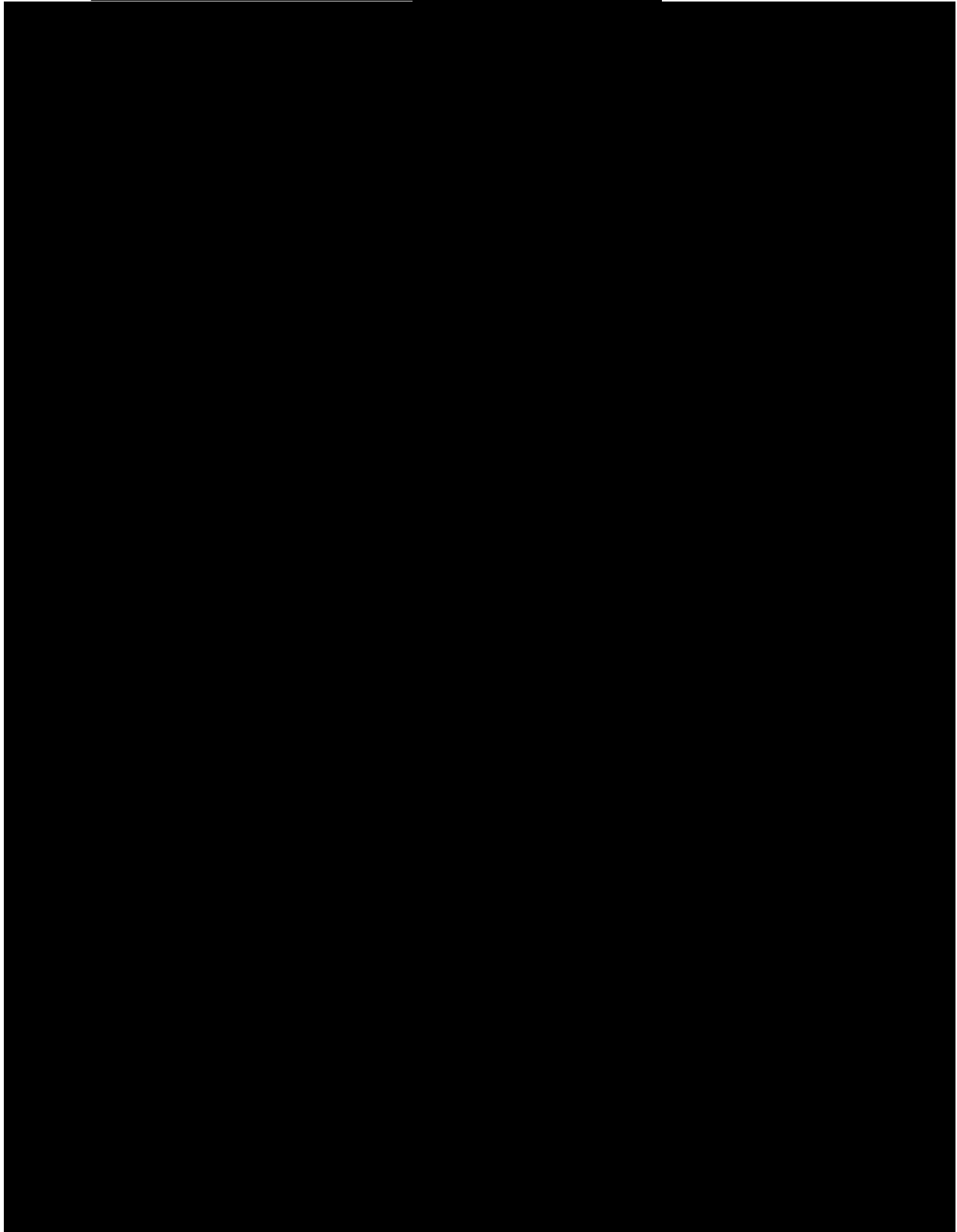


Figure 6-6 – Final Plugging Schematic for

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6.3.4.1 Final P&A Wellbore Schematic –

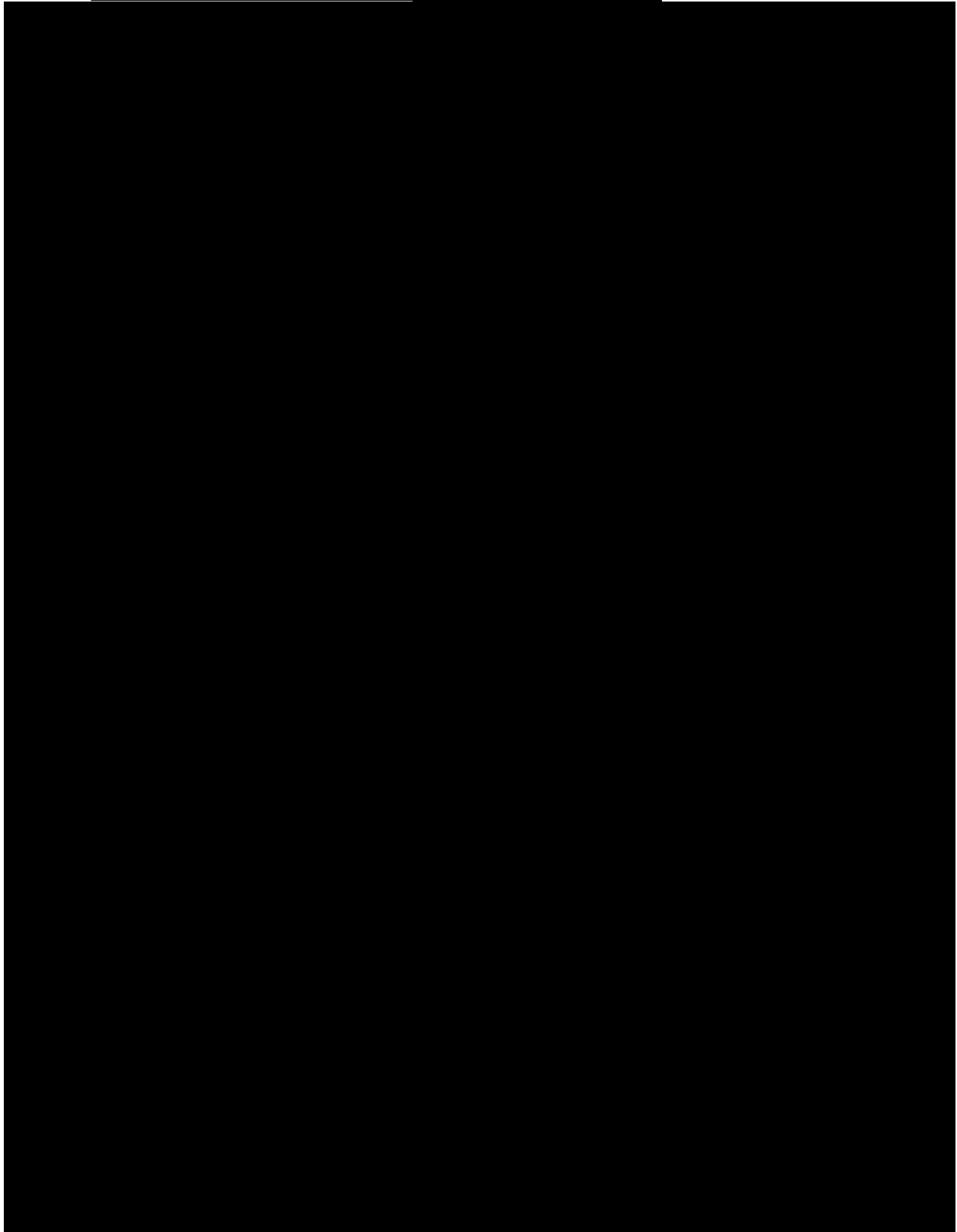


Figure 6-7 – Final Plugging Schematic for

6.3.5 Plugging Procedure for [REDACTED] [REDACTED]



Figure 6-8 shows the plugging schematic for [REDACTED]

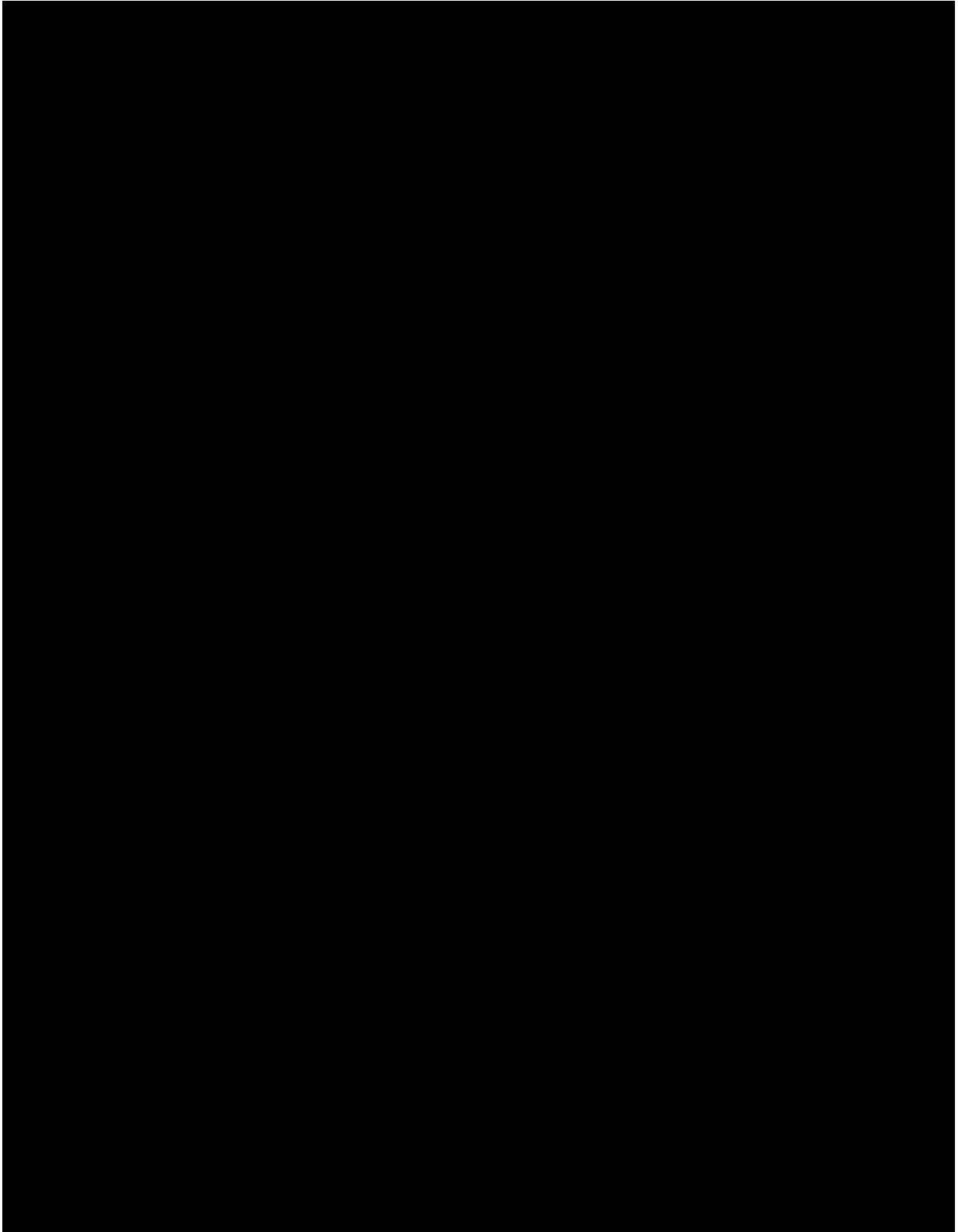


Figure 6-8 – Final Plugging Schematic for [REDACTED]

6.3.6 Plugging Procedure for [REDACTED]



Figure 6-9 shows the plugging schematic for [REDACTED]

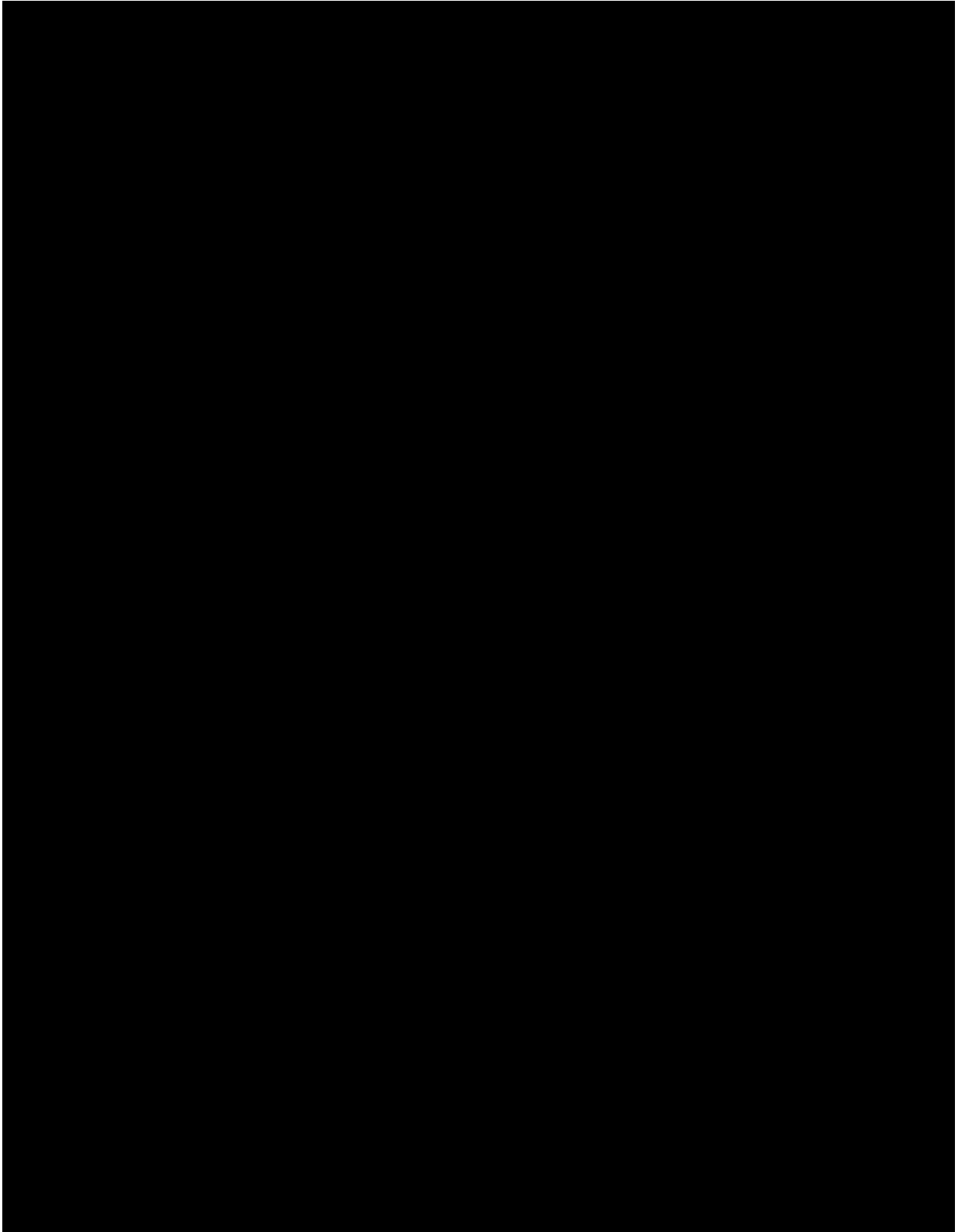


Figure 6-9 – Final Plugging Schematic for [REDACTED]

6.3.7 Plugging Procedure for [REDACTED]



Figure 6-10 shows the plugging schematic for [REDACTED]

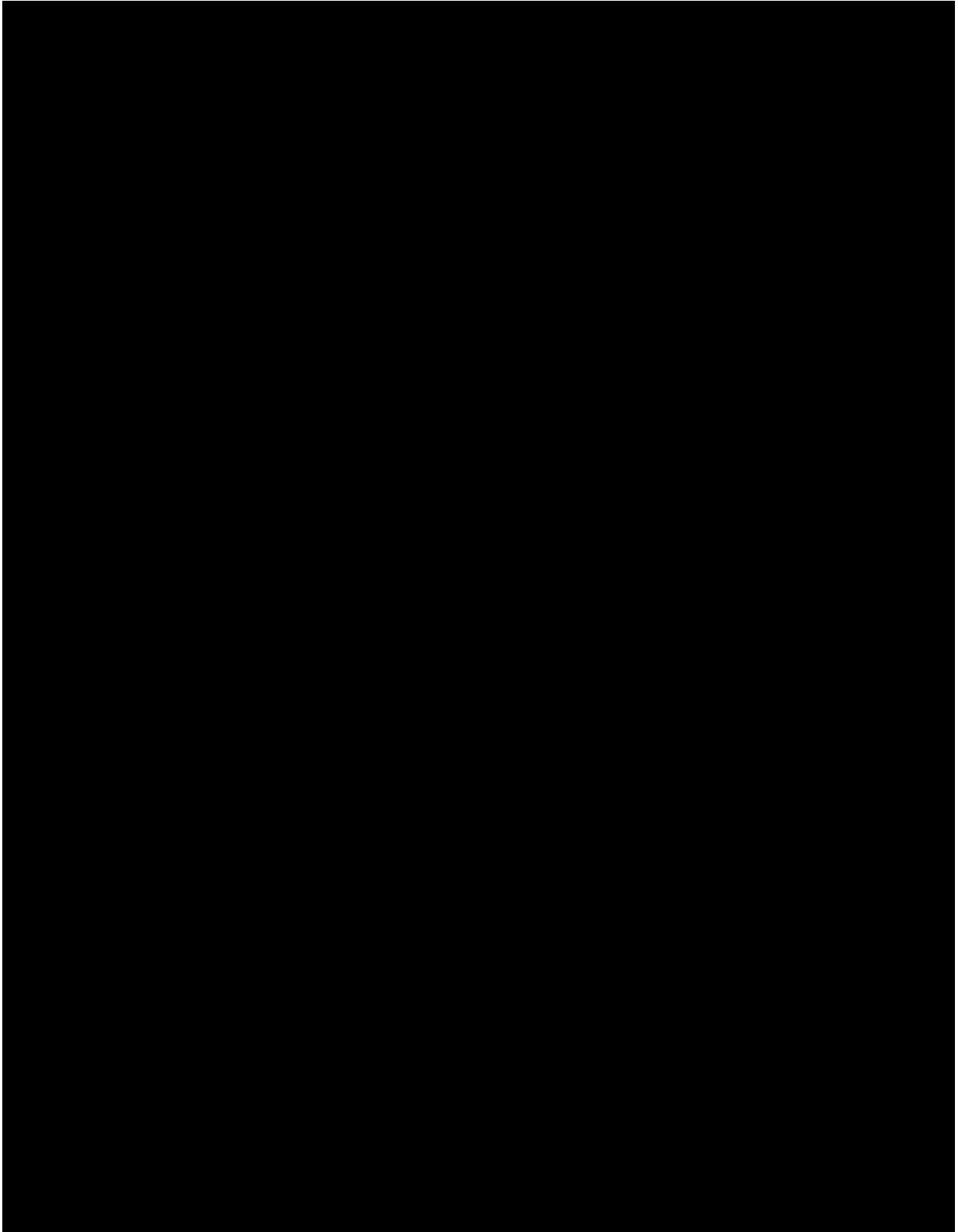


Figure 6-10 – Final Plugging Schematic for [REDACTED]

Appendix H – Well Plugging Schematics and Procedures:

- Appendix H-1 Loblolly CCS No. 001 Zonal Isolation Schematic
- Appendix H-2 Loblolly CCS No. 002 Zonal Isolation Schematic
- Appendix H-3 Loblolly CCS No. 001 Detailed Plugging Procedure
- Appendix H-4 Loblolly CCS No. 002 Detailed Plugging Procedure
- Appendix H-5 Loblolly CCS No. 001 Final P&A Schematic
- Appendix H-6 Loblolly CCS No. 002 Final P&A Schematic
- Appendix H-7 [REDACTED]
- Appendix H-8 [REDACTED]
- Appendix H-9 [REDACTED]
- Appendix H-10 [REDACTED]
- Appendix H-11 [REDACTED]
- Appendix H-12 [REDACTED]



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

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

February 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 Evergreen Sequestration Hub, LLC's (Evergreen) injection wells Loblolly CCS No. 001 and Loblolly CCS No. 002 was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3633.A.1** [Title 40, US Code of Federal Regulations (40 CFR) **§146.93(a)**]. This plan describes the various activities that will occur once injection has ceased and during the site closure. The Site Closure Plan will be implemented once Evergreen demonstrates that no additional monitoring is needed to ensure that this project poses no further endangerment to Underground Sources of Drinking Water (USDWs).

7.2 Pre- and Post-Injection Pressure Differentials

To meet the requirements of SWO 29-N-6 **§3633.A.1.b** [40 CFR **§146.93(a)(2)**], the following table shows the expected pressure differential between pre- and predicted post-injection pressures in the injection zone, as determined by the plume model described in *Section 2 – Plume Model*. As discussed there and in *Section 4 – Engineering Design and Operating Strategy*, both Evergreen Sequestration Hub (Evergreen Hub) project injection wells [REDACTED]

The highest pressure differential for Loblolly CCS No. 001 occurs in [REDACTED] The highest pressure differential for Loblolly CCS No. 002 occurs in [REDACTED] Once injection ceases in each stage, the pressure drops down to near-reservoir pressures. Table 7-1 shows the maximum pressure differential at the wellbore predicted in each year modeled.

Table 7-1 – Maximum Pressure Differential by Year

Year	Max Pressure Differential (psi) Loblolly CCS No. 001	Max Pressure Differential (psi) Loblolly CCS No. 002
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]

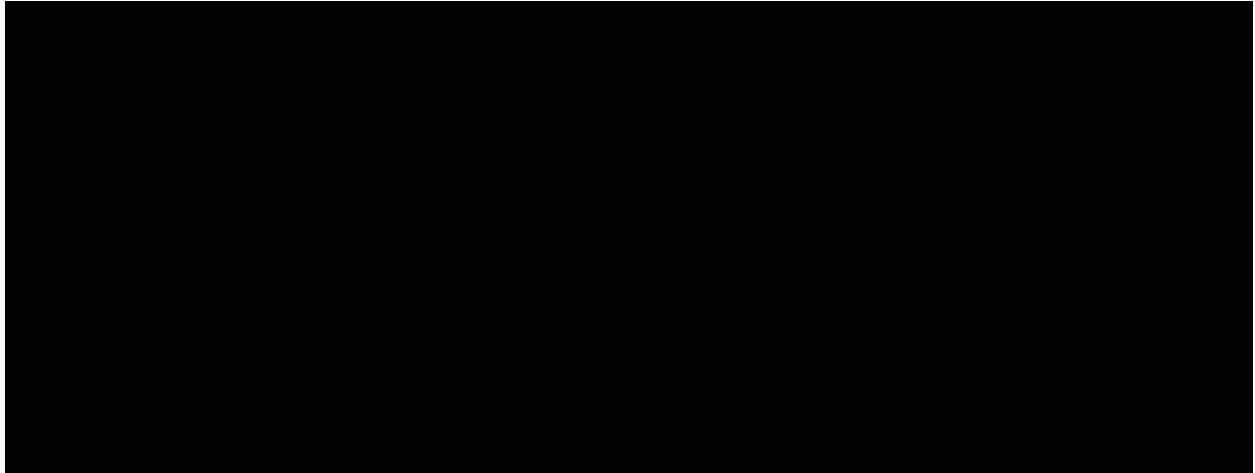


Figure 7-2 – Maximum Pressure Differential Over Time for Loblolly CCS No. 002

7.3 CO₂ Plume Position and Pressure Front at End of Closure

The area of review (AOR) consists of both the CO₂ plume and critical pressure maximum extent. Figure 7-3 shows the AOR and its subcomponents. The CO₂ plumes are indicated by the pink shaded area, based on the maximum extent of all the differing plume layers in the model, extracted at [REDACTED] post-injection. The black outlined areas represent the critical pressure front. The CO₂ plume area and critical pressure front AOR consider both Loblolly CCS No. 001 and Loblolly CCS No. 002.

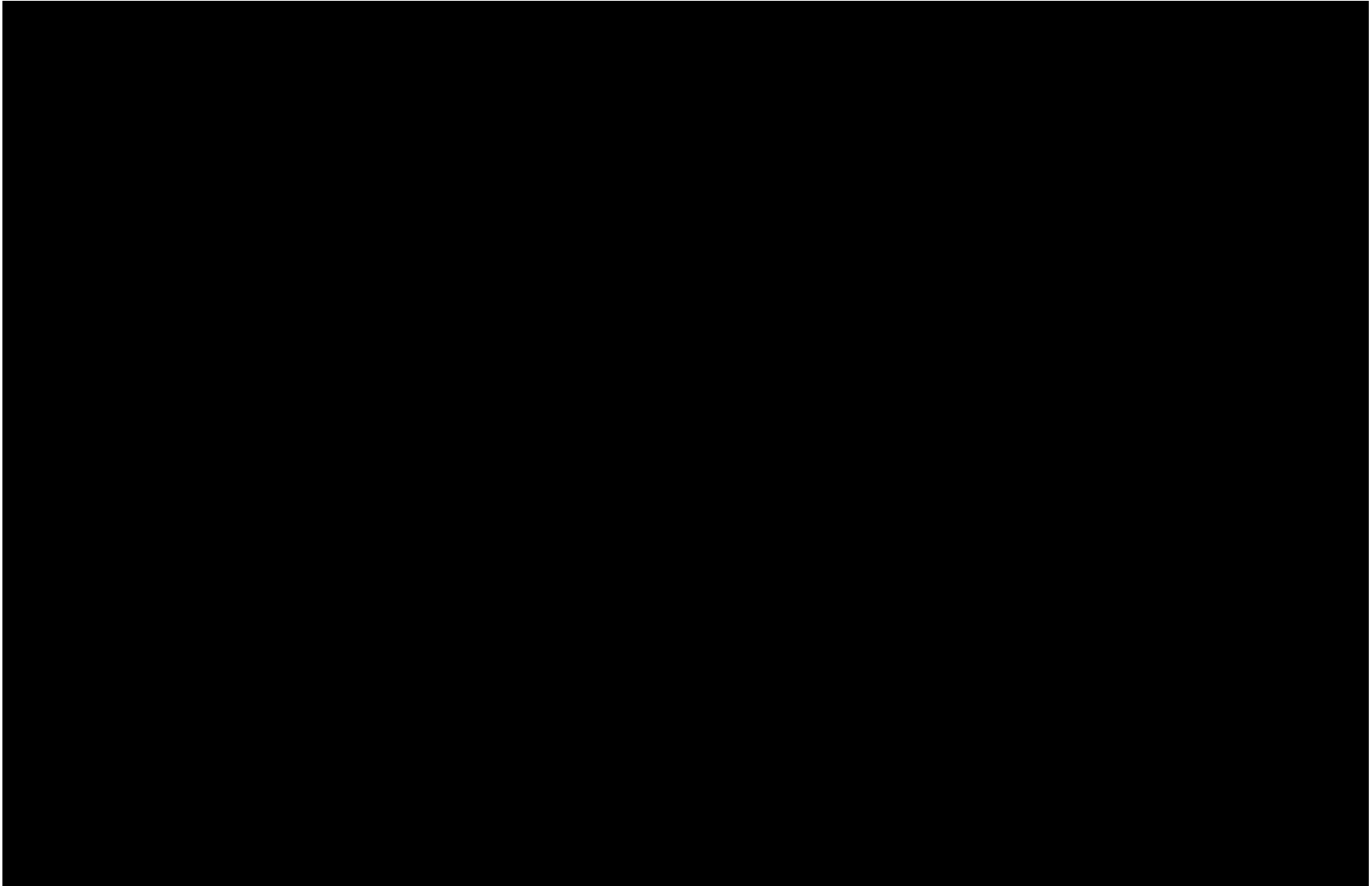


Figure 7-3 – CO₂ Plume and Pressure Front

7.4 Post-Injection Monitoring Plan

As required by SWO 29-N-6 §3633.A.2 [40 CFR §146.93(b)], Evergreen will continue to monitor the site for [REDACTED] or until it is demonstrated that the project no longer poses a potential endangerment to the USDW, as described in *Section 7.6*. The reservoir model will continue to be updated, using monitoring data, throughout the project. Upon cessation of injection, an amended PISC—if the updated model warrants it—will be submitted to the Commissioner of Conservation(Commissioner).

7.5 Post-Injection Monitoring Activities

During the monitoring period, the testing and monitoring activities, as described in *Section 5 – Testing and Monitoring Plan*, will be performed and reported at the frequency shown in Table 7-2. The post-injection monitoring results will be submitted to the Commissioner and to the EPA.

Table 7-2 – Post-Injection Monitoring and Reporting Frequency

Testing/Monitoring Activity	Frequency	Reporting Schedule	Comment
USDW monitoring well fluid sampling and analysis	[REDACTED]	[REDACTED] [REDACTED] [REDACTED]	
Above-zone monitoring interval (AZMI) monitoring well-fluid sampling and analysis	[REDACTED] [REDACTED] [REDACTED]	[REDACTED] [REDACTED] [REDACTED]	
AZMI pressure measurements	[REDACTED]	[REDACTED]	
Injection-well wellhead pressure monitoring (tubing and annulus)	[REDACTED]	[REDACTED]	
Injection well in-zone pressure/temperature (P/T) monitoring	[REDACTED] [REDACTED] [REDACTED] [REDACTED]	[REDACTED]	[REDACTED] [REDACTED] [REDACTED] [REDACTED] [REDACTED] [REDACTED] [REDACTED] [REDACTED] [REDACTED] [REDACTED]
[REDACTED] [REDACTED]	[REDACTED] [REDACTED]	[REDACTED] [REDACTED]	[REDACTED] [REDACTED]

	██████████ ██████████ ██████████ ██████████ ██████████	██████████ ██████████ ██████████	████████████████████ ████████████████████ ████████████████████ ██████████
Direct plume calculations based on P/T data	██████████	██████████	

██

All testing and monitoring activities listed will be performed and analyzed as discussed in *Section 5*, including quality assurance/quality control (QA/QC) measures.

7.6 Demonstration of Nonendangerment of USDW

The primary mechanism through which the USDWs are protected is the upper confining zone (UCZ), which is characterized as a single confining shale. The monitoring data that will be collected after injection ceases verifies that the UCZ is functioning as expected and that the USDW is not endangered.

The monitoring data will also be used to calibrate the simulation model and further enhance its ability to accurately predict the movement of CO₂. These calibrated simulation-model predictions are used to identify any UCZ-penetrating features with which the CO₂ plume may interact prior to final stabilization. Examples of these features of concern are legacy wellbores and fault planes. Any legacy wellbore with which the CO₂ plume is modeled to interact will be assessed, to determine if it is adequately abandoned. This effort ensures that (1) legacy wellbores do not compromise the integrity of the UCZ and (2) the USDW is not endangered. The calibrated simulation-model predictions are also used to verify that the CO₂ does not reach fault planes cutting through the UCZ.

Prior to the approval of the site-closure authorization, as required by SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(c)**], Evergreen will provide documentation that the USDW is not at risk of future endangerment from the CO₂ plume. While the PISC duration is ██████████, it may be possible to demonstrate USDW non-endangerment earlier. For example, after ██████ years of post-injection monitoring, ████████████████████, combined with other monitoring measurements, will be available to demonstrate the containment of the plume. Evergreen will submit a report to the Commissioner supporting non-endangerment of the USDW, including site-specific conditions, updated plume model, predicted pressure decline within the injection zone, and any updates to the underlying geological assumptions used in the original model.

7.7 Site Closure Plan

To meet the requirements of SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(e)**], the following activities will be performed: plugging of all wells, site closure, and submittal of final site-closure reports.

7.7.1 Pre-Closure

Notice of Intent to Close the site will be submitted to the Commissioner 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.

7.7.2 Plugging Activities

The Loblolly injection, AZMI monitoring, and USDW monitoring wells will be plugged as discussed in *Section 6 – Plugging Plan*. The plugging and abandonment procedures for the injectors include measures to prevent CO₂ or formation fluids in the injection interval from migrating to the USDW. Prior to plugging the injection and AZMI wells, the mechanical integrity of those wells will be verified. Plugging schematics and procedures are provided in *Appendix H*.

7.7.3 Site Restoration

Once the injection and monitoring wells are plugged and capped below grade, all surface equipment will be decommissioned and removed. The site will be restored according to the agreement with the surface owner.

7.7.4 Documentation of Site Closure

Within 90 days of site closure, a final report must be submitted to the Commissioner and the EPA, per the requirements of SWO 29-N-6 **§3633.A.6** [40 CFR **§146.93(f)**], and will include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats;
- Documentation of well-plugging report to the Louisiana Department of Natural Resources (LDNR); and
- Records of the nature, composition, and volume of the CO₂ stream over the injection period.

A record of notation in the facility property deed will be added to provide, in perpetuity, any potential purchaser of the property the following information:

- The fact that the land was used to sequester carbon dioxide;
- The name of the state agency (LDNR) with which the survey plat was filed, and the address of the EPA Regional Office to which it was submitted; and
- The total volume of fluid injected, the injection zones into which it was injected, and the period over which injection occurred.

Evergreen will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, Evergreen will deliver all records to the Commissioner for retention at a location designated by the Commissioner for that purpose.



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

February 2024



SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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None included in this section.

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8.1 Introduction

This Emergency and Remedial Response Plan (ERRP) for the Evergreen Sequestration Hub (Evergreen Hub) project was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 §3623 [Title 40, U.S. Code of Federal Regulations (40 CFR) §146.94]. The plan describes potential adverse events that could occur in the development, operation, and post-injection site care phases of the project, and the actions to be taken in the event of such an emergency. This plan will be reviewed and updated as needed and no less than every five years. Any change in key personnel will also cause the ERRP to be updated immediately.

8.2 Resources/Infrastructure in the Area of Review

The Evergreen Hub injection wells are approximately [REDACTED] miles (mi) west-southwest of DeQuincy, Louisiana, and [REDACTED] mi northeast of Starks, Louisiana. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] A plugging operation is proposed—planned to ensure the protection of the USDW—because this wellbore reaches the upper confinement zone (UCZ).

The lowermost USDW in the AOR is estimated to be at [REDACTED]

8.3 Resources/Infrastructure – Specific Events and Response Plans

The following scenarios represent a high-level concept of potentially significant adverse events, methods of prevention and detection, and the likely remedial responses.

8.3.1 Event Category – Water Quality Impact

8.3.1.1 Specific Event Description – Leakage of drilling fluid contaminates potable water aquifer *Risk Assessment Matrix, Section 1.1 (Appendix G-2)*

It is possible that drilling fluid could leak during the drilling of the well. In the unlikely event that drilling fluid leaks, it may impact the freshwater aquifer.

Prevention and Detection:

- Select a proper drilling-fluids program including freshwater-based muds while drilling through USDW intervals.
- The wells are specifically designed to prevent the likelihood of this occurring.

Potential Response Actions:

- If groundwater/USDW is impacted:
 - Notify any appropriate emergency services and agencies.
 - Apply “pump and treat” methods to remove trace elements.
 - Extract and treat affected water at an above-ground treatment facility.
 - Provide an alternative water supply if groundwater-based public water supplies are impacted.

8.3.1.2 Specific Event Description – Poor cement job in CO₂ sequestration well

Risk Assessment Matrix, Section 1.2 (Appendix G-2)

A well-seal failure could occur due to a poor cement job of the cement behind the casing in the form of micro-annuli or channeling. This event could also occur due to the corrosive nature of the CO₂ stream creating a leakage pathway in the cement, if improper materials were used. Either scenario could allow for an escape of CO₂ into USDW intervals.

Prevention and Detection:

- Proper wellbore design, including a proper cement design, procedure, and testing program, will be implemented in the construction phase, prior to any injection of CO₂.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5 – Testing and Monitoring Plan* during injection operations.
- Routine casing inspection logs, temperature surveys, and other tools to detect fluid movement behind the casing will be employed.

Potential Response Actions:

- Stop the injection and notify the State of Louisiana’s Commissioner of Conservation (Commissioner) within 24 hours.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of the failure to determine if the CO₂ stream or formation fluids may have been released into any unauthorized zone.
- Install a chemical-sealant barrier and/or attempt a cement squeeze to block leaks.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.1.3 Specific Event Description – Well-casing failure of CO₂ sequestration well

Risk Assessment Matrix, Section 1.3 (Appendix G-2)

A well-seal failure could occur due to the failure of the casing during installation or operation. This event could also occur due to a corrosive CO₂ stream creating a break in the casing—and escaping either into USDW intervals.

Prevention and Detection:

- Proper wellbore design, including proper metallurgy of the casing, will be implemented in the construction phase.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5 – Testing and Monitoring Plan*.
- Routine casing inspection logs will be employed.

Potential Response Actions:

- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of the failure to determine if the CO₂ stream or formation fluids may have been released into any unauthorized zone.
- Install a chemical-sealant barrier and/or attempt a cement squeeze to block leaks.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the Commissioner when injection can be expected to resume.

8.3.1.4 Specific Event Description – Subsurface overpressurization (i.e., induced)

Risk Assessment Matrix, Section 1.4 (Appendix G-2)

Overpressurization during injection-facility operations could cause CO₂ to migrate into another zone—including the USDW—or to the surface. This situation could also occur if maximum allowable operating parameters change due to degradation or corrosion of equipment, and the changes are not recognized.

Prevention and Detection:

- Proper operation, inspection, and preventive maintenance of all surface facility equipment will be implemented.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- Surface wellhead trees will be regularly maintained and tested for integrity.
- Subsurface safety valves will be tested regularly.

- Automatic controls, equipment shutdowns, and pressure relief devices will be incorporated into the facility design and operations—to monitor for and prevent overpressurization.
- Carbon dioxide detectors will be utilized to continuously monitor ambient air.

Potential Response Actions:

- Shut in the flow line upon any detection of CO₂ at the surface.
- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Activate the downhole safety valve.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Allow pressure to bleed off the equipment and process system, and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.1.5 Specific Event Description – Caprock/reservoir failure

Risk Assessment Matrix, Section 1.5 (Appendix G-2)

Unforeseen geological complications could cause CO₂ to migrate into another zone—including the USDW—or to the surface.

Prevention and Detection:

- Due diligence will be exercised when collecting information from offset wells in the AOR.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will be performed according to guidelines in *Section 5 – Testing and Monitoring Plan*.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- Carbon dioxide detectors will be utilized to continuously monitor ambient air.

Potential Response Actions:

- Shut in the flow line upon any detection of CO₂ at the surface.
- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Activate the downhole safety valve.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring

operations. Coordinate with local emergency services.

- Allow pressure to bleed off the equipment and process system, and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5– Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.
- If groundwater/USDW is impacted:
 - Pump CO₂-impacted groundwater to the surface and aerate it to remove the CO₂.
 - Apply pump-and-treat methods to remove trace elements.
 - Drill well(s) that intersect the accumulations in groundwater and extract CO₂.
 - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
- If surface water is impacted:
 - Verify that no nearby surface water is seen in the AOR. However, any surface water would quickly release dissolved CO₂ back into the atmosphere.
 - Potentially drill well(s) upstream of the leak.
 - Potentially create a hydraulic barrier by increasing the reservoir pressure downstream of the leak.

8.3.1.6 Specific Event Description – Well-seal failure of adjacent wells (i.e., plugged and abandoned (P&A) wells, monitoring wells) or unknown wells (i.e., wells not identified prior to injection)

Risk Assessment Matrix, Section 1.6 (Appendix G-2)

It is possible that well seals in an adjacent well could fail due to improper construction materials, including the cement inside and behind casing, casing and equipment metallurgy characteristics, and plugging materials. This event could also occur due to previously undiscovered orphan wells that create leak paths to the surface because of improper plugging.

Prevention and Detection:

- Perform proper corrective action review and design, including appropriate cement and metallurgy of the plugging materials.
- Perform magnetic surveying to discover undocumented/unknown wellbores.
- Continuous pressure monitoring at surface and downhole will highlight potential issues.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will be performed according to *Section 5 – Testing and Monitoring Plan*.
- Operate via competent management a closely monitored facility and surrounding area.

Potential Response Actions:

- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Activate downhole safety valve.

- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if the CO₂ stream or formation fluids may have been released into any unauthorized zone.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Allow pressure to bleed off the equipment and process system, and allow atmospheric gas levels to return to normal.
- Perform reentry and corrective action as necessary to regain isolation of injectate/formation fluids.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.1.7 Specific Event Description – Seismic event occurs in project area resulting in plume leakage into USDW

Risk Assessment Matrix, Section 1.7 (Appendix G-2)

If a seismic event were to occur in the project area that creates or opens faults or fractures, such an event could provide a pathway for CO₂ migration into another zone, including the USDW. Failure of the confining zone caused by a seismic event could also cause CO₂ to migrate and contaminate the USDW.

Prevention and Detection:

- The CO₂ plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- The chosen project location is within a low-risk seismic area. While some deep faults exist within the plume area, these faults do not reach the upper confinement zone. Outside of the carbon dioxide plume area, two faults terminate above the injection zone—one of which extends above the upper confining zone. A fault seal analysis confirmed that these faults are of a sealing nature through the confining zone. A geomechanical study of the fault slip potential of these faults indicated low increased potential of slip from proposed injection operations. Sensitivity tests run on the deeper faults showed that the plume extent does not change. Additionally, the injection well placement was selected to avoid any intersection of the carbon dioxide front with the surface fault to the south. Based on extensive studies performed during the site characterization for the proposed project—including the fault seal analysis, fault slip potential, and sensitivity studies during the plume modeling—there is little to no risk of CO₂ leaks above the confining zone.
- The wells and operating strategies are designed to prevent the likelihood of this occurring.

Potential Response Actions:

- Lower the injection rates or stop the injection and notify the Commissioner within 24 hours.
- Use [REDACTED] to assess the location and degree of CO₂

movement, as described in *Section 5 – Testing and Monitoring Plan*.

- Resume the injection, if possible, at reduced rates.
- Continue monitoring the plume at more frequent intervals to determine if migration continues.
- If groundwater/USDW is impacted:
 - Pump CO₂-impacted groundwater to the surface and aerate it to remove the CO₂.
 - Apply pump-and-treat methods to remove trace elements.
 - Drill well(s) that intersect the accumulations in groundwater and extract CO₂.
 - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, assess the next planned injection interval for potential leakage and recomplete if satisfactory.
- Notify the Commissioner when injection can be expected to resume.

8.3.1.8 Specific Event Description – Water-CO₂-formation (i.e., geochemistry) interaction contaminates potable water by carryover of dissolved contaminants via leakage.

Risk Assessment Matrix, Section 1.8 (Appendix G-2)

This event could occur due to interactions between injectate and connate reservoir fluids (i.e., geochemical interactions that create hazardous material). This hazardous material could be transported into a USDW or to the surface if a leak path developed, either from the interactions or by other means.

Prevention and Detection:

- Proper wellbore design, including proper metallurgy of the casing, will be implemented in the construction phase.
- Site characterization has been done to determine that the upper confinement will prevent carryover.
- Samples of the CO₂ stream will be collected from the injection-source pipeline. Samples representative of injection conditions will be sent to a third-party laboratory for analysis.
- Baseline geochemical analysis of fluids in injection interval will be conducted before injection.

Potential Response Actions:

- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if the CO₂ stream or formation fluids may have been released into any unauthorized zone.

- Install a chemical-sealant barrier and/or attempt a cement squeeze to block leaks.
- Investigate potential interactions between the injectate and connate formation fluids.
- Chemically treat the injectate stream to reduce the effects of geochemical interactions.
- Demonstrate mechanical integrity per the methods discussed in *Section 5– Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.2 Event Category – CO₂ Release to or at the Surface

8.3.2.1 Specific Event Description – Major mechanical failure of flowlines or distribution system *Risk Assessment Matrix, Section 2.1 (Appendix G-2)*

A major mechanical failure of the CO₂ flowlines and distribution system is possible during injection-facility operations by operating equipment (1) outside designed operating parameters, (2) beyond recommended preventive maintenance cycles, or (3) improperly.

Prevention and Detection:

- Operate a closely monitored facility with competent management.
- Automatic controls, equipment shutdowns and pressure relief devices will be incorporated into the facility design and operations to monitor for and prevent overpressurization.
- Proper operation, inspection, and preventive maintenance of all surface-facility equipment will be performed.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- Monitor the incoming CO₂ stream for corrosive impurities to prevent/stop their entry into the system.
- Surface wellhead trees will be regularly maintained and tested for integrity.
- Carbon dioxide detectors will be utilized to continuously monitor ambient air.

Potential Response Actions:

- Shut in the flow line upon any detection of CO₂ at the surface.
- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Activate the downhole safety valve.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Allow pressure to bleed off the equipment and process system, and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and*

Monitoring Plan.

- Notify the Commissioner when injection can be expected to resume.

8.3.2.2 Specific Event Description – Sabotage/terrorist attack

Risk Assessment Matrix, Section 2.2 (Appendix G-2)

Theoretically, this event could happen during injection-facility operations by any person or organization wishing to cause harm to life, property, or environment. This facility is not of strategic or cultural importance; therefore, this event has a very low risk.

Prevention and Detection:

- Stay current with recent events in the local area and around the country and globe, that could potentially warrant a threat to the facility.
- Properly secure the facility and surrounding area.
- Proper operation and preventive maintenance of all surface-facility equipment will be performed.
- Surface wellhead trees will be regularly maintained and tested for integrity.
- Subsurface safety valves will be regularly tested.
- Carbon dioxide detectors will be utilized to continuously monitor ambient air.

Potential Response Actions:

- Shut in the flow line upon any detection of CO₂ at the surface.
- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Activate the downhole safety valve.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Allow pressure to bleed off the equipment and process system, and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.2.3 Specific Event Description – Act of God

Risk Assessment Matrix, Section 2.3 (Appendix G-2)

A hurricane, tropical storm, un-named storm, tornado, wildfire, etc., could potentially impact surface infrastructure. Safety shutdown systems that will be installed limit risk to safety and environment.

Prevention and Detection:

- Stay current locally with weather and wildfire-related events that could threaten facility.
- Properly secure the facility and surrounding area.
- Proper operation and preventive maintenance of all surface-facility equipment will be performed.
- Surface wellhead trees will be regularly maintained and tested for integrity.
- Subsurface safety valves will be regularly tested.
- Carbon dioxide detectors will be utilized to continuously monitor ambient air.

Potential Response Actions:

- Shut in the flow line upon any detection of CO₂ at the surface.
- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Activate the downhole safety valve.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations. Coordinate with local emergency services.
- Allow pressure to bleed off the equipment and process system, and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.3 Event Category – Storage Rights Infringement

8.3.3.1 Specific Event Description – Injected plume migrates into adjacent pore space *Risk Assessment Matrix, Section 3.1 (Appendix G-2)*

This event could occur if the plume expands beyond reservoir model predictions and migrates off the operator-controlled acreage and into neighboring pore space.

Prevention and Detection:

- The CO₂ plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- Model the AOR to confirm ownership and/or control of pore space within the AOR.

Potential Response Actions:

- Lower the injection rates or stop the injection and notify the Commissioner within 24 hours.
- Use [REDACTED] [REDACTED] to assess the location and degree of CO₂ movement, as described in *Section 5 – Testing and Monitoring Plan*.
- Restart the injection, if possible, at reduced rates.

- Possibly recomplete into an untried, shallower injection interval.
- Continue monitoring the plume at more frequent intervals to determine if migration continues.
- If migration off of Evergreen Hub pore space is detected or identified to be likely:
 - Negotiate with neighboring landowner to acquire rights to store within the affected pore space.

8.3.3.2 Specific Event Description – Migration of CO₂ by others/competitors on the Evergreen Hub site

Risk Assessment Matrix, Section 3.2 (Appendix G-2)

This event could occur if the carbon dioxide of others or competitors migrates into the pore space controlled by the operator.

Prevention and Detection:

- The CO₂ plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- Strategically locate the injection operations in an area devoid of other known carbon sequestration or injection operations.

Potential Response Actions:

- If migration is detected or identified to be likely:
 - Obtain control of additional pore space through outright ownership or lease agreements.
- Lower the injection rates or stop the injection and notify the Commissioner within 24 hours.
- Use [REDACTED] [REDACTED] to assess the location and degree of CO₂ movement, as described in *Section 5 – Testing and Monitoring Plan*.
- Restart the injection, if possible, at reduced rates.
- Possibly recomplete into an untried, shallower injection interval.
- Continue monitoring the plume at more frequent intervals to determine if migration continues.

8.3.3.3 Specific Event Description – Acts of God affecting storage capacity of pore space

Risk Assessment Matrix, Section 3.3 (Appendix G-2)

This event could occur in the event of an earthquake or other act of God. Risk is considered remote due to the low seismic risk profile of the area—and considering that any known faults in the area have been assessed and modeled appropriately. Acts of God are more likely to affect the surface than the subsurface.

Prevention and Detection:

- The CO₂ plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.

Potential Response Actions:

- If migration is detected or identified to be likely:
 - Lower injection rates or stop the injection and notify the Commissioner within 24 hours.
- Use [REDACTED] [REDACTED] to assess the location and degree of CO₂ movement, as described in *Section 5*.
- Restart the injection, if possible, at reduced rates.
- Possibly recomplete into an untried, shallower injection interval.
- Continue monitoring the plume at more frequent intervals to determine if pore space impact further affects CO₂ migration.

8.3.4 Event Category – Entrained Contaminant (Non-CO₂) in Injection Stream

8.3.4.1 Specific Event Description – Change in CO₂ composition/properties from its source impacts the reservoir

Risk Assessment Matrix, Section 4.1 (Appendix G-2)

This event could occur due to changes in contamination levels in the CO₂ source. The sources of contaminants may impact dissolution and geochemical reactions in the injection interval.

Prevention and Detection:

- Samples of the CO₂ stream will be collected from the injection-source pipeline. Samples representative of injection conditions will be sent to a third-party laboratory for analysis which will indicate contaminant levels.
- Baseline geochemical analysis of fluids in injection interval prior to injection.
- Monitor the incoming CO₂ stream for corrosive impurities to prevent/stop their entry into the system.

Potential Response Actions:

- Lower the injection rates or stop the injection.
- Notify the Commissioner within 24 hours.
- Determine the cause of contaminants.
- Investigate potential interactions between contaminants and connate formation fluids.
- Remediate the source of contaminants.
- Chemically treat the stream to reduce the effect of contaminants.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.4.2 Specific Event Description – Change in CO₂ composition/properties from its source causes impact to metallurgical considerations

Risk Assessment Matrix, Section 4.2 (Appendix G-2)

This event could occur due to changes in contamination levels in the CO₂ source. The sources of contaminants may cause metallurgical incompatibilities between injectate and/or connate reservoir fluids, affecting the wellbore integrity of all penetrations in injection interval.

Prevention and Detection:

- Samples of the CO₂ stream will be collected from the injection-source pipeline. Samples representative of injection conditions will be sent to a third-party laboratory for analysis, which will indicate contaminant levels.
- Baseline geochemical analysis of fluids in injection interval will be conducted prior to injection.
- Proper wellbore design, including proper metallurgy of the casing, will be implemented in the construction phase.
- Perform proper corrective action review and design, including appropriate cement and metallurgy of the plugging materials.
- Monitor the incoming CO₂ stream for corrosive impurities to prevent/stop their entry into the system.

Potential Response Actions:

- Lower the injection rates or stop the injection.
- Notify the Commissioner within 24 hours.
- Determine the cause of contaminants.
- Investigate potential interactions between contaminants and connate formation fluids.
- Investigate potential interactions between contaminants and wellbore materials within injection interval.
- Remediate the source of contaminants.
- Chemically treat the stream to reduce the effect of contaminants.
- Replace tubing and packer if necessary.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.

8.3.4.3 Specific Event Description – Microbial activity initiated by injection process or composition, allowing possible production of H₂S

Risk Assessment Matrix, Section 4.3 (Appendix G-2)

This event could occur due to changes in contamination levels in the CO₂ source that allows microbial activity conducive to H₂S gas production. These sources of contaminants may impact dissolution, geochemical reactions, and wellbore integrity.

Prevention and Detection:

- Samples of the CO₂ stream will be collected from the injection-source pipeline. Samples representative of injection conditions will be sent to a third-party laboratory for analysis, which will indicate contaminant levels.

Potential Response Actions:

- Lower the injection rates or stop the injection.
- Notify the Commissioner within 24 hours.
- Determine the cause of contaminants.
- Investigate downhole issues.
- Remediate the source of contaminants.
- Chemically treat the stream to reduce the effect of contaminants.
- Replace tubing and packer if necessary.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.5 Event Category – Accidents/Unplanned Events (Typical Insurable Events)

8.3.5.1 Specific Event Description – Surface infrastructure damage (e.g., wellhead of flowlines) *Risk Assessment Matrix, Section 5.1(Appendix G-2)*

Unforeseen events, such as surface infrastructure damage, pipeline leak, pump or compressor failure, motor craft or animal damage, or weather-related events, may occur while operating Loblolly CCS wells No. 001 and No. 002.

Prevention and Detection:

- Equipment will be inspected and maintained regularly to prevent or minimize damage.
- Damage-prevention infrastructure will be installed and markers placed to alert the public of the potential hazards. The markers will include the operator's name and telephone number.
- Barricades will be installed to prevent animals from entering the facility and accidental damage to equipment.
- Weather will be continuously monitored and, in the event of possible adverse conditions, precautions taken to limit the potential impact.

Potential Response Actions:

- Stop the injection and notify the Commissioner within 24 hours. If the release is significant, notify appropriate local emergency services.
- Activate the downhole safety valve, if necessary.
- Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

8.3.5.2 Specific Event Description – Hurricane *Risk Assessment Matrix, Section 5.2 (Appendix G-2)*

Unforeseen weather-related events (e.g., a hurricane) are likely to occur while operating Loblolly CCS wells No. 001 and No. 002.

Prevention and Detection:

- Equipment will be maintained regularly to prevent or minimize damage.
- Damage-prevention infrastructure will be installed, and markers placed to alert the public of the potential hazards. The markers will include the operator's name and telephone number.
- Weather will be continuously monitored, and, in the event of possible adverse conditions, precautions taken to limit the potential impact.

Potential Response Actions:

- Stop the injection and notify the Commissioner within 24 hours.
- Activate the downhole safety valves if necessary.
- Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the Commissioner when injection can be expected to resume.

The following tables (8-1 to 8-3) outline the risk assessment process discussed above.

8.4 Risk Activity Matrix

Table 8-1 – Risk Activity Matrix

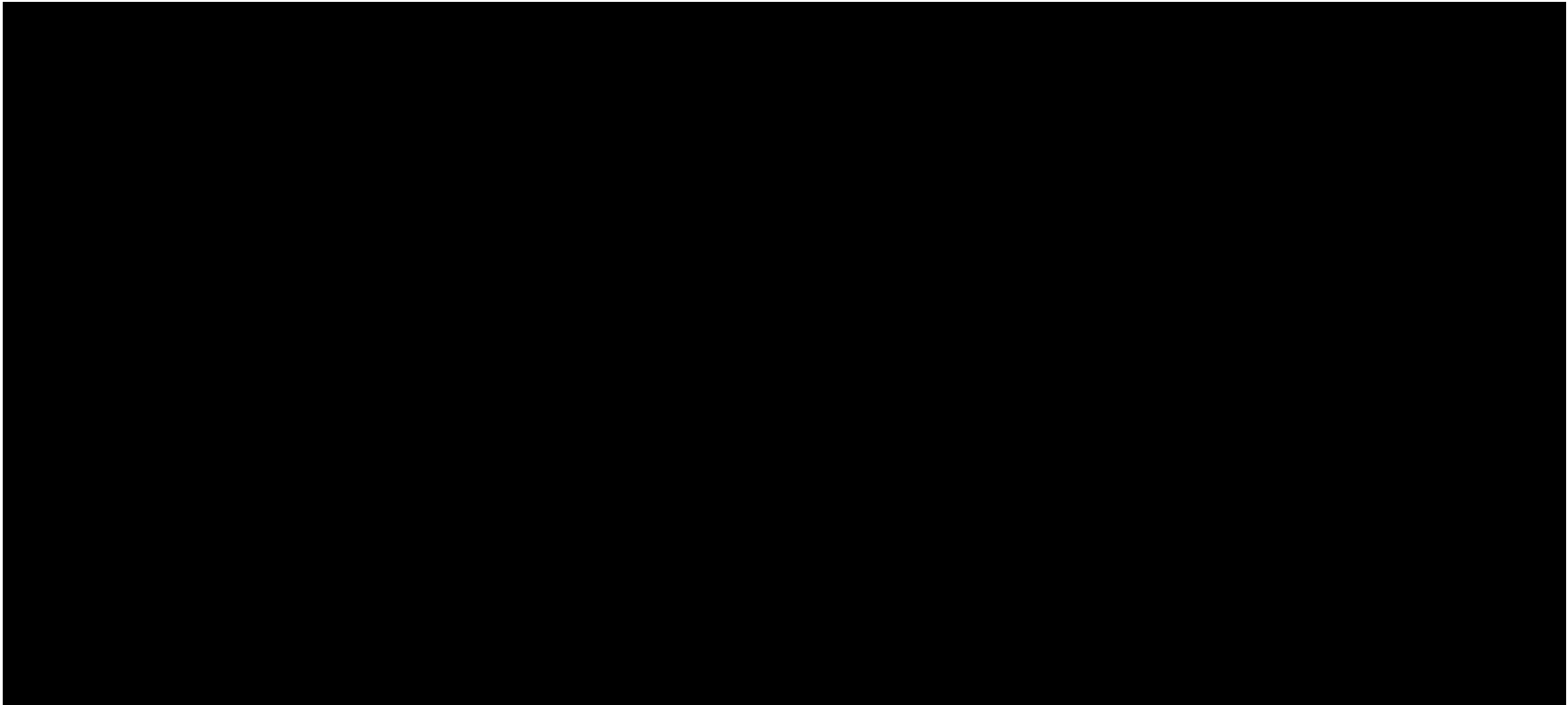


Table 8-2 – Risk Mitigation and Threat Scores

THREAT SCORES	RISK MITIGATION
≥15	Avoid. Risk reduction measures must be applied to reduce the probability of occurrence and/or the consequences (mitigate through immediate responsive action).
5 - 14.99	Monitoring required. Risk is acceptable if specified control and safety measures are in place. If possible, further risk reduction may be implemented.
0 - 4.99	Monitor situation. Risk is acceptable, no additional risk reduction is required.

Table 8-3 – Risk Assessment Scores

Risk Assessment Scores						
Likelihood	5 Almost Certain	5	10	15	20	25
	4 Likely	4	8	12	16	20
	3 Occasional	3	6	9	12	15
	2 Rare	2	4	6	8	10
	1 Remote	1	2	3	4	5
		Very Low 1	Low 2	Moderate 3	High 4	Very High 5
		Impact Severity				

8.5 Training

Personnel will be trained in their duties and responsibilities related to these facilities during annual on-site or table-top training exercises. All plant personnel, visitors, and contractors must attend a plant overview orientation before entering any of the facilities. A refresher course on this training is required annually for all personnel.

Evergreen Sequestration Hub, LLC (Evergreen) will provide to local first responders a copy of the ERRP that includes potential response scenarios.

8.6 Communications Plan and Emergency Notification Procedures

Table 8-4 – Emergency Services – CALL 911

Agency	Telephone Number
Beauregard Parish Fire District 4	911 or 337-463-5063
DeQuincy Volunteer Fire Department	911 or 337-786-4821
Beauregard Parish Sheriff Department	911 or 337-463-3281
Calcasieu Parish Sheriff Department	911 or 337-494-4590
Beauregard Parish Health Unit	337-463-4486
Calcasieu Parish Health Unit	337-478-6020
Beauregard Parish Office of Emergency Preparedness	337-460-5447
Calcasieu Parish Office of Emergency Preparedness	337-721-3800
Louisiana Emergency Preparedness Office	225-763-3535
Louisiana State Police	504-310-7000
Louisiana State Police – Hazardous Material Hotline	877-925-6595
Louisiana Department of Fish and Wildlife Service	225-765-2800

Table 8-5 – Government Agency Notification

Agency	Telephone Number
EPA Region 6	214-665-2200
Class VI Contact	214-665-8473
Louisiana Department of Natural Resources (LDNR)	225-342-5515
Injection Well Incidents	225-342-5515
National Response Center (NRC)	800-424-8802
Louisiana State Police – Hazardous Material Hotline	877-925-6595

Table 8-6 – Internal Call List

Name	Title	Telephone Number
██████████	████	██████████

██████████	██████████████████	██████████
██████████	██████████████	██████████

As appropriate, Evergreen will communicate with the public regarding events that require an emergency response, including the impact of the event on drinking water or the severity of the event, actions taken or planned to address the event, and other information needed to protect the public during the event.

8.7 Flood Hazard Risk

The proposed Loblolly CCS wells No. 001 and No. 002 and the surrounding area are designated as FEMA flood hazard Zone X (Unshaded), which is defined as an area above the 500-year flood level and of minimal flood hazard. The injection well locations and FEMA flood zones are shown in *Appendix G-3*.

8.8 Emergency and Remedial Response Plan Review and Updates

This ERRP will be reviewed and updated no less than every five years. Any amendments to the plan must be approved by the Commissioner and will be incorporated into the permit:

- Within 1 year of an AOR evaluation
- Following any significant changes to the facility, such as addition of injection or monitoring wells
- After a change in key personnel
- As required by the Commissioner

The following attachments are in *Appendix G*:

- Appendix G-1 Resources and Infrastructure in AOR Map
- Appendix G-2 Complete Risk Assessment Matrix
- Appendix G-3 FEMA Flood Zone Hazards Map



Underground Injection Control – Class VI Permit Application for the Evergreen Sequestration Hub

Beauregard and Calcasieu Parishes, Louisiana

SECTION 9 – FINANCIAL RESPONSIBILITY

February 2024



70SECTION 9 – FINANCIAL RESPONSIBILITY

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Figures

None included in this section.

Tables

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9.1 Facility Information

Facility Name: Evergreen Sequestration Hub, LLC
(Evergreen)

Facility Contact: [REDACTED]
Phone: [REDACTED]
Email: [REDACTED]

Project Site Name: Evergreen Sequestration Hub

Project Location: Beauregard and Calcasieu Parishes, Louisiana

Injection Well Information:

Well Name and Number	Loblolly CCS No. 001
Parish	Beauregard
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
	[REDACTED]
Well Name and Number	Loblolly CCS No. 002
Parish	Beauregard
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
	[REDACTED]

9.2 Introduction

Under Statewide Order (SWO) 29-N-6 **§3609.C.**, owners or operators of geologic sequestration (GS)¹ wells in Louisiana are required to demonstrate financial responsibility for GS activities. Consistent with the requirements set forth by the Louisiana Department of Natural Resources (LDNR) Office of Conservation, Evergreen Sequestration Hub, LLC (“Trace”) has prepared this section to summarize the combination of qualifying financial instruments that it proposes to use to demonstrate financial responsibility for the following GS project phases: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care and Site Closure; and (4) Emergency and Remedial Response (ERR).

As detailed in this permit application, Trace plans to construct two Class VI injection wells to sequester up to a combined [REDACTED] (MMT/yr) of CO₂ at the Evergreen Sequestration Hub project (Evergreen Hub). The Evergreen Hub is designed to accommodate GS of anthropogenic CO₂ emissions. Located in proximity to both natural gas pipelines and industrial

¹ Per **§3601** of SWO 29-N-6, “Geologic Sequestration” refers to the long-term containment of CO₂ in subsurface geologic formations; also, commonly referred to as carbon capture and storage (CCS).

emitters, this project will serve as an ideal location to safely store CO₂ in the deep saline aquifers of the Gulf Coast region. The Evergreen Hub is located within 50 miles (mi) of significant industrial emissions, summing to over 70 MMT/yr. These emissions are most concentrated in industrial corridors surrounding Lake Charles, Louisiana (approximately 25 mi from the proposed hub) and the cities of Beaumont and Port Arthur, Texas (approximately 40 mi from the hub).

Presently, Trace proposes to use a [REDACTED] to demonstrate financial responsibility for Corrective Action (§3615.C), Injection Well Plugging (§3631), and Post-Injection Site Care and Site Closure (§3633) of each injection well and [REDACTED] to demonstrate financial responsibility for ERR (§3623)

Specifically, Trace intends [REDACTED]

Per §3609.C.2, Trace intends to execute [REDACTED] with a face value no less than the amount identified in the cost estimate of the corresponding corrective action plan, closure plan, and Post-Injection Site Care and Site Closure Plan for the Evergreen Hub site, as detailed in *Section 7*. In addition, Trace will ensure that the financial responsibility instruments will be sufficient to address the endangerment of Underground Sources of Drinking Water (USDWs) should it become necessary to do so. Attachment 1 includes documentation affirming Trace's commitment to procure [REDACTED] for the purposes of demonstrating financial responsibility for all non-ERR GS activities.

Separately, per §3609.C.4.a.ii, Trace proposes to procure a [REDACTED] at a level sufficient to respond to any emergency or to perform any remedial action that meets the requirements of §3623. Trace intends to execute [REDACTED] with a limit of liability no less than the amount identified in the cost estimate of its Emergency and Remedial Response Plan, as detailed in *Section 8*. Trace intends to procure an [REDACTED]

[REDACTED] Attachment 2 includes documentation affirming Trace's commitment to procure [REDACTED] for the purposes of demonstrating financial responsibility for all ERR activities at the Evergreen Hub Site.

Per §3609.C.4.d.i, Trace will provide final qualifying financial-responsibility documentation for consideration and approval by the Louisiana Commissioner of Conservation (Commissioner)², or their designee, prior to beginning GS of CO₂ in a Class VI well. Further, Trace provides its demonstration of financial responsibility with the understanding that the financial instruments referenced herein will be updated and verified over time and any updated information will be provided annually. As each GS activity occurs, Trace will ensure that the coverage limits provided by the respective financial responsibility instruments are sufficient to cover the corresponding project costs prior to initiating the GS project phase.

² Per §3601 of SWO 29-N-6, Trace understands the *commissioner* to be defined as the Assistant Secretary of the Office of Conservation, Louisiana Department of Natural Resources.

The sections that follow summarize in greater detail the Evergreen Hub site’s GS activities, as well as the qualifying financial instruments that Trace proposes to use to demonstrate financial responsibility for: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care and Site Closure; and (4) Emergency and Remedial Response.

9.3 Estimated Financial Responsibility Coverage Amounts

Per §3609(C)(d), Trace requests approval from the Commissioner, or their designee, to use a [REDACTED]
[REDACTED]
[REDACTED]

To determine the cost basis for the coverage amounts underpinning its financial responsibility demonstration, Trace relies on currently available price quotes and technical data. Project costs are presented in 2024 dollars and assume the hiring of independent, third-party contractors for each GS activity. Specifically, the costs are separated into GS project phases as shown in Table 10-1.

Table 10-1 summarizes the total estimated financial responsibility coverage values by GS activity, along with the timeline for which coverage is expected to be needed. [REDACTED]
[REDACTED]
[REDACTED]

Table 10-1 – Summary of Estimated Financial Responsibility Coverage Values by GS Activity

GS Activity	Timeline of Coverage	Estimated Financial Responsibility Coverage Value (2024 \$)	Qualifying Financial Instrument
[REDACTED]	[REDACTED] [REDACTED] [REDACTED] [REDACTED]	[REDACTED]	[REDACTED] [REDACTED]
[REDACTED]			
[REDACTED]	[REDACTED] [REDACTED] [REDACTED] [REDACTED]	[REDACTED]	[REDACTED] [REDACTED]
[REDACTED] [REDACTED]	[REDACTED] [REDACTED] [REDACTED] [REDACTED]	[REDACTED]	[REDACTED] [REDACTED]

In *Section 6 – Injection Well Plugging Plan*, per §3631, Trace provides its well plugging plan for the Evergreen Hub Site—for the Loblolly CCS No. 001 and No. 002 injection wells.

As shown in Table 10-2, the total current cost estimate of this activity is [REDACTED] based on independent, third-party engineering data. In deriving this financial responsibility coverage value, Trace has considered the costs for logs/wireline to be run in the wellbore before cementing occurs. [REDACTED]

[REDACTED] The cost estimate also accounts for all expenses relating to personnel and equipment. Finally, Trace includes pressure-test costs for additional verification of the integrity of the wells. Table 10-2 provides additional detail regarding the well plugging cost elements that inform the total financial responsibility coverage value for this GS activity.

9.5.2 Monitoring Well Plugging and Abandonment

As noted above, the well plugging plan for the Evergreen Hub site is discussed in *Section 6*. Per §3631, Trace anticipates using the same plan to plug and abandon the monitoring wells within the project site. As discussed in *Section 6*, the monitoring wells will be completed above the uppermost confining geologic interval, and therefore conventional plugging procedures will be used.

As shown in Table 10-2 the total current cost estimate for this activity is [REDACTED] based on independent, third-party engineering data. In deriving this financial responsibility coverage value, Trace has designed its plan with the goal of assuring that no movement of fluids will occur from the injection interval, in order to protect against USDW endangerment.

In deriving the total current cost estimate for this activity, Trace considered the costs for logs/wireline to be run in the wellbore before cementing occurs. The cost estimate also accounts for all expenses relating to personnel and equipment. Finally, Trace includes pressure-test costs for additional verification of the integrity of the wells. Table 10-2 provides additional detail regarding the well-plugging cost elements that inform the total financial responsibility coverage value for this GS activity.

Table 10-2 – Summary of Estimated Financial Responsibility Coverage Values, Well Plugging and Abandonment

Cost Category	Estimated Financial Responsibility Coverage Value (2024 \$)	
	PER-WELL	TOTAL
<i>Injection Well Plugging (x two wells)</i>		[REDACTED]
Workover Rig	[REDACTED]	
Kill/Buffer Fluid and Disposal	[REDACTED]	
Personnel/Permitting	[REDACTED]	

goal of site closure is adequate site restoration to leave minimal environmental impact.

9.7 Emergency and Remedial Response

As noted, the Emergency and Remedial Response Plan for the Evergreen Hub site is discussed in *Section 8*. Per §3623, and as summarized in Figure 10-1, the total estimated cost of ERR is [REDACTED]. This proposed financial responsibility coverage value is based on independent, third-party engineering data.

[REDACTED]

[REDACTED]

9.8 Financial Responsibility Demonstration

Per §3609.C., Trace intends to demonstrate financial responsibility for the Evergreen Hub site through [REDACTED]

[REDACTED]

The combination of these financial instruments will provide appropriate assurance to LDNR of Trace’s ability to fulfill its financial responsibilities at the Evergreen Hub site for the life of the project, across all GS activities. Table 10-4 summarizes the financial responsibility coverages for the project site by GS activity and qualifying financial instrument.

Table 10-4 – Summary of Financial Responsibility Coverages by GS Activity, by Qualifying Instrument

GS Project Phase / Activity	Estimated Financial Responsibility Coverage Value (2024 \$)	Covered by Performance Surety Bond	Covered by Commercial Insurance
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

APPENDIX A: SURVEY PLATS

- Appendix A-1 Project Overview Map
- Appendix A-2 Project Overview (Aerial) Map
- Appendix A-3 Well Location Plats – Loblolly CCS No. 001 & No. 002
- Appendix A-4 Surface Ownership Map
- Appendix A-5 Pore Space Ownership Map
- Appendix A-6 Project Topography Map

APPENDICES A01 TO A06 ARE
PROPRIETARY BUSINESS INFORMATION
THIS DATA HAS BEEN REDACTED.

APPENDIX B: GEOLOGIC MAPS AND CROSS SECTIONS

- Appendix B-1 N-S Structural Cross Section
- Appendix B-2 E-W Structural Cross Section
- Appendix B-3 N-S Stratigraphic Cross Section
- Appendix B-4 E-W Stratigraphic Cross Section
- Appendix B-5 Cross Section Reference Map
- Appendix B-6 Top Upper Confining Structure Map
- Appendix B-7 Top Injection Interval Structure Map
- Appendix B-8 Top Lower Confining Structure Map
- Appendix B-9 Top Regional Shale Structure Map
- Appendix B-10 Regional Sand Structure Map
- Appendix B-11 Upper Confining Isochore Map
- Appendix B-12 Injection Interval Isochore Map
- Appendix B-13 Lower Confining Isochore Map
- Appendix B-14 Upper Confining Net Shale Map
- Appendix B-15 Injection Interval Net Sand Map
- Appendix B-16 Lower Confining Net Shale Map
- Appendix B-17 USGS Offset Produced Water Map
- Appendix B-18 N-S USDW Cross Section
- Appendix B-19 E-W USDW Cross Section
- Appendix B-20 USDW Structure Cross Section Reference Map
- Appendix B-21 Fault Slip Potential
- Appendix B-22 North-South 3D Seismic Survey Line
- Appendix B-23 West-East 3D Seismic Survey
- Appendix B-24 Synthetic Seismograms
- Appendix B-25 Proximity North Starks Dome Salt Diapir
- Appendix B-26 Structural Model 3D
- Appendix B-27 Sweetness Attribute

APPENDICES B01 TO B27 ARE
PROPRIETARY BUSINESS INFORMATION
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APPENDIX C: AOR

- Appendix C-1 USDW Determination Map
- Appendix C-2 Map of Oil and Gas Wells in/near AOR
- Appendix C-3 List of Oil and Gas Wells in AOR
- Appendix C-4 Map of Active Freshwater Wells in/near AOR
- Appendix C-5 List of Freshwater Wells in/near AOR
- Appendix C-6 Map of AOR Site Review
- Appendix C-7 [REDACTED]
- Appendix C-8 [REDACTED]
- Appendix C-9 [REDACTED]
- Appendix C-10 [REDACTED]
- Appendix C-11 [REDACTED]
- Appendix C-12 [REDACTED]
- Appendix C-13 [REDACTED]
- Appendix C-14 [REDACTED]
- Appendix C-15 [REDACTED]
- Appendix C-16 [REDACTED]

APPENDICES C01 TO C16 ARE
PROPRIETARY BUSINESS INFORMATION
THIS DATA HAS BEEN REDACTED.

APPENDIX D: CONSTRUCTION

- Appendix D-1 Drilling and Completion Prognosis – Loblolly CCS No. 001
- Appendix D-2 Drilling and Completion Prognosis – Loblolly CCS No. 002
- Appendix D-3 Drilling and Completion Wellbore Schematic – Loblolly CCS No. 001
- Appendix D-4 Drilling and Completion Wellbore Schematic – Loblolly CCS No. 002
- Appendix D-5 Recompletion Wellbore Schematic – Loblolly CCS No. 001
- Appendix D-6 Recompletion Wellbore Schematic – Loblolly CCS No. 002
- Appendix D-7 Cement Program – Loblolly CCS No. 001
- Appendix D-8 Cement Program – Loblolly CCS No. 002
- Appendix D-9 [REDACTED]
- Appendix D-10 [REDACTED]

APPENDICES D01 TO D10 ARE
PROPRIETARY BUSINESS INFORMATION
THIS DATA HAS BEEN REDACTED.

APPENDIX E: METALLURGY

- Appendix E-1 Trace Evergreen Metallurgical Analysis

APPENDIX E IS
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THIS DATA HAS BEEN REDACTED.

APPENDIX F: TESTING AND MONITORING

- Appendix F-1 USDWM Well Plan Map
- Appendix F-2 AZMI Well Plan Map
- Appendix F-3 [REDACTED]
- Appendix F-4 [REDACTED]
- Appendix F-5 [REDACTED]
- Appendix F-6 [REDACTED]
- Appendix F-7 [REDACTED]
- Appendix F-8 [REDACTED]

APPENDICES F01 TO F08 ARE
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APPENDIX G: EMERGENCY OPERATIONS

- Appendix G-1 Resources and Infrastructure Map
- Appendix G-2.1 Risk Matrix Summary
- Appendix G-2.2 Risk Matrix Details
- Appendix G-2.3 Risk Matrix Scoring
- Appendix G-3 FEMA Flood Zone Hazard Map

APPENDICES G01 TO G03 ARE
PROPRIETARY BUSINESS INFORMATION
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APPENDIX H: PLUGGING AND ABANDONMENT

- Appendix H-1 Loblolly CCS No. 001 Zonal Isolation Schematic
- Appendix H-2 Loblolly CCS No. 002 Zonal Isolation Schematic
- Appendix H-3 Loblolly CCS No. 001 Detailed Plugging Procedure
- Appendix H-4 Loblolly CCS No. 002 Detailed Plugging Procedure
- Appendix H-5 Loblolly CCS No. 001 Final P&A Schematic
- Appendix H-6 Loblolly CCS No. 002 Final P&A Schematic
- Appendix H-7 [REDACTED]
- Appendix H-8 [REDACTED]
- Appendix H-9 [REDACTED]
- Appendix H-10 [REDACTED]
- Appendix H-11 [REDACTED]
- Appendix H-12 [REDACTED]

APPENDICES H01 TO H12 ARE
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APPENDIX I: FINANCIAL ASSURANCE

- Appendix I-1
- Appendix I-2

[REDACTED]

[REDACTED]

APPENDICES I01 TO I02 ARE
PROPRIETARY BUSINESS INFORMATION
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APPENDIX J: REFERENCES

Please see separate .zip folder for references