Underground Injection Control – Class VI Permit Application

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

Prepared for
Titan Carbon Sequestration, LLC

By
Lonquist Sequestration, LLC
Austin, TX

February 2024

FOREWORD

Titan Carbon Sequestration, LLC (Titan), a fully-owned subsidiary of Sempra Infrastructure Partners (Sempra), is developing a CO_2 sequestration facility in Jefferson County, Texas. The Titan Carbon Sequestration Project (Titan Project) is designed to sequester CO_2 from Sempra's Port Arthur LNG (PALNG) facility in the Port Arthur area. The company is leveraging the integrated capabilities of its business segments to develop both the proposed Port Arthur Pipeline Texas Connector project and the proposed Port Arthur Pipeline Louisiana Connector project—as well as to develop new gas storage facilities—all of which would serve the PALNG facility. Sempra continues to evaluate opportunities to develop the entirety of the Port Arthur site, while also exploring potential projects to reduce the carbon intensity of its LNG, hence positioning Port Arthur as a flagship hub for the energy transition. To further the advancement of the proposed Port Arthur Clean Energy Hub, Sempra recently acquired 38,000 acres of pore space and relevant surface rights to support the proposed Titan Project.

This site is ideally suited for the sequestration of CO_2 with thick intervals of stacked sand and shale sequences of Miocene-aged rock that are high in porosity and permeability. Additionally, no artificial penetrations exist within the modeled area of review. Sempra has built strong community relationships through the development of the PALNG facility and will continue its communication activities specific to its sequestration efforts.

The following application will fully detail and characterize the geology of the proposed well locations, evaluate the formations for properties necessary to contain the sequestered CO_2 permanently, and describe the engineering design and safety considerations for both well. The application will also discuss the proposed monitoring system that will be used to compare 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 Texas Administrative Code (TAC), Part 1, Title 16, Chapter 5 (16 TAC **§5**). 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 16 TAC **§5.203(d)(1)(A)**, the permit will be updated every five years thereafter for the active injection life of the well.

ACRONYMS AND ABBREVIATIONS

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

AAPG	American Association of Petroleum Geologists
ACZ	above confining zone
AOI	area of interest
AOR	area of review
API	American Petroleum Institute
ASCII	American Standard Code for Information Interchange
ASTM	American Society for Testing and Materials
AZM	above-zone monitoring interval
bbl	barrel(s)
BEG	Bureau of Economic Geology
BHP	bottomhole pressure
BMP	best management practices
BOE	barrels of oil equivalent
BP	bridge plug
bpd	barrels per day
bph	barrels per hour
bpm	barrels per minute
CBL	cement bond log
CBG	census block group
CCL	casing collar locator
CCS	carbon capture and sequestration
CCUS	carbon capture, utilization, and storage
CDF	cumulative distribution function
CEQ	Center for Environmental Quality
CFR	U.S. Code of Federal Regulations

Chicot EAS	Chicot Equivalent Aquifer System
CIL	casing inspection log
CMG	Computer Modelling Group, Ltd.
CRA	corrosion-resistant alloy
DAS	distributed acoustic sensing
DSA	double-studded adaptor
DTS	distributed temperature sensing
DV	diverter valve
EJ	environmental justice
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
GAU	Groundwater Advisory Unit
GHG	greenhouse gas (emissions)
gpm	gallons per minute
GR	gamma ray
HDIL	high-definition induction log
HNBR	hydrogenated nitrile butadiene rubber
HRVRT	high-resolution vertilog (tool)
ID	inner diameter
IEA	International Energy Agency
IMD	Injection and Mining Division
JSA	job safety analysis
kg/m^3	kilograms per cubic meter

lb/ft^3	pounds per cubic foot
LAS	Log ASCII Standard
lbm	pounds per square mass
LCZ	lower confining zone
LDNR	Louisiana Department of Natural Resources
LNG	liquefied natural gas
Ma	mega annum
Mcf	thousand cubic feet
mD	millidarcy
MD	measured depth
MDT	modular formation dynamics tester
mg/L	milligrams per liter
Mgal/D	million gallons per day
MIT	mechanical integrity test
MMI	Modified Mercalli Intensity
MMcf	million cubic feet
MMscf	million standard cubic feet
MMscf/D	million standard cubic feet per day
MT	metric tons
MMT/yr	million metric tons per year
NACE	National Association of Corrosion Engineers
NAD	North American Datum
NCEDC	Northern California Earthquake Data Center
NEPA	National Environmental Policy Act
NRC	National Response Center
NSHM	National Seismic Hazard Model
OBG	overburden gradient
OD	outer diameter
OSHA	Occupational Safety and Health Administration

P&A	plugging and abandonment
P&M	preventive and mitigative
PALNG	Port Arthur Liquefied Natural Gas (facility)
PBR	polished bore receptacle
PBTD	plugged back total depth
PE	photoelectric
PEC	pulsed eddy current
PG	pore gradient
PHIE	effective porosity
PHIEST	estimated effective porosity
PHIT	total porosity
PISC	post-injection site care
PP	pore pressure
ppg	pounds per gallon
PPG	pore pressure gradient
ppm	parts per million
ppmv	parts per million by volume
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSDM	Pre-Stack Depth Migration
PSTM	Pre-Stack Time Migration
P/T	pressure/temperature
QA/QC	quality assurance/quality control
REFPROP	Reference Fluid Thermodynamic and Transport Properties (database)
Rwa	water resistivity
SAU	storage assessment unit
SC	specific conductivity
SCADA	Supervisory Control and Data Acquisition

scf/D	standard cubic feet per day
SCITS	Stanford Center for Induced and Triggered Seismicity
sDAS	seismic distributed acoustic sensing
SEM	scanning electron microscopy
SGR	shale gouge ratio
SHmax	maximum horizontal stress
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
SRK	Soave-Redlich-Kwong (method)
SSIV	subsurface safety injection valve
SSV	subsurface safety valve
SWC	sidewall core
SWO	Statewide Order
SWPPP	Stormwater Pollution Prevention Plan
TAC	Texas Administrative Code
TD	total depth
TDS	total dissolved solids
TEC	tubing encapsulated conductor
TexNet	Texas Seismological Network and Seismology Research
TRRC	Texas Railroad Commission
TVD	true vertical depth
TVDSS	true vertical depth subsea
UCZ	upper confining zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

USGS	U.S. Geological Survey
VDL	variable density log
VSP	vertical seismic profile
WAG	water-alternating-gas
WHP	wellhead pressure
WIRE	wire integrity real-time evaluation
W/m	watts per meter
XRD	X-ray diffraction

TABLE OF CONTENTS

FOREWORD

CERTIFICATIONS

ACRONYMS AND ABBREVIATIONS

TABLE OF CONTENTS

REQUIREMENTS MATRIX

INTRODUCTION

SECTION 1 – SITE CHARACTERIZATION

SECTION 2 – PLUME MODEL

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

SECTION 5 – TESTING AND MONITORING PLAN

SECTION 6 – INJECTION WELL PLUGGING PLAN

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

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

SECTION 9 – FINANCIAL RESPONSIBILITY

SECTION 10 – ENVIRONMENTAL JUSTICE

APPENDICES:

- APPENDIX A: PROJECT MAPS
- APPENDIX B: SITE CHARACTERIZATION FILES
- APPENDIX C: AREA OF REVIEW MAPS
- APPENDIX D: WELL CONSTRUCTION SCHEMATICS AND PROCEDURES
- APPENDIX E: METALLURGY SUMMARY
- APPENDIX F: TESTING AND MONITORING
- APPENDIX G: EMERGENCY OPERATIONS PLAN
- APPENDIX H: PLUGGING SCHEMATICS AND PROCEDURES
- APPENDIX I: ENVIRONMENTAL JUSTICE
- APPENDIX J: REFERENCES

REQUIREMENTS MATRIX

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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82 - Required Class VI permit information						
§146.82		This section sets forth the information which must be considered by the Director in authorizing Class VI wells. For converted Class I, Class II, or Class V experimental wells, certain maps, cross-sections, tabulations of wells within the area of review and other data may be included in the application by reference provided they are current, readily available to the Director, and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Regional Administrator.				
§146.82(a)		Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to § 146.91(e), and the Director shall consider the following:				
§146.82(a)(1)	Required class VI permit Information	Information required in § 144.31(e)(1) through (6) of this chapter;	§5.203 (a)(2)	General	General information.	
§146.82(a)(2)	Required class VI permit Information	A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	§5.203 (b)	Surface Map Information	Surface map and information. Only information of public record is required to be included on this map.	Intro
			§5.203 (b)(1)	Surface Map Information	The applicant must file with the director a surface map delineating the proposed location of any injection wells and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR.	3.3.3
			§5.203 (b)(2)	Surface Map Information	The applicant must show within the AOR on the map the number or name and the location of:	
			§5.203 (b)(2)(A)	Surface Map Information	all known artificial penetrations through the confining zone, including injection wells, producing wells, inactive wells, plugged wells, or dry holes;	3.3.4; Appendix C
			§5.203 (b)(2)(B)	Surface Map Information	the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and	Appendix C
			§5.203 (b)(2)(C)	Surface Map Information	other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.	Appendix C
			§5.203 (b)(3)	Surface Map Information	The applicant must identify on the map any known or suspected faults expressed at the surface.	1.8
§146.82(a)(3)	Required class VI permit Information	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	§5.203 (c)(2)	Geologic, geochemical, and hydrologic information	The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including the following information:	
§146.82(a)(3)(i)		Maps and cross sections of the area of review;				
§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;	§5.203 (c)(2)(C)	Geologic, geochemical, and hydrologic information	the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment;	Section 1.8
§146.82(a)(3)(iii)	Required class VI permit Information	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	§5.203 (c)(2)(B)	Geologic, geochemical, and hydrologic information	The depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	Section 1
§146.82(a)(3)(iv)		Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	§5.203 (c)(2)(E)	Geologic, geochemical, and hydrologic information	geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;	1.4.1, 1.4.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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	§5.203 (c)(2)(D)	Geologic, geochemical, and hydrologic information	the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;	1.11
§146.82(a)(3)(vi)		Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.				1.2, 1.3.4, 1.9.2, Appendix A
§146.82(a)(4)	Required class VI permit Information	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	§5.203 (d)(1)(B)	AOR and corrective action	Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR [area of review] that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled, location, depth, record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.	3.4; Appendix C
§146.82(a)(5)	Required class VI permit Information	Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	§5.203 (c)(2)(A)	Geologic, geochemical, and hydrologic information	geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	1.9.2, 1.9.4
§146.82(a)(6)	Required class VI permit Information	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	§5.203 (c)(2)(G)	Geologic, geochemical, and hydrologic information	Baseline geochemical data on subsurface formations, including all formations containing USDWs in the AOR;	1.7; 5.5.5
§146.82(a)(7)	Required class VI permit Information	Proposed operating data for the proposed geologic sequestration site:	§5.203 (i)(1)	Operating Information	Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) [§5.206(c)] of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:	4.4
§146.82(a)(7)(i)	Required class VI permit Information	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	§5.203 (i)(1)(A)	Operating Information	The average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	4.2.1, 4.2.6, Intro
§146.82(a)(7)(ii)	Required class VI permit Information	Average and maximum injection pressure;	§5.203 (i)(1)(B)	Operating Information	The average and maximum surface injection pressure;	4.4
§146.82(a)(7)(iii)	Required class VI permit Information	The source(s) of the carbon dioxide stream; and	§5.203 (i)(1)(C)	Operating Information	The sources of the carbon dioxide stream and the volume of carbon dioxide from each source; and	Intro
§146.82(a)(7)(iv)	Required class VI permit Information	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	§5.203 (i)(1)(D)	Operating Information	An analysis of the chemical and physical characteristics of the carbon dioxide stream prior to injection.	Intro, Appendix E
§146.82(a)(8)	Required class VI permit Information	Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;	§5.203 (c)(2)(F)	Geologic, geochemical, and hydrologic information	a description of the formation testing program used and the analytical results used to determine the chemical and physical characteristics of the injection zone and the confining zone; and	4.3.1, 4.3.2,

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(a)(9)	Required class VI permit Information	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	§5.203 (e)(4)	Injection well construction	Well stimulation plan. The applicant must submit, as applicable, a description of the proposed well stimulation program and a determination that stimulation will not compromise containment	4.2.2
§146.82(a)(10)	Required class VI permit Information	Proposed procedure to outline steps necessary to conduct injection operation;	§5.203 (i)(1)	Operating Information	Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) of this title, and that outlines the steps necessary to conduct injection operation The applicant must include the following proposed operating data in the plan:	
§146.82(a)(11)	Required class VI permit Information	Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	§5.203 (e)(2)(K)	Injection well construction	Schematic drawings of the surface and subsurface construction details.	4.2, 4.2.1
§146.82(a)(12)	Required class VI permit Information	Injection well construction procedures that meet the requirements of § 146.86;	§5.203 (e)(3)	Injection well construction	Well construction plan. The applicant must submit an injection well construction plan that meets the criteria in paragraph (1) of this subsection.	4.2
§146.82(a)(13)	Required class VI permit Information	Proposed area of review and corrective action plan that meets the requirements under § 146.84;	§5.203 (d)(2)	AOR and corrective action	Area of review and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information:	3.3, 3.4
§146.82(a)(14)	Required class VI permit Information	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	§5.202 (c)(2)	Applicability and compliance	Evidence of financial responsibility. The operator acquiring the permit must provide the director with evidence of financial responsibility satisfactory to the director in accordance with §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	9.3
			§5.203 (n)	Fees, financial responsibility, and financial assurance	Fees, financial responsibility, and financial assurance. The applicant must pay the fees, demonstrate that it has met the financial responsibility requirements, and provide the Commission with financial assurance as required under §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	9.3
§146.82(a)(15)	Required class VI permit Information	Proposed testing and monitoring plan required by § 146.90;	§5.203 (h)(2)	Mechanical integrity testing	Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. [The plan must include a schedule for the performance of a series of tests at a minimum frequency of five years.] The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:	5.4.2, 5.4.3
§146.82(a)(16)	Required class VI permit Information	Proposed injection well plugging plan required by § 146.92(b);	§5.206 (j)	Permit Standards	Well plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by §5.203(k) of this title.	6.2, 6.3, Appendix H
§146.82(a)(17)	Required class VI permit Information	Proposed post-injection site care and site closure plan required by § 146.93(a);	§5.206 (k)(1)	Permit Standards	Post-injection storage facility care and closure plan.	Section 7
§146.82(a)(18)	Required class VI permit Information	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);	§5.203 (m)(8)(F)	Post-Injection storage facility carea and closure plan	an analysis must be performed to identify and assess aspects of the alternative PISC timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(a)(19)	Required class VI permit Information	Proposed emergency and remedial response plan required by § 146.94(a);	§5.206 (h)(1)	Permit Standards	The operator must maintain and comply with the approved emergency and remedial response plan required by §5.203(l) of this title. The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title (relating to Reporting and Record-Keeping). The operator must make copies of the plan available at the storage facility and at the company headquarters.	8.1
§146.82(a)(20)	Required class VI permit Information	A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and				Intro
§146.82(a)(21)	Required class VI permit Information	Any other information requested by the Director.				
§146.82(b)	Required class VI permit Information	The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.				
§146.82(c)	Required class VI permit Information	Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:				
§146.82(c)(1)	Required class VI permit Information	The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;				
§146.82(c)(2)	Required class VI permit Information	Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section;				
§146.82(c)(3)	Required class VI permit Information	Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;	§5.203 (g)	Compatibility determination	Compatibility determination. Based on the results of the formation testing program required by subsection (f) of this section, the applicant must submit a determination of the compatibility of the CO2 stream with:	
			§5.203 (g)(1)	Compatibility determination	the materials to be used to construct the well;	4.2, Appendix E
			§5.203 (g)(2)	Compatibility determination	fluids in the injection zone; and	1.7.2, 1.7.5
			§5.203 (g)(3)	Compatibility determination	minerals in both the injection and the confining zone.	1.7.3, 1.7.4, 1.7.5
§146.82(c)(4)	Required class VI permit Information	The results of the formation testing program required at paragraph (a)(8) of this section;				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(c)(5)	Required class VI permit Information	Final injection well construction procedures that meet the requirements of § 146.86;				
§146.82(c)(6)	Required class VI permit Information	The status of corrective action on wells in the area of review;				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(c)(7)	Required class VI permit Information	All available logging and testing program data on the well required by § 146.87;				
§146.82(c)(8)	Required class VI permit Information	A demonstration of mechanical integrity pursuant to § 146.89;				
§146.82(c)(9)	Required class VI permit Information	Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and				
§146.82(c)(10)	Required class VI permit Information	Any other information requested by the Director.				
§146.82(d)	Required class VI permit Information	Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.	§5.201 (f)	Applicability and compliance	Injection depth waiver. An operator may seek a waiver from the Class VI injection depth requirements for geologic storage to allow injection into non-USDW formations while ensuring that USDWs above and below the injection zone are protected from endangerment. An operator seeking a waiver of the requirement to inject below the lowermost USDW shall submit, concurrent with the permit application, a supplemental report that complies with 40 21 CFR §146.95. The Commission adopts 40 CFR §146.95 by reference, effective July 1, 2022.	
			§5.203 (o)		Letter from the Groundwater Advisory Unit of the Oil and Gas Division. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with Texas Water Code, §27.046.	
§146.83 - Minimum criteria for siting						
§146.83						
§146.83(a)	Minimum Criteria for siting	Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	§5.206 (b)(6)	General Criteria	the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include:	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.83(a)(1)	Minimum Criteria for siting	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	§5.206 (b)(6)(A)	General Criteria	an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO2 stream; and	1.12
§146.83(a)(2)	Minimum Criteria for siting	Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	§5.206 (b)(6)(B)	General Criteria	a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs;	1.12
§146.83(b)	Minimum Criteria for siting	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.				
§146.84 - Area of Review and Corrective Action						
§146.84	Area of review and corrective action		§5.203 (d)	AOR and corrective action	Area of Review and Corrective Action. This subsection describes the standards for the information regarding the delineation of the AOR, the identification of penetrations, and corrective action that an applicant must include in an application.	Section 3
§146.84(a)	Area of review and corrective action	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization,	§5.203 (d)(1)(A)(ii)(IV)	AOR and corrective action	considers the physical and chemical properties of injected and formation fluids; and	Section Intro, 1.6.1, 3.3.1
§146.84(b)	Area of review and corrective action	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	§5.203 (d)(1)	AOR and corrective action	Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3.3, 3.4
§146.84(b)(1)	Area of review and corrective action	The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	§5.203 (d)(2)(A)	AOR and corrective action	The method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	3.2
§146.84(b)(2)	Area of review and corrective action	A description of:	§5.203 (d)(2)(B)	AOR and corrective action	For AOR, a description of:	
§146.84(b)(2)(i)	Area of review and corrective action	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	§5.203 (d)(2)(B)(i)	AOR and corrective action	the minimum frequency subject to the annual certification pursuant to §5.206(f) of this title (relating to Permit Standards) at which the applicant proposes to re-evaluate the AOR during the life of the geologic storage facility;	3.5.1

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.84(b)(2)(ii)	Area of review and corrective action	The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	§5.203 (d)(2)(B)(iii)	AOR and corrective action	the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and	3.5.1
§146.84(b)(2)(iii)	Area of review and corrective action	How monitoring and operational data (e.g., injection rate **and pressure**) will be used to inform an area of review reevaluation; and	§5.203 (d)(2)(B)(ii)	AOR and corrective action	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	3.5.1
§146.84(b)(2)(iv)	Area of review and corrective action	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be	§5.203 (d)(2)(C)	AOR and corrective action	a corrective action plan that describes:	
			§5.203 (d)(2)(C)(i)	AOR and corrective action	how the corrective action will be conducted;	3.4
			§5.203 (d)(2)(C)(ii)	AOR and corrective action	how corrective action will be adjusted if there are changes in the AOR;	3.4
			§5.203 (d)(2)(C)(iii)	AOR and corrective action	if a phased corrective action is planned, how the phasing will be determined; and	N/A
			§5.203 (d)(2)(C)(iv)	AOR and corrective action	how site access will be secured for future corrective action.	3.4
§146.84(c)	Area of review and corrective action	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:				
§146.84(c)(1)	Area of review and corrective action	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§5.203 (d)(1)(A)(i)	AOR and corrective action	Using computational modeling that considers the volumes and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods:	
			§5.203 (d)(1)(A)(i)(I)	AOR and corrective action	five years after initiation of injection;	3.5.1
			§5.203 (d)(1)(A)(i)(II)	AOR and corrective action	from initiation of injection to the end of the injection period proposed by the applicant; and	3.5.1
			§5.203 (d)(1)(A)(i)(III)	AOR and corrective action	from initiation of injection until the plume movement ceases, for a minimum of [to] 10 years after the end of the injection period proposed by the applicant.	3.5.1
			§5.203 (d)(1)(A)(ii)	AOR and corrective action	The applicant must use a computational model that:	
§146.84(c)(1)(i)	Area of review and corrective action	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§5.203 (d)(1)(A)(ii)(I)	AOR and corrective action	Is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone	2.2.2
			§5.203 (d)(1)(A)(ii)(II)	AOR and corrective action	is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	2.6
§146.84(c)(1)(ii)	Area of review and corrective action	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§5.203 (d)(1)(A)(ii)(III)	AOR and corrective action	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	2.2.1-2.2.2; 2.3.1-2.3.3
§146.84(c)(1)(iii)	Area of review and corrective action	Consider potential migration through faults, fractures, and artificial penetrations.	§5.203 (d)(1)(A)(ii)(V)	AOR and corrective action	Considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.	3.3.1-3.3.2
			§5.203 (d)(1)(A)(iii)	AOR and corrective action	The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.	3.2; 3.3.2;

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.84(c)(2)	Required class VI permit Information	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	§5.203 (d)(1)(B)	AOR and corrective action	Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR [area of review] that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.	3.3.4; Appendix C
§146.84(c)(3)	Area of review and corrective action	Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	§5.203 (d)(1)(C)	AOR and corrective action	Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO2 stream. Corrective action may be phased.	3.3.4; Appendix C
§146.84(d)	Area of review and corrective action	Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.				3.3.4; Appendix C
§146.84(e)	Area of review and corrective action	At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	§5.206 (g)	AOR and corrective action	Permit conditions for AOR and corrective action. At the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must:	3.5.1
§146.84(e)(1)	Area of review and corrective action	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	§5.206 (g)(1)	AOR and corrective action	perform a re-evaluation of the AOR by performing all of the actions specified in §5.203(d)(1)(A) - (C) of this title to delineate the AOR;	3.5.1
§146.84(e)(2)	Area of review and corrective action	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	§5.206 (g)(2)	AOR and corrective action	Identify all wells in the reevaluated area of review that require corrective action;	3.5
§146.84(e)(3)	Area of review and corrective action	Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	§5.206 (g)(3)	AOR and corrective action	perform corrective action on wells requiring corrective action in the re-evaluated AOR in the same manner specified in §5.203(d)(1)(C) of this title;	3.5
§146.84(e)(4)	Area of review and corrective action	Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.206 (g)(4)	AOR and corrective action	submit an amended AOR and corrective action plan or demonstrate to the director through monitoring data and modeling results that no change to the AOR and corrective action plan is needed. Any amendments to the AOR and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at §5.202 of this title (relating to Permit Required, and Draft Permit and Fact Sheet), as applicable; and	3.5
§146.84(f)	Financial Responsibility	The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	§5.205 (b)(3)	Fees, financial responsibility, and financial assurance	The applicant's demonstration of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.84(g)	Area of review and corrective action	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	§5.206 (g)(5)	AOR and corrective action	retain all modeling inputs and data used to support AOR reevaluations for at least 10 years.	3.5
§146.85 - Financial responsibility						
			§5.205 (b)(1)	Fees, financial responsibility, and financial assurance	A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The operator must demonstrate and maintain financial responsibility and resources for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.2
			§5.205 (b)(2)	Fees, financial responsibility, and financial assurance	In determining whether the person is financially responsible, the director must rely on:	
			§5.205 (b)(2)(A)	Fees, financial responsibility, and financial assurance	the person's most recent audited annual report 1 filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); and	9.2
			§5.205 (b)(2)(B)	Fees, financial responsibility, and financial assurance	the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or	9.2
			§5.205 (b)(2)(C)	Fees, financial responsibility, and financial assurance	if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the director.	9.2
			§5.205 (b)(3)	Fees, financial responsibility, and financial assurance	The applicant's demonstratio of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.3
			§5.205 (c)	Financial assurance	Financial assurance.	
			§5.205 (c)(1)	Fees, financial responsibility, and financial assurance	Injection and monitoring wells. The operator must comply with the requirements of §3.78 of this title for all monitoring wells that penetrate the base of usable quality water and this subsection for all injection wells.	9.5.1-9.5.2
			§5.205 (c)(2)	Fees, financial responsibility, and financial assurance	Geologic storage facility.	
			§5.205 (c)(2)(A)	Fees, financial responsibility, and financial assurance	The applicant must include in an application for a geologic storage facility permit:	
			§5.205 (c)(2)(A)(iii)	Fees, financial responsibility, and financial assurance	information concerning the issuer of the bond or letter of credit including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.	TBD
			§5.205 (c)(2)(B)	Fees, financial responsibility, and financial assurance	A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.	
			§5.205 (c)(2)(C)	Fees, financial responsibility, and financial assurance	The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:	
			§5.205 (c)(2)(C)(ii)	Fees, financial responsibility, and financial assurance	A qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act; and	Cover sheets
			§5.205 (c)(2)(C)(iii)	Fees, financial responsibility, and financial assurance	The Commission may use the proceeds of financial assurance filed under this subsection to pay the costs of plugging any well or wells at the facility if the financial assurance for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.205 (c)(2)(D)	Financial assurance	Bonds and letters of credit filed in satisfaction of the financial assurance requirements for a geologic storage facility must comply with the following standards as to issuer and form.	
			§5.205 (c)(2)(D)(i)	Financial assurance	The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection must be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection must provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.	Cover sheets
			§5.205 (c)(2)(D)(ii)	Financial assurance	Any letter of credit filed in satisfaction of the requirements of this subsection must be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit must be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101 - 5.118. The letter of credit must provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the director.	
			§5.205 (c)(2)(D)(iii)	Financial assurance	The qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	
			§5.205 (c)(2)(D)(iii)(I)	Financial assurance	Cancellation. An owner or operator must provide that its financial instrument may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the director. The cancellation must not be final until at least 120 days after the Commission receives the cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.	
			§5.205 (c)(2)(D)(iii)(II)	Financial assurance	Renewal. If a financial instrument expires, the owner or operator must renew the financial instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	
			§5.205 (c)(2)(D)(iii)(III)	Financial assurance	Financial instrument to remain in effect. Cancellation, termination, or failure to renew shall not occur and the financial instrument shall remain in full force and effect if on or before the date of expiration:	
			§5.205 (c)(2)(D)(iii)(III)(-a-)		the director deems the facility abandoned;	
			§5.205 (c)(2)(D)(iii)(III)(-b-)		the permit is terminated or revoked or a new permit is denied;	
			§5.205 (c)(2)(D)(iii)(III)(-c-)		closure is ordered by the director or a United States district court or other court of competent jurisdiction;	
			§5.205 (c)(2)(D)(iii)(III)(-d-)		the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or	
			§5.205 (c)(2)(D)(iii)(III)(-e-)		the amount due is paid.	
			§5.205 (c)(2)(A)(ii)	Fees, financial responsibility, and financial assurance	a copy of the form of the bond or letter of credit that will be filed with the Commission; and	TBD

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.205 (c)(2)(C)(i)	Fees, financial responsibility, and financial assurance	The director must approve the dollar amount of the financial assurance. The amount of financial assurance required to be filed under this subsection must be equal to or greater than the maximum amount necessary to perform corrective action, emergency response, and remedial action, post-injection monitoring and site care, and closure of the geologic storage facility at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit;	
			§5.205 (c)(2)(A)(i)	Fees, financial responsibility, and financial assurance	a written estimate of the highest likely dollar amount necessary to perform post-injection monitoring and closure of the facility that shows all assumptions and calculations used to develop the estimate;	9.6
			§5.205 (c)(2)(E)	Fees, financial responsibility, and financial assurance	The operator of a geologic storage facility must provide to the director annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The operator must provide to the director upon request an adjustment of the cost estimate if the director has reason to believe that the original demonstration is no longer adequate to cover the cost of injection well plugging and post-injection storage facility care and closure.	
			§5.205 (c)(2)(F)	Fees, financial responsibility, and financial assurance	The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
			§5.205 (c)(2)(G)	Fees, financial responsibility, and financial assurance	Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the operator has received written approval from the director.	
			§5.205 (c)(2)(H)	Fees, financial responsibility, and financial assurance	The requirement to maintain adequate financial responsibility is directly enforceable regardless of whether the requirement is a condition of the permit.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.205 (c)(2)(H)(i)	Fees, financial responsibility, and financial assurance	The owner or operator must maintain financial responsibility until:	
			§5.205 (c)(2)(H)(i)(I)	Fees, financial responsibility, and financial assurance	the director receives and approves the completed post-injection storage facility care and closure plan; and	
			§5.205 (c)(2)(H)(i)(II)	Fees, financial responsibility, and financial assurance	the director issues the certificate of closure.	
			§5.205 (c)(2)(H)(ii)	Fees, financial responsibility, and financial assurance	The owner or operator may be released from a financial instrument in the following circumstances:	
			§5.205 (c)(2)(H)(ii)(I)	Fees, financial responsibility, and financial assurance	The owner or operator has completed the phase of the geologic storage project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the director, including obtaining financial responsibility for the next phase of the geologic storage project, if required; or	
			§5.205 (c)(2)(H)(ii)(II)	Fees, financial responsibility, and financial assurance	The owner or operator has submitted a replacement financial instrument and received written approval from the director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.	
			§5.205 (c)(3)	Fees, financial responsibility, and financial assurance	The director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors.	
			§5.205 (c)(4)	Fees, financial responsibility, and financial assurance	The director may approve a reduction in the amount of financial assurance required for post-injection monitoring and/or corrective action based on project-specific monitoring results.	
			§5.205 (c)(5)		The owner or operator must maintain the required financial responsibility regardless of the status of the director's review of the financial responsibility demonstration.	
			§5.205 (D)	Fees, financial responsibility, and financial assurance	Notice of adverse financial conditions	
			§5.205 (D)(1)	Fees, financial responsibility, and financial assurance	The operator must notify the Commission of adverse financial conditions that may affect the operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An operator must file any notice of bankruptcy in accordance with §3.1(f) of this title (relating to Organization Report; Retention of Records; Notice Requirements). The operator must give such notice by certified mail.	
			§5.205 (D)(2)	Fees, financial responsibility, and financial assurance	The operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business.	
			§5.205 (D)(3)	Fees, financial responsibility, and financial assurance	Upon the incapacity of a bank or surety company by reason of bankruptcy, insolvency or suspension, or revocation of its charter or license, the Commission must deem the operator to be without bond coverage. The Commission must issue a notice to any operator who is without bond coverage and must specify a reasonable period to replace bond coverage, not to exceed 60 days.	
§146.85	Financial Responsibility					
§146.85(a)	Financial Responsibility	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:				
§146.85(a)(1)		The financial responsibility instrument(s) used must be from the following list of qualifying instruments:				
§146.85(a)(1)(i)		Trust Funds.				
§146.85(a)(1)(ii)		Surety Bonds.				9.3
§146.85(a)(1)(iii)		Letter of Credit.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(1)(iv)		Insurance				
§146.85(a)(1)(v)		Self Insurance (i.e., Financial Test and Corporate Guarantee).				
§146.85(a)(1)(vi)		Escrow Account				
§146.85(a)(1)(vii)		Any other instrument(s) satisfactory to the Director.				
§146.85(a)(2)		The qualifying instrument(s) must be sufficient to cover the cost of:	§5.203 (n)(1)		The applicant must demonstrate financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided to the operator a written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.3.1
§146.85(a)(2)(i)		Corrective action (that meets the requirements of § 146.84);				
§146.85(a)(2)(ii)		Injection well plugging (that meets the requirements of § 146.92);				
§146.85(a)(2)(iii)		Post injection site care and site closure (that meets the requirements of § 146.93); and				
§146.85(a)(2)(iv)		Emergency and remedial response (that meets the requirements of § 146.94).				
§146.85(a)(3)		The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.				9.3.1
§146.85(a)(4)		The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.				
§146.85(a)(4)(i)		Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.				
§146.85(a)(4)(i)(A)		Cancellation - for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.				
§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.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(4)(i)(C)		Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.				
§146.85(a)(5)		The qualifying financial responsibility instrument(s) must be approved by the Director.				
§146.85(a)(5)(i)		The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).				
§146.85(a)(5)(ii)		The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.				
§146.85(a)(5)(iii)		The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.				
§146.85(a)(6)		The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.				
§146.85(a)(6)(i)		In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.				
§146.85(a)(6)(ii)		When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.				
§146.85(a)(6)(iii)		An owner or operator using certain types of third-party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(6)(iv)		An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.				
§146.85(a)(6)(v)		An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than −0.1; and a net profit (revenues minus expenses) greater than 0.				
§146.85(a)(6)(vi)		An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.				
§146.85(a)(6)(vii)		An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.				
§146.85(b)		The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.				
§146.85(b)(1)		The owner or operator must maintain financial responsibility and resources until:				
§146.85(b)(1)(i)		The Director receives and approves the completed post-injection site care and site closure plan; and				7.5
§146.85(b)(1)(ii)		The Director approves site closure.				7.5
§146.85(b)(2)		The owner or operator may be released from a financial instrument in the following circumstances:				
§146.85(b)(2)(i)		The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(b)(2)(ii)		The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.				
§146.85(c)		The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.				9.3.1
§146.85(c)(1)		The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.				9.3.1
§146.85(c)(2)		During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).				9.3.1
§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.				9.3.1
§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.				9.3.1
§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.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(d)(1)		In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.				
§146.85(d)(2)		A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.				
§146.85(d)(3)		An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.				
§146.85(e)	Financial Responsibility	The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94).				
§146.85(f)	Financial Responsibility	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.				
§146.86 - Injection well construction requirements						
§146.86	Injection well construction requirements		§5.203 (e)	Injection well construction	Injection well construction	
§146.86(a)	Injection well construction requirements	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	§5.203 (e)(1)	Injection well construction	Criteria for construction of anthropogenic CO2 injection wells. This paragraph establishes the criteria for the information about the construction and casing and cementing of, and special equipment for, anthropogenic CO2 injection wells that an applicant must include in an application.	
			§5.203 (e)(1)(A)	Injection well construction	General. The operator of a geologic storage facility must ensure that all anthropogenic CO2 injection wells are constructed and completed in a manner that will:	
§146.86(a)(1)	Injection well construction requirements	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	§5.203 (e)(1)(A)(i)	Injection well construction	Prevent the movement of injected CO2 or displaced fromation fluids into any unauthorized zones or into any areas where they could endanger USDWs;	4.2, 4.2.1
§146.86(a)(2)	Injection well construction requirements	Permit the use of appropriate testing devices and workover tools; and	§5.203 (e)(1)(A)(ii)	Injection well construction	Allow the use of appropriate testing devices and workover tools; and	4.2.1
§146.86(a)(3)	Injection well construction requirements	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	§5.203 (e)(1)(A)(iii)	Injection well construction	Allow continuous monitoring of the annulus space between the injection tubing and long string casing.	4.2
§146.86(b)	Injection well construction requirements	Casing and cementing of Class VI wells.	§5.203 (e)(1)(B)	Injection well construction	Casing and Cementing of anthropogenic CO2 injection wells	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.86(b)(1)	Injection well construction requirements	Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	§5.203 (e)(1)(B)(ii)	Injection well construction	Casing and cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards approved by the Director.	4.2.1
			§5.203 (e)(2)	Injection well construction	Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:	
§146.86(b)(1)(i)	Injection well construction requirements	Depth to the injection zone(s);	§5.203 (e)(2)(A)	Injection well construction	Depth to the injection zone(s);	4.2
§146.86(b)(1)(ii)	Injection well construction requirements	Injection pressure, external pressure, internal pressure, and axial loading;				4.2.1
§146.86(b)(1)(iii)	Injection well construction requirements	Hole size;	§5.203 (e)(2)(B)	Injection well construction	Hole size	4.2
§146.86(b)(1)(iv)	Injection well construction requirements	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	§5.203 (e)(2)(C)	Injection well construction	size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths);	4.2.1
§146.86(b)(1)(v)	Injection well construction requirements	Corrosiveness of the carbon dioxide stream and formation fluids;	§5.203 (e)(2)(F)	Injection well construction	a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids;	Appendix E
§146.86(b)(1)(vi)	Injection well construction requirements	Down-hole temperatures;	§5.203 (e)(2)(G)	Injection well construction	Down-hole temperatures and pressures	2.5.2.4, 4.2.1
§146.86(b)(1)(vii)	Injection well construction requirements	Lithology of injection and confining zone(s);	§5.203 (e)(2)(H)	Injection well construction	Lithology of injection and confining zone(s)	1.3.1; 1.3.2; 1.3.3, 4.2,4.2.1
§146.86(b)(1)(viii)	Injection well construction requirements	Type or grade of cement and cement additives; and	§5.203 (e)(2)(I)	Injection well construction	Type or grade of cement and cement additives; and	4.2.1, Appendix D
§146.86(b)(1)(ix)	Injection well construction requirements	Quantity, chemical composition, and temperature of the carbon dioxide stream.	§5.203 (e)(2)(J)	Injection well construction	Quantity, chemical composition, and temperature of the carbon dioxide stream.	4.2.1
			§5.203 (e)(1)(B)(i)	Injection well construction	The operator must ensure that injection wells are cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), in addition to the requirements of this section.	4.2.1, Appendix D
§146.86(b)(2)	Injection well construction requirements	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	§5.203 (e)(1)(B)(iii)	Injection well construction	Surface casing must extend through the base of the lowermost USDW above the injection zone and be cemented to the surface	4.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.86(b)(3)	Injection well construction requirements	At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	§5.203 (e)(1)(B)(v)	Injection well construction	At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The long string casing must isolate the injection zone and other intervals as necessary for the protection of USDWs and to ensure confinement of the injected and formation fluids to the permitted injection zone using cement and/or other isolation techniques. If the long string casing does not extend through the injection zone, another well string or liner must be cemented through the injection zone (for example, a chrome liner).	4.2.1
§146.86(b)(4)	Injection well construction requirements	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	§5.203 (e)(1)(B)(iv)	Injection well construction	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	
§146.86(b)(5)	Injection well construction requirements	Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	§5.203 (e)(1)(B)(vi)	Injection well construction	The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered.	4.3.2
§146.86(c)		Tubing and packer.	§5.203 (e)(1)(C)	Injection well construction	Special equipment.	
§146.86(c)(1)	Injection well construction requirements	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.				4.2, Appendix E
§146.86(c)(2)	Injection well construction requirements	All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	§5.203 (e)(1)(C)(i)	Injection well construction	Tubing and packer. All injection wells must inject fluids through tubing set on a mechanical packer. Packers must be set no higher than 100 feet above the top of the permitted injection interval or at a location approved by the director.	4.2.1; 4.4.4.1
			§5.203 (e)(1)(C)(ii)	Injection well construction	Pressure observation valve. The wellhead of each injection well must be equipped with a pressure observation valve on the tubing and each annulus of the well.	4.2.3.10
§146.86(c)(3)	Injection well construction requirements	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:				
§146.86(c)(3)(i)	Injection well construction requirements	Depth of setting;				4.2.1
§146.86(c)(3)(ii)	Injection well construction requirements	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;				4.2.3; Appenedix E

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.86(c)(3)(iii)	Injection well construction requirements	Maximum proposed injection pressure;				4.2.6
§146.86(c)(3)(iv)	Injection well construction requirements	Maximum proposed annular pressure;				4.2.6
§146.86(c)(3)(v)	Injection well construction requirements	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	§5.203 (e)(2)(D)	Injection well construction	proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, and maximum proposed volume and/or mass of the CO2 stream to be injected;	4.2.6
			§5.203 (e)(2)(E)	Injection well construction	type of packer and packer setting depth	4.2.1; 4.2.3.7
§146.86(c)(3)(vi)	Injection well construction requirements	Size of tubing and casing; and				4.2.3.4, 4.2.3.6
§146.86(c)(3)(vii)	Injection well construction requirements	Tubing tensile, burst, and collapse strengths.				4.2.3.6
§146.87 - Logging, sampling, and testing prior to injection well operation						
§146.87		Logging, sampling, and testing prior to injection well operation				
			§5.203 (c)(1)	Geologic, geochemical, and hydrologic information	The applicant must submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations.	4.3.1-4.3.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.87(a)	Logging, sampling, and testing prior to injection well operation	During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	§5.203 (f)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The applicant must submit a plan for logging, sampling, and testing of each injection well after permitting but prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.	
			§5.203 (f)(1)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Logs and surveys of newly drilled and completed injection wells.	4.3.1-4.3.4
§146.87(a)(1)	Logging, sampling, and testing prior to injection well operation	Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	§5.203 (f)(1)(A)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	During the drilling of any hole that is constructed by drilling a pilot hole which is enlarged by reaming or another method, the operator must perform deviation checks at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.	
§146.87(a)(2)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the surface casing:				4.3.2
§146.87(a)(2)(i)	Logging, sampling, and testing prior to injection well operation	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§5.203 (f)(1)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	4.3.2
§146.87(a)(2)(ii)	Logging, sampling, and testing prior to injection well operation	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.				4.3.2
§146.87(a)(3)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the long string casing:	§5.203 (f)(1)(D)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.	4.3.2
§146.87(a)(3)(i)	Logging, sampling, and testing prior to injection well operation	Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and				4.3.2
§146.87(a)(3)(ii)	Logging, sampling, and testing prior to injection well operation	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	§5.203 (f)(1)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.	4.2.4.1

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.203 (h)(1)(E)	Mechanical integrity testing	The operator must test injection wells after any workover that disturbs the seal between the tubing, packer, and casing in a manner that verifies internal mechanical integrity of the tubing and long string casing.	5.4.2
			§5.203 (h)(1)(F)	Mechanical integrity testing	An operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
§146.87(a)(4)	Logging, sampling, and testing prior to injection well operation	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	§5.203 (h)(2)	Mechanical integrity testing	Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. [The plan must include a schedule for the performance of a series of tests at a minimum frequency of five years.] The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:	5.4.2, 5.4.3, 5.5.1
§146.87(a)(4)(i)	Logging, sampling, and testing prior to injection well operation	A pressure test with liquid or gas;	§5.203 (h)(2)(A)	Mechanical integrity testing	A pressure test with liquid or gas;	5.4.2
§146.87(a)(4)(ii)	Logging, sampling, and testing prior to injection well operation	A tracer survey such as oxygen-activation logging;	§5.203 (h)(2)(B)	Mechanical integrity testing	A tracer survey such as oxygen-activation logging;	
§146.87(a)(4)(iii)	Logging, sampling, and testing prior to injection well operation	A temperature or noise log;	§5.203 (h)(2)(C)	Mechanical integrity testing	A temperature or noise log;	5.4.3
§146.87(a)(4)(iv)	Logging, sampling, and testing prior to injection well operation	A casing inspection log; and	§5.203 (h)(2)(D)	Mechanical integrity testing	A casing inspection log; and	5.4.5
§146.87(a)(5)	Logging, sampling, and testing prior to injection well operation	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	§5.203 (h)(2)(E)	Mechanical integrity testing	Any alternative methods approved by the director, and if necessary by the Administrator of EPA under 40 CFR §146.89(e), that provides equivalent or better information approved by the director.	
§146.87(b)	Logging, sampling, and testing prior to injection well operation	The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	§5.203 (f)(3)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must submit analyses of whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well.	1.3, 1.3.1-1.3.3, 4.3.1, 4.3.3
§146.87(c)	Logging, sampling, and testing prior to injection well operation	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	§5.203 (f)(3)(A)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must record the formation fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone.	4.3.3
§146.87(d)	Logging, sampling, and testing prior to injection well operation	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	§5.203 (f)(2)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Testing and determination of hydrogeologic characteristics of injection and confining zone.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.87(d)(1)	Logging, sampling, and testing prior to injection well operation	Fracture pressure;	§5.203 (f)(2)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone	1.4.3; 4.3.4, 4.4
§146.87(d)(2)	Logging, sampling, and testing prior to injection well operation	Other physical and chemical characteristics of the injection and confining zone(s); and				1.3, 4.3
§146.87(d)(3)	Logging, sampling, and testing prior to injection well operation	Physical and chemical characteristics of the formation fluids in the injection zone(s).				1.3, 4.3.3
§146.87(e)	Logging, sampling, and testing prior to injection well operation	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):				
§146.87(e)(1)	Logging, sampling, and testing prior to injection well operation	A pressure fall-off test; and,	§5.203 (f)(2)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO_2.	5.4.4
§146.87(e)(2)		A pump test; or				
§146.87(e)(3)		Injectivity tests.				5.4.1
§146.87(f)	Logging, sampling, and testing prior to injection well operations	The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	§5.206 (i)	Permit Standards	Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	4.2.2
§146.88 - Injection well operating requirements						
§146.88		Injection well operating requirements				
			§5.203 (i)(2)	Operating Information	Maximum injection pressure. The director will approve a maximum injection pressure limit that:	
			§5.203 (i)(2)(A)	Operating Information	Considers the risks of tensile failure and, where appropriate, geomechanical or other studies that assess the risk of tensile failure and shear failure;	
			§5.203 (i)(2)(B)	Operating Information	With a reasonable degree of certainty will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive; and	
		Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of	§5.203 (i)(2)(C)	Operating Information	in no case may cause the movement of injection fluids or formation fluids in a manner that endangers USDWs.	3.5

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.88(a)	Injection well operating requirements	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	§5.203 (f)(2)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone	1.4.3, 4.3
§146.88(b)	Injection well construction requirements	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	§5.206 (d)(2)(A)	Operating a geologic storage facility	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	
§146.88(c)	Injection well construction requirements	The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	§5.206 (d)(2)(D)	Operating a geologic storage facility	The owner or operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	4.2.1
§146.88(d)	Injection well operating requirements	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	§5.203 (h)(1)(A)	Mechanical integrity testing	Other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.	
§146.88(d)	Injection well operating requirements	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	§5.206 (f)(2)	Mechanical integrity	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	
§146.88(e)	Injection well operating requirements	The owner or operator must install and use:	§5.206 (d)(2)(F)	Operating a geologic storage facility	The operator must comply with the following requirements for alarms and automatic shut-off systems.	
§146.88(e)(1)	Injection well operating requirements	Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	§5.206 (d)(2)(F)(i)	Operating a geologic storage facility	The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	4.2, 5.5.2
§146.88(e)(2)	Injection well operating requirements	Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and				5.5.2
§146.88(e)(3)	Injection well operating requirements	Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.88(f)	Injection well operating requirements	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:	§5.206 (d)(2)(F)(ii)	Operating a geologic storage facility	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must	8.3.2
§146.88(f)(1)	Injection well operating requirements	Immediately cease injection;	§5.206 (d)(2)(F)(ii)(I)	Operating a geologic storage facility	Immediately cease injection;	8.3.2
§146.88(f)(2)	Injection well operating requirements	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;	§5.206 (d)(2)(F)(ii)(II)	Operating a geologic storage facility	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone	8.3.2
§146.88(f)(3)	Injection well operating requirements	Notify the Director within 24 hours;	§5.206 (d)(2)(F)(ii)(III)	Operating a geologic storage facility	Notify the Director within 24 hours	8.3.2
§146.88(f)(4)	Injection well operating requirements	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	§5.206 (d)(2)(F)(ii)(IV)	Operating a geologic storage facility	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	8.3.2
§146.88(f)(5)	Injection well operating requirements	Notify the Director when injection can be expected to resume.	§5.206 (d)(2)(F)(ii)(V)	Operating a geologic storage facility	Notify the Director when injection can be expected to resume	8.3.2
§146.89 - Mechanical integrity						
§146.89	Mechanical Integrity	Mechanical Integrity	§5.203 (h)	Mechanical integrity testing	Mechanical integrity testing.	
			§5.203 (h)(1)	Mechanical integrity testing	Criteria. This paragraph establishes the criteria for the mechanical integrity testing plan for anthropogenic CO2 injection wells that an applicant must include in an application.	
			§5.206 (f)	Mechanical integrity	Mechanical Integrity	
§146.89(a)	Mechanical Integrity	A Class VI well has mechanical integrity if:				
§146.89(a)(1)	Mechanical Integrity	There is no significant leak in the casing, tubing, or packer; and				
§146.89(a)(2)	Mechanical Integrity	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.				
			§5.203 (h)(1)(B)	Mechanical integrity testing	Before beginning injection operations and at least once every five years thereafter, the operator must demonstrate internal mechanical integrity for each injection well by pressure testing the tubing-casing annulus.	5.4.2
§146.89(b)	Mechanical Integrity	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	§5.203 (h)(1)(C)	Mechanical integrity testing	Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, injected volumes and pressure on the annulus between tubing and long-string casing to confrim that the injected fluids are confined to the injection zone.	5.5.2
§146.89(c)	Mechanical Integrity	At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	§5.203 (h)(1)(D)	Mechanical integrity testing	At least once per year until the injection well is plugged the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).	5.4.3
§146.89(c)(1)	Mechanical Integrity	An approved tracer survey such as an oxygen-activation log; or				
§146.89(c)(2)	Mechanical Integrity	A temperature or noise log.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.89(d)	Mechanical Integrity	If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.				5.4.5.1
§146.89(e)	Mechanical Integrity	The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.				
§146.89(f)	Mechanical Integrity	In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.				
§146.89(g)	Mechanical Integrity	The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	§5.206 (f)(4)	Mechanical integrity	The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	
§146.90 - Testing and monitoring requirements						
§146.90	Testing and monitoring requirements	The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during	§5.203 (j)	Plan for monitoring, sampling, and testing after initiation of operation	Plan for monitoring, sampling, and testing after initiation of operation.	5.3; 5.5.1
			§5.203 (j)(1)	Plan for monitoring, sampling, and testing after initiation of operation	The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.	5.3; 5.5.1
			§5.203 (j)(2)	Plan for monitoring, sampling, and testing after initiation of operation	The plan must include the following:	
§146.90(a)	Testing and monitoring requirements	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	§5.203 (j)(2)(A)	Plan for monitoring, sampling, and testing after initiation of operation	The analysis of the carbon dioxide stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;	5.5.1, 5.5.3
§146.90(b)	Testing and monitoring requirements	Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	§5.203 (j)(2)(B)	Plan for monitoring, sampling, and testing after initiation of operation	The installation and use of continuous recording devices to monitor injection pressure, rate, and volume and the pressure on the annulus between the tubing and the long string casing, except during workovers	5.5.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.90(c)	Testing and monitoring requirements	Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:	§5.203 (j)(2)(C)	Plan for monitoring, sampling, and testing after initiation of operation	After initiation of injection, the performance on a semi-annual basis of corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in subsection (e)(1)(A) of this section. The operator must report the results of such monitoring annually. Corrosion monitoring may be accomplished by:	5.4.5.1
§146.90(c)(1)	Testing and monitoring requirements	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	§5.203 (j)(2)(C)(i)	Plan for monitoring, sampling, and testing after initiation of operation	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	
§146.90(c)(2)	Testing and monitoring requirements	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	§5.203 (j)(2)(C)(ii)	Plan for monitoring, sampling, and testing after initiation of operation	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	5.5.4.1
§146.90(c)(3)	Testing and monitoring requirements	Using an alternative method approved by the Director;	§5.203 (j)(2)(C)(iii)	Plan for monitoring, sampling, and testing after initiation of operation	using an alternative method, materials, or time period approved by the director;	
§146.90(d)	Testing and monitoring requirements	Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	§5.203 (j)(2)(D)	Plan for monitoring, sampling, and testing after initiation of operation	Monitoring of geochemical and geophysical changes, including:	
			§5.203 (j)(2)(D)(i)	Plan for monitoring, sampling, and testing after initiation of operation	Periodic sampling of the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone and monitoring for pressure changes, and for changes in geochemistry, in a permeable and porous formation near to and above the top confining zone;	5.5.5
			§5.203 (j)(2)(D)(iii)	Plan for monitoring, sampling, and testing after initiation of operation	The location and number of monitoring wells justified on the basis of AOR, injection rate and volume, geology, the presence of artificial penetrations and other factors specific to the geologic storage facility; and	5.5.5, 5.5.6
§146.90(d)(2)	Testing and monitoring requirements	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).	§5.203 (j)(2)(D)(iv)	Plan for monitoring, sampling, and testing after initiation of operation	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under subsection (c)(2) of this section and any modeling results in the AOR evaluation;	5.5.5
§146.90(e)		A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	§5.203 (j)(2)(F)		a demonstration of external mechanical integrity pursuant to subsection (h)(2) of this section at least once per year until the injection well is plugged, and, if required by the director, a casing inspection log pursuant to requirements in subsection (h)(2) of this section at a frequency established in the testing and monitoring plan;	5.4.3, 5.5.1
§146.90(f)	Testing and monitoring requirements	A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	§5.203 (j)(2)(G)	Plan for monitoring, sampling, and testing after initiation of operation	A pressure fall-off test at least once every five years unless more frequent testing is required by the director based on site-specific information; and	5.4.4, 5.5.1
§146.90(g)	Testing and monitoring requirements	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	§5.203 (j)(2)(E)	Plan for monitoring, sampling, and testing after initiation of operation	tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO2 detection tools;	
§146.90(g)(1)		Direct methods in the injection zone(s); and,				5.5.1, 5.5.7

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.90(g)(2)	Testing and monitoring requirements	Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	§5.203 (j)(2)(E)	Plan for monitoring, sampling, and testing after initiation of operation	tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO2 detection tools;	5.5.1, 5.5.7
§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.				
§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;				
§146.90(h)(2)		The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter;				5.5.1
§146.90(h)(3)		If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;				
§146.90(i)	Testing and monitoring requirements	Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	§5.203 (j)(2)(H)	Plan for monitoring, sampling, and testing after initiation of operation	Additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.	
			§5.206 (e)(3)	Monitoring, sampling, and testing requirements	The director may require additional monitoring as necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirement that the injection activity not allow movement of fluid that would endanger USDWs	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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:				5.3
§146.90(j)(1)		Within one year of an area of review reevaluation;				5.3
§146.90(j)(2)		Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or	§5.207 (a)(3)	Reporting and Record-Keeping	The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	
§146.90(j)(3)		When required by the Director.				
			§5.203 (a)(4)	General	Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.	
§146.90(k)	Testing and monitoring requirements	A quality assurance and surveillance plan for all testing and monitoring requirements.	§5.203 (a)(4)	General	Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.	5.5.5.6
§146.91 - Reporting requirements						
§146.91	Reporting requirements	The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	§5.207 (a)	Reporting and Record-Keeping	Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information:	
			§5.207 (a)(1)	Reporting and Record-Keeping	Test records. The operator must file a complete record of all tests in duplicate with the district office within 30 days after the testing. In conducting and evaluating the tests enumerated in this subchapter or others to be allowed by the director, the operator and the director must apply methods and standards generally accepted in the industry. When the operator reports the results of mechanical integrity tests to the director, the operator must include a description of any tests and methods used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.	5.2
			§5.207 (a)(2)(D)	Reporting and Record-Keeping	Annual reports. The operator must submit an annual report detailing:	
			§5.207 (a)(2)(D)(i)	Reporting and Record-Keeping	corrective action performed;	5.2
			§5.207 (a)(2)(D)(ii)	Reporting and Record-Keeping	new wells installed and the type, location, number, and information required in §5.203(e) of this title (relating to Application Requirements);	Not stated in 5.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.207 (a)(2)(D)(iii)	Reporting and Record-Keeping	re-calculated AOR unless the operator submits a statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR on file with the Commission;	5.2
			§5.207 (a)(2)(D)(iv)	Reporting and Record-Keeping	the updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;	5.2
			§5.207 (a)(2)(D)(v)	Reporting and Record-Keeping	tons of CO2 injected; and	5.2
			§5.207 (a)(2)(D)(vi)	Reporting and Record-Keeping	other information as required by the permit.	
			§5.207 (a)(2)(E)	Reporting and Record-Keeping	Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter.	
			§5.207 (a)(2)(E)(i)	Reporting and Record-Keeping	Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has:	
			§5.207 (a)(2)(E)(i)(I)	Reporting and Record-Keeping	reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title; and	
			§5.207 (a)(2)(E)(i)(II)	Reporting and Record-Keeping	determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator.	
			§5.207 (a)(2)(E)(ii)	Reporting and Record-Keeping	Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.	
§146.91(a)	Reporting requirements	Semi-annual reports containing:	§5.207 (a)(2)(C)	Reporting and Record-Keeping	Semi-annual reports containing:	
§146.91(a)(1)	Reporting requirements	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	§5.207 (a)(2)(C)(ii)	Reporting and Record-Keeping	Any changes to the source as well as the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	5.2
§146.91(a)(2)	Reporting requirements	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	§5.207 (a)(2)(C)(i)	Reporting and Record-Keeping	a summary of well head pressure monitoring;	5.2
			§5.207 (a)(2)(C)(iii)	Reporting and Record-Keeping	monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;	5.2
§146.91(a)(3)	Reporting requirements	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	§5.207 (a)(2)(C)(v)	Reporting and Record-Keeping	description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;	5.2
§146.91(a)(4)	Reporting requirements	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	§5.207 (a)(2)(C)(vi)	Reporting and Record-Keeping	a description of any event that triggers a shutdown device and the response taken; and	5.2
§146.91(a)(5)	Reporting requirements	The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	§5.207 (a)(2)(C)(iii)	Reporting and Record-Keeping	monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;	5.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.91(a)(6)	Reporting requirements	Monthly annulus fluid volume added; and	§5.207 (a)(2)(C)(iv)	Reporting and Record-Keeping	monthly annulus fluid volume added;	5.2
§146.91(a)(7)	Reporting requirements	The results of monitoring prescribed under § 146.90.	§5.207 (a)(2)(C)(vii)	Reporting and Record-Keeping	the results of monitoring prescribed under §5.206€ [§5.206(d)] of this title (relating to Permit Standards).	5.2
§146.91(b)	Reporting requirements	Report, within 30 days, the results of:	§5.207 (a)(2)(B)	Reporting and Record-Keeping	Report, within 30 days, the results of:	
§146.91(b)(1)	Reporting requirements	Periodic tests of mechanical integrity;	§5.207 (a)(2)(B)(i)	Reporting and Record-Keeping	the results of periodic tests for mechanical integrity;	5.2
§146.91(b)(2)	Reporting requirements	Any well workover; and,	§5.207 (a)(2)(B)(iii)	Reporting and Record-Keeping	a description of any well workover.	5.2
§146.91(b)(3)	Reporting requirements	Any other test of the injection well conducted by the permittee if required by the Director.	§5.207 (a)(2)(B)(ii)	Reporting and Record-Keeping	the results of any other test of the injection well conducted by the operator if required by the director; and	5.2
§146.91(c)	Reporting requirements	Report, within 24 hours:	§5.207 (a)(2)	Reporting and Record-Keeping	Operating reports. The operator also must include summary cumulative tables of the information required by the reports listed in this paragraph.	
			§5.207 (a)(2)(A)	Reporting and Record-Keeping	Report within 24 hours. The operator must report to the appropriate district office the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir. Such report must be made orally as soon as practicable, but within 24 hours, following the discovery of the leak, and must be confirmed in writing within five working days.	5.2
			§5.207 (a)(2)(A)(i)		the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir;	5.2
§146.91(c)(1)	Reporting requirements	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	§5.207 (a)(2)(A)(ii)	Reporting and Record-Keeping	any evidence that the injected CO2 stream or associated pressure front may cause an endangerment to a USDW;	5.2
§146.91(c)(2)	Reporting requirements	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	§5.207 (a)(2)(A)(iii)	Reporting and Record-Keeping	any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	5.2
§146.91(c)(3)	Reporting requirements	Any triggering of a shut-off system (i.e., down-hole or at the surface);	§5.207 (a)(2)(A)(iv)	Reporting and Record-Keeping	any triggering of a shut-off system (i.e., down-hole or at the surface); and	5.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.91(c)(4)	Reporting requirements	Any failure to maintain mechanical integrity; or.	§5.207 (a)(2)(A)(v)	Reporting and Record-Keeping	any failure to maintain mechanical integrity.	5.2
§146.91(c)(5)	Reporting requirements	Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.				
§146.91(d)	Reporting requirements	Owners or operators must notify the Director in writing 30 days in advance of	§5.206 (i)	Commission witnessing of testing and logging.	Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	
§146.91(d)(1)	Reporting requirements	Any planned well workover;				5.2
§146.91(d)(2)	Reporting requirements	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and				5.2
§146.91(d)(3)	Reporting requirements	Any other planned test of the injection well conducted by the permittee.				5.2
			§5.207 (b)(1)	Reporting and Record-Keeping	The operator must report the results of injection pressure and injection rate monitoring of each injection well on Form H-10, Annual Disposal/Injection Well Monitoring Report, and the results of internal mechanical integrity testing on Form H-5, Disposal/Injection Well Pressure Test Report. Operators must submit other reports in a format acceptable to the Commission. At the discretion of the director, other formats may be accepted.	5.2
§146.91(e)	Reporting requirements	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	§5.207 (b)(2)	Reporting and Record-Keeping	The operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by director.	
			§5.207 (c)	Reporting and Record-Keeping	Signatories to reports.	
			§5.207 (c)(1)	Reporting and Record-Keeping	Reports. All reports required by permits and other information requested by the director, shall be signed by a person described in §5.203(a)(1)(B) of this title, or by a duly authorized representative of that person. A person is a duly authorized representative only if:	
			§5.207 (c)(1)(A)	Reporting and Record-Keeping	the authorization is made in writing by a person described in §5.203(a)(1)(B) of this title;	
			§5.207 (c)(1)(B)	Reporting and Record-Keeping	the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility; and	
			§5.207 (c)(1)(C)	Reporting and Record-Keeping	the written authorization is submitted to the director.	
			§5.207 (c)(2)	Reporting and Record-Keeping	Changes to authorization. If an authorization under paragraph (1) of this subsection is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (1) of this subsection must be submitted to the director prior to or together with any reports, information, or applications to be signed by an authorized representative.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.207 (d)	Reporting and Record-Keeping	Certification. All reports required by permits and other information requested by the director under this subchapter, shall be certified as follows: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."	
§146.91(f)	Reporting requirements		§5.207 (e)	Reporting and Record-Keeping	Record retention.	
§146.91(f)(1)	Reporting requirements	All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	§5.207 (e)(1)	Reporting and Record-Keeping	The operator must retain all data collected under §5.203 of this title for Class VI permit applications throughout the life of the geologic sequestration project and for 10 years following storage facility closure.	5.2
§146.91(f)(2)	Reporting requirements	Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.	§5.207 (e)(2)	Reporting and Record-Keeping	The operator must retain data on the nature and composition of all injected fluids collected pursuant to §5.203(j)(2)(A) of this title until 10 years after storage facility closure. The operator shall submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	5.2
			§5.207 (e)(7)	Reporting and Record-Keeping	The director may require the operator to submit the records to the director at the conclusion of the retention period.	
§146.91(f)(3)	Reporting requirements	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	§5.207 (e)(3)	Reporting and Record-Keeping	The operator must retain all testing and monitoring data collected pursuant to the plans required under §5.203(j) of this title, including wellhead pressure records, metering records, and integrity test results, and modeling inputs and data used to support AOR calculations for at least 10 years after the data is collected.	5.2
§146.91(f)(4)	Reporting requirements	Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.	§5.207 (e)(4)	Reporting and Record-Keeping	The operator must retain well plugging reports, post-injection storage facility care data, including data and information used to develop the demonstration of the alternative post-injection storage facility care timeframe, and the closure report collected pursuant to the requirements of §5.206(k)(6) and (m) of this title for 10 years following storage facility closure.	5.2
			§5.207 (e)(5)	Reporting and Record-Keeping	The operator must retain all documentation of good faith claim to necessary and sufficient property rights to operate the geologic storage facility until the director issues the final certificate of closure in accordance with §5.206(k)(7) of this title.	5.2
§146.91(f)(5)	Reporting requirements	The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	§5.207 (e)(6)	Reporting and Record-Keeping	The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years after storage facility closure.	
§146.92 - Injection well plugging						
§146.92	Injection Well Plugging	Injection well plugging	§5.203 (k)	Well Plugging Plan	Injection well plugging	6.2.2
§146.92(a)	Injection Well Plugging	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	§5.203 (k)(2)(A)	Well Plugging Plan	flush each injection well with a buffer fluid;	6.2.2.1
			§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.2.2.1
			§5.203 (k)(2)(C)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.2.2.1

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.92(b)	Injection Well Plugging	Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	§5.203 (k)	Well Plugging Plan	Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that penetrate the base of usable quality water that includes the following:	6.2.2, 6.3.2, 6.3.3, 6.3.4 Appendix H
			§5.203 (k)(1)	Well Plugging Plan	A proposal for plugging all monitoring wells that penetrate the base of usable quality water and all injection wells upon abandonment in accordance with §3.14 of this title (relating to Plugging), in addition to the requirements of this section. The proposal must include:	6.2.2, 6.3.2, 6.3.3, 6.3.4 Appendix H
§146.92(b)(1)	Injection Well Plugging	Appropriate tests or measures for determining bottomhole reservoir pressure;	§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.2.2.1
§146.92(b)(2)	Injection Well Plugging	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	§5.203 (k)(2)(C)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.2.2.1
§146.92(b)(3)	Injection Well Plugging	The type and number of plugs to be used;	§5.203 (k)(1)(A)	Well Plugging Plan	The type and number of plugs to be used;	6.2.2, 6.3.2, 6.3.3, 6.3.4 Appendix H
§146.92(b)(4)	Injection Well Plugging	The placement of each plug, including the elevation of the top and bottom of each plug;	§5.203 (k)(1)(B)	Well Plugging Plan	The placement of each plug, including the elevation of the top and bottom of each plug;	6.2.2, 6.3.2, 6.3.3, 6.3.4 Appendix H
§146.92(b)(5)	Injection Well Plugging	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	§5.203 (k)(1)(C)	Well Plugging Plan	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	6.2.2, 6.3.2, 6.3.3, 6.3.4 Appendix H
			§5.203 (k)(2)(D)	Well Plugging Plan	ensuring that the material to be used in plugging must be compatible with the CO2 stream and the formation fluids;	6.2.2
§146.92(b)(6)	Injection Well Plugging	The method of placement of the plugs.	§5.203 (k)(1)(D)	Well Plugging Plan	The method of placement of the plugs.	6.2.2, 6.3.2, 6.3.3, 6.3.4 Appendix H
§146.92(c)	Injection Well Plugging	Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.203 (k)(3)(A)	Well Plugging Plan	the operator notifies the director at least 60 days before plugging a well. At this time, if any changes have been made to the original well plugging plan, the operator must also provide a revised well plugging plan. At the discretion of the director, an operator may be allowed to proceed with well plugging on a shorter notice period; and	6.2.2, 6.3.1
			§5.203 (k)(3)(B)	Well Plugging Plan	the operator will file a notice of intention to plug and abandon (Form W-3A) a well with the appropriate Commission district office and the division in Austin at least five days prior to the beginning of plugging operations;	6.2.2, 6.3.1
§146.92(d)	Injection Well Plugging	Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	§5.203 (k)(4)	Well Plugging Plan	plugging report for monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that within 30 days after plugging the operator will file a complete well plugging record (Form W-3) in duplicate with the appropriate district office. The operator and the person who performed the plugging operation (if other than the operator) must certify the report as accurate;	Appendix H
§146.93 - Post-injection site care and site closure						
§146.93	Post-injection and site closure	Post-injection site care and site closure	§5.203 (m)	Post-injection storage facility care and closure plan	The applicant must submit a post-injection storage facility care and closure plan.	Section 7
§146.93(a)	Post-injection and site closure	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.				
§146.93(a)(1)	Post-injection and site closure	The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.93(a)(2)	Post-injection and site closure	The post-injection site care and site closure plan must include the following information:				
§146.93(a)(2)(i)	Post-injection and site closure	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	§5.203 (m)(2)	Post-injection storage facility care and closure plan	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	7.2
§146.93(a)(2)(ii)	Post-injection and site closure	The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1);	§5.203 (m)(3)	Post-injection storage facility care and closure plan	the predicted position of the CO2 plume and associated pressure front at closure as demonstrated in the AOR evaluation required under subsection (d) of this section;	7.4
§146.93(a)(2)(iii)	Post-injection and site closure	A description of post-injection monitoring location, methods, and proposed frequency;	§5.203 (m)(4)	Post-injection storage facility care and closure plan	A description of post-injection monitoring location, methods, and proposed frequency;	7.4, 7.5
§146.93(a)(2)(iv)	Post-injection and site closure	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	§5.203 (m)(5)	Post-injection storage facility care and closure plan	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	7.5
§146.93(a)(2)(v)	Post-injection and site closure	The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	§5.203 (m)(1)	Post-injection storage facility care and closure plan	a demonstration containing substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the post-injection storage facility care timeframe. The demonstration must be based on significant, site-specific data and information, including all data and information collected pursuant subsections (b)-(d) of this section and §5.206(b)(5) of this title;	7.6
§146.93(a)(3)	Post-injection and site closure	Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.				7.6
§146.93(a)(4)	Post-injection and site closure	At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	§5.206 (k)(1)(B)	Post-injection storage facility care and closure	The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post-injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements in §5.202 of this title (relating to Permit Required), as appropriate.	7.6
§146.93(b)	Post-injection and site closure	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	§5.206 (k)(2)	Post-injection storage facility care and closure	Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	7.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	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.				7.4
§146.93(b)(2)		If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.				7.6
§146.93(b)(3)	Post-injection and site closure	Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	§5.206 (k)(3)	Post-injection storage facility care and closure	Prior to closure. Prior to authorization for storage facility closure, the operator must demonstrate to the Director based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs. The operator must demonstrate, based on the current understanding of the site, including monitoring data and/or modeling, all of the following:	7.6
§146.93(b)(4)						
§146.93(c)	Post-injection and site closure	Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.				7.6
			§5.203 (m)(6)	Post-injection storage facility care and closure plan	the estimated cost of proposed post-injection storage facility care and closure; and	9.6.2
§146.93(c)(1)	Post-injection and site closure	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	§5.203 (m)(7)	Post-injection storage facility care and closure plan	consideration and documentation of:	
§146.93(c)(1)(i)	Post-injection and site closure	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	§5.203 (m)(7)(A)	Post-injection storage facility care and closure plan	the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;	
§146.93(c)(1)(ii)	Post-injection and site closure	The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	§5.203 (m)(7)(B)	Post-injection storage facility care and closure plan	the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre-injection pressures;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.93(c)(1)(iii)	Post-injection and site closure	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	§5.203 (m)(7)(C)	Post-injection storage facility care and closure plan	the predicted rate of CO2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO2 plume and associated pressure front;	
§146.93(c)(1)(iv)	Post-injection and site closure	A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	§5.203 (m)(7)(D)	Post-injection storage facility care and closure plan	a description of the site-specific processes that will result in CO2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	
§146.93(c)(1)(v)	Post-injection and site closure	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	§5.203 (m)(7)(E)	Post-injection storage facility care and closure plan	the predicted rate of CO2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	
§146.93(c)(1)(vi)	Post-injection and site closure	The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section;	§5.203 (m)(7)(F)	Post-injection storage facility care and closure plan	the results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in subparagraphs (D) and (E) of this paragraph;	
§146.93(c)(1)(vii)	Post-injection and site closure	A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	§5.203 (m)(7)(G)	Post-injection storage facility care and closure plan	a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., CO2, formation fluids) movement;	
§146.93(c)(1)(viii)	Post-injection and site closure	The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	§5.203 (m)(7)(H)	Post-injection storage facility care and closure plan	the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO2 plume and area of elevated pressure;	
§146.93(c)(1)(ix)	Post-injection and site closure	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	§5.203 (m)(7)(I)	Post-injection storage facility care and closure plan	a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;	
§146.93(c)(1)(x)	Post-injection and site closure	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	§5.203 (m)(7)(J)	Post-injection storage facility care and closure plan	the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	
§146.93(c)(1)(xi)	Post-injection and site closure	Any additional site-specific factors required by the Director.	§5.203 (m)(7)(K)	Post-injection storage facility care and closure plan	any additional site-specific factors required by the director; and	
§146.93(c)(2)	Post-injection and site closure	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	§5.203 (m)(8)	Post-injection storage facility care and closure plan	information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:	
§146.93(c)(2)(i)	Post-injection and site closure	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	§5.203 (m)(8)(A)	Post-injection storage facility care and closure plan	all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	
§146.93(c)(2)(ii)	Post-injection and site closure	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	§5.203 (m)(8)(B)	Post-injection storage facility care and closure plan	estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	
§146.93(c)(2)(iii)	Post-injection and site closure	Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	§5.203 (m)(8)(C)	Post-injection storage facility care and closure plan	predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.93(c)(2)(iv)	Post-injection and site closure	Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	§5.203 (m)(8)(D)	Post-injection storage facility care and closure plan	predictive models must be calibrated using existing information where sufficient data are available;	
§146.93(c)(2)(v)	Post-injection and site closure	Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	§5.203 (m)(8)(E)	Post-injection storage facility care and closure plan	reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	
§146.93(c)(2)(vi)	Post-injection and site closure	An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	§5.203 (m)(8)(F)	Post-injection storage facility care and closure plan	an analysis must be performed to identify and assess aspects of the alternative PISC timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;	
§146.93(c)(2)(vii)	Post-injection and site closure	An approved quality assurance and quality control plan must address all aspects of the demonstration; and	§5.203 (m)(8)(G)	Post-injection storage facility care and closure plan	an approved quality assurance and quality control plan must address all aspects of the demonstration; and	
§146.93(c)(2)(viii)	Post-injection and site closure	Any additional criteria required by the Director.	§5.203 (m)(8)(H)	Post-injection storage facility care and closure plan	any additional criteria required by the director.	
§146.93(d)	Post-injection and site closure	Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	§5.206 (k)(4)	Post-injection storage facility care and closure	Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	7.7.1
§146.93(e)	Post-injection and site closure	After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	§5.206 (k)(5)	Post-injection storage facility care and closure	Authorization for storage facility closure. No operator may initiate storage facility closure until the director has approved closure of the storage facility in writing. After the Director has authorized site closure, the operator must plug all monitoring wells in accordance with the approved plan required by §5.203(k) of this title.	7.7.2
§146.93(f)	Post-injection and site closure	The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	§5.206 (k)(6)	Post-injection storage facility care and closure	Storage facility closure report. Once the director has authorized storage facility closure, The operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	7.7.4
§146.93(f)(1)	Post-injection and site closure	Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;	§5.206 (k)(6)(A)	Post-injection storage facility care and closure	Documentation of appropriate injection and monitoring well plugging. The operator must provide a copy of a survey plat which has been submitted to the Regional Administrator of Region 6 of the United States Environmental Protection Agency. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks.	7.7.4
§146.93(f)(2)	Post-injection and site closure	Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	§5.206 (k)(6)(B)	Post-injection storage facility care and closure	Documentation of appropriate notification and information to such State and local authorities that have authority over drilling activities to enable such State and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	7.7.4
§146.93(f)(3)	Post-injection and site closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	§5.206 (k)(6)(C)	Post-injection storage facility care and closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	7.7.4
			§5.206 (k)(7)		Certificate of closure. Upon completion of the requirements in paragraphs (3) - (6) of this subsection, the director will issue a certificate of closure. At that time, the operator is released from the requirement in §5.205(c) of this title to maintain financial assurance.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.93(g)	Post-injection and site closure	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	§5.206 (l)	Deed notation	Deed notation. The operator of a geologic storage facility must record a notation on the deed to the facility property; on any other document that is normally examined during title search; or on any other document that is acceptable to the county clerk for filing in the official public records of the county that will in perpetuity provide any potential purchaser of the property the following information:	7.7.4
			§5.206 (l)(1)	Permit Standards	a complete legal description of the affected property;	
§146.93(g)(1)	Post-injection and site closure	The fact that land has been used to sequester carbon dioxide;	§5.206 (l)(2)	Deed notation	The fact that land has been used to sequester carbon dioxide;	7.7.4
§146.93(g)(2)	Post-injection and site closure	The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and	§5.206 (l)(3)	Deed notation	that the survey plat has been filed with the Commission;	7.7.4
			§5.206 (l)(4)	Deed notation	the address of the office of the United States Environmental Protection Agency, Region 6, to which the operator sent a copy of the survey plat; and	7.7.4
§146.93(g)(3)	Post-injection and site closure	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	§5.206 (l)(5)	Deed notation	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	7.7.4
			§5.206 (m)		Permit conditions for retention of records. The permittee shall retain records as follows.	
			§5.206 (m)(1)		All modeling inputs and data used to support area of review reevaluations under subsection (e) of this section shall be retained for 10 years.	5.2, 7.7.4
			§5.206 (m)(2)		The permittee shall retain records as follows:	
			§5.206 (m)(2)(A)		All data collected under §5.203 of this title for Class VI permit applications shall be retained throughout the life of the geologic storage project and for 10 years following site closure.	5.2, 7.7.4
			§5.206 (m)(2)(B)		Data on the nature and composition of all injected fluids collected pursuant to §5.203(i)(1)(D) of this title shall be retained until 10 years following site closure. The director may require the operator to submit the records to the director at the conclusion of the retention period.	5.2, 7.7.4
			§5.206 (m)(2)(C)		Monitoring data collected pursuant to §5.203(j)(2) of this title shall be retained for 10 years after it is collected.	5.2, 7.7.4
			§5.206 (m)(2)(D)		Well plugging reports, post-injection site care data, including data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements of subsection (k)(6) of this section and paragraph (4) of this subsection shall be retained for 10 years following site closure.	5.2
			§5.206 (m)(2)(E)		The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years following site closure.	
			§5.206 (m)(3)		Within 60 days after plugging, the operator must submit, pursuant to §5.207(b)(2) of this title, a plugging report to the director. The report must be certified as accurate by the operator and by the person who performed the plugging operation (if other than the operator.) The operator shall retain the well plugging report for 10 years following site closure.	7.7.4, Appendix H
			§5.206 (m)(4)		The operator must submit a site closure report to the director within 90 days of site closure, which must thereafter be retained at a location designated by the director for 10 years following site closure. The report must include:	7.7.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (m)(4)(A)		documentation of appropriate injection and monitoring well plugging as specified in §5.203(k) of this title. The operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; and	7.7.4
			§5.206 (m)(4)(B)		documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	7.7.4
			§5.206 (m)(5)		Records reflecting the nature, composition, and volume of the CO2 plume shall be retained for 10 years following site closure.	7.7.4
§146.93(h)	Post-injection and site closure	The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	§5.206 (m)(6)	Retention of Records	The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	7.7.4
§146.94 - Emergency and remedial response						
§146.94	Emergency and remedial response	Emergency and remedial response	§5.206 (h)	Emergency, mitigation, and remedial response	Emergency mitigation, and remedial response	
§146.94(a)	Emergency and remedial response	As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§5.203 (l)	Emergency and remedial response plan	Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:	
			§5.203 (l)(1)	Emergency and remedial response plan	accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	8.2
			§5.203 (l)(2)	Emergency and remedial response plan	describes actions to be taken to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to USDWs during construction, operation, closure, and post-closure periods;	8.3
			§5.203 (l)(3)	Emergency and remedial response plan	Includes a safety plan that includes:	
			§5.203 (l)(3)(A)	Emergency and remedial response plan	emergency response procedures;	8.3
			§5.203 (l)(3)(B)	Emergency and remedial response plan	provisions to provide security against unauthorized activity;	8.3.2.7
			§5.203 (l)(3)(C)	Emergency and remedial response plan	CO2 release detection and prevention measures;	8.3.2
			§5.203 (l)(3)(D)	Emergency and remedial response plan	instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency;	8.6
			§5.203 (l)(3)(E)	Emergency and remedial response plan	procedures for requesting assistance and for follow-up action to remove the public from an area of exposure;	8.6
			§5.203 (l)(3)(F)	Emergency and remedial response plan	provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO2,	8.6
			§5.203 (l)(3)(G)	Emergency and remedial response plan	the manner in which the public will be notified of an emergency and steps to be taken in case of an emergency; and	8.6
			§5.203 (l)(3)(H)	Emergency and remedial response plan	if necessary, proposed actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring; and	8.6
§146.94(b)	Emergency and remedial response	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	§5.206 (h)(3)(A)	Emergency and remedial response plan	If an operator obtains evidence that the injected CO2 stream and associated pressure front may cause an endangerment to USDWs, the operator must:	
§146.94(b)(1)	Emergency and remedial response	Immediately cease injection;	§5.206 (h)(3)(A)(i)	Emergency and remedial response plan	immediately cease injection;	8.3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.94(b)(2)	Emergency and remedial response	Take all steps reasonably necessary to identify and characterize any release;	§5.206 (h)(3)(A)(ii)	Emergency and remedial response plan	take all steps reasonably necessary to identify and characterize any release;	8.3
§146.94(b)(3)	Emergency and remedial response	Notify the Director within 24 hours; and	§5.206 (h)(3)(A)(iii)	Emergency and remedial response plan	notify the director as soon as practicable but within at least 24 hours; and	8.3
§146.94(b)(4)	Emergency and remedial response	Implement the emergency and remedial response plan approved by the Director.	§5.206 (h)(3)(A)(iv)	Emergency and remedial response plan	implement the approved emergency and remedial response plan.	8.3
			§5.206 (h)(3)(B)		If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, except as authorized by an aquifer exemption, the director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting, including plugging of the injection well, as are necessary to prevent such movement.	
§146.94(c)	Emergency and remedial response	The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	§5.206 (h)(4)	Permit Standards	Resumption of injection. The Director may allow the operator to resume injection prior to remediation if the operator demonstrates that the injection operation will not endanger USDWs.	
§146.94(d)	Emergency and remedial response	The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:				8.8
§146.94(d)(1)	Emergency and remedial response	Within one year of an area of review reevaluation;				8.8
§146.94(d)(2)	Emergency and remedial response	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	§5.207 (a)(3)	Reporting and Record-Keeping	The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	8.8
§146.94(d)(3)	Emergency and remedial response	When required by the Director.				
Additional TAC 5 Regulations						
			§5.203 (a)(1)(A)	General	Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. **On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality.**	
			§5.203 (a)(1)(B)	General	Signatories to permit applications. An applicant must ensure that the application is executed by a party having knowledge of the facts entered on the form and included in the required attachments. All permit applications shall be signed as specified in this subparagraph:	Cover Sheet

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.203 (a)(1)(B)(i)	General	For a corporation, the permit application shall be signed by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision making functions for the corporation, or the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.	
			§5.203 (a)(1)(B)(ii)	General	For a partnership or sole proprietorship, the permit application shall be signed by a general partner or the proprietor, respectively.	
			§5.203 (a)(1)(B)(iii)	General	For a municipality, State, Federal, or other public agency, the permit application shall be signed by either a principal executive officer or ranking elected official.	
			§5.203 (a)(1)(C)	General	Certification. Any person signing a permit application or permit amendment application shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."	Cover Sheet
			§5.203 (a)(2)(A)		On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.	Intro
			§5.203 (a)(2)(B)		When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.	
			§5.203 (a)(2)(C)		The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Intro
			§5.203 (a)(2)(D)	General	A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued.	
			§5.203 (a)(3)	General	Application completeness. The Commission shall [may] not issue a permit before receiving a complete application. A permit application is complete when the director determines that the application contains information addressing each application requirement of the regulatory program and all information necessary to initiate the final review by the director.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.203 (a)(5)	General	If otherwise required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, a licensed professional engineer or geoscientist must conduct the geologic and hydrologic evaluations required under this subchapter and must affix the appropriate seal on the resulting reports of such evaluations.	
			§5.203 (f)(2)(A)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	4.2.4.2
			§5.203 (k)(6)	Well Plugging Plan	A plan for certifying that all monitoring wells that do not penetrate the base of usable quality water will be plugged in accordance with 16 TAC Chapter 76.	TBD
			§5.203 (l)(4)	Emergency and remedial response plan	includes a description of the training and testing that will be provided to each employee at the storage facility on operational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility. The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. Emergency measures specific to the contractor's work must be explained in the contractor safety meeting. Training schedules, training dates, and course outlines must be provided to Commission personnel upon request for the purpose of Commission review to determine compliance with this paragraph.	Section 8
			§5.206 (a)	Permit Standards	Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	
			§5.206 (a)(1)		Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	
			§5.206 (a)(2)		The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.	
			§5.206 (b)	Permit Standards	General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that:	
			§5.206 (b)(1)	Permit Standards	the injection and geologic storage of anthropogenic CO2 will not endanger or injure any existing or prospective oil, gas, geothermal, or other mineral resource, or cause waste as defined by Texas Natural Resources Code, §85.046(11);	
			§5.206 (b)(2)	Permit Standards	with proper safeguards, both USDWs and surface water can be adequately protected from CO2 migration or displaced formation fluids;	
			§5.206 (b)(3)	Permit Standards	the injection of anthropogenic CO2 will not endanger or injure human health and safety;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (b)(4)		the construction, operation, maintenance, conversion, plugging, abandonment, or any other injection activity does not allow the movement of fluid containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons;	
			§5.206 (b)(5)	Permit Standards	the reservoir into which the anthropogenic CO2 is injected is suitable for or capable of being made suitable for protecting against the escape or migration of anthropogenic CO2 from the storage reservoir;	
			§5.206 (b)(7)	Permit Standards	the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit;	
			§5.206 (b)(8)	Permit Standards	the applicant has provided a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with §5.203(o) of this title (relating to Application Requirements);	Appendix D
			§5.206 (b)(9)	Permit Standards	the applicant has provided a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ;	TBD
			§5.206 (b)(10)	Permit Standards	the applicant has provided a signed statement that the applicant has a good faith claim to the necessary and sufficient property rights for construction and operation of the geologic storage facility for at least the first five years after initiation of injection in accordance with §5.203(d)(1)(A) of this title;	Cover sheets
			§5.206 (b)(11)	Permit Standards	the applicant has paid the fees required in §5.205(a) of this title (relating to Fees, Financial Responsibility, and Financial Assurance);	
			§5.206 (b)(12)	Permit Standards	the director has determined that the applicant has sufficiently demonstrated financial responsibility as required in §5.205(b) of this title; and	
			§5.206 (b)(13)	Permit Standards	the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.	9.2
			§5.206 (c)(1)	Permit Standards	Construction of anthropogenic CO 2 injection wells must meet the criteria in §5.203(e) of this title.	4.1
			§5.206 (c)(2)	Permit Standards	Within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on the appropriate form showing the current completion.	4.2.2
			§5.206 (c)(3)	Permit Standards	Except in the case of an emergency repair, the operator of a geologic storage facility must notify the director in writing at least 30 days prior to conducting any well workover that involves running tubing and setting packers, beginning any workover or remedial operation, or conducting any required pressure tests or surveys. Such activities shall not commence before the end of the 30 days unless authorized by the director. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical.	5.2
			§5.206 (d)	Permit Standards	Operating a geologic storage facility.	
			§5.206 (d)(1)(A)	Permit Standards	Operating plan. The operator must maintain and comply with the approved operating plan.	
			§5.206 (d)(1)(B)		Prior to approval for the operation of a Class VI injection well, the operator shall submit, and the director shall consider, the following information:	
			§5.206 (d)(1)(B)(i)		the final AOR based on modeling, using data obtained during logging and testing of the well and the formation as required by clauses (ii), (iii), (iv), (vi), (vii), and (x) of this subparagraph;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (d)(1)(B)(ii)		any relevant updates, based on data obtained during logging and testing of the well and the formation as required by clauses (iii), (iv), (vi), (vii), and (x) of this subparagraph to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of §5.203(c)(2) and (3) of this title;	
			§5.206 (d)(1)(B)(iii)		information on the compatibility of the CO2 stream with fluids in the injection zones and minerals in both the injection and the confining zones, based on the results of the formation testing program, and with the materials used to construct the well;	
			§5.206 (d)(1)(B)(iv)		the results of the formation testing program required by §5.203(f) of this title;	
			§5.206 (d)(1)(B)(v)		final injection well construction procedures that meet the requirements of §5.203(e) of this title;	
			§5.206 (d)(1)(B)(vi)		the status of corrective action on wells in the AOR;	
			§5.206 (d)(1)(B)(vii)		all available logging and testing program data on the well required by §5.203(f) of this title;	
			§5.206 (d)(1)(B)(viii)		a demonstration of mechanical integrity pursuant to §5.203(h) of this title;	
			§5.206 (d)(1)(B)(ix)		any updates to the proposed AOR and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection storage facility care and closure plan, or the emergency and remedial response plan submitted under §5.203(m) of this subchapter, which are necessary to address new information collected during logging and testing of the well and the formation as required by this section, and any updates to the alternative post-injection storage facility care timeframe demonstration submitted under §5.203(m) of this title, which are necessary to address new information collected during the logging and testing of the well and the formation as required by this section; and	
			§5.206 (d)(1)(B)(x)		any other information requested by the director.	
			§5.206 (d)(2)	Permit Standards	Operating criteria.	
			§5.206 (d)(2)(B)	Permit Standards	The total volume of CO2 injected into the storage facility must be metered through a master meter or a series of master meters. The volume and/or mass of CO2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.	5.5.2
			§5.206 (d)(2)(C)	Permit Standards	The operator must comply with a maximum surface injection pressure limit approved by the director and specified in the permit. In approving a maximum surface injection pressure limit, the director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults or fractures transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection fluids or formation fluids in a manner that endangers USDWs. The Commission shall include in any permit it might issue a limit of 90 percent of the fracture pressure to ensure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. The director may approve a plan for controlled artificial fracturing of the injection zone.	4.2.6

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (d)(2)(E)	Permit Standards	The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO2 stream. The operator must monitor the pressure on the annulus between the tubing and the long string casing. The operator must continuously record, continuously monitor, or control by a preset high-low pressure sensor switch the wellhead pressure of each injection well.	5.5.1; 5.5.2
			§5.206 (e)	Permit Standards	Monitoring, sampling, and testing requirements.	
			§5.206 (e)(1)	Permit Standards	The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.	
			§5.206 (e)(2)	Permit Standards	All permits shall include the following requirements:	
			§5.206 (e)(2)(A)	Permit Standards	the proper use, maintenance, and installation of monitoring equipment or methods;	
			§5.206 (e)(2)(B)	Permit Standards	monitoring including type, intervals, and frequency sufficient to yield data that are representative of the monitored activity including, when required, continuous monitoring;	5.5.1
			§5.206 (e)(2)(C)	Permit Standards	reporting no less frequently than as specified in §5.207 of this title (relating to Reporting and Record-Keeping).	5.2
			§5.206 (e)(4)	Permit Standards	The director may require measures and actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring.	
			§5.206 (e)(5)		The operator shall comply with the following monitoring and record retention requirements.	
			§5.206 (e)(5)(A)		Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.	
			§5.206 (e)(5)(B)		The permittee shall retain records of all monitoring information, including the following:	
			§5.206 (e)(5)(B)(i)		calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for a period of at least ten years from the date of the sample, measurement, report, or application. This period may be extended by the director at any time; and	
			§5.206 (e)(5)(B)(ii)		the nature and composition of all injected fluids until ten years after the completion of any plugging and abandonment procedures specified in §5.203(k)(2) of this title for the injection wells. The director may require the operator to submit the records to the director at the conclusion of the retention period. This period may be extended by the director at any time.	
			§5.206 (e)(5)(C)		Records of monitoring information shall include:	
			§5.206 (e)(5)(C)(i)		the date, exact place, and time of sampling or measurements;	
			§5.206 (e)(5)(C)(ii)		the individuals who performed the sampling or measurements;	
			§5.206 (e)(5)(C)(iii)		the dates analyses were performed;	
			§5.206 (e)(5)(C)(iv)		the individuals who performed the analyses;	
			§5.206 (e)(5)(C)(v)		the analytical techniques or methods used; and	
			§5.206 (e)(5)(C)(vi)		the results of such analyses.	
			§5.206 (e)(5)(D)		Operators of Class VI wells shall retain records as specified in this subchapter.	
			§5.206 (f)(1)	Permit Standards	The operator must maintain and comply with the approved mechanical integrity testing plan submitted in accordance with §5.203(j) of this title.	5.4.3; 5.4.4
			§5.206 (f)(3)	Permit Standards	The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (f)(5)	Permit Standards	The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	
			§5.206 (h)(2)(A)	Permit Standards	The operator must prepare and implement a plan to train and test each employee at the storage facility on occupational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must make copies of the plan available at the geological storage facility. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility.	8.4
			§5.206 (h)(2)(B)	Permit Standards	The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. The operator must explain emergency measures specific to the contractor's work in the contractor safety meeting.	8.4
			§5.206 (h)(2)(C)	Permit Standards	The operator must provide training schedules, training dates, and course outlines to Commission personnel annually and upon request for the purpose of Commission review to determine compliance with this paragraph.	8.4
			§5.206 (k)(1)(A)	Permit Standards	The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan.	7.4, 7.5
			§5.206 (k)(1)(C)	Permit Standards	Upon cessation of injection, the operator of a geologic storage facility must either submit an amended plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed.	7.4.2
			§5.206 (k)(3)(A)	Permit Standards	the estimated magnitude and extent of the facility footprint (the CO2 plume and the area of elevated pressure);	7.3
			§5.206 (k)(3)(B)	Permit Standards	that there is no leakage of either CO2 or displaced formation fluids that will endanger USDWs;	7.4.2
			§5.206 (k)(3)(C)	Permit Standards	that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into USDWs;	7.4.2
			§5.206 (k)(3)(D)	Permit Standards	that the injection wells at the site completed into or through the injection zone or confining zone will be plugged and abandoned in accordance with these requirements; and	6.1; 7.5.2
			§5.206 (k)(3)(E)	Permit Standards	any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.	6.2; 7.5.2
			§5.206 (n)	Permit Standards	Signs. The operator must identify each location at which geologic storage activities take place, including each injection well, by a sign that meets the requirements specified in §3.3(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign must include a telephone number where the operator or a representative of the operator can be reached 24 hours a day, seven days a week in the event of an emergency.	
			§5.206 (o)	Permit Standards	Other permit terms and conditions.	
			§5.206 (o)(1)	Permit Standards	Protection of USDWs. In any permit for a geologic storage facility, the director must impose terms and conditions reasonably necessary to protect USDWs. Permits issued under this subchapter continue in effect until revoked, modified, or terminated by the Commission. The operator must comply with each requirement set forth in this subchapter as a condition of the permit unless modified by the terms of the permit.	
			§5.206 (o)(2)	Permit Standards	Other conditions. The following conditions shall also be included in any permit issued under this subchapter.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (o)(2)(A)	Permit Standards	Duty to comply. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. However, the permittee need not comply with the provisions of the permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR §144.34.	
			§5.206 (o)(2)(B)	Permit Standards	Need to halt or reduce activity not a defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.	
			§5.206 (o)(2)(C)	Permit Standards	Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.	
			§5.206 (o)(2)(D)	Permit Standards	Proper operation and maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.	
			§5.206 (o)(2)(E)	Permit Standards	Property rights not conveyed. The issuance of a permit does not convey property rights of any sort, or any exclusive privilege.	
			§5.206 (o)(2)(F)		Activities not authorized. The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulations.	
			§5.206 (o)(2)(G)	Permit Standards	Coordination with exploration. The permittee of a geologic storage well shall coordinate with any operator planning to drill through the AOR to explore for oil and gas or geothermal resources and take all reasonable steps necessary to minimize any adverse impact on the operator's ability to drill for and produce oil and gas or geothermal resources from above or below the geologic storage facility.	1.1
			§5.206 (o)(2)(H)	Permit Standards	Duty to provide information. The operator shall furnish to the Commission, within a time specified by the Commission, any information that the Commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The operator shall also furnish to the Commission, upon request, copies of records required to be kept under the conditions of the permit.	
			§5.206 (o)(2)(I)	Permit Standards	Inspection and entry. The operator shall allow any member or employee of the Commission, on proper identification, to:	
			§5.206 (o)(2)(I)(i)	Permit Standards	enter upon the premises where a regulated activity is conducted or where records are kept under the conditions of the permit;	
			§5.206 (o)(2)(I)(ii)	Permit Standards	have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit;	
			§5.206 (o)(2)(I)(iii)	Permit Standards	inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and	
			§5.206 (o)(2)(I)(iv)	Permit Standards	sample or monitor any substance or parameter for the purpose of assuring compliance with the permit or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012.	

Underground Injection Control – Class VI Permit Application

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

Prepared for
Titan Carbon Sequestration, LLC

By
Lonquist Sequestration, LLC
Austin, TX

February 2024

SECTION 0 – INTRODUCTION

TABLE OF CONTENTS

Project Overview 2
Climate Drivers and Objectives 2
About Sempra Infrastructure Partners and Titan Carbon Sequestration 2
Key Components of the Titan Project 4
Pore Space 4
Subsurface Characteristics 5
Surface Facilities 5
Key Project Attributes 7
Site Suitability 7
Community Outreach 8
Summary 8
Required Administrative Information 9
General Application Information 9
Additional Permits 10

Figures

Figure 0-1 – Project Overview Map 4
Figure 0-2 – PALNG CO_2 Flow Diagram 5

Tables

Table 0-1 – CO_2 Injection Stream Composition 6
Table 0-2 – Additional Required Permits 10

Project Overview

Climate Drivers and Objectives

Climate change is a key defining issue of our time. From shifting weather patterns that threaten food production, to rising sea levels that increase the risk of catastrophic flooding, the impacts of climate change are global in scope and unprecedented in scale. Without action today, adapting to these impacts will be more difficult and costly in the future. Under the 2015 Paris Agreement, world leaders agreed to keep global temperature increases well below 2 degrees Celsius and, if possible, 1.5 degrees Celsius—compared with pre-industrial levels. This goal, however, can only be achieved through a significant reduction in emissions of greenhouse gases (GHG).

To meet such ambitious goals for critical reductions in GHG, the United States and the global community are increasingly viewing large-scale capture of anthropogenic CO_2 as critical—as it is one of the few technologies that can be immediately deployed to reduce CO_2 resulting from industrial processes, in a cost-effective way. Carbon capture and sequestration (CCS) can play four critical roles in the transition to net zero: (1) tackling emissions from existing energy assets; (2) solving emissions for sectors where emissions are hard to abate; (3) creating a platform for clean hydrogen production; and (4) removing carbon from the atmosphere to balance emissions that cannot be directly abated or avoided. The urgency to address GHG emissions stems in part from the International Energy Agency (IEA), in their Net-Zero Emissions (NZE) by 2050 Scenario, which requires capturing 1.2 gigaton (Gt)/yr by 2050. However, current production plans, the IEA states, indicate only about one-third of that amount being captured by 2050. Worldwide, CCS only exceeded 45 million metric tons per year (MMT/yr) as of 2023. Therefore, additional opportunities and investments in CCS projects are necessary to meet the IEA and worldwide sustainability goals.

About Sempra Infrastructure Partners and Titan Carbon Sequestration

Sempra Infrastructure Partners (Sempra), including wholly owned subsidiaries, Sempra Infrastructure Net Zero Holdings, LP and Titan Carbon Sequestration LLC (Titan) are focused on delivering energy for a better world by developing, building, operating, and investing in clean power, energy networks, and liquified natural gas (LNG) and net-zero solutions that are expected to play a crucial role in future energy systems. Through the combined strength of its assets in North America, Sempra is connecting customers across the globe to modern energy infrastructure, to source and transport renewables and natural gas, while advancing carbon sequestration and clean hydrogen.

For the past several years, Sempra has invested time and money developing projects in the Port Arthur, Texas area. With Port Arthur LNG (PALNG) Phase 1 currently under construction, the development of the proposed PALNG Phase 2 project could increase the total liquefaction capacity of the facility from approximately 13 MMT/yr to approximately 26 MMT/yr. The proposed project is also expected to include an additional LNG storage tank and marine berth. Moreover, the company is leveraging the integrated capabilities of its business segments to develop both the proposed Port Arthur Pipeline Texas Connector project and the proposed Port

Arthur Pipeline Louisiana Connector project—as well as to develop new gas storage facilities—all of which would serve the PALNG facility.

Beyond the activities above, Sempra continues to evaluate opportunities to develop the entirety of the Port Arthur site, while also exploring potential projects to reduce the carbon intensity of its LNG, hence positioning Port Arthur as a flagship hub for the energy transition. To further the advancement of the proposed Port Arthur Clean Energy Hub, Sempra recently acquired [redacted] of pore space and relevant surface rights to support the proposed Titan Carbon Sequestration Project (Titan Project), which is proximal to the PALNG facility. The Titan Project will target capturing carbon from Sempra Infrastructure's developing PALNG Phase 1 and 2 projects—and might also unlock other net-zero energy infrastructure opportunities. This comprehensive approach utilizes Sempra's broad development and operational expertise to enhance the total value of Port Arthur. It can also deliver significant value for the local community, opening substantial avenues for economic growth opportunities for the region.

One of Sempra's four pillars of sustainability is enabling the energy transition. Sempra believes it is possible to advance energy security while simultaneously developing solutions to help address climate change. As such, Sempra is continuously pursuing opportunities to lower emissions from its facilities and expand its low carbon solutions portfolio. Sempra believes that the Titan Project fits within its energy transition strategy and that it is an advantaged CCS project because (a) its anchor customer is an affiliated LNG facility with a relatively pure stream of CO_2; (b) the project has a minimized pipeline scope, thereby reducing project costs and risk; (c) the commercial risk is reduced due to a manageable number of customers; and (d) Sempra is heavily engaged in the Texas community where the project is being proposed.

Titan, a wholly-owned subsidiary of Sempra, is developing the Titan Project with the primary objective of capturing, transporting and sequestering CO_2 from affiliated assets, thereby reducing the carbon intensity of Sempra's energy products that are consumed by energy users. Although the key target customer (i.e., CO_2 source) for the Titan Project is PALNG, the Titan Project could also be utilized to sequester CO_2 from other potential affiliated development projects such as a Port Arthur Blue Hydrogen/Ammonia facility (PAH2A) (which is part of the HyVelocity Hub selected by the DOE as part of the Hydrogen Hub Program), other Sempra net-zero projects, and possibly third party industrial facilities. The extent of CO_2 volumes sequestered from each of these CO_2 sources depends on the ultimate capacity of the storage facility and the volume of CO_2 available from those sources. The storage capacity will initially be designed to collect, transport, and sequester up to [redacted] within the southern portion of Titan's acreage position.

Through the development of LNG and hydrogen with related CCS efforts, Sempra is demonstrating its decarbonization efforts to provide access to cleaner reliable energy, while serving the energy decarbonization needs of its customers.

Key Components of the Titan Project

Pore Space

[redacted] which is intended to be developed for the purpose of injecting and permanently storing CO_2 streams in the first phase of the Titan Project. The storage easements cover all the acreage within the projected plume and area of review (AOR) as shown on Figure 0-1.[1] The easements also provide the right to access the overlying surface acreage to conduct all necessary monitoring and testing during the life of the project.

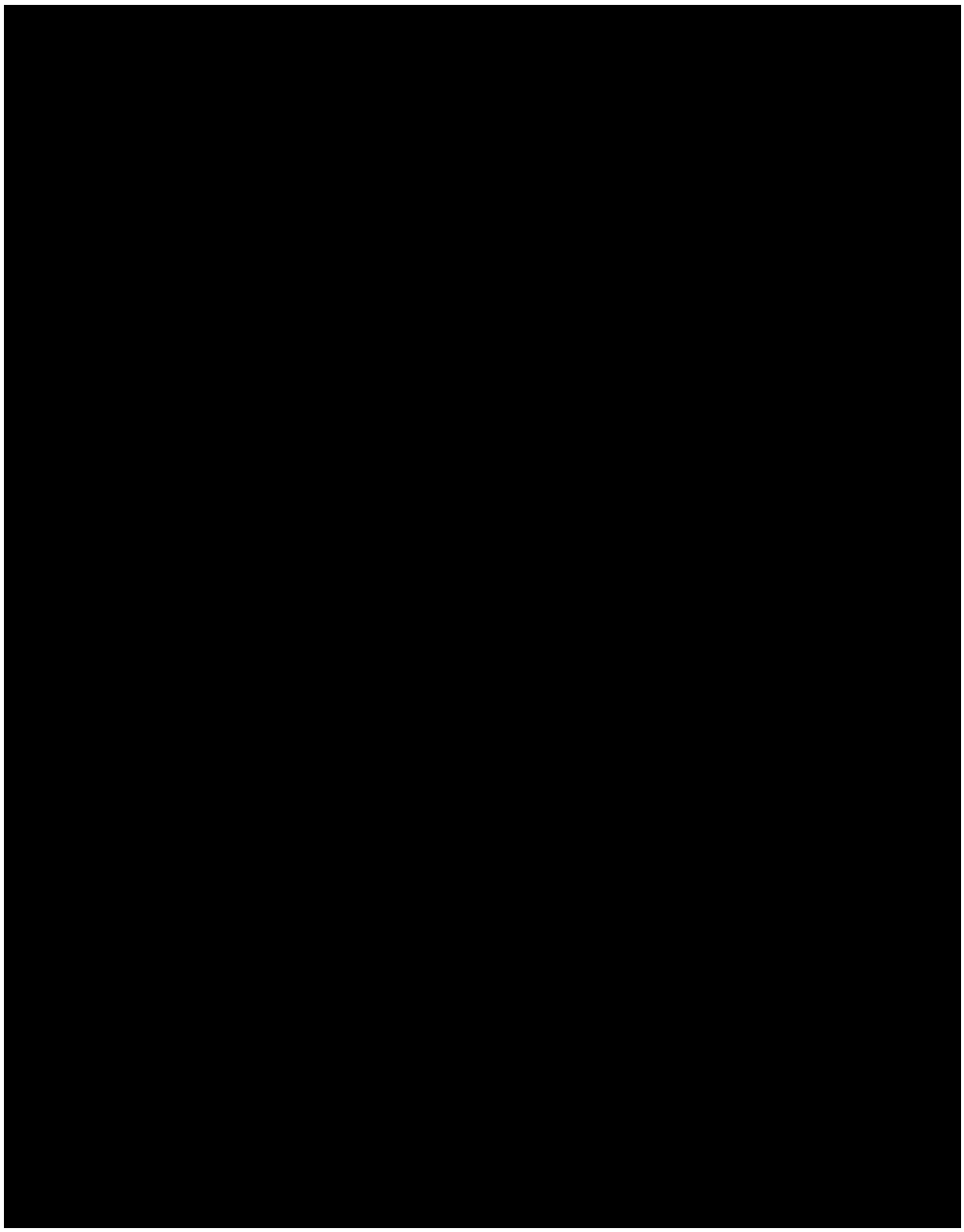

[redacted]

Figure 0-1 – Project Overview Map

Subsurface Characteristics

The subsurface geologic environment of the southeast Texas coastal area provides an ideal CO_2 sequestration environment, on the property where Sempra has acquired storage easements, which will be assigned to Titan, for the development and operation of the Titan Project. The stacked sand-shale sequences of the Miocene-age rock are high in both porosity and permeability, which creates a highly effective storage-and-trapping mechanism for CO_2 to be permanently sequestered in this project.

Surface Facilities

The CO_2 will be captured from the acid-gas recovery unit (AGRU) from each natural gas liquefaction train, where it will go into a header and be piped to the LNG fence line. Blowers will likely be required to push the CO_2 to the receipt point, whereby Titan will take title of the CO_2 (Figure 0-2). The streams from the CO_2 sources will be combined and required to meet the overall quality profile/thresholds shown in Table 0-1.

Figure 0-2 – PALNG CO_2 Flow Diagram

[redacted] where it will be discharged and directed to the Titan Project injection wells via the short distance pipeline system. Upon reaching the wells, the CO_2 stream will pass through a second meter to record the amount of CO_2 being injected into the subsurface formation.

The project consists of the following facilities: CO_2 metering station(s); an interconnecting pipe rack; tie-ins to an acid-gas removal CO_2 system; a compression, aftercooling, and dehydration unit; auxiliary blowers (if required); utilities and supporting infrastructure; a CO_2 pipeline; platforms for equipment on well pads (if required); and roads.

Table 0-1 – CO_2 Injection Stream Composition

Component	Value
[redacted]	

*MMscf – million standard cubic feet
ppm – parts per million

Key Project Attributes

The following are the key attributes of the Titan Project:

- Thick storage reservoir in the Miocene-age rock (approximately [redacted] feet of gross vertical reservoir)
- Reservoir consisting of stacked sand-shale sequences with excellent permeability and porosity
- No artificial penetrations within the plume boundaries
- Carbon dioxide storage capacity of [redacted]
- Short pipeline [redacted] mostly over leased or owned acreage
- Secured pore space rights
- Project within proximity of Sempra's PALNG facility, as well as any additional net-zero development projects that may be built on Sempra's 3,000-acre potential Port Arthur Clean Energy Hub
- Strong community relationships developed during the development of PALNG
- Experience in CCS and learnings from a similar CCS project in Louisiana owned by the company
- Strong partnership interests in Titan

Site Suitability

The Titan Project acreage in Jefferson County, Texas, is well-suited for the location of the planned sequestration project due to its advantaged subsurface geology and its proximity to planned infrastructure associated with Sempra's LNG facility and owned waterfront acreage. In addition, the secured storage easements cover all the acreage within the projected plume and AOR. These storage easements also provide the right to access the overlying surface acreage to conduct all necessary monitoring and testing during the life of the project.

In compliance with the applicable regulations, a preliminary evaluation of the proposed site ("Site Suitability") has been conducted by considering factors such as follows:

- Location of the proposed project site relative to potential emitters and pipelines
- Faults or fractures in the project area based on seismic analysis or geophysical well-log characterization
- Artificial penetrations in the project area
- Underground Sources of Drinking Water in the project area
- Environmental justice issues

These site-specific questions are answered throughout this Class VI permit application. The result of this evaluation was the selection of the site for the proposed injection wells and associated facilities.

Community Outreach

Dedicated to being a good partner to the community, Sempra has been actively engaged in Jefferson County and the communities of Port Arthur and Sabine Pass since 2004 through the development of its PALNG facility. Community involvement, stakeholder engagement, and feedback are critical components of both PALNG and the Titan project. Sempra also recognizes that effective communication with its stakeholders may address and reduce community concerns, help build trust and transparency, and contribute to the project's overall success. As part of the Titan Stakeholder Engagement Plan, the project team is committed to the following:

- Conducting a community assessment to help identify and validate concerns and opportunities related to the developmental and operational projects in the area. This assessment will also help to identify not only the project's environmental justice community status, but also opportunities for meaningful social investment.
- Implementing stakeholder engagement activities in which the team actively solicits feedback from the community and property owners about the Titan Project
- Providing regular Titan Project updates to local stakeholders during the calendar year
- Maintaining communication channels for stakeholders, to include a dedicated toll-free phone line, email address, website, and social media channels
- Providing a dedicated outreach team to address community questions and concerns
- Coordinating contributions of the company and employees' time, talent, and funding to support community investment initiatives and events in Jefferson County.

Sempra has established good relationships with stakeholders in the community and intends to continue to build on them. Community engagement specific to CCS is underway through multiple stakeholder-feedback roundtables. Sempra plans to continue to execute its full Stakeholder Engagement Plan (included in *Section 10 – Environmental Justice*) as it progresses in the development of the Titan Project.

Summary

Two injection wells, Cronos No. 1 and Rhea No. 1, are planned for the first phase of the Titan Project. This phase will support [redacted] of CO_2 sequestration and storage. Titan's overall project goal is to ultimately sequester [redacted] of CO_2. This permit application includes details of the geologic investigation, reservoir model, design of the Class VI wells, and all the associated components required as part of Title 16, Texas Administrative Code (16 TAC) **§5** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146(h)**].

This permit application is comprised of 10 sections that will address the regulatory requirements of this CCS project.

Required Administrative Information

General Application Information

Facility Name: Titan Carbon Sequestration Project

Injection Well Information:

Well Name and Number	Cronos Well No. 1
County	Jefferson County, TX
Latitude/ Longitude	[redacted]

Well Name and Number	Rhea Well No. 2
County	Jefferson County, TX
Latitude/ Longitude	[redacted]

*NAD 83 – North American Datum of 1983

Applicant:

Name	Titan Carbon Sequestration, LLC
Address	1500 Post Oak Blvd, Suite 1000 Houston, TX 77056
Facility contacts:	[redacted]
Ownership Status	Limited Liability Company
Entity Status	Public

Standard Industrial Classification (SIC) Codes:

- 4953 – Refuse Systems (nonhazardous waste disposal sites)

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

Additional Permits

Table 0-2 – Additional Required Permits

Agency	Permit and Authorization	Filing Date	Anticipated Receipt Date	Status
Texas Railroad Commission	Drilling Permit	TBD	TBD	To be filed
EPA	Class VI Injection Well Permit – 40 CFR **§146**	February 2024	TBD	To be filed

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 1 – SITE CHARACTERIZATION

February 2024

LONQUIST
SEQUESTRATION LLC

SECTION 1 – SITE CHARACTERIZATION

TABLE OF CONTENTS

1.1. Overview 5
1.2. Regional Geology 5
1.3. Site Geology 12
1.3.1 Injection Zone 19
1.3.2 Upper Confining Zone 28
1.3.3 Lower Confining Zone 31
1.3.4 Geologic Structure 34
1.4. Geomechanics 43
1.4.1 Local Stress Conditions 43
1.4.2 Elastic Moduli and Fracture Gradient 44
1.4.3 Geopressure 50
1.5. Porosity and Permeability 53
1.5.1 Upper Confining Zone 62
1.5.2 Injection Zone 65
1.5.3 Lower Confining Zone 68
1.6. Injection Zone Water Chemistry 71
1.6.1 Injection Zone Water Chemistry 71
1.7. Geochemistry 75
1.7.1 Methods 75
1.7.2 Brine Geochemistry 75
1.7.3 Mineral Geochemistry 76
1.7.4 Models 77
1.7.5 Results 77
1.8. Fault Seal Analysis 79
1.9. Hydrology 91
1.9.1 Area of Study 91
1.9.2 Groundwater Resources 92
1.9.3 Surface Water Resources 94
1.9.4 Hydrology Conclusion 95
1.10. Evaluation of Mineral Resources 97
1.10.1 Active Mines Near the Proposed Injection Location 97
1.10.2 Oil and Gas Resources 97
1.11. Seismic History 101
1.11.1 Identification of Historical Seismic Events 101
1.11.2 Faults and Influence 105
1.11.3 Fault Slip Potential Model 106
1.11.4 Seismic Hazard 107
1.12. Site Characterization Conclusion 113
1.13. References 115

Figures

Figure 1-1 – Regional Gulf of Mexico Locator Map 5
Figure 1-2 – Stratigraphic Column of the Gulf of Mexico 6
Figure 1-3 – Regional seismic line and locator map 8
Figure 1-4 – Stratigraphic column of Tertiary depositional episodes in the Gulf of Mexico basin 10
Figure 1-5 – Overview Map of Titan Project 13
Figure 1-6 – Well Log Data 17
Figure 1-7 – Stratigraphic column from [redacted] 18
Figure 1-8 – Injection Zone in the Gulf of Mexico, Miocene Stratigraphic Section 20
Figure 1-9 – Gulf of Mexico paleogeography during the Lower Miocene (LM1) 21
Figure 1-10 – Gulf of Mexico paleogeography during the Lower Miocene (LM2) 22
Figure 1-11 – Net sand isopach map from the BEG study. 23
Figure 1-12 – Gross Injection Zone Isopach Map 24
Figure 1-13 – Openhole log of [redacted] 25
Figure 1-14 – Map depicting High Island core data in relation to the proposed Titan injection wells. 27
Figure 1-15 – XRD analysis from High Island core data within the sand intervals 28
Figure 1-16 – Thin section of High Island core 28
Figure 1-17 – Openhole log of [redacted] 30
Figure 1-18 – XRD analysis of mudstone samples within the High Island core 31
Figure 1-19 – Thin section of mudstone showing high clay content and low porosity from High Island core 32
Figure 1-20 – Openhole log of [redacted] depicting the proposed lower confining zone. 33
Figure 1-21 – Location of 3D Seismic Surveys 35
Figure 1-22 – Structure Map of the Top of Amph B 37
Figure 1-23 – Structure Map of the Top of the Lower Miocene 38
Figure 1-24 – Structure Map of the Top of Siph Dav 39
Figure 1-25 – Location of well with a checkshot velocity survey 40
Figure 1-26 – Synthetic Seismogram Showing Well Calibration 41
Figure 1-27 - Seismic Line with Synthetic Well Tie 42
Figure 1-28 – Plot of pore pressure gradient vs. depth calculated from log data at the offset well [redacted]. 46
Figure 1-29 – Map depicting LA Storage SWD Well No. 3 core data in relation to the proposed Titan injection wells. 48
Figure 1-30 – USGS contour map of the first occurence of 0.6 psi/ft pressure gradient 51
Figure 1-31 – Openhole log of [redacted] depicting the resistivity trend 52
Figure 1-32 – Log depicting example QA process to ensure digital data resembles raster data. 54
Figure 1-33 – Example of SP Baseline Shift Over Depth 55
Figure 1-34 – Comparison between calculated effective porosity (PHIE) and estimated effective porosity (PHIEST), from the [redacted] 57
Figure 1-35 – Porosity vs. Permeability Scatterplot of Sidewall Core from [redacted] 59
Figure 1-36 – Openhole log display of [redacted] depicting the variabiliy of the core points within the section. 60
Figure 1-37 – Porosity Modeling Wells 61
Figure 1-38 – Openhole log of offset well [redacted] depicting the upper confining zone. 63
Figure 1-39 – Histogram of Porosity Distributions Within the Upper Confining Zone 64

Figure 1-40 – Histogram of Permeability Distributions Within the Upper Confining Zone 65
Figure 1-41 – Openhole log of [redacted] depicting the injection zone. 66
Figure 1-42 – Histogram of Porosity Distributions Within the Injection Zone 67
Figure 1-43 – Histogram of Permeability Distributions Within the Injection Zone 68
Figure 1-44 – Openhole log of [redacted] depicting the lower confining zone. 69
Figure 1-45 – Histogram of Porosity Distributions Within the Lower Confining Zone 70
Figure 1-46 – Histogram of Permeability Distributions Within the Lower Confining Zone 71
Figure 1-47 – Depth vs. TDS graph of collected water samples from the USGS. 72
Figure 1-48 – Schlumberger General 9 chart with red lines representing .025 Rwa value at 120°F. 74
Figure 1-49 – Example of log analysis performed on [redacted] to estimate TDS. 74
Figure 1-50 – Results of all constituents for the batch models for each facies. 78
Figure 1-51 – The results of minor constituents for the batch models for each facies. 79
Figure 1-52 – A 3D image of CO_2 plume (at stabilization) 80
Figure 1-53 – Shale Gouge Ratio Conceptual Diagram and Equation 81
Figure 1-54 – A 3D display of the shale gouge ratio on the fault planes 82
Figure 1-55 – Histograms of the SGR distribution for the (a) upper confining, (b) injection, and (c) lower confining zones. 83
Figure 1-56 – The 3D model layer slices show facies distribution and fault SGR for the (a) upper confining and (b) injection zones. 85
Figure 1-57 – A 3D model cross-section showing (a) SGR and Vsh distribution, and (b) SGR and facies distribution. 86
Figure 1-58 – Fault Zone Entry Capillary Pressure (FZP) vs. Shale Gouge Ratio (SGR) 87
Figure 1-59 – Distribution of the FZP Values 88
Figure 1-60 – Fault Zones Permeability vs. SGR 89
Figure 1-61 – Distribution of the fault zone predicted permeability values 89
Figure 1-62 – Histograms of the fault permeability distribution for the (a) upper confining, (b) injection, and (c) lower confining zones. 90
Figure 1-63 – Image of Gulf Coast Aquifer in Texas 92
Figure 1-64 – Regional Cross Section of the Gulf Coast Aquifer in Texas 93
Figure 1-65 – Gulf Coast outcroppings of the Jasper, Evangeline, and Chicot aquifers in Jefferson County, ... 94
Figure 1-66 – Map of water-level changes within the Gulf Coast aquifer, depicting the injection site (indicated by the red star) falling within the "Unconfined (outcrop)" area (Brunn, Jackson, Peter, & Walker, 2016). 96
Figure 1-67 – Oil and Gas Wells Within 6 Miles of the Titan Project 98
Figure 1-68 – Seismically active areas in Texas, ... 102
Figure 1-69 – Earthquake Search Parameters and Results from TexNet Website 103
Figure 1-70 – USGS-registered earthquakes inland east Texas, along the Gulf Coast and west Louisiana. 104
Figure 1-71 – Major Cenozoic fault zones in southeast Texas 106
Figure 1-72 – Total mean hazard map for 2% probability of exceedance in 50 years 108
Figure 1-73 – Risk of a Class VI earthquake shaking in 100 years at the 109
Figure 1-74 – Predicted damaging earthquakes shaking around the United States 110
Figure 1-75 – Jefferson County National Risk Index Map showing community resilience. 111
Figure 1-76 – Jefferson County National Risk Index Map showing hazard types. 112
Figure 1-77 – National Risk Index Scores for Jefferson County 113

Tables

Table 1-1 – Openhole Logging Plan 15
Table 1-2 – Planned Core Intervals, Prometheus No. 1 16
Table 1-3 – Injection and Confining Zones as Encountered in [redacted] 18
Table 1-4 – Calculated Vertical Stresses for Cronos No. 1 43
Table 1-5 – Calculated Vertical Stresses for Rhea No. 1 43
Table 1-6 – Triaxial Compressive Strength Test Results for Cronos No. 1 44
Table 1-7 – Triaxial Compressive Strength Test Results for Rhea No. 1 44
Table 1-8 – Fracture Gradients Calculated for Cronos No. 1 49
Table 1-9 – Fracture Gradients Calculated for Rhea No. 1 49
Table 1-10 – Core Data Values, [redacted] 58
Table 1-11 – Formation Brine Chemstry 72
Table 1-12 – Brine composition used in the PHREEQC reaction-path modeling. 75
Table 1-13 – Mineral Compositions Used in the Four-Facies Model 77
Table 1-14 – Productive Oil and Gas Wells Within 6 Miles of Titan Project Site 99

1.1. Overview

This site characterization for Titan Carbon Sequestration, LLC's (Titan) Titan Carbon Sequestration Project (Titan Project) was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(c)(2)** [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, academic and professional publications, and existing core-sample analyses.

1.2. Regional Geology

The proposed Titan Project is located in southeastern Texas within the Gulf of Mexico basin. The coastal portion of the basin covers approximately 148 million acres and includes parts of Texas, Louisiana, Mississippi, Alabama, Arkansas, Missouri, Kentucky, Tennessee, Florida, and Georgia (Roberts-Ashby, et al., 2012). Figure 1-1 depicts the location of the Titan Project relative to the present coastal extent of the Gulf of Mexico. A generalized stratigraphic column of the Gulf of Mexico basin is provided in Figure 1-2. The geologic section is comprised of up to 20 kilometers (km) of strata deposited in succession from the Jurassic to the Holocene (Roberts-Ashby, et al., 2012).

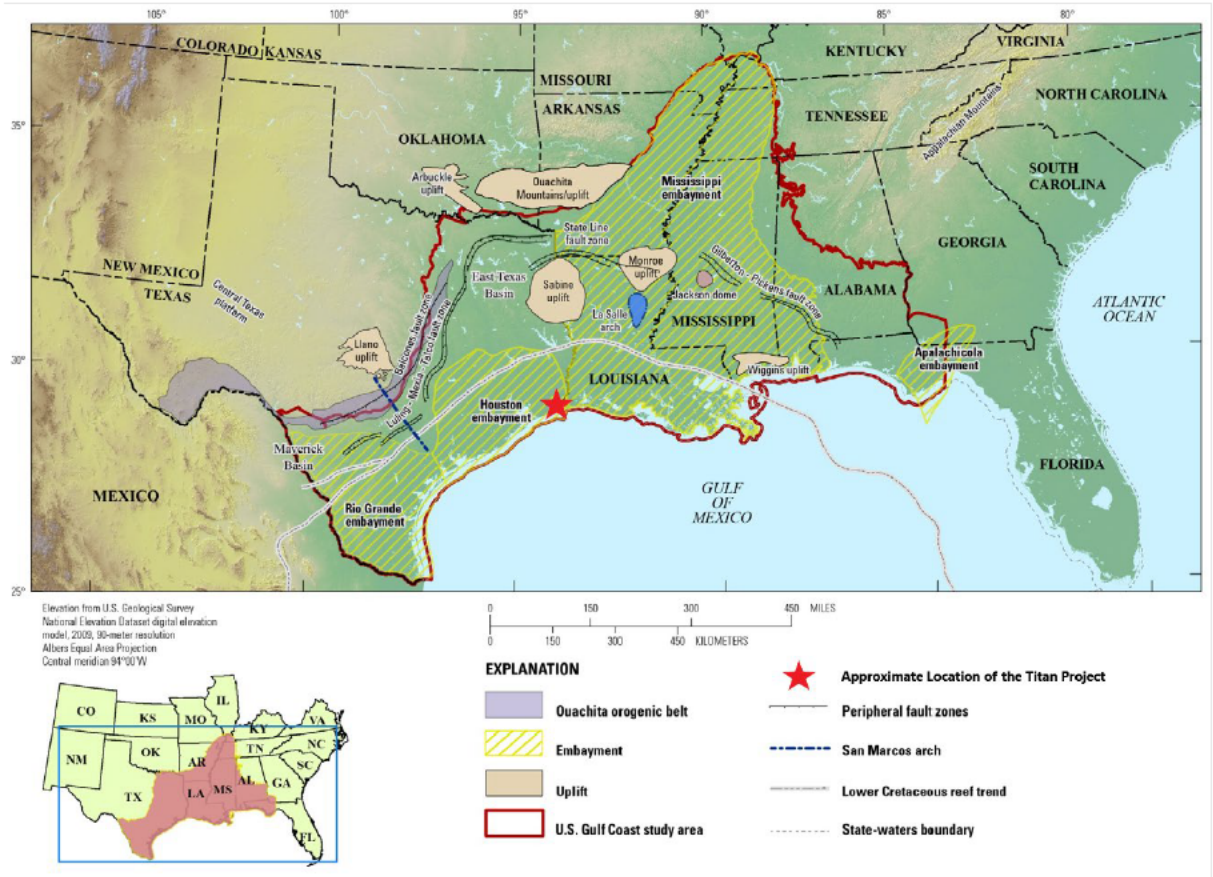


Figure 1-1 – Regional Gulf of Mexico Locator Map (modified from Roberts-Ashby et al., 2012)

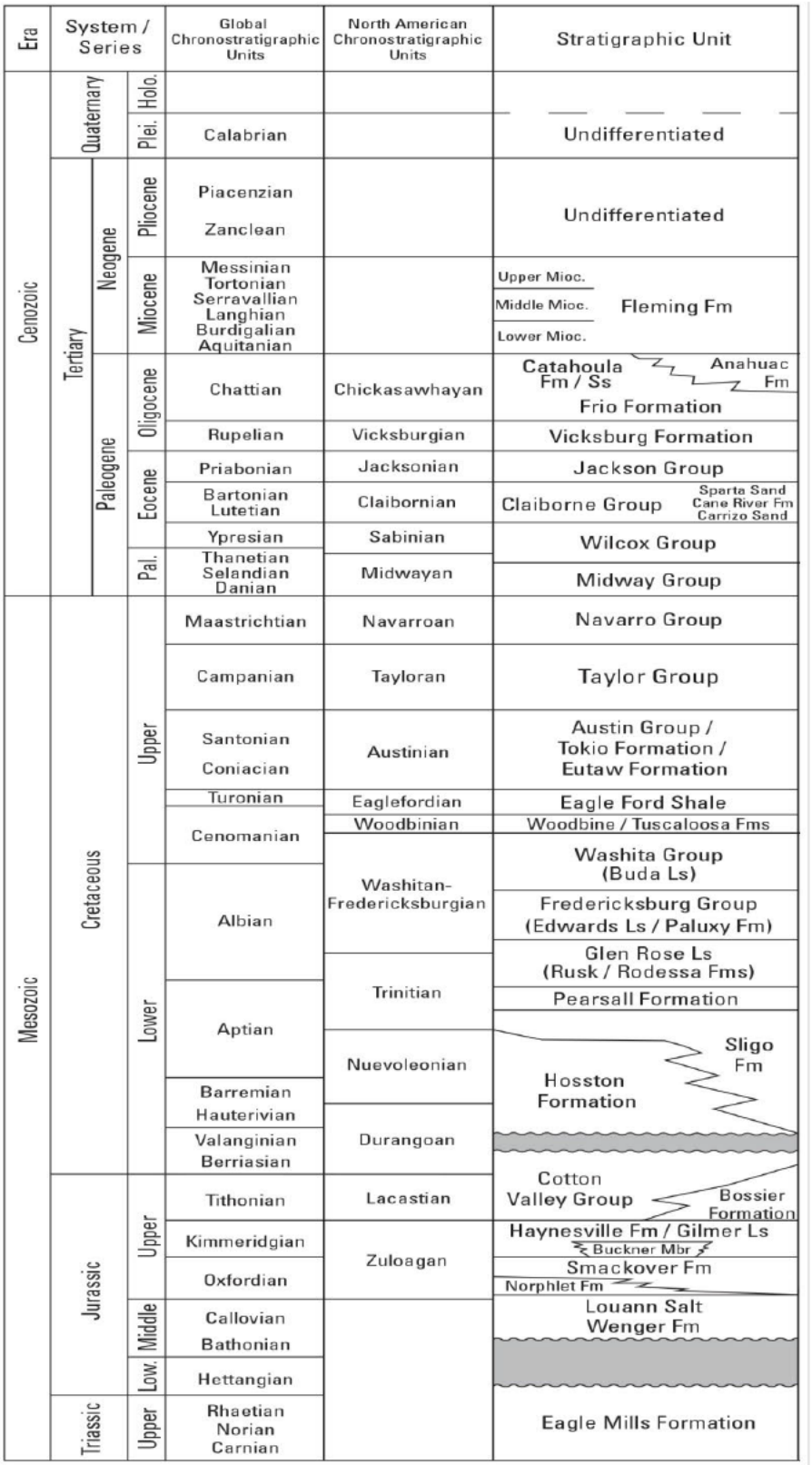


Figure 1-2 – Stratigraphic Column of the Gulf of Mexico (modified from Roberts-Ashby et al., 2012)

The Gulf of Mexico basin was formed by crustal extension and rifting events responsible for the separation of the North American plate and the Yucatan block during the Mesozoic breakup of Pangea. Rifting that commenced during the Middle Jurassic lasted approximately 25 million years and resulted in the variable thickness of transcontinental crusts underneath the basin (Galloway W. E., 2008).

Initial sedimentation occurred between the Late Triassic to Early Jurassic, with deposits filling accommodation space within graben structures created by seafloor spreading; these deposits consisted of terrestrial red beds and volcanics of the Eagle Mills formation (Galloway W. E., 2008). During the Middle to Late Jurassic, the basin consisted of a shallow, hypersaline environment with a narrow connection to the Atlantic Ocean (Treviño & Rhatigan, 2017). This resulted in large-scale deposition of a continuous evaporite sequence up to 4 km thick, known as the Louann Salt. The Louann Salt provided a foundation across the basin for subsequent deposition and played a critical role in later structural development of the basin (Galloway W. E., 2008).

Salt deposition halted by the end of the Jurassic, and subsequent fill into the basin consisted of successive sedimentation of clastics, carbonates, and evaporites. These strata were deposited in a highly cyclic environment, subject to frequent sea-level change and fluctuations in sediment supply that influenced deposition (Galloway W. E., 2008; Roberts-Ashby, et al., 2012). Deposition was also affected by five North American tectonic phases: (1) Laramide uplift, (2) mid-Cenozoic thermal phase, (3) basin and range tectonism, (4) southern Appalachian and Cumberland Plateau uplift and erosion, and (5) Rocky Mountain plateau tectonic uplift. Notably, the southern Appalachian and Cumberland Plateau uplift shifted the depocenter from the northwest portion of the basin margin to present-day Louisiana during the Miocene deposition (Galloway W. E., 2008).

The combination of subsidence and rapid sediment loading of up to 20 km of section over a foundation of salt up to 4 km thick resulted in significant salt mobilization and associated gravity tectonic structures—including growth faults, allochthonous salt bodies, salt welds, salt-based detachment faults, salt diapirs, and basin-floor compressional fold belts (Galloway W. E., 2008).

An interpreted regional seismic line through the Gulf of Mexico is provided in Figure 1-3 to illustrate the present-day structure of the basin. The figure includes a locator map and line of section for reference to the Titan Project, noted with a red star.

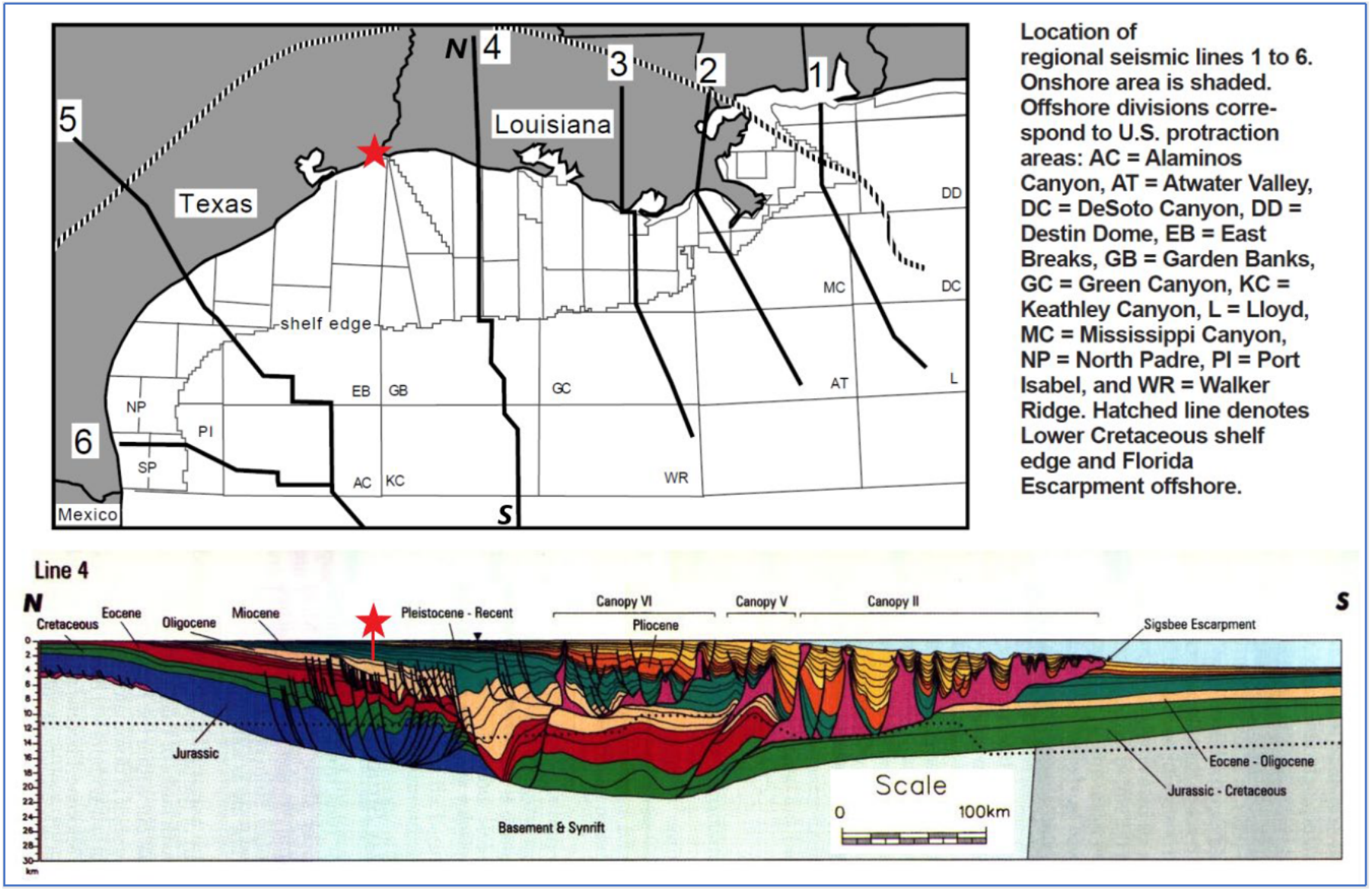


Figure 1-3 – Regional seismic line and locator map. The red star represents the approximate location of the Titan Project (modified from Peel et al., 1995).

1.2.1 Major Stratigraphic Units

The formations targeted in this study consist of Miocene deposits, specifically Lower Miocene to Middle Miocene in age. The Miocene geologic section along the Gulf Coast generally consists of four regressive, fluvio-deltaic depositional episodes, occasionally disrupted by marine transgression and regional deposition of shale. Regressive cycles are characterized by deposition of deltaic sands, silts, and clays; these intervals represent reservoir potential within the Miocene section. Periods of transgression and coastal onlaps are characterized by deposition of tight marine shales associated with biochronozone markers that "serve as fine-grained regional sealing units that subdivide the Miocene section into four SAUs [storage assessment units]": the Lower I, Lower II, Middle, and Upper series (Roberts-Ashby, et al., 2012).

Figure 1-4 contains a stratigraphic column of Tertiary depositional episodes in the Gulf of Mexico basin and clarifies the age of key biochronozone markers relative to sea-level fluctuation and the proposed stratigraphic intervals of the Titan Project. The stratigraphic intervals of interest are color coded by their role in the injection process, with confining zones shaded gray and the gross injection zone shaded yellow. The proposed injection zone for the Titan Project is located within the Lower Miocene regressive sequence and is confined by the overlying *Amphistegina B* (Amph B) and underlying *Siphonina davisi* (Siph Dav) transgressive cycles (Treviño & Rhatigan, 2017).

Sandstones within the four Miocene series are lithologically similar within the Gulf Coast region and are generally described as fluvial-dominated deltaic deposits that dip and thicken basin-ward. Deposition of Miocene sediments around the Titan Project occurred within the Calcasieu delta (Galloway, 2000; Roberts-Ashby et al., 2012).

A comprehensive stratigraphic review of Miocene strata and associated deposition within the Gulf of Mexico basin is available for reference in published material by Galloway (2008) and Snedden and Galloway (2019).

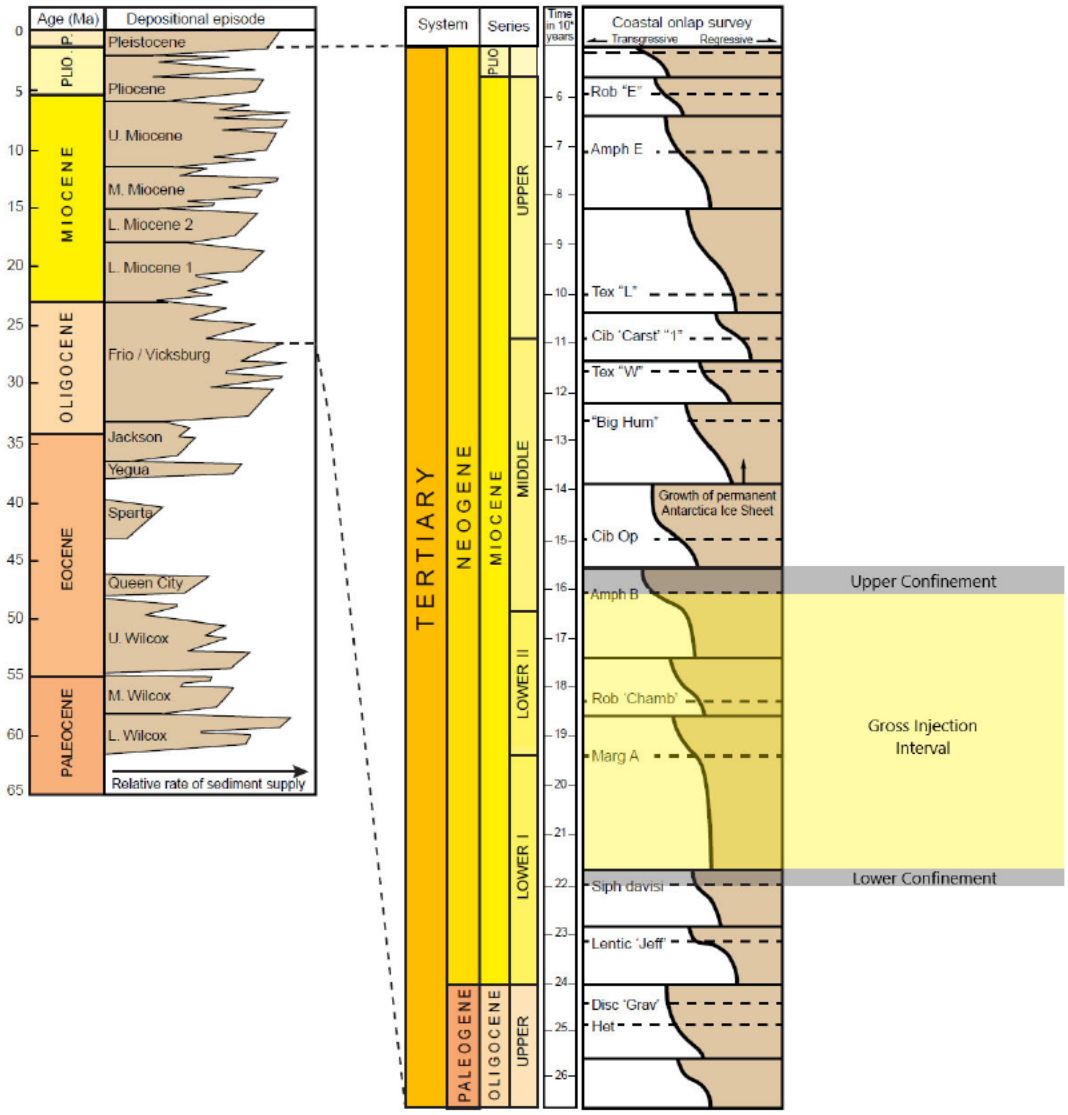


Figure 1-4 – Stratigraphic column of Tertiary depositional episodes in the Gulf of Mexico basin with Miocene sea-level fluctuations relative to associated biochronozones and proposed injection and confining zones (modified from Trevino and Rhatigan, 2017).

Lower Confining Zone: Lower Miocene Siph Dav

The proposed lower confining zone consists of the tight, transgressive Siph Dav shale located within the Lower Miocene. The Siph Dav shale consists of fine-grained silt and clay particles deposited during the maximum flooding surface associated with the first appearance of the Siph Dav biomarker. Maximum flooding surfaces are, by nature, deposited in a relatively high-water column, capable of dispersing fine-grained material and entrained clay well onto the continental shelf (Meckel and Trevino, 2014; Roberts-Ashby et al., 2012). Publicly available core data and published thin section analysis of Siph Dav core demonstrate "abundant clay and low porosity, therefore, high sealing capacity" (Meckel & Trevino, 2014). The base of the Siph Dav confining zone overlies the Lower Miocene "X Sand."

Injection Zone: Lower Miocene Sandstones

The proposed injection zone for the Titan Project consists of porous, regressive deposits located within the Lower Miocene. Lower Miocene sandstones and siltstones of the Gulf Coast are comprised of fluvial-deltaic deposits that were sourced primarily from the ancestral Red River and Mississippi River systems. Lower Miocene deposits prograde the continental margin approximately 65 km to 80 km during the 8 mega annum (Ma) depositional episode and are bound within the underlying Siph Dav shale and overlying Amph B shale (Galloway W. E., 2008).

In 2012, the U.S. Geological Survey (USGS) assessed the carbon dioxide storage resources of the Gulf Coast and determined that the Lower Miocene SAU covers an area of 8.43 million acres ± 10%. Detailed USGS regional mapping suggests that the gross sandstone thickness of the Lower Miocene SAU averages 3,100 feet (ft) ± 800 ft with an average net sand thickness of 1,150 ft ± 500 ft (Roberts-Ashby, et al., 2012).

The USGS also conducted a porosity and permeability analysis of Neogene reservoirs from production data reported by Nehring Associates, Inc., in 2010. The analysis reviewed 432 porosity measurements and 259 permeability measurements from petroleum reservoir averages to approximate the average porosity and permeability of the complete Miocene SAU. The report concluded that Miocene reservoirs along the U.S. coastal plain have an average porosity of 28% ± 4% and an average permeability of 500 millidarcy (mD). The report acknowledged that permeability varies significantly within the data set, like other geologic formations, with the permeability of some reservoirs reported as low as 20 mD and others as high as 8,000 mD. The porosity and permeability averages were modeled with a mean burial depth of 8,000 ft; however, the report clarified that porosity remained high regardless of burial depth (Roberts-Ashby, et al., 2012).

Upper Confining Zone: Middle Miocene Amph B Shale

The proposed Amph B upper confining zone consists of the tight, clay-rich, transgressive, shale located within the Middle Miocene geologic section. The Amph B shale is composed of calcareous mudrock deposited conformably over Lower Miocene sediments during a period of first-order marine transgression. Periods of first-order marine transgression tend to be associated with eustatic highs and deposition of extensive maximum flooding surfaces capable of depositing fine-grained material across large swaths of the continental shelf. Deposition occurred widespread and coincided with the first appearance of the Amph B faunal top that indicates the boundary between the Middle Miocene and Lower Miocene depositional episodes (Meckel & Trevino, 2014). The USGS National Assessment of Carbon Dioxide Storage Resources of the U.S. Gulf Coast concluded that marine shales such as the Amph B tend to be fine-grained and serve confining zones between periods of regressive deposition associated with porous sand and even silt deposition. This assessment is supported by the fact that 95% of oil production and 87% of gas production in Texas state waters occur below the Amph B, demonstrating that the shale is capable of containment. The Amph B shale and maximum flooding surface represent the thickest confining zone within the total Miocene section (Roberts-Ashby, et al., 2012).

Regional Shale Beds

Deposition of the Lower Miocene regressive sequence was interrupted by two periods of marine transgression. These regional shale beds are associated with the *Robulus L* and *Marginulina Asc (Marg Asc)* biochronozones, as was depicted in Figure 1-4 (page 10) (Treviño & Rhatigan, 2017). The Lower Miocene section contains similar lithology and petrophysical properties within the section and across the Titan Project; therefore, for the purposes of this permit application, the injection zone is limited to one single interval (Roberts-Ashby, et al., 2012).

1.3. Site Geology

Based on the modeled extents of the injection plume and pressure front, the Titan Project area of review (AOR) is located in Jefferson County, Texas, [redacted] as shown in Figure 1-5.

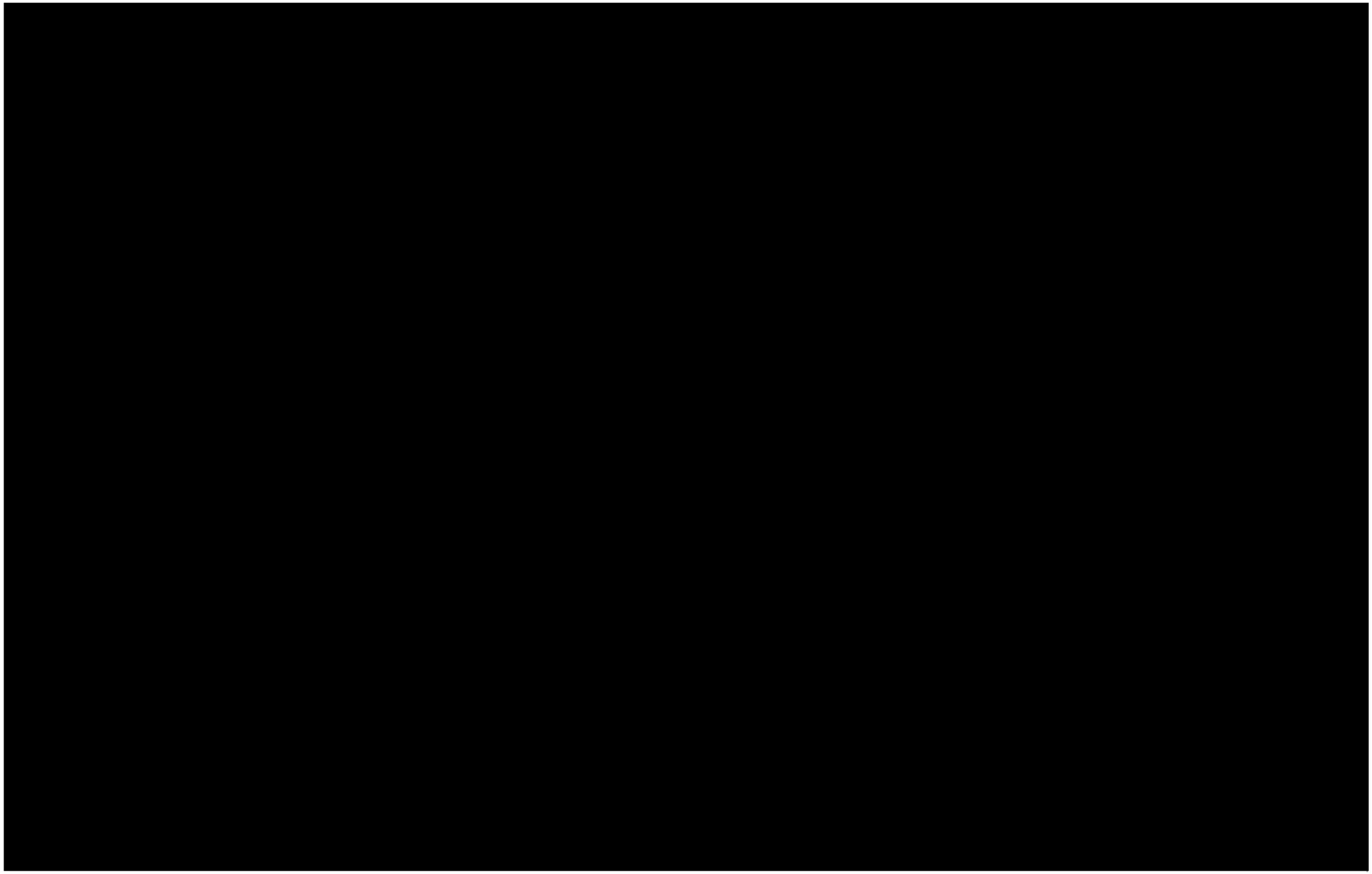


Figure 1-5 – Overview Map of Titan Project

Titan intends to obtain additional information to enhance the initial site-characteristics assessments, based on the prior research conducted across the project area, by implementing a stratigraphic test well, Prometheus No. 1, [redacted] The drilling of this proposed stratigraphic test well will yield site-specific subsurface information, enriching the data set acquired from previous investigative endeavors.

Table 1-1 offers a comprehensive list of wireline logs slated for acquisition during the drilling of Prometheus No. 1. These logs include projected top and base depths tailored to provide precise data relevant to the site characterization objectives. The top and base depths of investigation may be adjusted during drilling to accommodate the analysis of the intended target formations.

Table 1-2 outlines the expected intervals for coring operations during the drilling of the Prometheus No. 1 test well. These coring operations aim to gather mineralogical, fluid composition, petrophysical, mechanical, and geochemical data, which will contribute to the site-specific characterization efforts.

Table 1-1 – Openhole Logging Plan

Trip	Hole Section	Logging Suite	Openhole Diameter (in.)	Use	Cronos No. 1 Depths (ft)	Rhea No. 1 Depths (ft)
1	Surface Section	Spectral Gamma Ray, Resistivity, Bulk Density, Neutron Porosity, Spontaneous Potential	[redacted]	Rock properties; fluid identification and proportion (determining the Underground Source of Drinking Water (USDW) base); lithology/permeability identification	[redacted]	[redacted]
2		Multi-arm Caliper		Cement volume calculations		
3	Intermediate Section	Spectral Gamma Ray, Resistivity, Bulk Density, Neutron Porosity, Sonic/Acoustic, Spontaneous Potential		Synthetic seismogram tie; rock properties and geomechanics; fluid identification and proportion; lithology/permeability identification		
4		Multi-arm Caliper		Cement volume calculations		
5	Long String Section	Spectral Gamma Ray, Resistivity, Bulk Density, Neutron Porosity, Sonic/Acoustic, Spontaneous Potential		Synthetic seismogram tie; rock properties and geomechanics; fluid identification and proportion; lithology/permeability identification		
6		Sonic Scanner (Geomechanics Basket) – Four Arm Caliper-Borehole Imager		Rock properties and geomechanics/stress conditions/cement volume calculations		
7		Formation Fluid Tester		Formation fluid properties/rock properties		
8		MDT Stress Testing with MDT Dual Packer		Geomechanics		
[redacted]						

*MDT – modular formation dynamics tester
TD – total depth

Table 1-2 – Planned Core Intervals, Prometheus No. 1

Stratigraphic Unit	Zone
[redacted]	

*Rotary sidewall cores will be obtained in these sections.

Information regarding reservoir characteristics and geological properties for both the injection and confining zones is sourced from various data repositories, encompassing proprietary, licensed, subscribed, and publicly available data sets. These repositories include the Texas Railroad Commission (TRRC) online database, Louisiana Department of Natural Resources (LDNR) Strategic Online Natural Resources Information System (SONRIS), Texas Bureau of Economic Geology (BEG), IHS LogNet, Enverus, TGS R360, and published research—from which a comprehensive understanding of the general geologic setting and lithological attributes is derived. Additionally, where possible, this understanding is substantiated by offset wellbore and core data. The expected conditions across the proposed sequestration project site are projected through petrophysical analyses of 56 wells featuring wireline logs, as shown in Figure 1-6. This data set includes logs from 14 wells with digitized curves (Log American Standard Code for Information Interchange (ASCII) Standard (LAS)) logs, as well as production data from wellbores in proximity to the proposed well site.

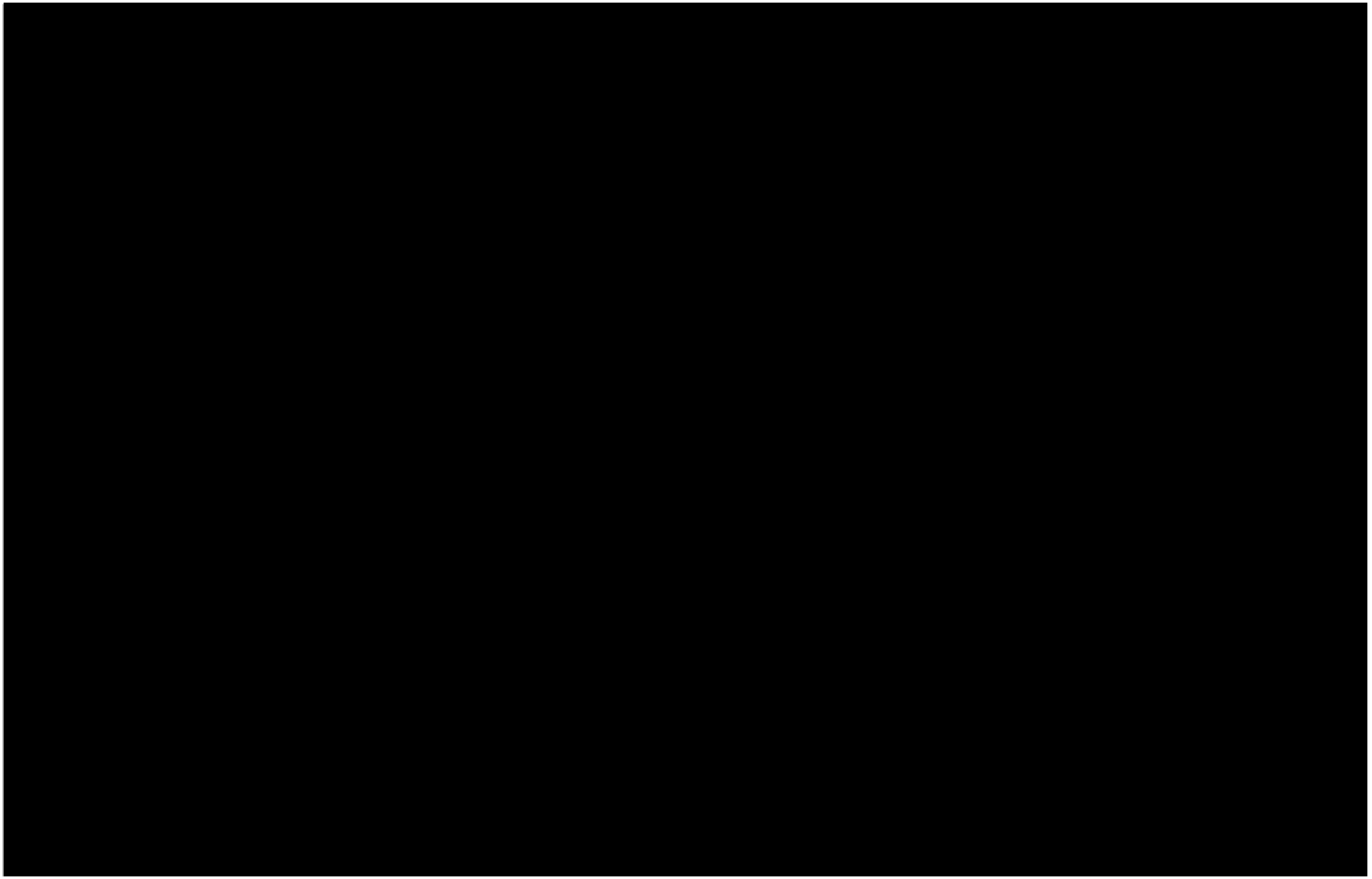


Figure 1-6 – Well Log Data

The [redacted] is the nearest offset wellbore relative to the proposed Titan Project location. [redacted] Table 1-3 provides information on the depths and corresponding thicknesses of the upper confining unit, injection zone, and lower confining unit—all as encountered within the well. Additionally, Figure 1-7 presents a stratigraphic column detailing lithologies, formations, and depth profiles observed in the Iles well.

Table 1-3 – Injection and Confining Zones as Encountered in [redacted]

System	Group/Formation Name	Injection/Confining	Formation Top-Bottom (ft)	Thickness (ft)
Miocene	Amph B	Upper Confining	[redacted]	
Miocene	Lower Miocene	Injection		
Miocene	Siph Dav	Lower Confining		

*Depths in true vertical depth (TVD)

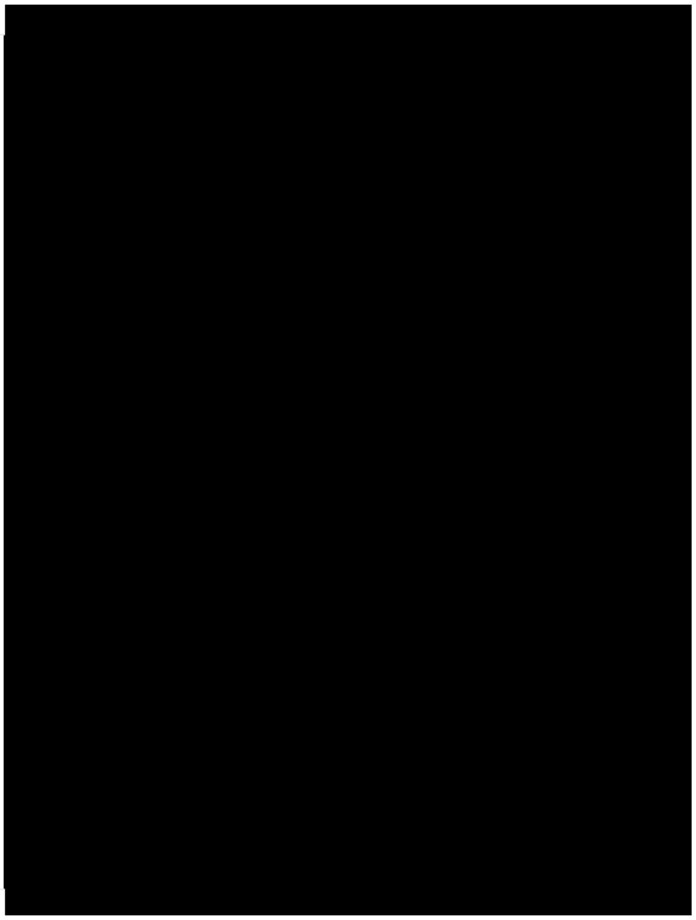


Figure 1-7 – Stratigraphic column from [redacted] Shallower depths than the log interval were referenced from the BEG surface casing estimator. (https://coastal.beg.utexas.edu/surfacecasing/#!/ for [redacted]).

1.3.1 Injection Zone

The injection zone was created from sediments deposited during the Lower Miocene period. These sediments include two shales linked to maximum flooding surfaces, namely *Robulus L* and *Marg Asc*, as identified in the study conducted by (Olariu, DeAngelo, Dunlap, & Treviño, 2019). Figure 1-8 illustrates the relationship between the injection zone and the stratigraphic chart.

The early Miocene was characterized as a period of "relative paleogeographic stability" (Galloway W. E., 2008). After the Anahuac transgression, the "Houston sediment dispersal axis was abandoned" in favor of the Red River axis, which supplied sediment to the Calcasieu delta (Galloway W. E., 2008). Figure 1-9 (page 21) is a depiction of the proposed project location in relation to the paleogeography of the early Lower Miocene, showing the proposed location falling within the Calcasieu delta. Sediment sourcing within the Lower Miocene was greatly influenced by the uplift of the Edwards Plateau and the influx of "reworked Cretaceous and older Cenozoic debris" (Galloway W. E., 2008). The Calcasieu delta "prograded on to a highly unstable, collapsing continental margin, creating an extensive, sand delta-fed apron" (Galloway W. E., 2008).

The Lower Miocene is broken into two subsections, LM1 and LM2, separated by the transgressive marine shale *Marg Asc*. Figure 1-8 is a stratigraphic column depicting this depositional relationship, where LM1 is the initial deposition of the early Miocene with the LM2 closing out the Lower Miocene deposition cycle. Although southern deltas within the Lower Miocene saw reduced sediment influx during LM2, the Calcasieu delta continued through LM2, allowing for ample sand sediment to be present throughout the Lower Miocene (Snedden & Galloway, 2019). Figure 1-10 (page 22) is a paleogeographic map of the LM2 with the proposed project location depicted by the red star.

The ongoing influx of sediment mass is evident in the net injectable-sand presence in the AOR. The BEG conducted a study to assess the suitability of Lower Miocene sediments for injection along the Texas coast. Within this study, sands meeting specific reservoir-quality criteria, as determined by the spontaneous potential (SP) curve, were identified as potential injection sands. Figure 1-11 (page 23) displays an isopach map of net injectable sands derived from the study, highlighting that the AOR has some of the highest onshore net injectable-sand values along the Texas coast. Gross thickness of the injection zone within the proposed injection area ranges from [redacted], as shown in *Appendix B-10* along with Figure 1-12 (page 24).

Throughout the Lower Miocene deposition, the Calcasieu depocenter displayed minimal variation, with a slight westward shift during LM2. This consistency in depocenter location, combined with a steady source of sediment throughout the Lower Miocene, has resulted in a uniform mineralogical composition within the entire injection zone. Lower Miocene sediments primarily consist of a mix of sandstones, siltstones, and shale layers. This geological composition is visually represented in Figure 1-13 (page 25), which presents an openhole log of the offset well [redacted]). The paleo tops depicted were correlated from offset paleo picks. The lithology is depicted in track one through the Vshale curve, where shale and

sand intervals are shaded based on the Vshale values calculated from the SP curve. *Section 1.5* contains additional details on how the Vshale values were computed.

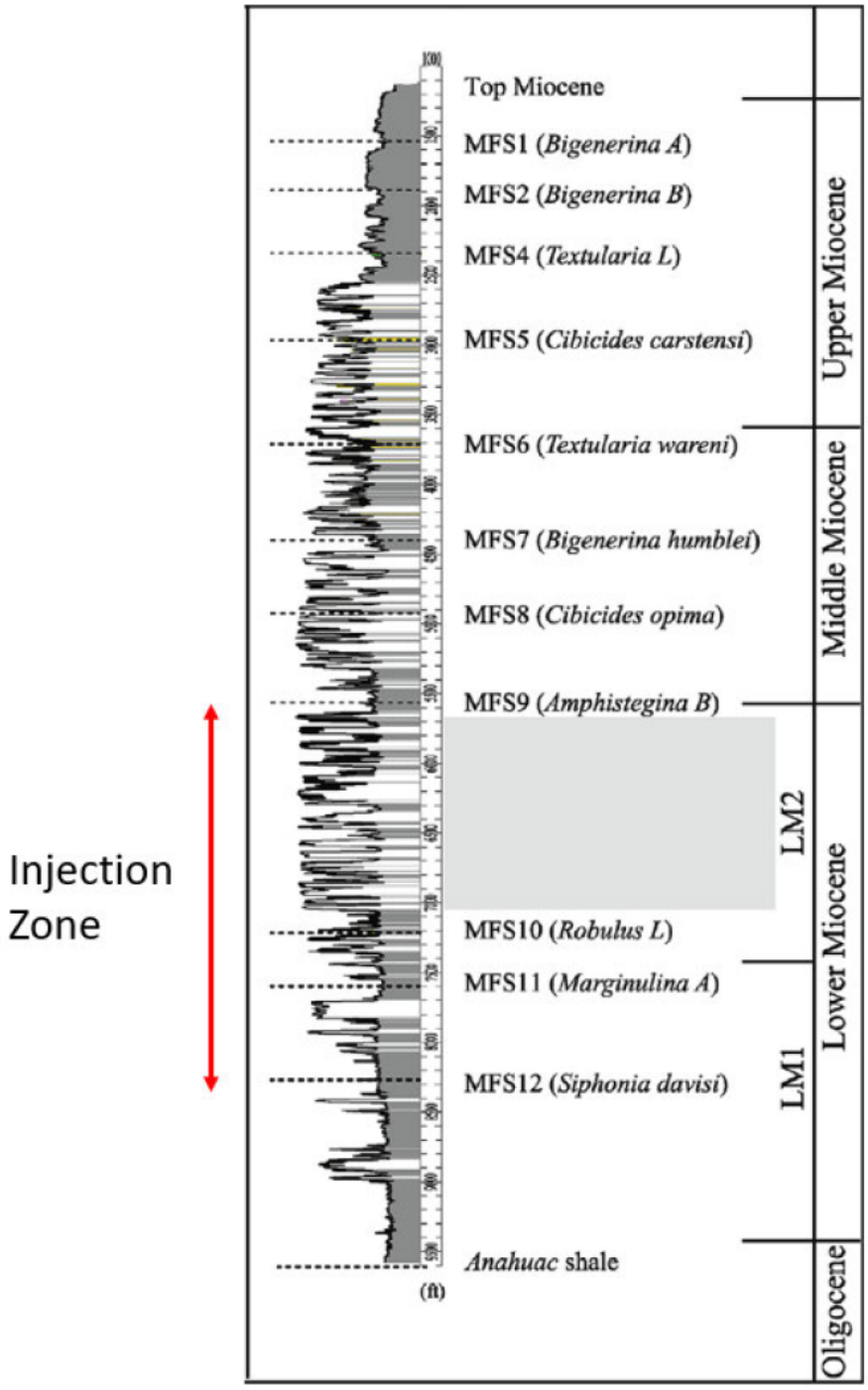


Figure 1-8 – Injection Zone in the Gulf of Mexico, Miocene Stratigraphic Section (Olariu, DeAngelo, Dunlap, & Treviño, 2019)

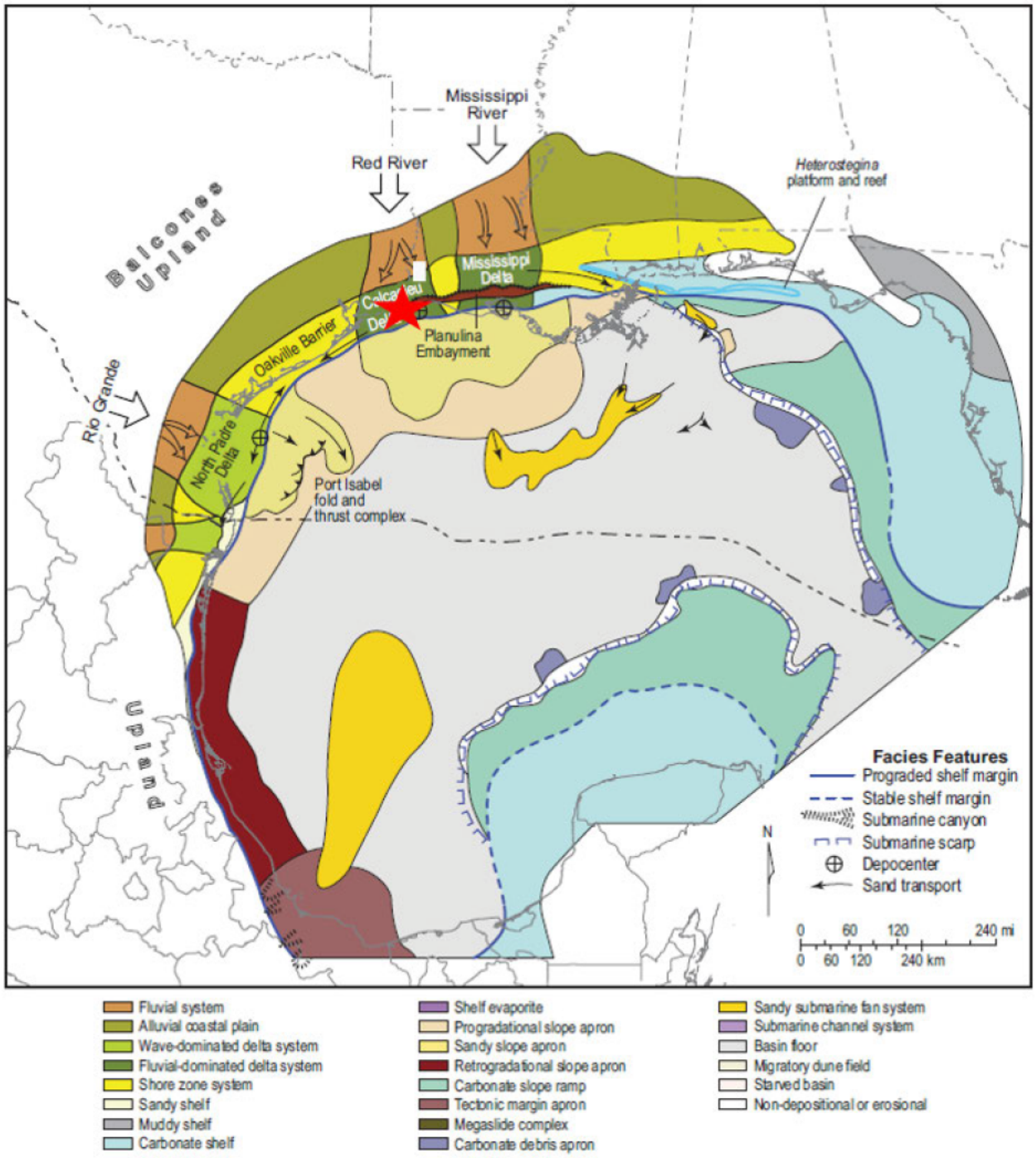


Figure 1-9 – Gulf of Mexico paleogeography during the Lower Miocene (LM1) (Snedden & Galloway, 2019). The red star denotes the project location.

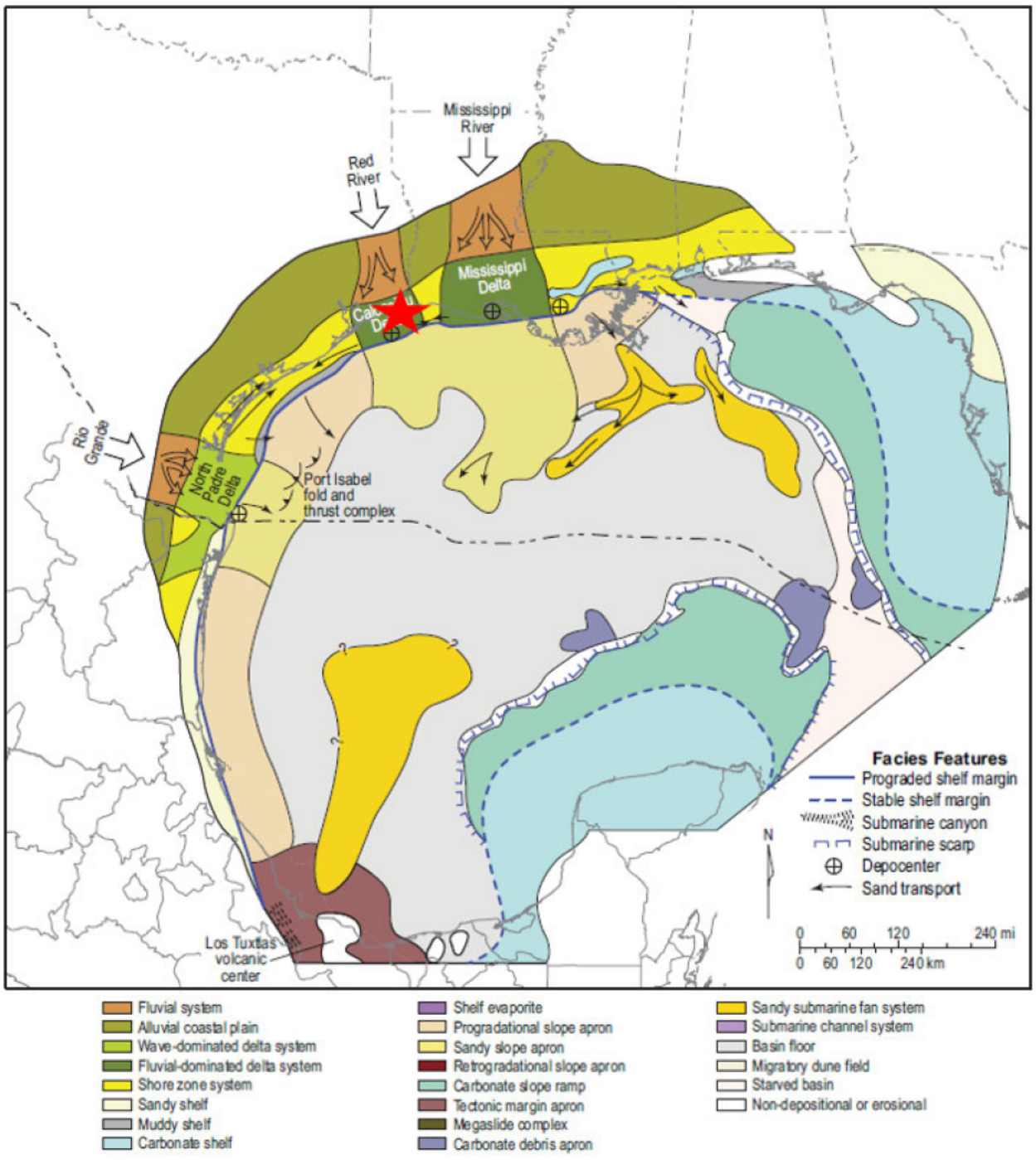


Figure 1-10 – Gulf of Mexico paleogeography during the Lower Miocene (LM2) (Snedden & Galloway, 2019). The red star denotes the project location.

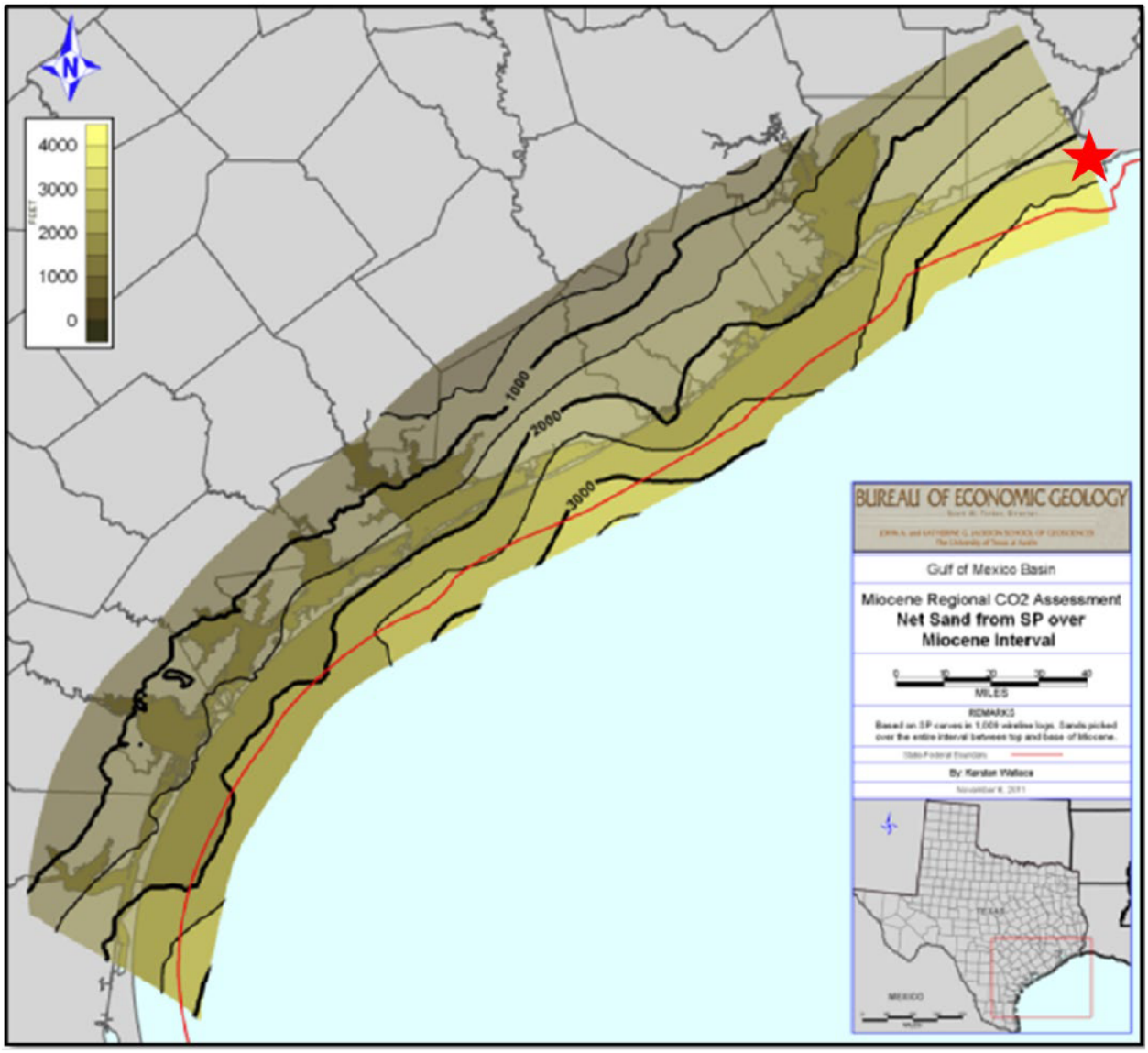


Figure 1-11 – Net sand isopach map from the BEG study. The red star represents the Titan Project location (Meckel & Trevino, 2014).

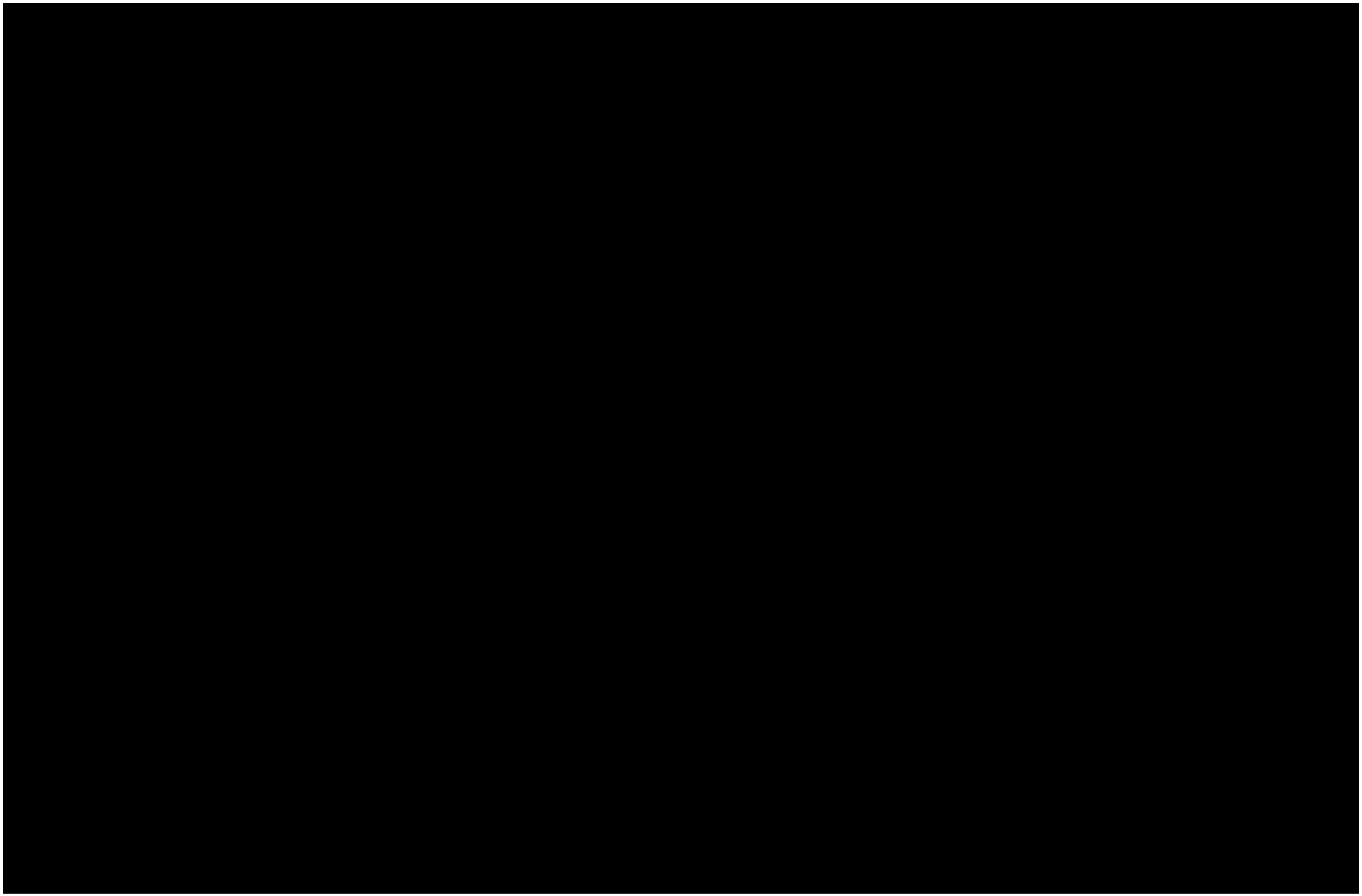


Figure 1-12 – Gross Injection Zone Isopach Map

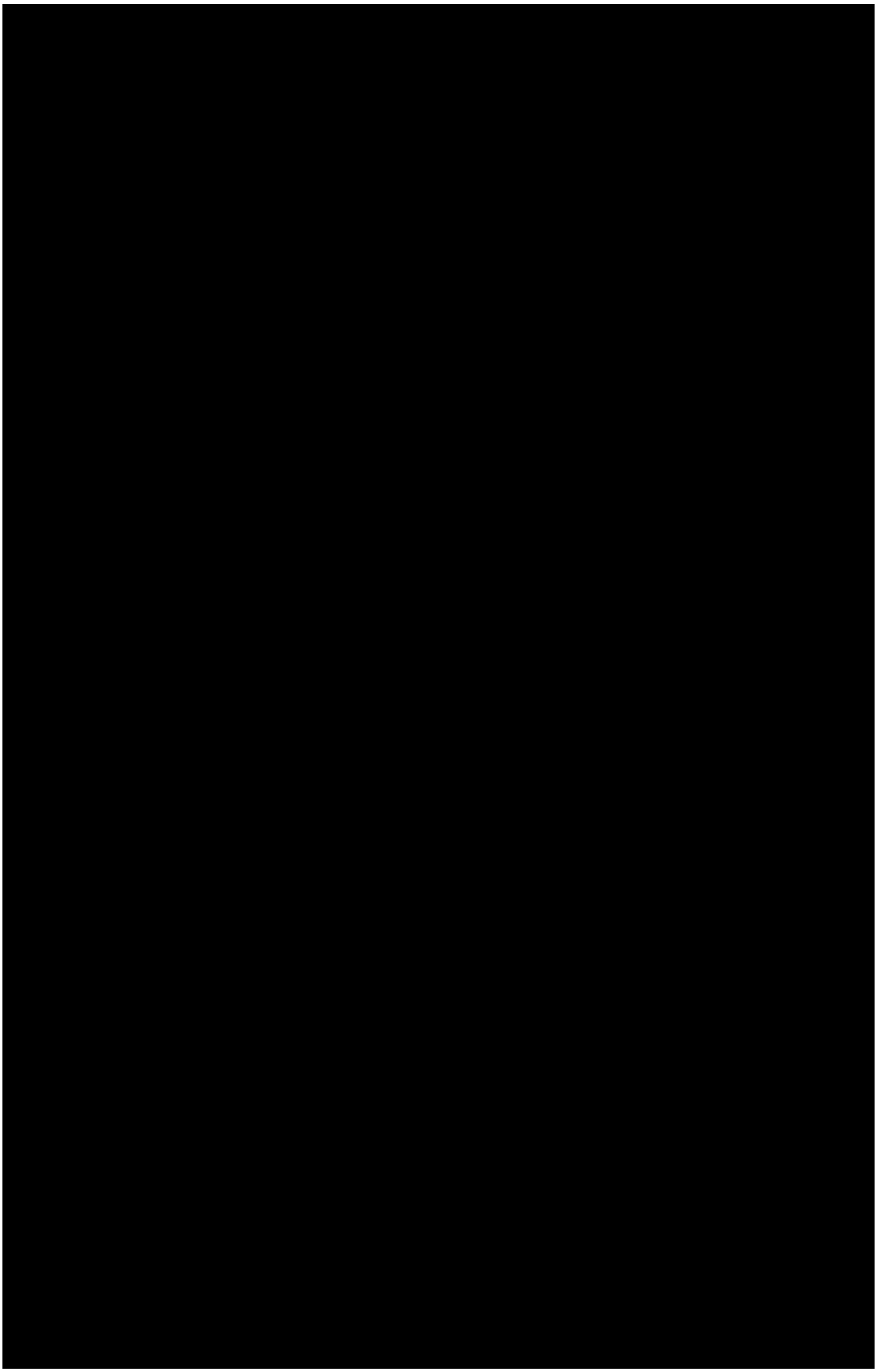


Figure 1-13 – Openhole log of [redacted] depicting the proposed injection zone.

Though limited core data of the stratigraphic section of interest are available for analysis, Lower Miocene core sampled from High Island well 24L No. 9 (42-708-30316) in the previously referenced BEG study were analyzed. [redacted] Conventional core, 106 ft in length, was taken over a 360-ft section that included calcareous mudstone, marine shale, medium coarse-grained sandstone, and interbedded shale and fine-grained sandstone. These samples resemble the primary lithofacies that will be encountered throughout the injection and confining zones. Therefore, it can be assumed that similar mineralogy will be encountered throughout the injection zone.

Samples were taken from these conventional cores for multiple analysis including thin section, X-ray diffraction (XRD), and scanning electron microscopy (SEM). Results from the XRD analysis in the injection sands within the Lower Miocene are shown in Figure 1-15 (page 28). Large concentrations of quartz and low concentrations of clay were examined and are expected throughout the Lower Miocene, within the sand intervals. A thin section displaying the grain distribution and excellent porosity (represented in blue) within a sandstone sample representative of sandstones targeted for injection is displayed in Figure 1-16 (page 28).

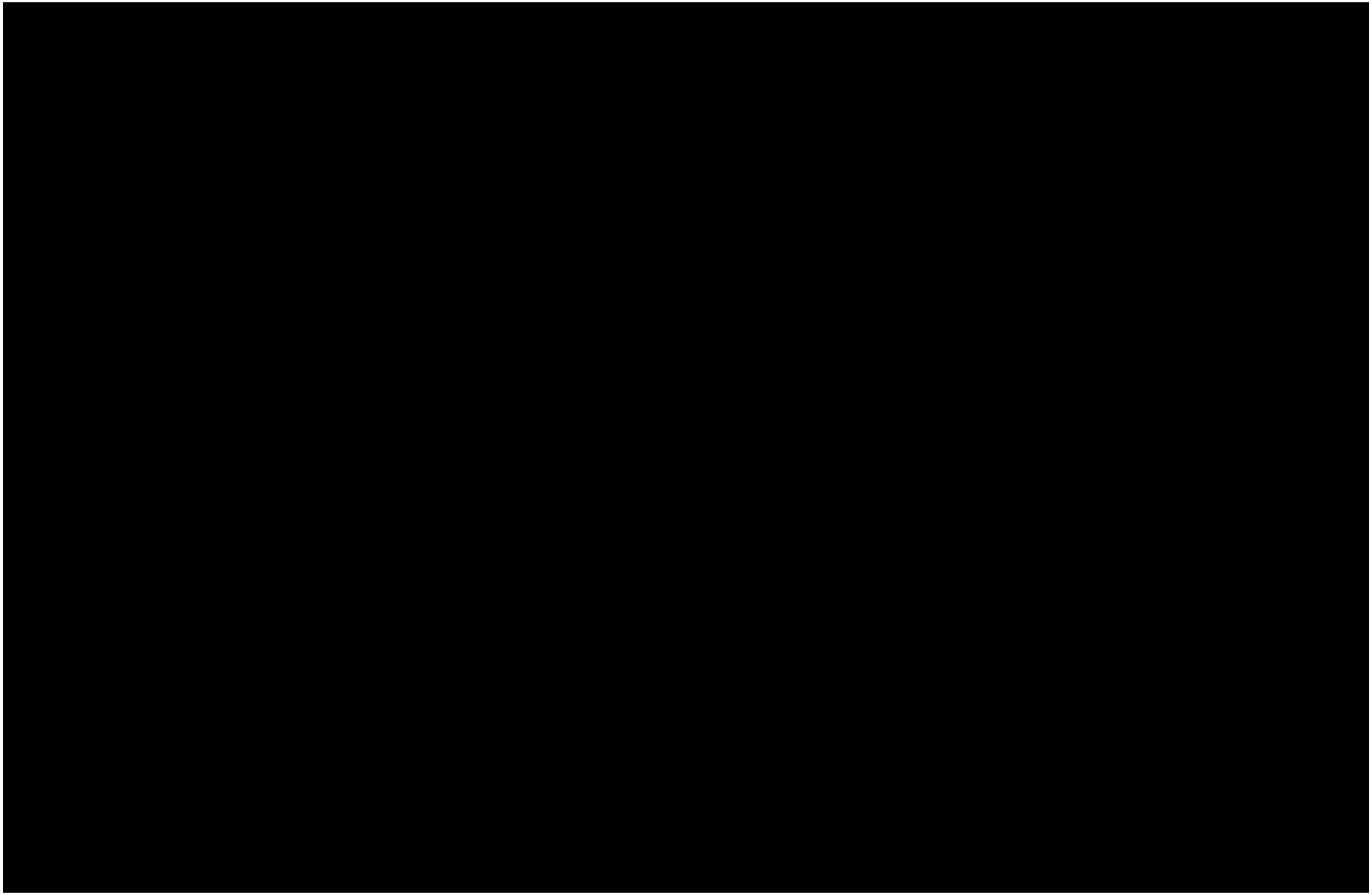


Figure 1-14 – Map depicting High Island core data in relation to the proposed Titan injection wells.

Well	Depth (ft)	Quartz	Kaolinite	Calcite	Illite	Plagioclase	K-Feld
High Island 24L #9	8555	48.49	3.73	1.62	4.65	19.61	21.92
High Island 24L #9	8560.5	49.14	3.58	1.83	5.03	18.85	21.57
High Island 24L #9	8570.6	51.88	2.20	1.99	4.85	18.74	20.34
High Island 24L #9	8572	50.86	2.74	2.29	4.98	18.82	20.31

Figure 1-15 – XRD analysis from High Island core data within the sand intervals (Meckel & Trevino, 2014).

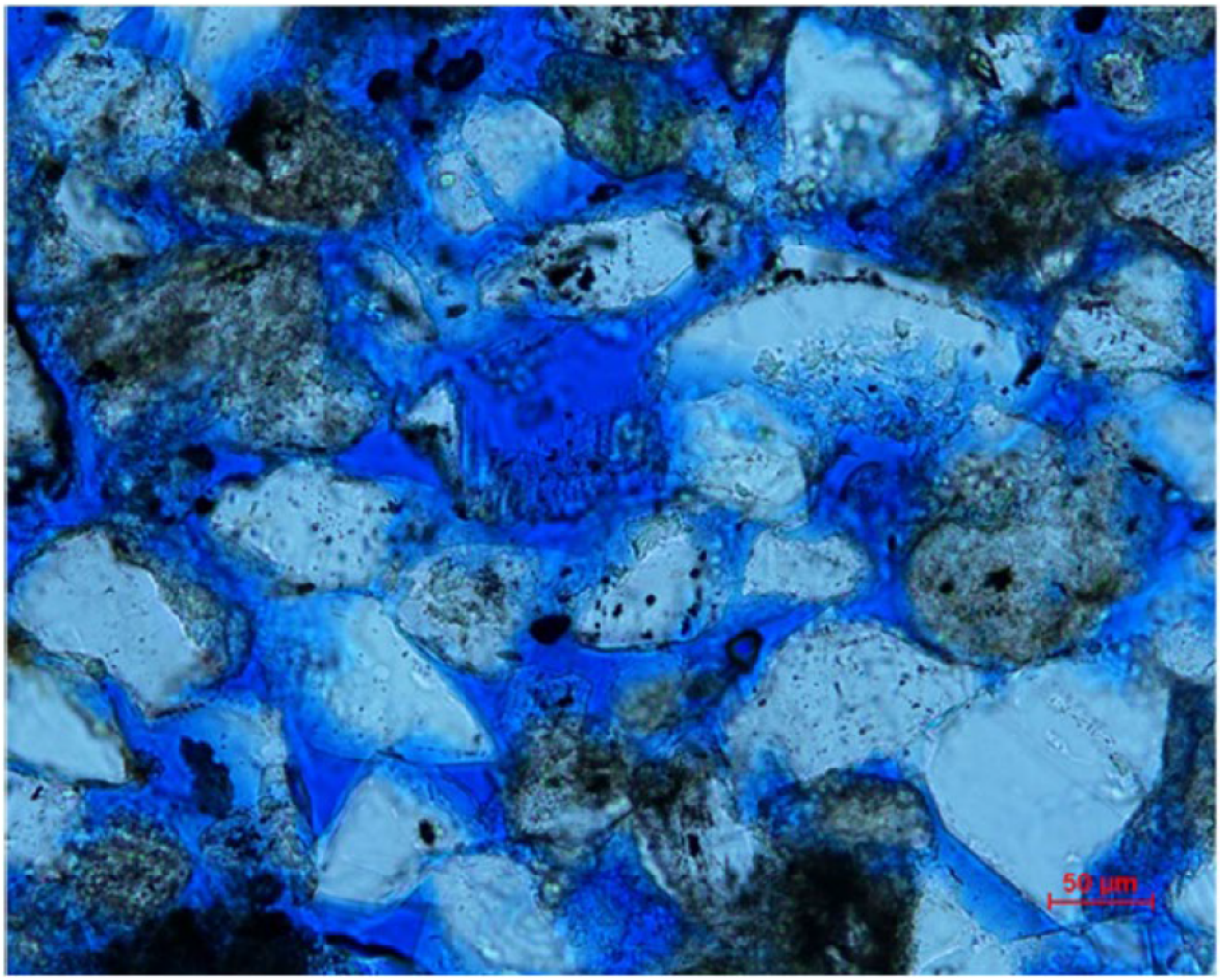


Figure 1-16 – Thin section of High Island core depicting high porosity (in blue) within the injection sands (Meckel & Trevino, 2014).

1.3.2 Upper Confining Zone

The Amph B shale is recognized as a regional marine shale that marks the lower boundary of the Middle Miocene and the upper boundary of the Lower Miocene (Galloway, 2000). Research conducted by the BEG has highlighted the Amph B's significance as a crucial confining layer for CO_2 injection, attributed to its extensive lateral presence and effective sealing properties (Treviño and Rhatigan, 2017). Further proof of the sealing properties of the Amph B is supported by the

fact that, as noted earlier, 95% of oil production and 87% of gas production in Texas state waters take place beneath Amph B, highlighting its effectiveness as a regional sealant (Meckel & Trevino, 2014). This shale is the result of a flooding event approximately 16 million years prior to the initial formation of the West Antarctic Ice Sheet. The Amph B transgression disrupted episodes of deltaic progradation dominated by sandstone and shore-zone advances, towards the end of the early Miocene and the beginning of the Middle Miocene (Meckel and Trevino, 2014).

Figure 1-17 displays an openhole log image of the upper confining zone in the [redacted] Within this image, [redacted]. Core-based analyses make it apparent that the Lower Miocene mudrocks are rich in clay and possess a good sealing capacity for CO_2 storage in the underlying sandstone units. The sealing effectiveness of the samples under study exhibits a positive association with the clay content and the presence of calcite cementation. Notably, mudstone samples with a higher clay content tend to exhibit greater capillary entry pressure and smaller pore-throat dimensions compared to the underlying sandstones. The SEM imaging reveals that these claystone samples predominantly feature isolated intraparticle pores that do not effectively interconnect to form pore networks (Meckel & Trevino, 2014).

Although cores in this study are not within the Amph B itself, similar mineralogic and lithologic characteristics are expected to be encountered within the Amph B (Meckel & Trevino, 2014). Figure 1-18 (page 31) represents the results from XRD analysis on the mudstones samples from the High Island core. [redacted]

The gross thickness of the Amph B ranges from approximately [redacted] within the project AOR. (Gross isopach maps of the Amph B are provided in *Appendix B-8*). Thin sand interbeds occur within the Amph B but will have no effect on the confining nature of the formation—due to the high clay content above and below the interbedded sand prohibiting an interconnected pore system that would induce transmissibility.

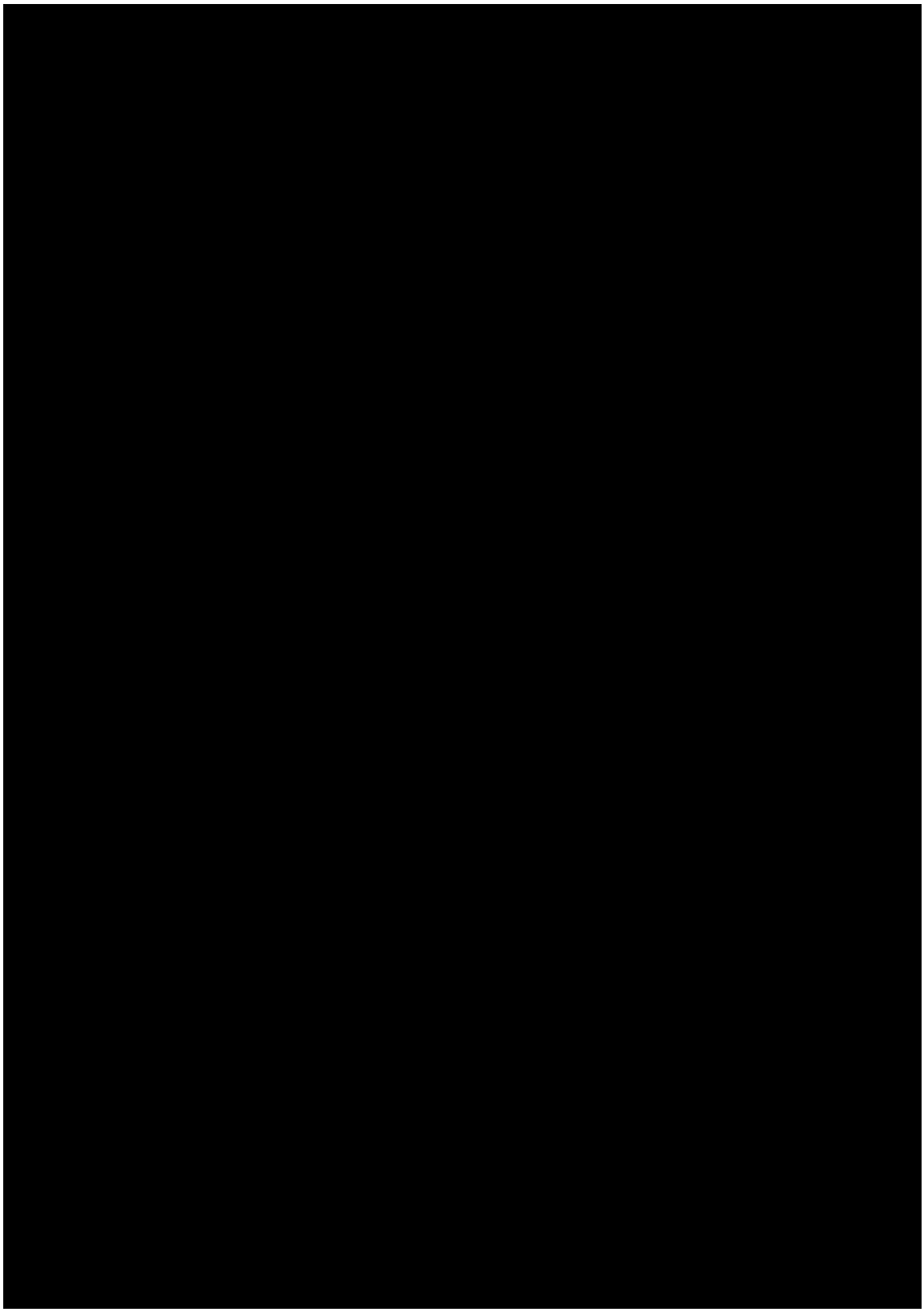


Figure 1-17 – Openhole log of [redacted] depicting the proposed upper confining zone.

Depth (ft)	Quartz	Kaolinite	Calcite	Illite	Albite	K-feldspar	Chlorite	Total
Well High Island 24L #9, API: 427083031600								
8403.1	23.7	12.7	15.8	22.5	6.7	18.6		100.0
8408.5	18.9	13.9	19.4	26.0	6.2	15.5		100.0
8412.9	27.0	10.3	11.2	21.6	9.5	20.4		100.0
8421	20.5	15.3	13.8	32.4	7.7	10.4		100.0
8421*	22.0	15.6	14.1	30.3	6.9	11.1		100.0
8423.1	20.4	15.6	13.3	33.9	7.0	9.8		100.0
8427.4	41.4	7.2	5.1	15.2	16.2	15.0		100.0
8429.5	40.1	9.9	2.4	20.7	13.4	13.5		100.0
8429.5*	42.5	7.7	3.1	19.1	14.5	13.1		100.0
8481.6	34.8	9.9	7.2	21.1	13.0	14.0		100.0
8481.6*	34.6	9.4	7.4	22.6	13.1	13.0		100.0
8485	29.8	10.7	11.5	24.2	11.0	12.8		100.0
8489	26.7	12.9	10.2	28.0	10.2	12.0		100.0
8492	36.0	2.9	20.5	4.7	17.5	18.4		100.0

Figure 1-18 – XRD analysis of mudstone samples within the High Island core (Meckel & Trevino, 2014).

1.3.3 Lower Confining Zone

The lower confining zone is directly associated with the maximum flooding surface of the Siph Dav. The High Island core data previously referenced was taken in the Siph Dav. Therefore, mudstones sampled in the High Island core data will adequately portray the mineral and lithologic conditions of the lower confining zone. Figure 1-18, as noted above, is an XRD analysis of the mudstone samples within the Siph Dav. Unlike the upper confining zone, the presence of illite is expected at these deeper burial depths. A thin section is shown in Figure 1-19 depicting the 8,408 ft sample from the High Island core, "showing abundant clay and low porosity, therefore, high sealing capacity" (Meckel & Trevino, 2014).

The base of the lower confining zone is bounded by the X Sand, a regional Lower Miocene sand. Figure 1-20 (page 33) displays the lower confining zone from the [redacted] The VSHL curve in the left track is a clay concentration curve based on the SP curve, shaded to represent sand and shale content, and the ILD curve in the right track is the measured deep-resistivity log. As evidenced through the response of both curves, the Siph Dav is a continuous shale/mudstone that will have optimal sealant characteristics.

The gross lower confining zone is [redacted] thick in the [redacted] and varies from [redacted] within the AOR. Structure and isopach maps of the Siph Dav are included in *Appendix B-9*.

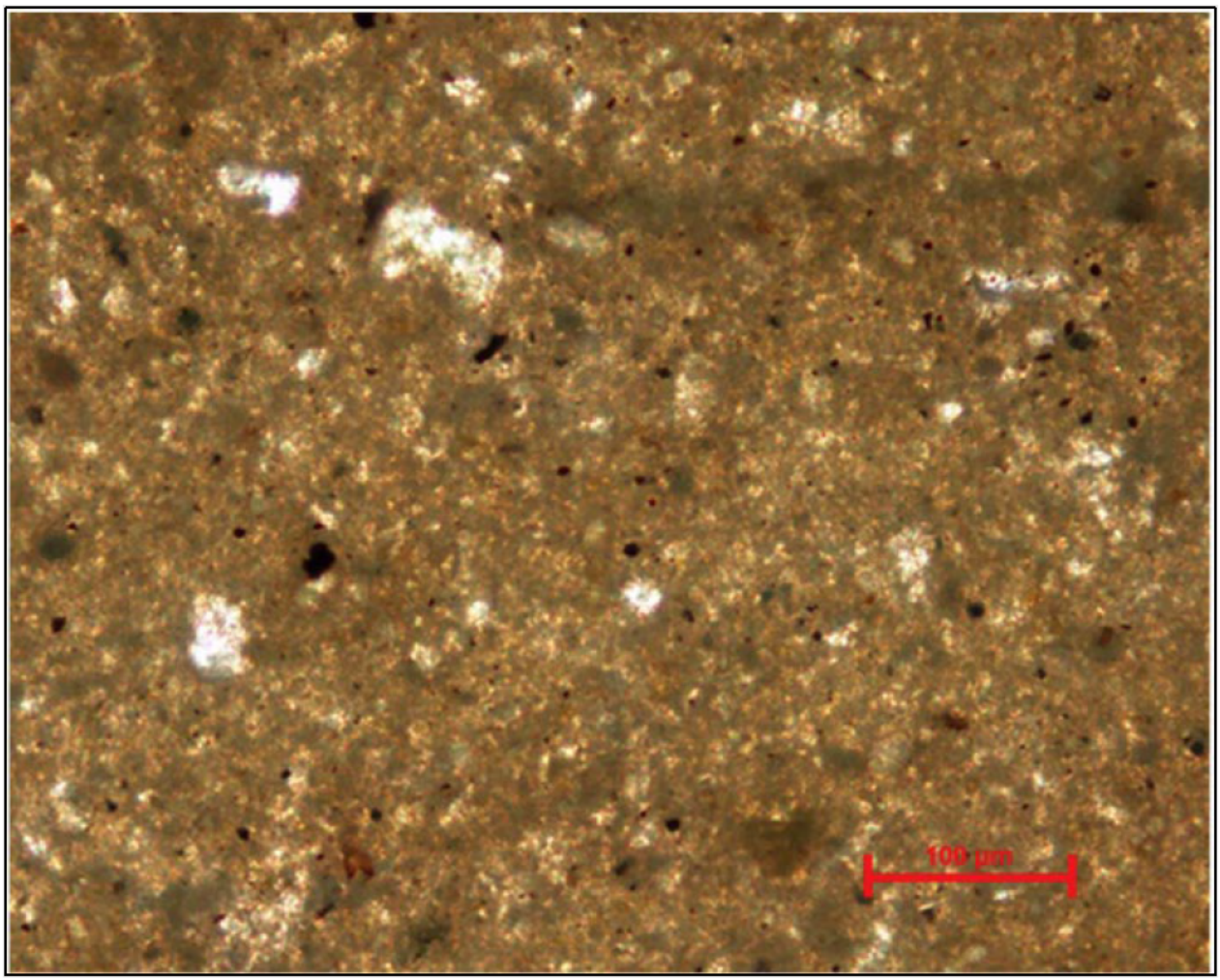


Figure 1-19 – Thin section of mudstone showing high clay content and low porosity from High Island core (Meckel & Trevino, 2014).

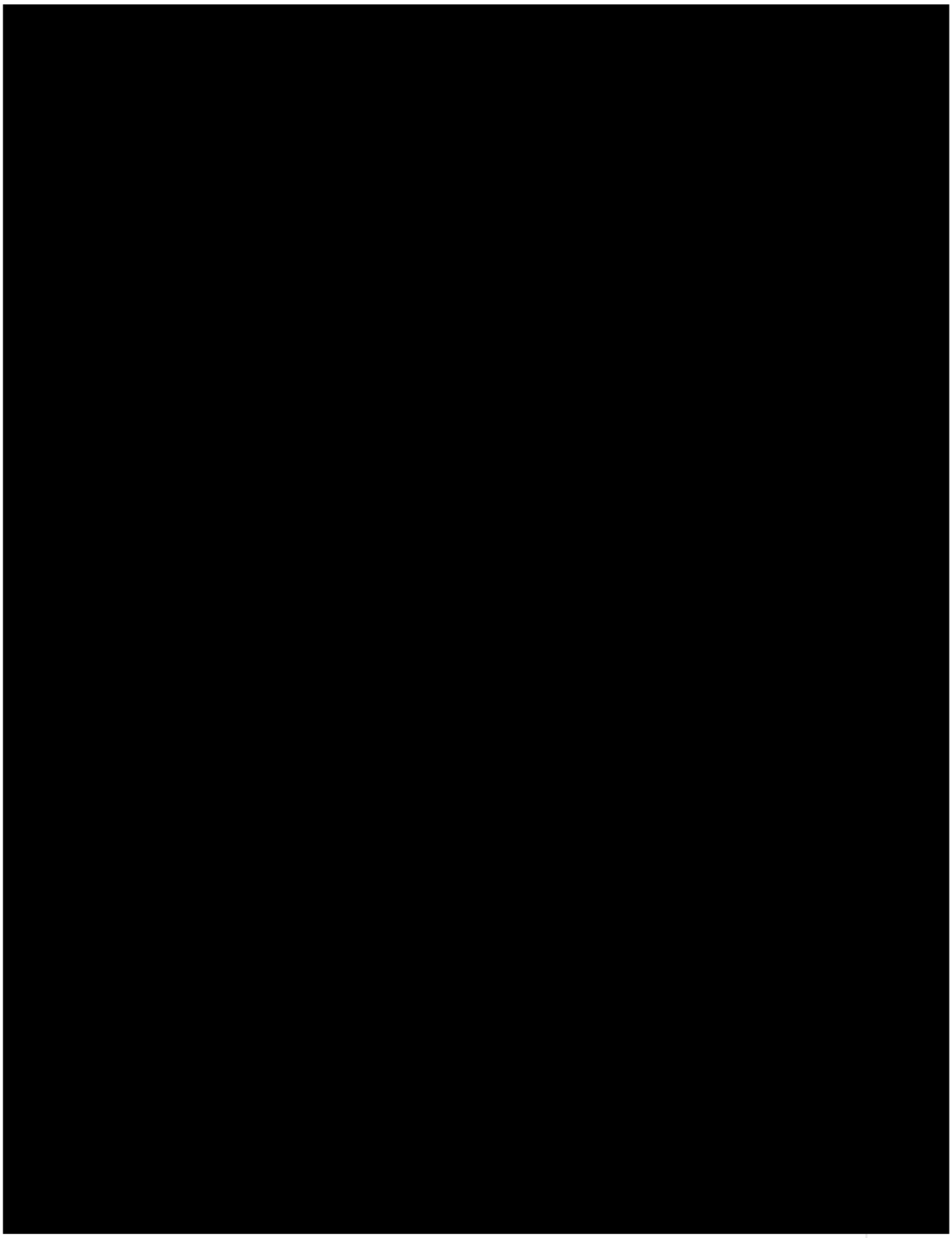


Figure 1-20 – Openhole log of [redacted] depicting the proposed lower confining zone.

1.3.4 Geologic Structure

1.3.4.1 Data sources

Structural dips of sedimentary strata within the injection zone were mapped using offset well control and 28 square miles (sq mi) of 3D seismic data. Subsurface control was provided from [redacted] Well information and log data were compiled for these wells from multiple data sources including TGS, Enverus, IHS, and the TRRC. Professional geologists and engineers cross-referenced data sets to ensure completeness and accuracy. Directional surveys were available and used for all deviated wellbores. The compiled well database was imported into Petra® for mapping. Raster logs were available for [redacted] of the wells and digital LAS curves were incorporated from [redacted] of those wells. Tops were correlated across the region based on log response and then integrated with the 3D seismic data for the structural interpretation. These tops were sourced from offset field papers to assist in regional stratigraphic correlations. Structure maps, cross sections, and isochore maps with further detail are included in *Appendices B-1* through *B-12.*

About 28 sq mi of 3D surface seismic data were obtained under license by Titan and used for the current interpretation. This data set is a segment of the [redacted] sourced from the [redacted]

The licensed data from the [redacted]

Figure 1-21 – Location of 3D Seismic Surveys

1.3.4.2 Reflection Seismic Profiles

The 3D reflection profiles, which visualize subsurface features by highlighting differences in velocity and density, were integrated with geological formation top data obtained from subsurface well control. This integration allowed for the creation of maps outlining the designated injection and confining zones, providing insights into formation depths and the presence of any anomalies like faults. These maps are presented in Figures 1-22 through 1-24 (pages 37 through 39, respectively).

The 3D seismic data set was used to chart a sequence of Miocene-era strata, measuring approximately 3,000 ft in thickness. The quality of the seismic data is high, featuring offsets adequate for delineating the target interval within the depth range of [redacted] TVD subsea (TVDSS). Across the envisioned CO_2 storage area (in the black polygon featured in Figure 1-22), the recorded and interpreted 3D seismic data does not indicate significant alterations in the injection or confining zones via major thinning or thickening events. [redacted]

[redacted]

[redacted]

Figure 1-22 – Structure Map of the Top of Amph B

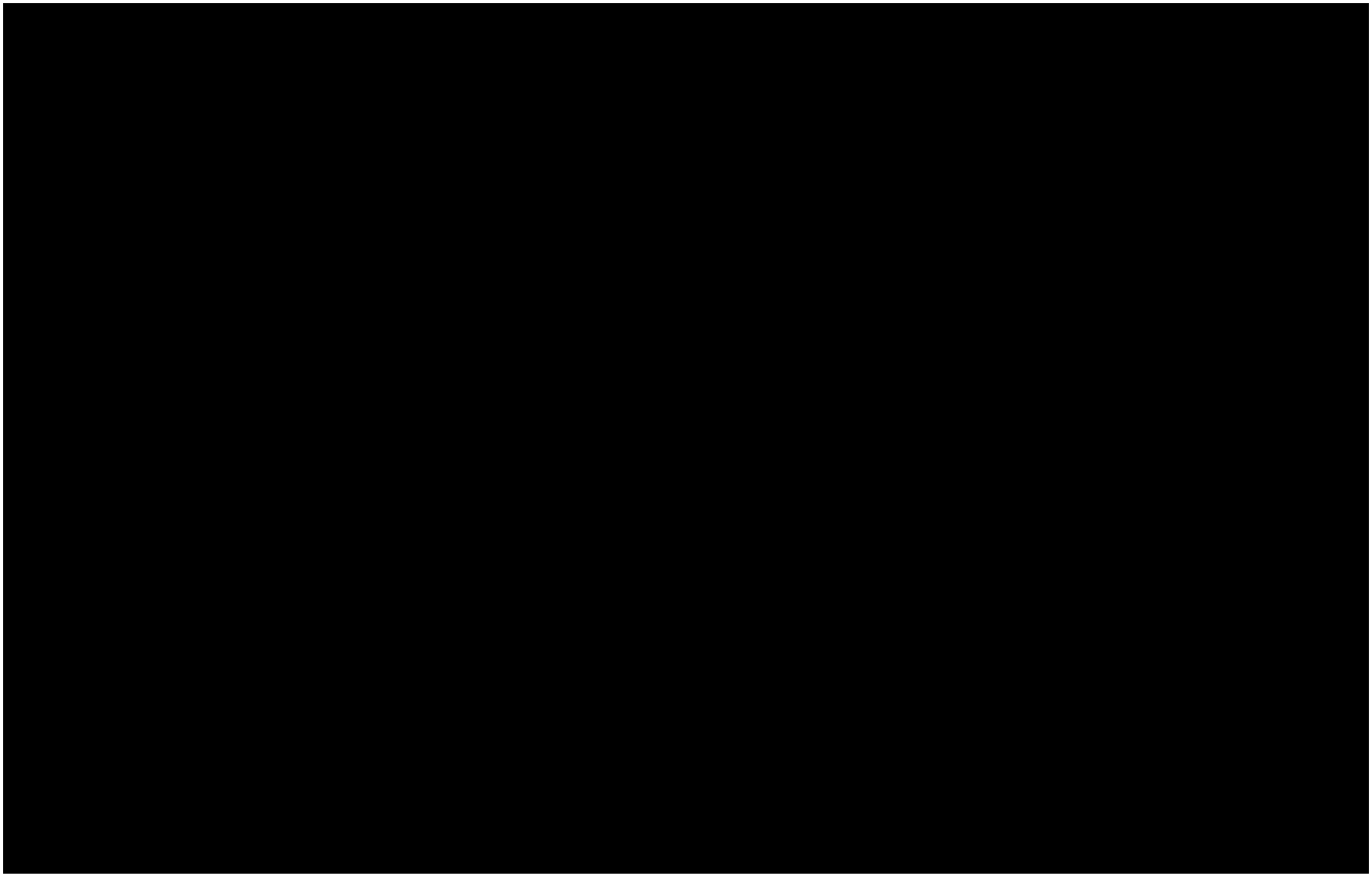


Figure 1-23 – Structure Map of the Top of the Lower Miocene

Figure 1-24 – Structure Map of the Top of Siph Dav

1.3.4.3 Velocity Control and Synthetic Seismogram

A velocity survey was used from [redacted] n Figure 1-25. The checkshot velocity information and synthetic well ties from [redacted] ere used to confirm the time-to-depth relationship of the PSTM data, illustrated in Figures 1-26 and 1-27.

Figure 1-25 – Location of well with a checkshot velocity survey (indicated by the blue circle), with wells used for synthetic ties to seismic (green circles). The red stars indicate the locations of the proposed injection wells.

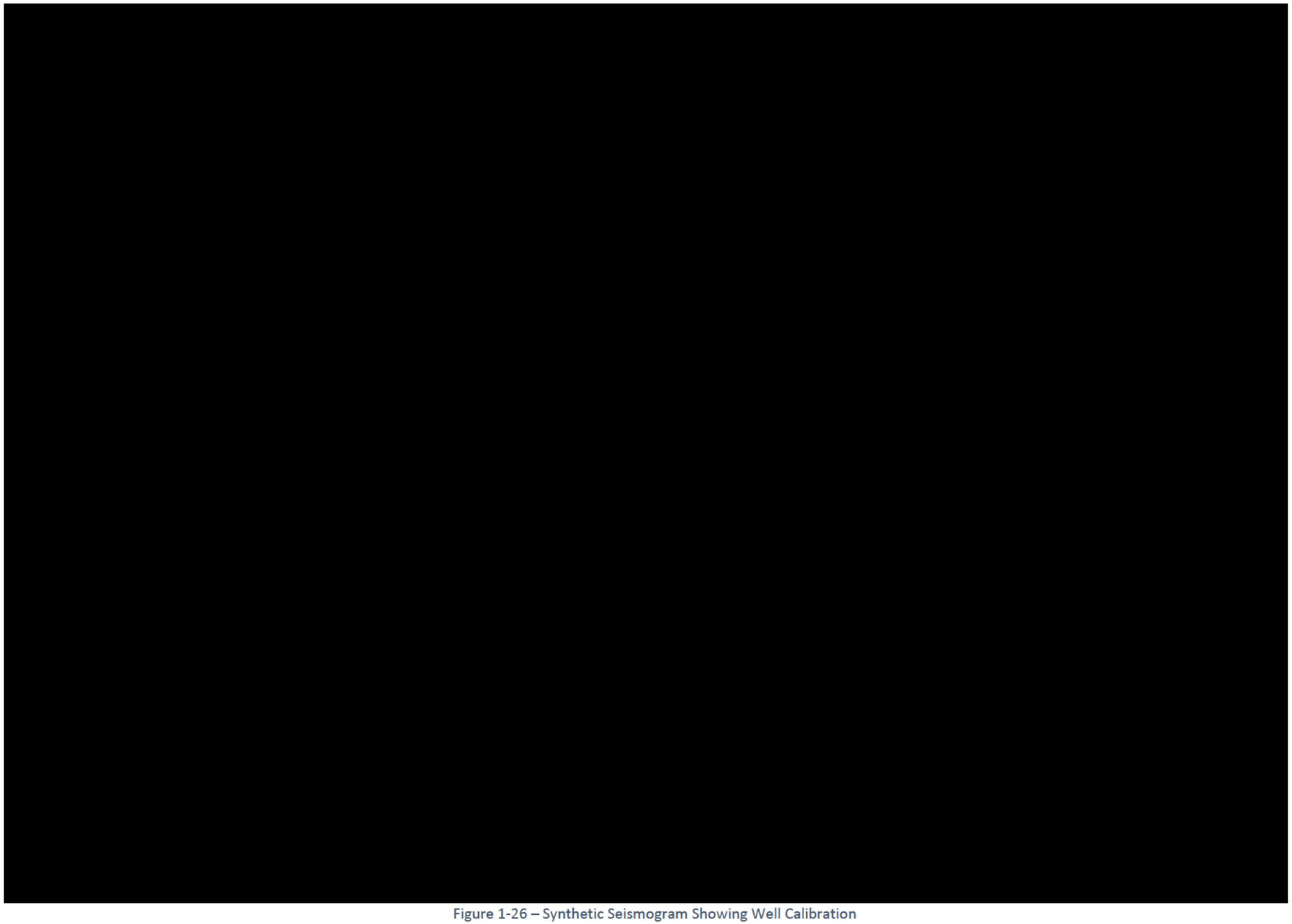


Figure 1-26 – Synthetic Seismogram Showing Well Calibration

Figure 1-27 - Seismic Line with Synthetic Well Tie

1.4. Geomechanics

1.4.1 Local Stress Conditions

Local formation stresses will be calculated by integrating mechanical rock properties from an X-dipole openhole log, calibrated with geomechanical core tests. According to published maps of crustal-stress orientation along the northern coast of the Gulf of Mexico basin, the maximum horizontal stress (SHmax) orientation is primarily parallel to the coast in an east-northeast direction near the AOR (Yassir and Zerwer, 1997; Heidbach et al., 2016).

1.4.1.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The vertical stress and overburden gradient at the top of the upper confining, injection, and lower confining zones were estimated from log data at the offset [redacted] These were calculated by integrating bulk density from surface to the formation depth in half-foot intervals. The average bulk density of the upper confining and injection zones was estimated from the same log. [redacted] Tables 1-4 and 1-5 show the overburden gradient and vertical stress (both in pounds per square inch (psi)) and average bulk densities (in grams per cubic centimeter (g/cm^3)) of the upper confining, injection, and lower confining zones for the two injection well locations.

Table 1-4 – Calculated Vertical Stresses for Cronos No. 1

Formation	Depth (ft)	Avg Bulk Density (g/cm^3)	Avg Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Amph B	[redacted]				
Lower Miocene					
Siph Dav					

Table 1-5 – Calculated Vertical Stresses for Rhea No. 1

Formation	Depth (ft)	Avg Bulk Density (g/cm^3)	Avg Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Amph B	[redacted]				
Lower Miocene					
Siph Dav					

1.4.2 Elastic Moduli and Fracture Gradient

Elastic moduli, including inputs for Eaton's equation, will be determined from laboratory analysis of core samples and log data where applicable. Core samples and log data for this project location are not available at this time and will be recovered during the drilling of the stratigraphic test well(s); the results of mechanical tests will be included in future permit updates. The core samples will undergo triaxial compressive strength testing to provide the geomechanical properties listed in Tables 1-6 and 1-7.

Table 1-6 – Triaxial Compressive Strength Test Results for Cronos No. 1

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
N/A[(a)]	N/A[(a)]	Upper Confining	Amph B	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Injection	Lower Miocene	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Lower Confining	Siph Dav	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]

(a) Results are pending the retrieval and lab testing of cores, which will occur when the stratigraphic test well(s) are drilled.

Table 1-7 – Triaxial Compressive Strength Test Results for Rhea No. 1

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
N/A[(a)]	N/A[(a)]	Upper Confining	Amph B	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Injection	Lower Miocene	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Lower Confining	Siph Dav	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]

(a) Results are pending the retrieval and lab testing of cores, which will occur when the stratigraphic test well(s) are drilled.

1.4.2.1 Fracture Gradient Calculations

The fracture pressure gradient was estimated using Eaton's equation, a method created for Gulf Coast sands to determine the fracture pressure of the rock. Eaton's equation is commonly accepted as the standard practice for the estimation of fracture gradients (Eaton, 1969). The calculation requires Poisson's ratio (v), overburden gradient (OBG), and pore gradient (PG) to determine the required pressure to fracture the injection zone. These variables can be changed to match the site-specific injection zone. The inputs and resulting fracture pressure gradients for the two proposed injection wells are shown in Tables 1-8 and 1-9 (page 49) for the upper and lower confining zones and injection zone, respectively.

The inputs for Eaton's equation were defined through a review of log data, available literature, and industry standards. The overburden gradients calculated from log data for each zone as was listed in Tables 1-4 and 1-5 (page 43) were utilized. Pore pressure for each zone was estimated from log data at [redacted] A total dissolved solids (TDS) curve was prepared using resistivity data. The TDS values were used to calculate fluid density and pore pressure in half-foot intervals. The resulting pore pressure vs. depth curve is provided in Figure 1-28. This pore pressure result should be considered an adequate representation of pore pressures encountered within the injection and confining zones within the region.

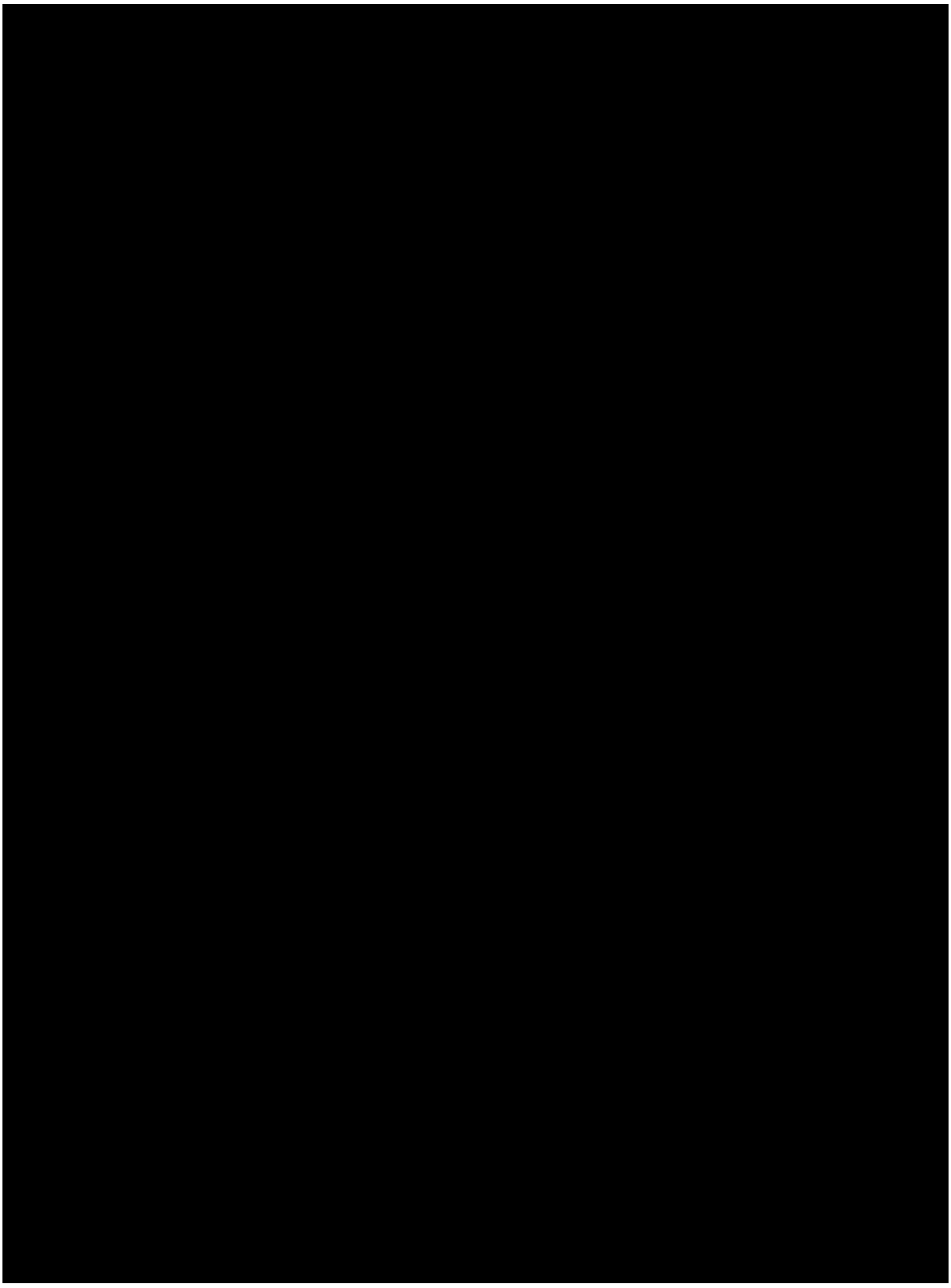


Figure 1-28 – Plot of pore pressure gradient vs. depth calculated from log data at the offset well [redacted]

The Poisson's ratio for the injection zone [redacted]. This well location is shown relative to the Titan Project location in Figure 1-29. The core was retrieved from the Lower Miocene and provided the best available estimate for the Poisson's ratio of the injection zone at the project location. The Poisson's ratio for the upper and lower confining zones was estimated based on a review of published literature. The confining zones consist of clay-rich shales overlying and underlying the injection zone. These shales have a typical range of a Poisson's ratio of 0.28–0.43 (Molina, Vilarrasa, and Zeidouni, 2016). A [redacted]

Figure 1-29 – Map depicting [redacted] core data in relation to the proposed Titan injection wells.

Using these values in Equation 1, a fracture gradient of [redacted] psi/ft was calculated for the injection zone at both injection locations. This gradient was selected to calculate the maximum allowable bottomhole pressure, because it is slightly lower than the fracture gradients of the upper and lower confining zones. A 10% safety factor, as required in 16 TAC 29-N-6 **§5.206(d)(2)(C)** [40 CFR **§146.88(a)**], was then applied to this number—resulting in a maximum allowable bottomhole pressure of [redacted] psi/ft. This safety factor was applied to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

(Eq. 1)

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

[redacted]

Table 1-8 – Fracture Gradients Calculated for Cronos No. 1

Depth (ft)	Zone	Member	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
[redacted]						

Table 1-9 – Fracture Gradients Calculated for Rhea No. 1

Depth (ft)	Zone	Member	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
[redacted]						

1.4.3 Geopressure

As indicated by the pore pressure gradient in Tables 1-8 and 1-9, pressures expected to be encountered within the injection zone will not reflect a geopressured reservoir. Figure 1-30 illustrates a contour map showing the depth of the first occurrence of a pressure gradient of 0.6 psi/ft. According to the map published by the USGS, a pore pressure gradient of 0.6 psi/ft should be anticipated at approximately [redacted] ft. This gradient corroborates with offset well log analysis identifying geopressure characteristics from openhole logs within the [redacted] as shown in Figure 1-31 (page 52).

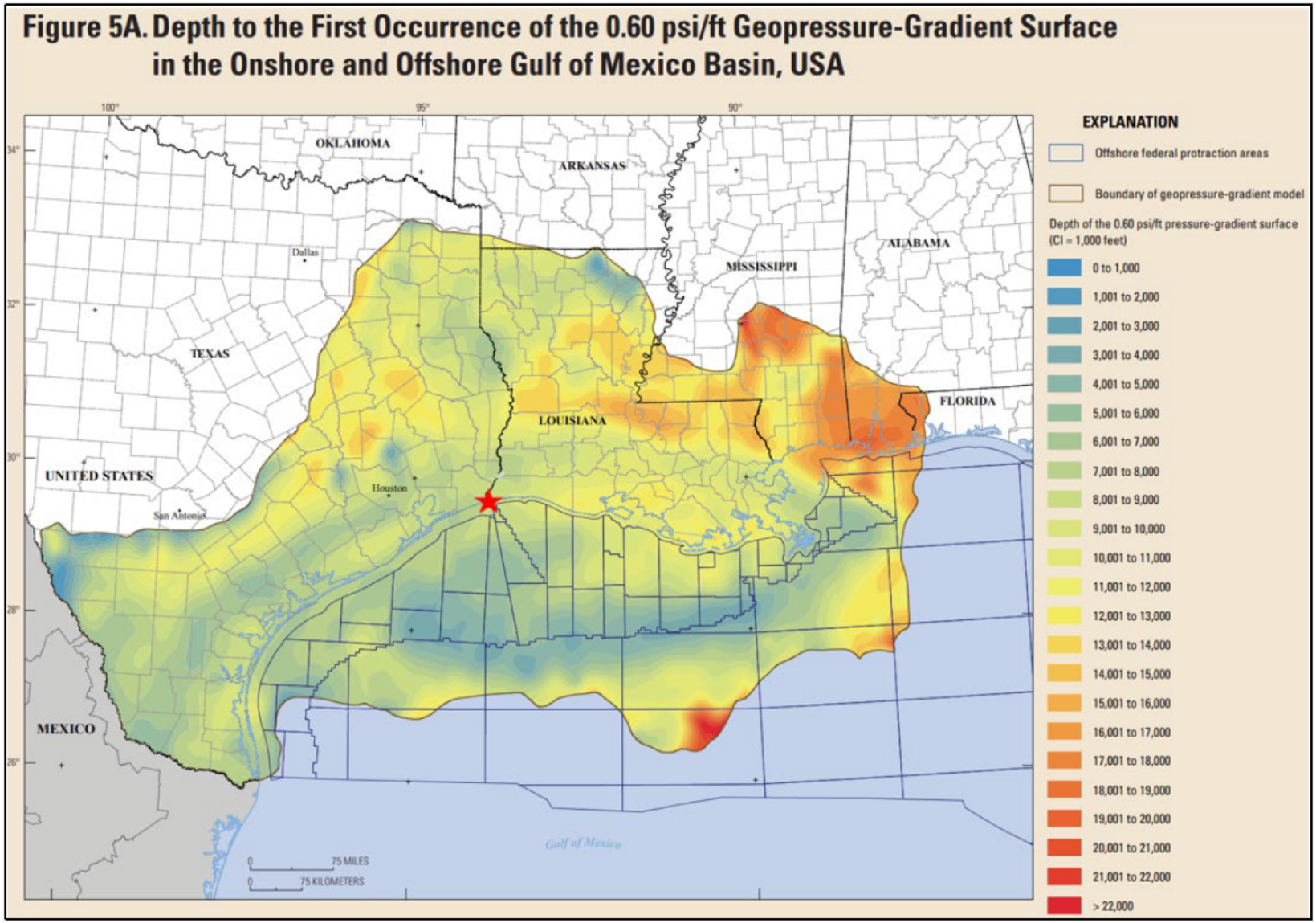


Figure 1-30 – USGS contour map of the first occurence of 0.6 psi/ft pressure gradient (Burke, Kinney, Dubiel, & Pitman, 2013).

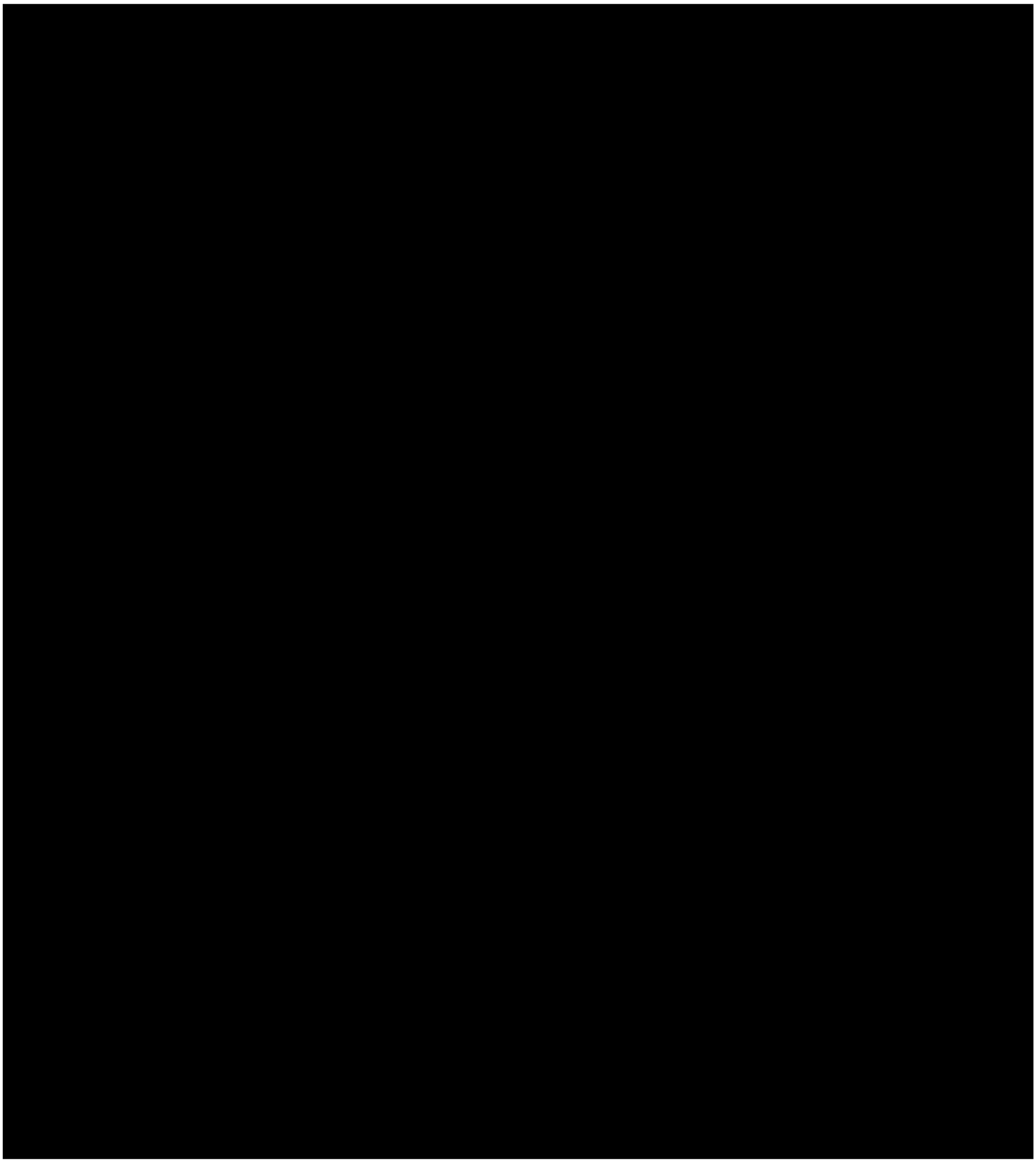


Figure 1-31 – Openhole log of [redacted]

1.5. Porosity and Permeability

The distributions of porosity and permeability within the Lower Miocene at the Titan Project locations are significantly influenced by both deposition and post-burial events. Deposition of sands and silts sourced from the Calcasieu delta system created an environment characterized by interbedded sands and shales. In line with the findings discussed in *Section 1.3.1*, XRD analysis has shown elevated concentrations of quartz with minimal calcite cementation, prohibiting permeability and porosity destruction through calcite cementation, and creating ideal conditions for porosity and permeability development within the injection sands. As a result, it is expected that the injection sands within this interval will remain unconsolidated and exhibit higher vertical-to-horizontal permeability ratios.

These ratios are closely linked to effective porosity, largely influenced by the presence of clays and shales within the injection zone, which serve as barriers. Based on literature, Gulf Coast unconsolidated sandstone formations can exhibit Kv/Kh ratios up to 0.9 (Hovorka et al., 2003). Within the dynamic model, the selection of [redacted] for the Kv/Kh ratio represents a standard upscaled value when extrapolating to the larger model grid block scale for high vertical permeability intervals (Weber and van Geuns, 1990). (This approach is discussed in more detail in *Section 2.5.2.1*, on porosity/permeability.) Common porosity trends within Gulf Coast sands show slightly decreasing porosities with depth but, overall, still have good porosity for injection. This trend is due to compaction defined as decreased intergranular pore space resulting from greater mechanical compaction. This trend is graphically depicted in Figure 1-31 illustrating the decline in porosity with depth. Data retained from the coring and logging operations within the stratigraphic test well and injection wells will be implemented into the current interpretations to enhance accuracy.

Porosity and permeability estimates for both the reservoir and confining zones were determined by conducting a petrophysical analysis using offset openhole logs and core data. During the drilling of the stratigraphic test well and injection wells, supplemental physical data on porosity, permeability, capillary entry pressure, and other reservoir characteristics will be acquired and analyzed. This information will enhance understanding and modeling of the containment and injectability aspects of the reservoir at the proposed injection site. The nearest well to the proposed storage site that provided density/neutron porosity log data for the intended injection zone corresponds to the [redacted] The following procedure was applied to this specific well to establish a correlation between lithology-indication logs and effective porosity. Effective porosity serves as a measure of the interconnected or intergranular void space within a rock, which offers a more accurate representation of the available pore space for fluid mobility as compared to total porosity. Total porosity encompasses intragranular pore space, which may not be directly linked to the overall pore network.

Quality assurance (QA) was conducted to verify the use of accurate data for subsequent calculations. An evaluation was carried out to compare digital or LAS log data with a corresponding raster log. Digital curves were adjusted as needed to maintain consistency with the original raster log data, as illustrated in Figure 1-32. Furthermore, a trend line was

established to interpret the variation of SP with depth, and during this analysis, baseline shifts in SP were detected, as depicted in Figure 1-33.

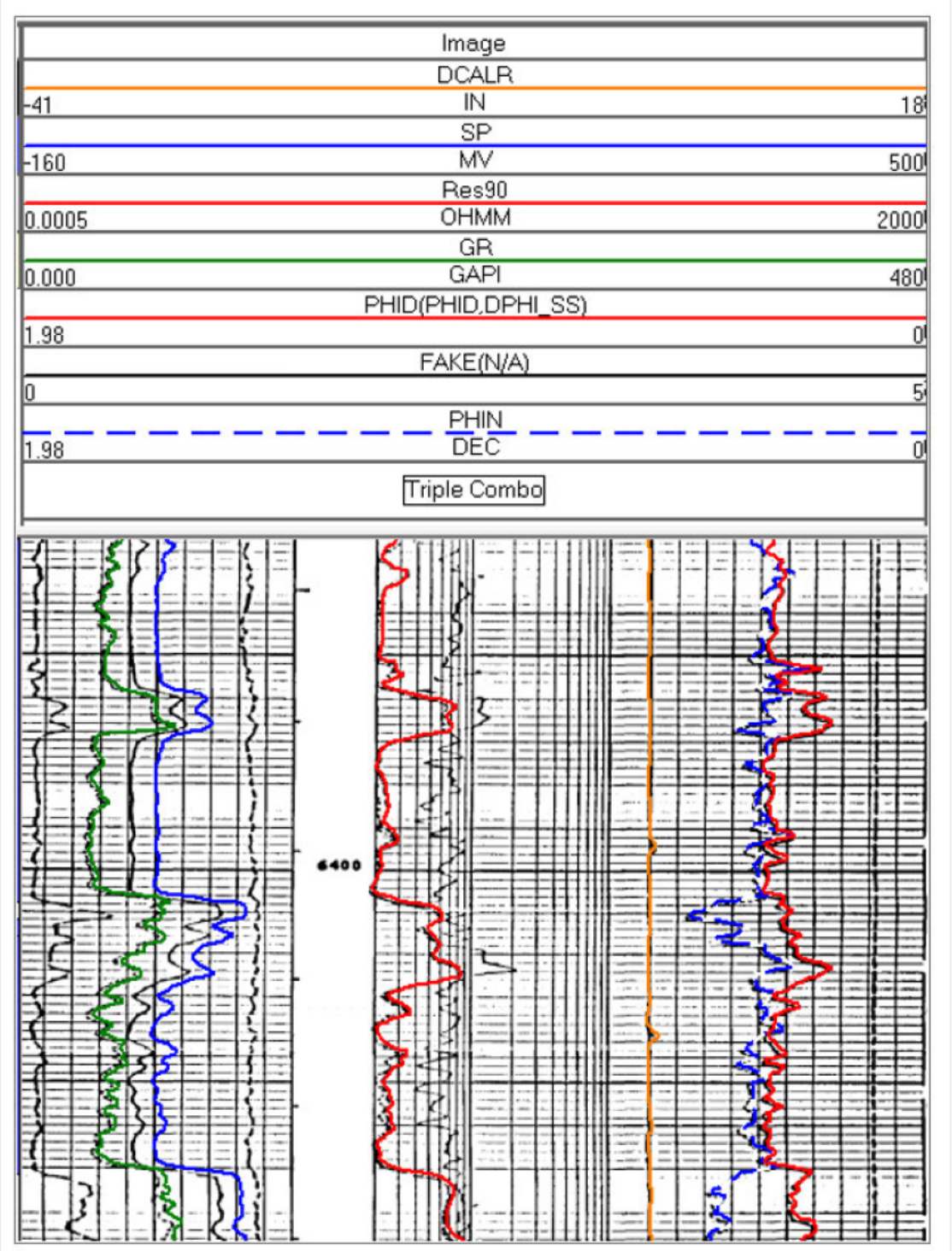


Figure 1-32 – Log depicting example QA process to ensure digital data resembles raster data.

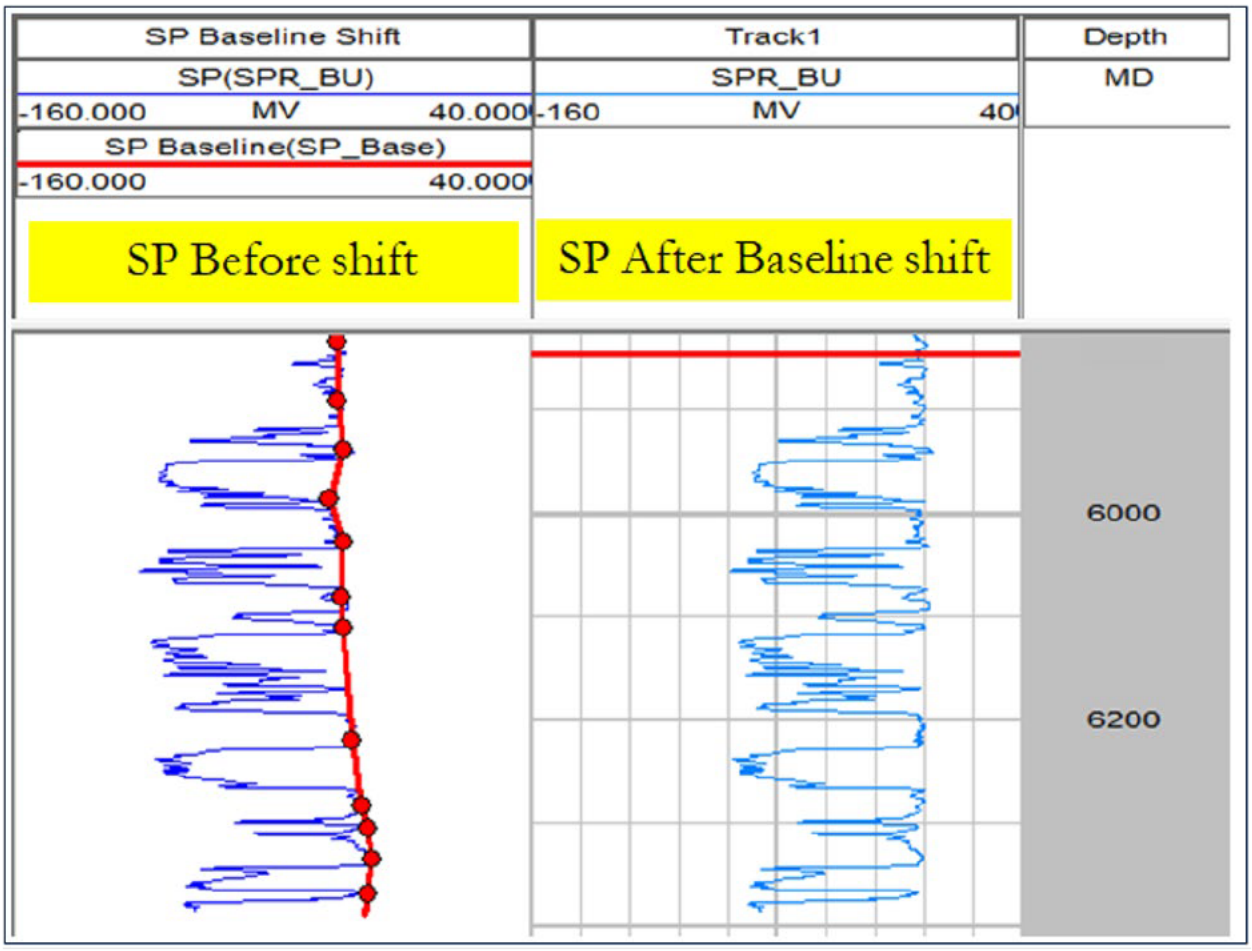


Figure 1-33 – Example of SP Baseline Shift Over Depth

After the spontaneous potential curves were corrected, Vshale was computed from the SP logs, using Equation 2.

(Eq. 2) $$Vshale = \frac{(SP - SPsand)}{(SPshale - SPsand)}$$

Where:
SP = spontaneous potential
$SPsand$ = spontaneous potential reading of a sand
$SPshale$ = spontaneous potential reading of a shale

Estimated effective porosity (PHIEST, Φ_{eff}) was calculated using the Vshale log and PHIMEAN, using Equation 3.

(Eq. 3) $$\emptyset_{eff} = \emptyset_{mean} * (1 - Vshale)$$

Where:
$\emptyset_{eff}$ = effective porosity
$\emptyset_{mean}$ = mean porosity

The PHIEST curve was compared to the PHIE derived from actual density porosity logs for validation. Figure 1-34 illustrates the strong correlation between the computed and measured curves. The PHIEST curve was then used in adjacent wells with SP log data to generate the most accurate estimates of effective porosities within the Miocene intervals.

Since Φ_{eff} reflects the degree of interconnected pore space, a correlation can be established between porosity and permeability. Sidewall core reports were obtained and analyzed from an offset operator for [redacted], located approximately [redacted] of the Titan Project. Table 1-10 lists the core points along with their corresponding reservoir values. A correlation was established between porosity and the corresponding permeabilities based on the core data presented in Figure 1-35 (page 59). These cores were collected from diverse lithologic intervals, offering a comprehensive representation of the likely permeability ranges encountered within the injection and confining zones. This variability is shown in Figure 1-36 through an openhole log with the core points depicted. The gamma ray (GR) and SP curves in Track 1 aid in identifying the lithology of the cored interval. Higher GR and SP readings (lines trending to the right side of the track) indicate shale, while the opposite trend suggests sand. As indicated in the image, the cores were taken within the *Marg Asc* maximum flooding surface and sand deposit that followed thereafter. This variability enabled the development of a single equation to represent a reliable relationship between porosity and permeability. Equation 4 was used to determine permeability as follows:

(Eq. 4) $$K(mD) = $$ [redacted]

These equations were applied to [redacted] offset wells near the proposed injection site and used to develop porosity and permeability distributions within the model. Figure 1-37 shows the location of the offset wells utilized for the porosity and permeability evaluation.

Figure 1-34 – Comparison between calculated effective porosity (PHIE) and estimated effective porosity (PHIEST), from the [redacted]

Table 1-10 – Core Data Values, [redacted]

Depth (ft)	Permeability (md)	Porosity	Oil Saturation	Water Saturation
[redacted]				

Figure 1-35 – Porosity vs. Permeability Scatterplot of Sidewall Core from [redacted]

Figure 1-36 – Openhole log display of [redacted] depicting the variabiliy of the core points within the section.

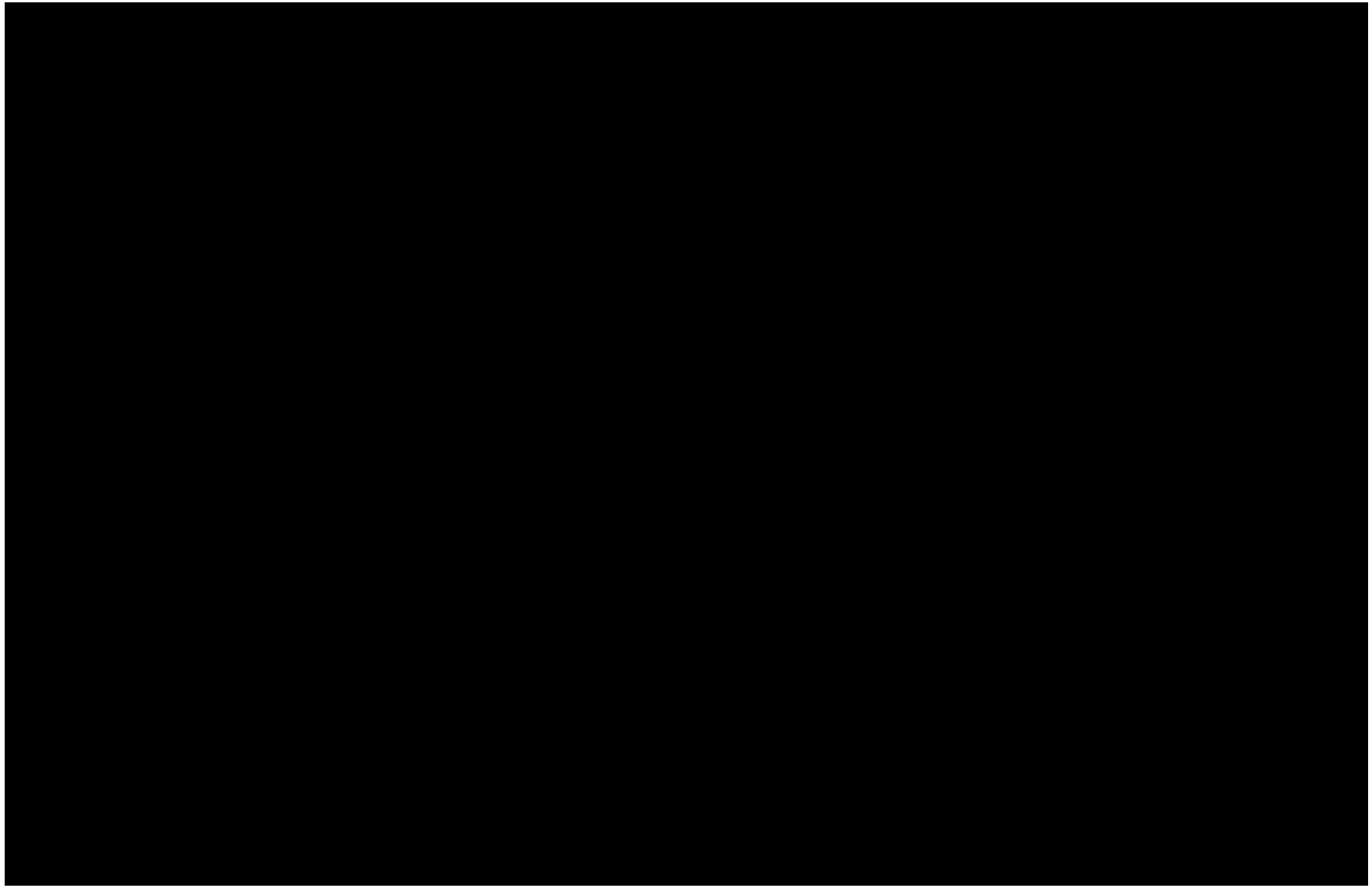


Figure 1-37 – Porosity Modeling Wells

1.5.1 Upper Confining Zone

The Amph B maximum flooding surface contains high clay content due to the depositional features described in *Section 1.3.2*. Figure 1-38 is an openhole log image of the [redacted], with PHIE representing effective porosity and K_Core representing permeability. As displayed in the openhole log, the Amph B contains thin sand members with little porosity and permeability development within the center of the formation. These sands will not impact the sealing capabilities of the clays above and below them. The clay-rich shales in the Amph B contain isolated pores that cannot create effective pore networks, rendering them "sufficient" for CO_2 sequestration (Meckel & Trevino, 2014). Distributions of the porosity and permeabilities within the geocellular model that reflect these shale facies are depicted in Figures 1-39 and 1-40 (pages 64 and 65, respectively).

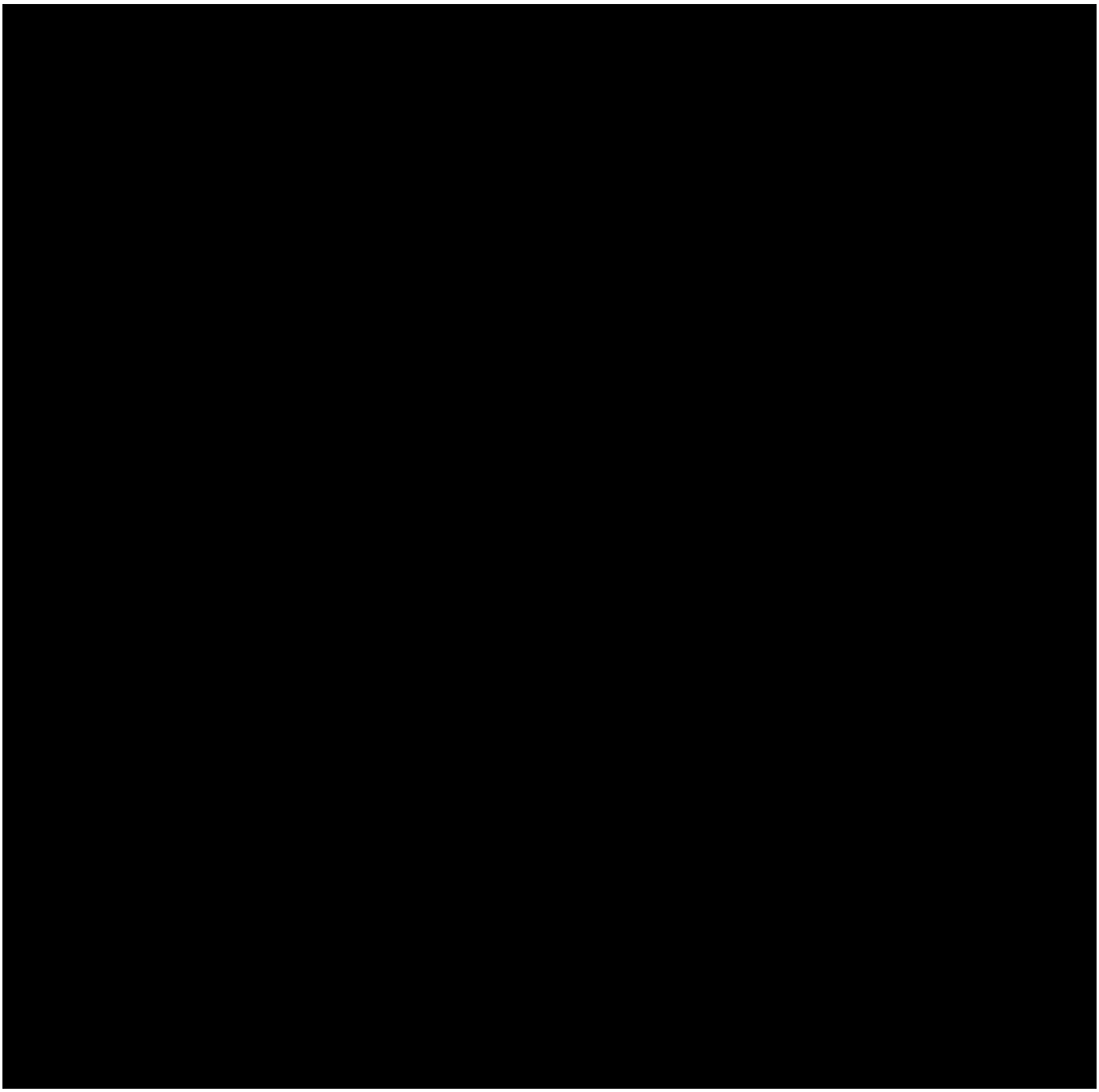


Figure 1-38 – Openhole log of offset well [redacted] depicting the upper confining zone. Effective porosity is displayed in green and permeability in red.

1.5.1.1 Upper Confining Zone Porosity

Within the shale facies in the upper confining zone, the average effective porosity is [redacted] Figure 1-39 presents the histogram displaying these distributions. With such an ample amount of net low-porosity facies within the upper confining zone, transmissibility through this confining unit is unlikely.

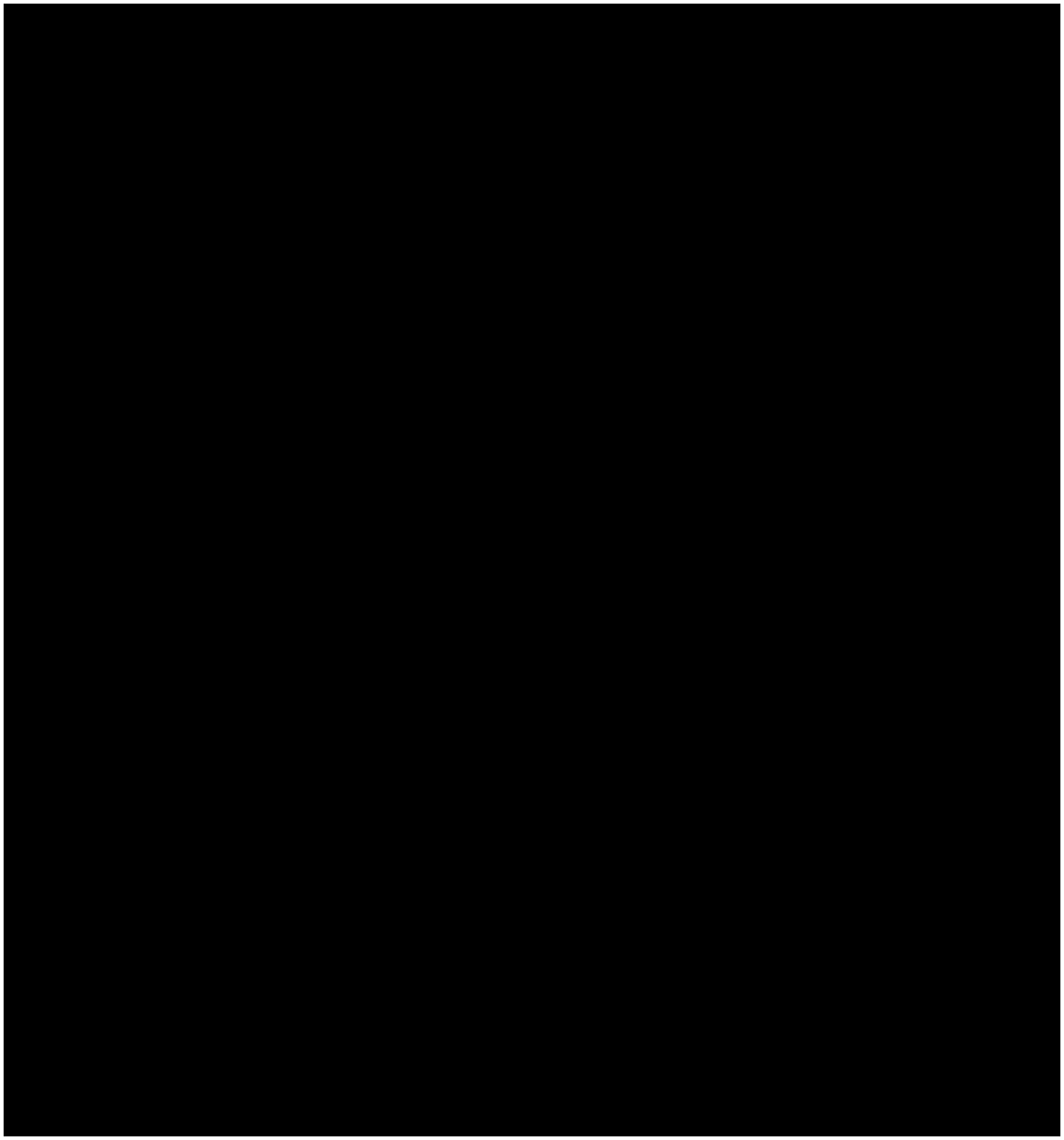


Figure 1-39 – Histogram of Porosity Distributions Within the Upper Confining Zone

1.5.1.2 Upper Confining Zone Permeability

Within the shale facies in the upper confining zone, the average horizontal permeability is [redacted] mD. Figure 1-40 presents the histogram displaying these distributions. Because of the very low horizontal and vertical permeabilities, transmissibility through this confining unit is unlikely.

Figure 1-40 – Histogram of Permeability Distributions Within the Upper Confining Zone

1.5.2 Injection Zone

The proposed Titan Project site will target the Lower Miocene formations as its injection zone. The distribution of permeability and porosity within this interval is notably influenced by the absence of calcite cementation and the prevalence of quartz, as evidenced in the core analysis detailed in *Section 1.3.1*. Figure 1-41 displays an openhole log of the [redacted] where PHIE represents effective porosity and K_Core represents permeability.

Within this injection zone, the target compartments for injection are the deltaic/shallow marine sands characterized by higher effective porosities and permeabilities. These sands are separated by interbedded shales that serve as compartmental seals. Figure 1-40 illustrates these injection compartments, with the sand intervals displaying noticeably higher porosity and permeability compared to the shale intervals. The subsequent sections provide descriptions of porosity and permeability distributions within the sand facies determined in the model.

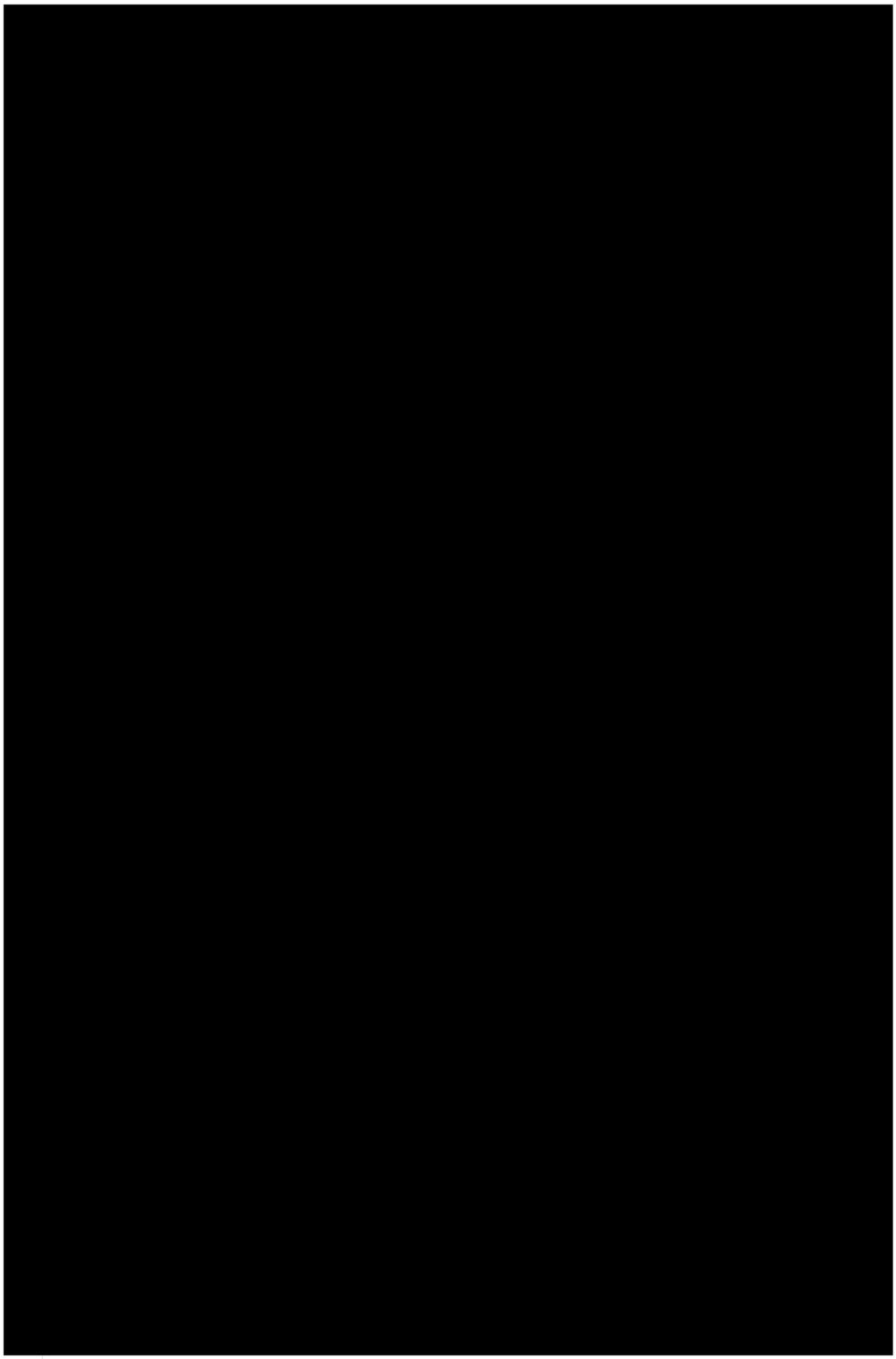


Figure 1-41 – Openhole log of [redacted] depicting the injection zone. Effective porosity is displayed in green and permeability in red.

1.5.2.1 Injection Zone Porosity

In the sand facies of the injection zone, the average effective porosity is [redacted] Figure 1-42 provides the histogram that illustrates these porosity distributions within the geocellular model. As mentioned in Section 1.5, porosity trends within the Miocene sands exhibit a decrease with depth, primarily due to compaction, which is evident in Figure 1-42. An isopach map, displaying porosity values [redacted] has been generated for the injection zone and is included in *Appendix B-12*. That map shows approximately [redacted] ft of net sand with porosities exceeding 12% at the proposed location.

Figure 1-42 – Histogram of Porosity Distributions Within the Injection Zone

1.5.2.2 Injection Zone Permeability

In the sand facies of the injection zone, the average permeability is [redacted] mD. Figure 1-43 provides histograms illustrating these permeability distributions within the geocellular model. Notably, because permeability is closely linked to porosity, the same trends observed in porosity distributions apply to permeability.

The vertical-to-horizontal (Kv/Kh) permeability ratios are expected to increase with higher porosity and permeability values due to the lack of cementation, which would drive unconsolidated sands within the injection zone.

Figure 1-43 – Histogram of Permeability Distributions Within the Injection Zone

1.5.3 Lower Confining Zone

The Siph Dav represents a widespread regional maximum flooding surface from the early Lower Miocene era. This flooding surface led to the deposition of a regional layer consisting of clay and mudstone. Offset core analysis from High Island revealed the prevalence of high calcite concentrations, which functioned as cements. This presence of calcite cementation is anticipated to significantly diminish the porosity and permeability of the samples, as highlighted by Meckel and Trevino (2014). (Additional information regarding the depositional environment was provided in *Section 1.3.3*.) Figure 1-44 is an openhole log image of [redacted] with PHIE representing effective porosity and K_Core representing permeability. As evident from the log, there is minimal-to-no sand formation within the Siph Dav, making it an excellent choice as a consistently thick and extensive lateral seal. The distributions of these predominantly shale facies within the Siph Dav in the geocellular model are presented in Figure 1-44.

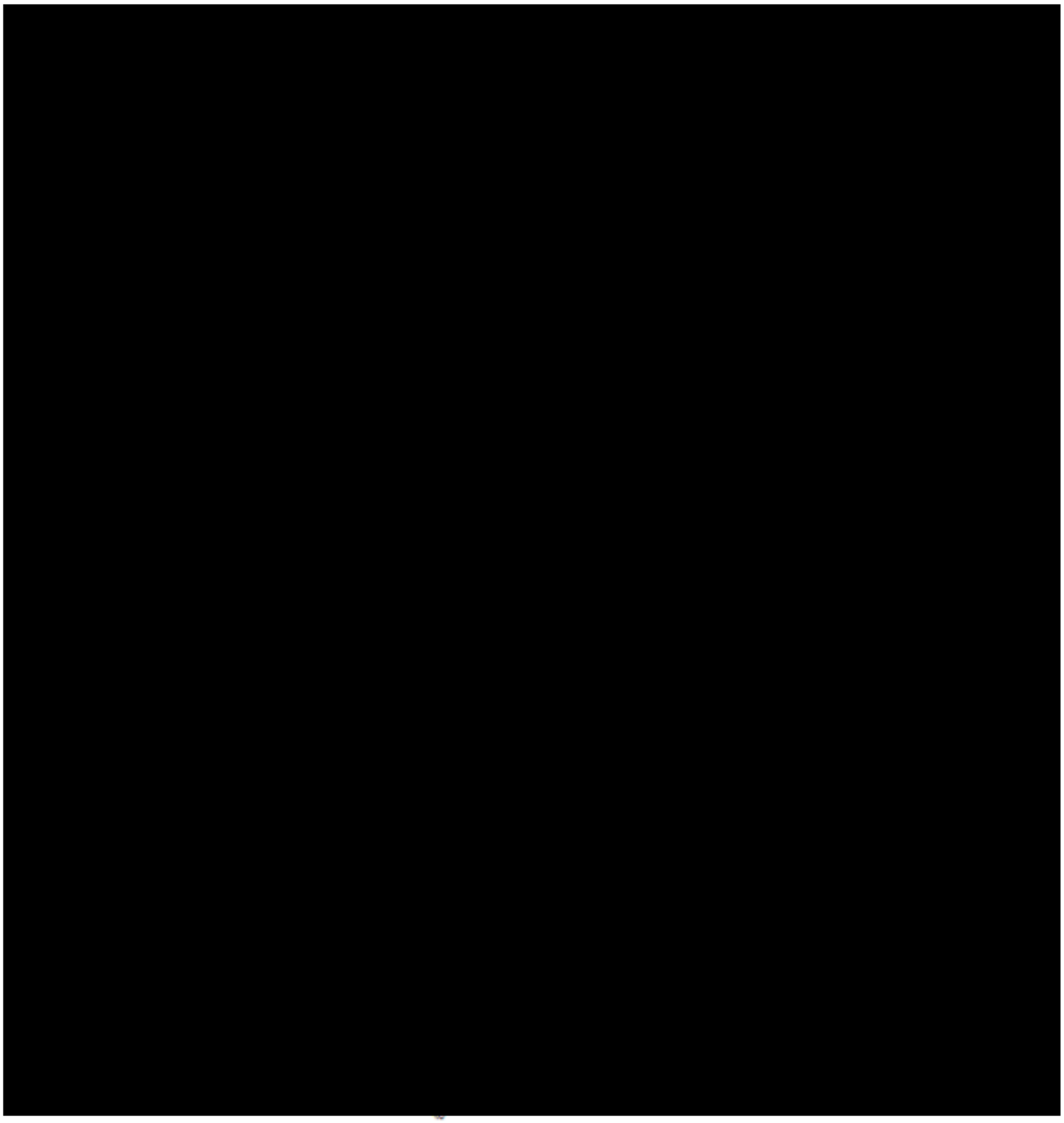


Figure 1-44 – Openhole log of [redacted] depicting the lower confining zone. Effective porosity is displayed in green and permeability in red.

1.5.3.1 Lower Confining Zone Porosity

Within the shale facies in the lower confining zone, the average effective porosity is [redacted]. Figure 1-45 presents the histogram displaying these distributions within the geocelluar model.

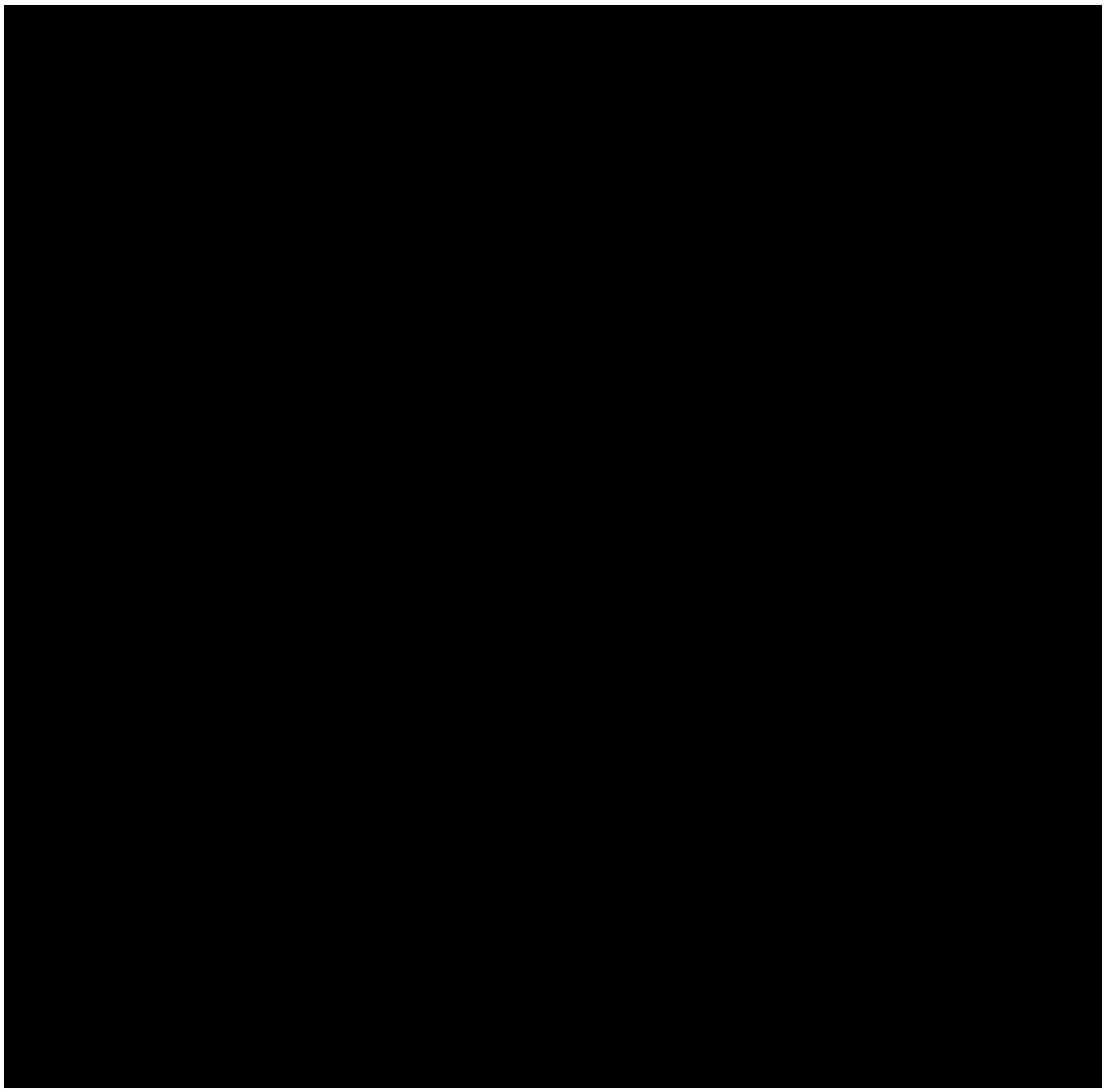


Figure 1-45 – Histogram of Porosity Distributions Within the Lower Confining Zone

1.5.3.2 Lower Confining Zone Permeability

Within the shale facies in the lower confining zone, the average permeability is [redacted] mD. Figure 1-46 presents the histograms displaying these distributions within the geocelluar model. These findings indicate an ideal lower confining zone that will effectively serve as a lower seal for the proposed injection site.

Figure 1-46 – Histogram of Permeability Distributions Within the Lower Confining Zone

1.6. Injection Zone Water Chemistry

1.6.1 Injection Zone Water Chemistry

To help determine the water chemistry within the injection zone, publicly available data from the USGS National Produced Waters Geochemical Database was accessed along with openhole log analysis. The database was filtered to fluid samples from Miocene sands, in a geographic window ranging from [redacted] This data was tabulated and plotted to examine the relationship between TDS and depth. Figure 1-47 depicts this relationship, with the red dashed lines representing the approximate depths of the injection zone. As seen in the graph, the majority of the Miocene samples occur[redacted] mark. A breakdown of the average chemical makeup of the sampled water samples is provided in Table 1-11.

Figure 1-47 – Depth vs. TDS graph of collected water samples from the USGS. The red dashed lines indicate the approximate injection zone.

Table 1-11 – Formation Brine Chemstry

Species	Concentration	Units
TDS		mg/L
Sp. Grav		g/cm^3
Ca		mg/L
Fe		mg/L
Mg		mg/L
Mn		mg/L
K		mg/L
Na		mg/L
SiO_2		mg/L
Cl		mg/L
HCO_3		mg/L
SO_4		mg/L

Furthermore, a thorough analysis of openhole logging was conducted for the [redacted]. This involved determining the apparent water resistivity (Rwa) by utilizing deep resistivity and porosity logs. Equation 5 provides an illustrative example of this calculation.

(Eq. 5) $$Rwa = Deep\ Resistivity * Porosity^2$$

Following the calculation of Rwa, the Schlumberger General 9 chart equation (as illustrated in Figure 1-48) was used to transform Rwa into TDS. Figure 1-49 presents the results of this calculation, demonstrating an average TDS value of roughly [redacted] milligrams per liter (mg/L) within clean sands (Vshale < 10%). Additionally, the log analysis showcases an example of an Rwa value at [redacted], which is depicted on the Schlumberger General 9 chart, indicating an estimated salinity of [redacted] TDS under those specific conditions. With that TDS value being a single data point within the log, the average of [redacted] mg/L was selected as the best fit to use in the plume modeling. There is a notable level of uncertainty when estimating the composition of the connate fluid. This will be verified with physical samples from the formations when drilled and cored.

[redacted] Water samples from the injection zone will be collected during the drilling operations of the proposed injection wells. Comprehensive water analyses will be conducted to establish the baseline reservoir fluid conditions. Once this data set is acquired, the models will be revised accordingly.

Additional data from water samples and analysis from the drilling process of the stratigraphic test well and injection wells will, once collected, be utilized in the model.

Figure 1-48 – Schlumberger General 9 chart with red lines representing [redacted]

Figure 1-49 – Example of log analysis performed on [redacted] to estimate TDS.

1.7. Geochemistry

The mineral-brine-CO_2 interactions that occur during CO_2 sequestration lead to the alteration of the host rock, and eventual equilibrium in the mineral-brine-CO_2 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 CO_2-brine mixture, and pressure and temperature in the subsurface. This section covers the modeling of the mineral-brine-CO_2 system across the mineralogical facies associations present for the subject site.

1.7.1 Methods

Simplified, batch kinetic simulations (i.e., models) were created for each facies present at the subject location. The models are built to simulate the reactions that occur in the mineral-brine-CO_2 system contained inside a laboratory reactor vessel as a proxy for the subsurface system. 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-CO_2 interactions. Each experiment is isothermal, with the temperature set to match the subject location and depth. The pressure for each simulation 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 CO_2 is supplied to the system during the simulation and that any consumed molecule of CO_2 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 comes from the USGS National Produced Waters Geochemical Database. The database contained 37 samples of produced water from the Miocene-age sandstones in the [redacted] oil and gas fields located in Jefferson County, Texas. The average brine composition derived from the USGS database was then adjusted to match the log derived average salinity of [redacted] mg/L. The adjusted analytical value is then used in each mineral batch kinetics model (Table 1-12).

Table 1-12 – Brine composition used in the PHREEQC reaction-path modeling.

Species	Concentration	Units	
TDS	[redacted]	mg/L	
Sp. Grav		g/cm^3	
Ca		mg/L	
Fe		mg/L	

Species	Concentration	Units	
Mg	[redacted]	mg/L	
Mn		mg/L	
K		mg/L	
Na		mg/L	
SiO_2		mg/L	
Cl		mg/L	
HCO_3		mg/L	
SO_4		mg/L	

1.7.3 Mineral Geochemistry

Despite the well understood nature of the stratigraphy in the vicinity of the subject site, published XRD data from core are limited. The mineral compositions used in simulations were generated by averaging 18 sample values from the High Island 24L No. 9 (42-708-30316) into two average values, one for confining zones (shales) and the other for injection zones (sands) (Meckel and Trevino, 2008). The averaged values are in line with other published lithologic descriptions and generalized XRD data along the Gulf Coast published by Hovorka et al. (2003), Loucks et al. (1977), Meckel and Trevino (2014), and McGuire (2009), as well as XRD analyses of silicate rocks from similar depositional environments published in Weaver (1977).

Mineral compositions used in the models are shown in Table 1-13. [redacted]

Table 1-13 – Mineral Compositions Used in the Four-Facies Model

Facies Name	Upper Confining Zone	Top Injection Zone	Base Injection Zone	Lower Confining Zone
Modeled Depth (ft)	[redacted]			
Stratigraphic Interval				
Quartz				
Calcite				
Plag (albite)				
K-spar				
Illite				
Kaolinite				

1.7.4 Models

A total of four geochemical models were created: one each for the upper and lower confining zones and two for the injection zone. [redacted]

The reaction processes expected 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] psi/ft and a thermal gradient of [redacted] with a mean annual surface temperature of 70°F. The injected volume of CO_2 was assumed to fill the pore spaces.

1.7.5 Results

Across each of the models, the results displayed in Figures 1-50 and 1-51 show that [redacted]

During the injection period, the modeled changes of the injection zone mineralogy are relatively minor. [redacted]

A number of necessary assumptions used in this modeling work leads to the models overrepresenting the speed and amount of alteration, compared to what will occur in the natural system. [redacted], geologic and hydrologic factors such as fluid flow paths may alter ion availability and system reactivity.

Figure 1-50 – Results of all constituents for the batch models for each facies. The x-axis is "log10" time in years. The reaction time spans from 0.001 seconds to 10,000 years.

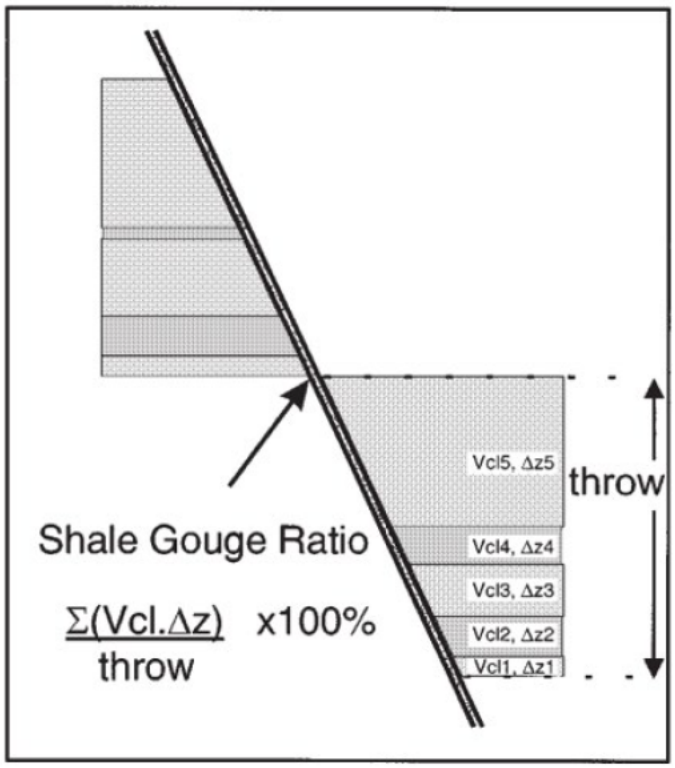
Figure 1-51 – The results of minor constituents for the batch models for each facies. The x-axis is log10 time in years. The reaction time spans from 0.001 seconds to 10,000 years.

1.8. Fault Seal Analysis

The fault seal analysis is conducted to evaluate the sealing capacity of the faults. Within the CCS scope, two scenarios are considered: (1) when the plume reaches a surface-reaching fault; and (2) when only the pressure front reaches a fault. Therefore, only the second scenario—of the pressure front potentially reaching the faults—needs to be addressed.

Figure 1-52 – A 3D image of CO_2 plume (at stabilization) relative to nearby faults, viewed (a) from the northeast and (b) from the top.

To estimate fault sealing capacity, the shale gouge ratio (SGR), fault zone entry capillary pressure (FZP), and fault zone permeability 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 certainly 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 and SGR equation (Yielding et al., 1997) is a widely accepted method used to estimate the amount of clay within the fault gouge, as shown in Figure 1-53. These equations provide calculations for a sequence of reservoir zones where Δz is the thickness of each reservoir zone, and Vcl is the clay volume fraction in the zone (Yielding et al., 1997).



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

Figure 1-53 – Shale Gouge Ratio Conceptual Diagram and Equation (Yielding et al., 1997)

The SGR has been shown to be an effective qualitative predictor for sealing vs. non-sealing faults in hydrocarbon systems. The SGR data from the fault-bounded reservoirs of both sealing and non-sealing faults show that SGR values of approximately 15% to 20% are the typical cutoff for sealing vs. non-sealing faults (e.g., Bretan et al., 2003; Meckel and Trevino, 2014). Therefore,

anything with an SGR value greater than 20% is deemed to be sealant in nature. The SGR values were calculated from the Vshale, derived from available GR or SP logs. These values were conditioned to facies using the sequential Gaussian simulation algorithm while distributed through 3D volume. Figure 1-54 shows the 3D view of the fault planes with SGR values. Figure 1-55 shows histograms of SGR distribution for the confining and injection zones. Generally, it can be concluded that the [redacted]

Figure 1-54 – A 3D display of the shale gouge ratio on the fault planes (calculated for each cell within the faults for confining and injection zones).

Figure 1-55 – Histograms of the SGR distribution for the (a) upper confining, (b) injection, and (c) lower confining zones.

[redacted]

[redacted]

Figure 1-56 – The 3D model layer slices show facies distribution and fault SGR for the (a) upper confining and (b) injection zones. The maximum extent of the injection plumes is shown as a pink outline. The cross-section shown in Figure 1-57 is shown here as a black dashed line.

Figure 1-57 – A 3D model cross-section showing (a) SGR and Vsh distribution, and (b) SGR and facies distribution. The cross-section location was shown as a black dashed line on Figure 1-56.

To identify if the capillary entry pressure of the fault gouge was reached from the influence of the injected CO_2, FZP calculations were then performed. This effect is applicable only for the faults or their parts if the CO_2 plume reaches those faults. The classic SGR equation for hydrocarbon systems (Bretan et al., 2003) to calculate the FZP using SGR and fault rock strength is:

(Eq. 6) $$FZP\ or\ P_C\ (bar) = 10^{\left(\frac{SGR}{27} - C\right)}$$

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

The C values are as follows: C = 0.5 for burials depths less than 9,850 ft; C = 0.25 for burial depths between 9,850 ft and 11,500 ft; C = 0 where burial depths exceed 11,500 ft (Bretan, 2003). However, since the wetting properties of various rock-forming minerals are different for CO_2 and hydrocarbons, this equation needs modification. The most recent work to address this difference was done by Karolyte et al. (2020). As noted by Bretan et al. (2022), proposed modifications lead to FZP reduction of about one-third of the classic FZP results. Therefore, the correction multiplier of 0.667 was applied to the resulting FZP value plus a unit conversion from bar to psi. Figure 1-58 shows calculated threshold FZP values vs. SGR. The FZP threshold increases with SGR increase. 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 at some parts of the fault during the injection, then the fault will lose its sealing properties at those portions.

Figure 1-59 shows the distribution of the FZP values on the fault plane.

Figure 1-58 – Fault Zone Entry Capillary Pressure (FZP) vs. Shale Gouge Ratio (SGR)

Figure 1-59 – Distribution of the FZP Values on the Fault Planes

Another useful estimation based on the SGR calculations is fault permeability (Figures 1-60 and 1-61). Different empirical equations have been proposed and used for permeability estimation. In most cases, as with this project, the input parameters are insufficient for the precise calculations, but the global equation of Jolley et al. (2007), which has been applied here, may provide some general insights on the fault permeability:

(Eq. 7) $$k_f = 4 \times 10^{-5} \times SGR^{-3.47}$$

Where:
k_f = fault permeability, mD
SGR = shale gouge ratio, %

Figure 1-60 – Fault Zones Permeability vs. SGR

Figure 1-61 – Distribution of the fault zone predicted permeability values on the fault planes.

Figure 1-62 shows histograms of permeability distribution for the confining and injection zones. These histograms show that the planes of the fault zones are mostly characterized by low permeabilities. For example, per corresponding histograms, abou

Figure 1-62 – Histograms of the fault permeability distribution for the (a) 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. Additionally, this analysis includes a permeable-impermeable rocks juxtaposition captured in the geostatic model and typically accounted for at the dynamic modeling stage. Three parameters provided by the fault seal analysis are SGR, FZP, and fault permeability at the present/static conditions. These calculated parameters indicate that, [redacted] These parameters define the fault behavior under present conditions and, along with FZP, set thresholds for the fault behavior under changing dynamic conditions.

[redacted]

[redacted]

1.9. Hydrology

Located in the southeastern area of Texas, Jefferson County encompasses an area of more than 1,100 sq mi. The cities of Beaumont and Port Arthur are the two primary population centers in the county, nearly a quarter of which is covered in water. This section discusses water resources and hydrology within the county. The USGS and other entities have written detailed reports, dissertations, and literature from peer-reviewed journals within this area of study.

1.9.1 Area of Study

Groundwater resources are nearly nonexistent in the area except for the Chicot aquifer. The Chicot is the shallowest aquifer of the major Gulf Coast aquifers and only provides fresh or treatable water at shallow depths along the Jefferson County coastline. The Titan Project area falls within this region of limited groundwater resources as shown in Figure 1-63.

Surface water resources include Sabine Lake, also known as the Sabine Estuary, and numerous smaller lakes. The Neches River and basin are also present and contain many tributaries and bayous that also provide inflow to the river.

Figure 1-63 – Image of Gulf Coast Aquifer in Texas with the red star representing the proposed injection site (Brunn, Jackson, Peter, & Walker, 2016).

1.9.2 Groundwater Resources

1.9.2.1 Major Aquifer – Gulf Coast Aquifer

The Gulf Coast aquifer is located along the entirety of the coastline from western Louisiana to northern Mexico and is comprised of multiple aquifers, to include the Jasper, Evangeline, and Chicot. A confining unit known as the Burkeville is found between the Evangeline and Jasper aquifers.

A regional cross section depicting those four different sedimentary units is displayed in Figure 1-64. More than 50 Texas counties are supplied with fresh water from this regional resource. The primary uses of the aquifer are for municipal, industrial, and irrigation districts. The Houston area is provided with a yield of approximately 1,600 gallons per minute (gpm). The quality of the water differs from region to region but tends to be better in the northeastern section, which includes Jefferson County. Total dissolved solids are nominally no higher than 500 mg/L, but saltwater intrusions have been noted in the area. The thickness of the aquifer can be as much as 1,300 ft, with the average freshwater thickness nearing 1,000 ft.

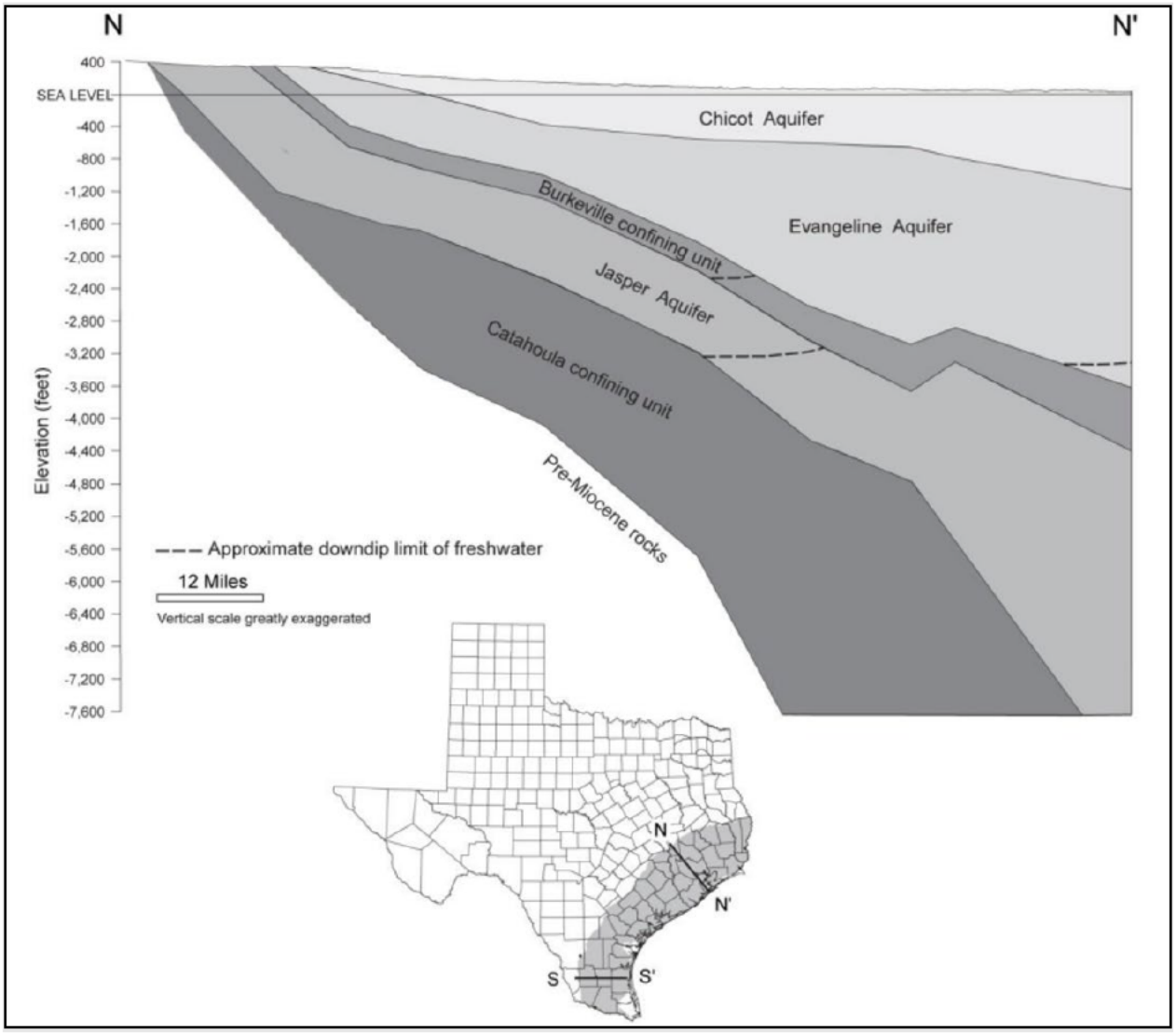


Figure 1-64 – Regional Cross Section of the Gulf Coast Aquifer in Texas (Brunn, Jackson, Peter, & Walker, 2016)

1.9.2.2 Chicot Aquifer

The Chicot aquifer is the shallowest underground water source of the major Gulf Coast aquifer system and is made of Quaternary-age sediments. The Chicot, which contains a larger abundance of sand than clay, has a thickness of nearly 1,200 ft at the coastline. Though the aquifer only bears consumable fresh water at very shallow depths, the Chicot is still present. It has been heavily pumped, providing water sources for irrigation, municipal supply, and industrial uses to the northern parts of the target area. The city of Houston has the most built-up development, with large-scale wells capable of yielding thousands of gallons per minute rates. Other cities near the Titan Project have also developed infrastructure to support their residential, commercial, and agricultural communities. Figure 1-65 is a map depicting the outcrop areas of the Jasper,

Evangeline, and Chicot aquifers, along with the Burkeville confining unit. A list of water wells discovered in the area is provided in *Appendix C-4*, with most reaching total depths no greater than 20 ft. One well (6317504) tested water from a depth of 119 ft but is listed as "plugged or destroyed" and is no longer producing water from these depths.

Figure 1-65 – Gulf Coast outcroppings of the Jasper, Evangeline, and Chicot aquifers in Jefferson County, with the red star representing the injection site (Kasmarek, 2004).

1.9.3 Surface Water Resources

1.9.3.1 Neches River

The Neches River flows from north to south through Jefferson County into the Sabine Lake, next to the city of Port Arthur, Texas. The last 40 mi of the river are considered industrialized. Kept at a deep draft so that deepwater vessels can navigate it, the river is approximately 40 ft deep and 400 ft wide—and planned to be deepened by another 8 feet. The Lower Neches Valley Authority provides most of the fresh water to Port Arthur and its surrounding areas. The valley authority also oversees the Neches River in multiple counties to include Jefferson County. "Freshwater inflow contributions to the Sabine-Neches estuary consist of (1) gauged inflow from the Sabine and Neches River Basins; (2) ungauged runoff; (3) return flows from municipal, industrial, and agricultural sources in ungauged areas; and (4) direct precipitation on the estuary" (Texas Department of Water Resources, 1981). Once near the coastline, the river becomes more saline until it empties into the primarily saltwater Sabine Lake or Sabine Estuary.

1.9.3.2 Sabine Lake

Sabine Lake covers approximately 90,000 acres and is considered a saltwater estuary and bay. The lake borders both Texas and Louisiana with Port Arthur situated next to it. The lake was created by the joining of two separate rivers—the Sabine and the Neches—which provide most of the fresh water, around 85%, in the lake. Near the area are several smaller lakes, such as Johnson Lake and Keith Lake to the north, and Salt Lake to the west of the target area.

1.9.4 Hydrology Conclusion

[redacted]n, as illustrated in Figure 1-66. [redacted] The water wells in this area are generally shallow, with most having depths of less than 50 ft—except for well [redacted] Consequently, an estimated depth for the USDWs, in alignment with the estimated USDW depths provided by the BEG, is approximately [redacted] ft, to safeguard all water sources located at or near the surface.

Figure 1-66 – Map of water-level changes within the Gulf Coast aquifer, depicting the injection site (indicated by the red star) falling within the "Unconfined (outcrop)" area (Brunn, Jackson, Peter, & Walker, 2016).

1.10. Evaluation of Mineral Resources

1.10.1 Active Mines Near the Proposed Injection Location

A public data search determined that no active surface mines are near the proposed site of the Titan Project; therefore, no surface mineral impacts will occur from project activities.

1.10.2 Oil and Gas Resources

Exploration activity in far southeast Texas began in the mid-1950s and 1960s. Much of the drilling activity focused around the salt domes found along the Gulf Coast. These domes, plus additional faulting in the area, created structural traps for hydrocarbons. However, the Titan Project is in an area where fewer hydrocarbons have successfully been recovered, as no structural trap exists across the area. [redacted] Within the AOR, no wells were drilled.

[redacted]

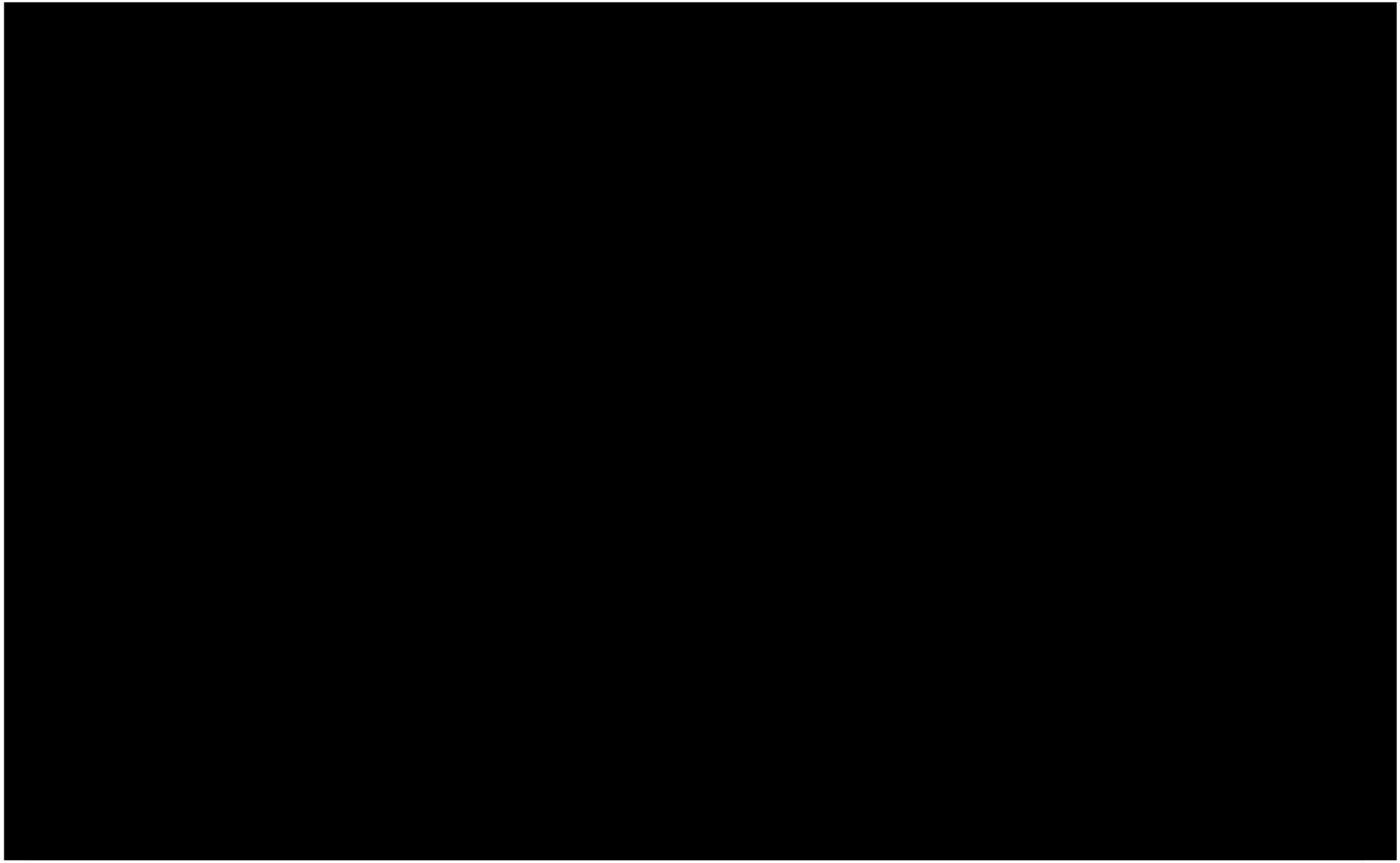


Figure 1-67 – Oil and Gas Wells [redacted] of the Titan Project

Table 1-14 – Productive Oil and Gas Wells Within 6 Miles of Titan Project Site

API No.	Well Name	Field	County/Parish	Well Status	Reservoir(s)	Spud Date	Plugged Date	First Prod Date	Last Prod Date
[redacted]									

API No.	Well Name	Field	County/Parish	Well Status	Reservoir(s)	Spud Date	Plugged Date	First Prod Date	Last Prod Date
[redacted]									

The closest well to the Titan Project, the [redacted] is located just under [redacted] of the project. [redacted]

With the lack of economically viable hydrocarbons in the area, the Titan Project is well suited for the injection and sequestration of CO_2.

1.11. Seismic History

Every new injection well project must consider, during the design and development phase, the potential for seismic activity caused by the injection operations. This part complies with 16 TAC **§5.203 (c)(2)(D)** [40 CFR **§146.82(a)(3)(v)]**, the Class VI rule, by carrying out the following four steps:

1. Identification of historical seismic events in proximity to the project
2. Faulting and determination of operational influences of nearby faults
3. Performance of a fault slip potential (FSP) simulation model
4. Review of seismic hazard

1.11.1 Identification of Historical Seismic Events

Texas experiences seismic activity in six key areas (Figure 1-68): the Delaware Basin and Midland-Odessa area in west Texas, the Panhandle, east Texas, the Eagle Ford area of south Texas, and the Cogdell Field near Snyder (Savvaidis, 2022). The area of interest (AOI) reviewed for this section was defined as a 9.08-km radius[1] around the project wells, based on seismographic recordings from a global network of seismological stations. According to a search of the Texas Seismological Network and Seismology Research (TexNet), [redacted] from the Titan Project site (Figure 1-69, page 103). Additional research into other seismic catalogs, including those from the USGS Earthquake Archive, Volcano Discovery, and Northern California Earthquake Data Center (NCEDC), supported the TexNet findings. Although Texas does have seismic active areas, the proposed project is located in an area where regional stress is low, as no earthquakes have occurred along southeast Texas and the Gulf Coast, demonstrated in Figure 1-70 (page 104). [redacted]

[1] Texas Railroad Commission FSP AOI Standard under the Seismicity Review.

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

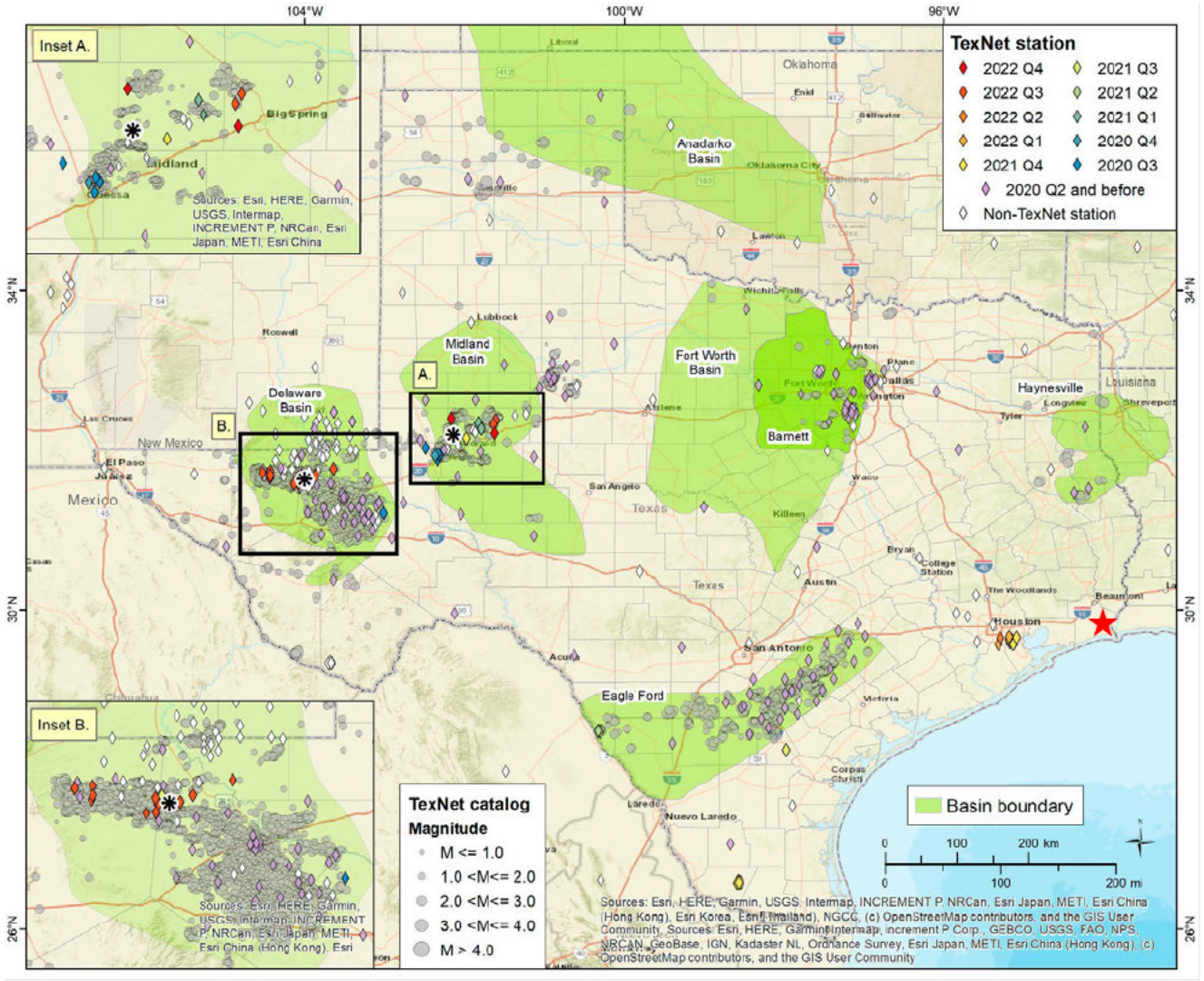


Figure 1-68 – Seismically active areas in Texas, with the red star indicating the proposed project location (Savvaidis, 2022).

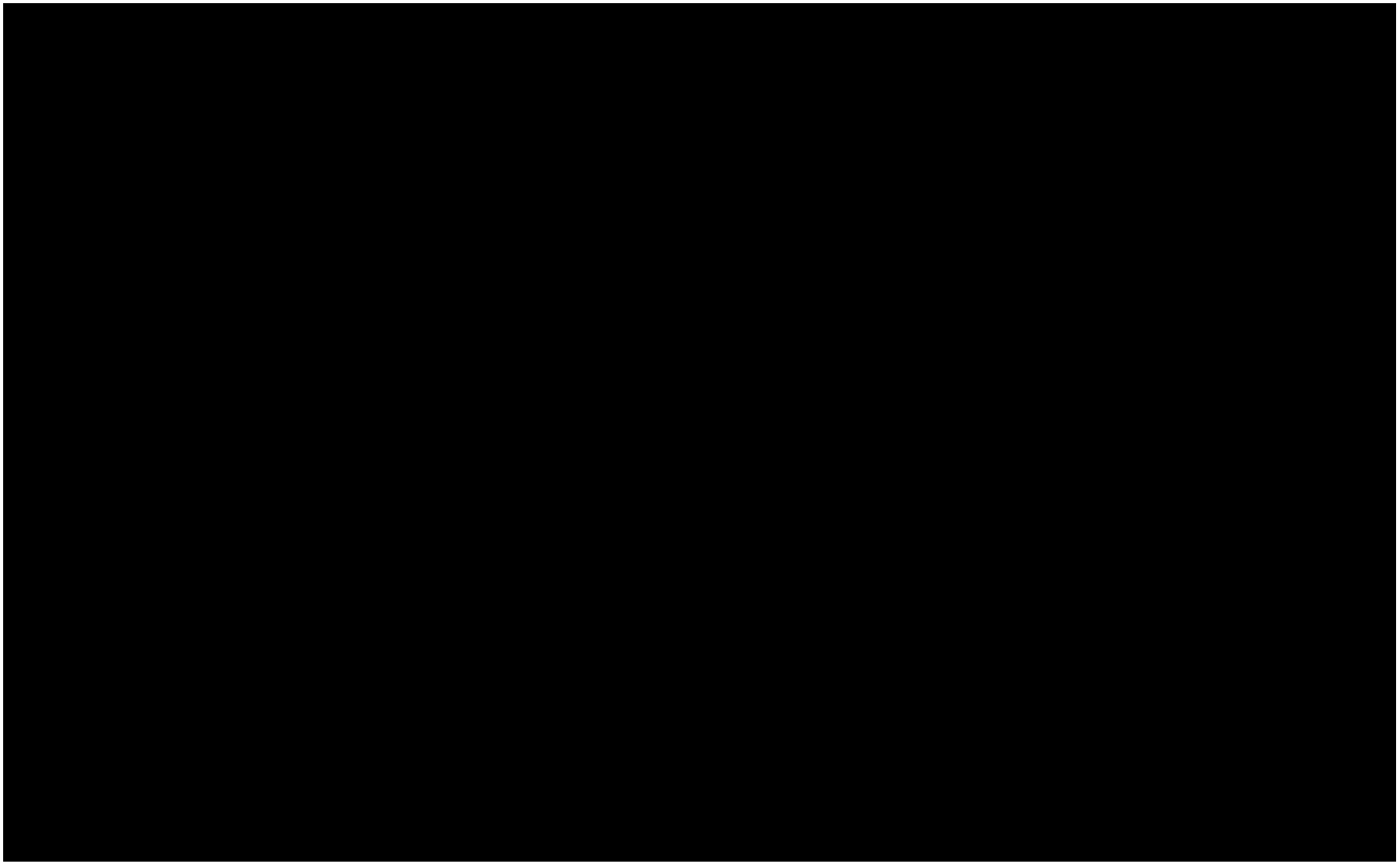


Figure 1-69 – Earthquake Search Parameters and Results from TexNet Website

Figure 1-70 – USGS-registered earthquakes inland east Texas, along the Gulf Coast and west Louisiana.
In red is the location of the proposed project, the green circle is the 9.08-km radius around the project, and the green dot is the closest earthquake.

1.11.2 Faults and Influence

The USGS has created a comprehensive database with respect to faults and associated folds, which includes five classes: A, B, C, D, and E. This database classifies faults in southeast Texas as "Class B," because most of them are in sediments and poorly lithified rocks that cannot withstand the forces necessary for the propagation of massive seismic ruptures that might cause dangerous ground motions. Additionally, Crone and Wheeler (2000) reference the possibility that the post-rift sequence and its band of normal faults along the Gulf of Mexico margin are mechanically separated from the underlying crust, reducing the risk of a significant earthquake[3]. These Cenozoic fault zones (Figure 1-71), from Oligocene- and Miocene-age displacement, showed a regional tendency to strike [redacted] g faults within the higher clay-concentrated layers, including the upper and lower confining zones.

[3] The USGS defines a *significant earthquake* to be greather than 600, a number derived by magnitude, number of "Did You Feel It" responses, and PAGER alert level.

Figure 1-71 – Major Cenozoic fault zones in southeast Texas and the location of the proposed project (indicated by the red star) (Meckel and Trevino, 2014).

1.11.3 Fault Slip Potential Model

The FSP model calculates the cumulative likelihood of a known fault exceeding the Mohr-Coulomb slip criteria due to fluid injection. Accounting for pressure variations at the prospective site is critical to prevent faults from reactivating or the seal from being hydraulically fractured (Meckel and Trevino, 2014). Based on the injection strategy, an FSP model was designed to assess the seismic risk, match the 3D flow simulation in Computer Modelling Group's GEM 2023.20 (GEM) software, and replicate the correct fault transmissivity discovered in the AOI. The results and data, including assumptions and uncertainties, are discussed in *Appendix B-13*.

[redacted] The FSP models reproduced the GEM models using sealing fault properties; however, the injection reservoir is [redacted]

1.11.4 Seismic Hazard

A seismic hazard analysis was carried out for the Titan Project using the EPA-recommended tools found in the USGS 2018 National Seismic Hazard Model (NSHM) Project and derived maps. The 2018 NSHM integrated and updated the 2014 NSHM, including fault models, seismic catalogs, population density, ground motion models, soil amplification factors, amplified shaking estimates of long-period ground motions, and seismic hazard calculation. The 2018 Modified Mercalli Intensity[4] (MMI) earthquake hazard map (Figure 1-72) reveals that, for a hard rock site, there is a 2% chance that peak ground accelerations will be surpassed in 50 years. Furthermore, in that time span according to Figure 1-72, a Class IV[5] or V[6] earthquake is most likely to impact southeast Texas (per the 2018 model). The AOI is in a Class IV hazard area. Figure 1-73 (page 109), which illustrates the likelihood of a minor damaging earthquake occurring over the conterminous United States in 100 years, shows southeast Texas having a 4%–19% chance of experiencing a Class VI[7] earthquake. In terms of 10,000 years, Figure 1-74 (page 110) depicts fewer than two damaging earthquakes[8] to occur in southeast Texas.

Based on the 2018 NSHM, therefore, the Titan Project location is within the lowest seismic hazard areas in United States.

[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, causing structural failure.

Natural Hazards

In terms of natural hazards[9], Jefferson County, Texas, is considered "Relatively High" based on

Figure 1-72 – Total mean hazard map for 2% probability of exceedance in 50 years and the location of the proposed project (indicated by the red star) (Petersen, et al., 2019, p. 33).

[9] *Natural hazard* includes the following 18 hazards: Avalanche, Coastal Flooding, Cold Wave, Drought, Earthquake, Hail, Heat Wave, Hurricane, Ice Storm, Landslide, Lightning, Riverine Flooding, Strong Wind, Tornado, Tsunami, Volcanic Activity, Wildfire, and Winter Weather.

Figure 1-73 – Risk of a Class VI earthquake shaking in 100 years at the location of the proposed project (indicated by the red star), plus population density (Petersen, et al., 2019, p. 7).

Figure 1-74 – Predicted damaging earthquakes shaking around the United States and the location of the proposed project (indicated by the red star) ("Frequency of Damaging Earthquake Shaking Around the U.S", retrieved 2023).

Figure 1-75 – Jefferson County National Risk Index Map showing community resilience. The red star indicates the location of the proposed project (National Risk Index FEMA, 2023).

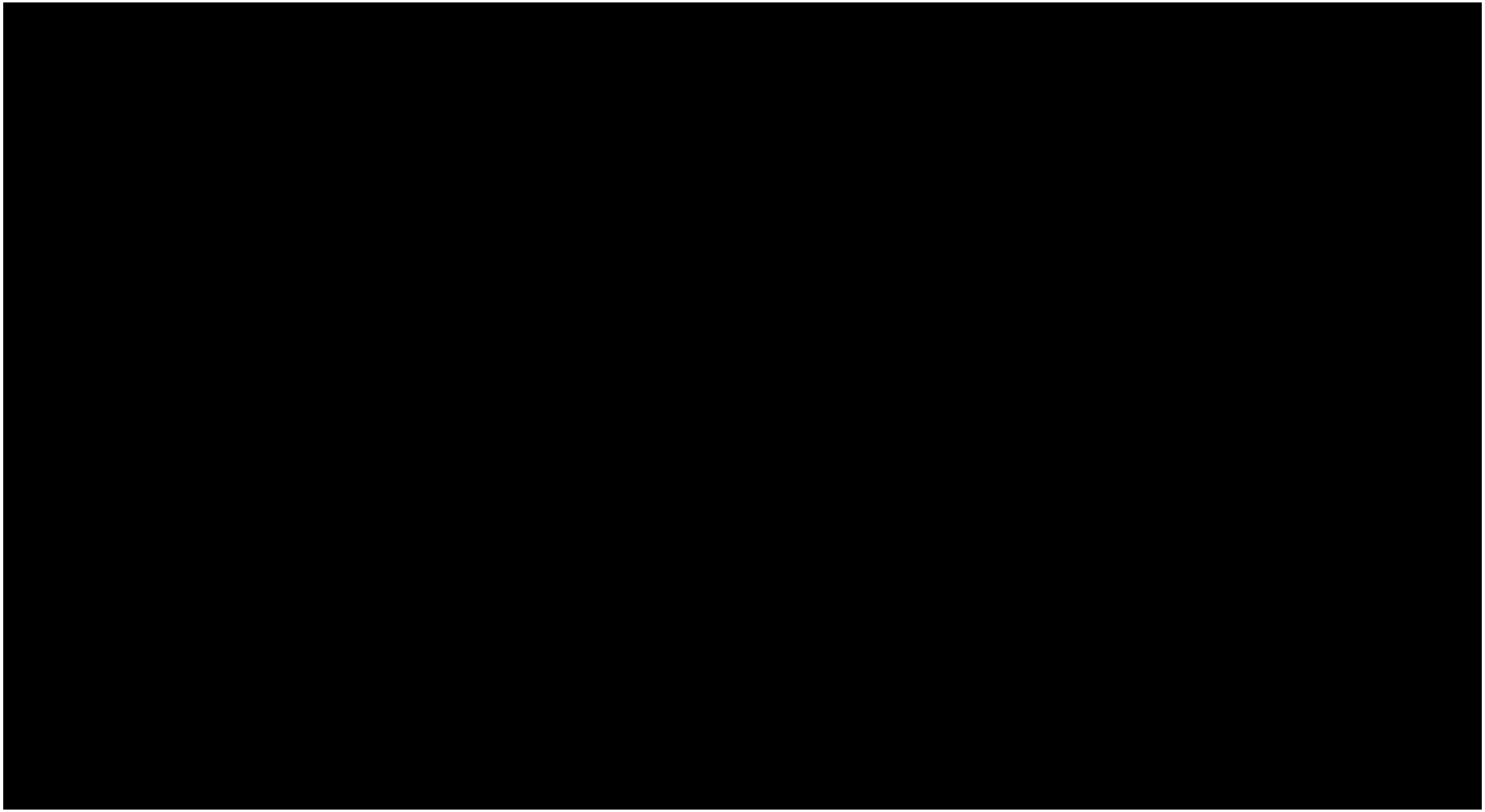


Figure 1-76 – Jefferson County National Risk Index Map showing hazard types. The red star indicates the location of the proposed project (National Risk Index FEMA, 2023).

Figure 1-77 – National Risk Index Scores for Jefferson County

1.12. Site Characterization Conclusion

The evaluation of the proposed injection wells, Cronos No. 1 and Rhea No. 1, demonstrates that the Lower Miocene sandstones possess ample porosity, permeability, lateral continuity, and depth to effectively accommodate the intended volume of CO_2. The Amph B exhibits sufficient thickness and is laterally distributed within the injection area, featuring desirable confining characteristics including high clay content with low effective porosity and permeability. Likewise, the Siph Dav shares similar characteristics with the Amph B, making it a suitable lower confining zone. The assessment of faulting in the area has been thorough, involving evaluation, modeling, and determination of low risk concerning containment within the proposed injection zone. Upon the drilling of the stratigraphic test well, additional data will be gathered and analyzed to ensure that the site maintains a low-risk status for CO_2 injection and storage.

The following attachments are in *Appendix B:*

- Appendix B-1 SW-NE Structural Cross Section
- Appendix B-2 NW-SE Structural Cross Section
- Appendix B-3 SW-NE Stratigraphic Cross Section
- Appendix B-4 NW-SE Stratigraphic Cross Section
- Appendix B-5 Cross Section Reference Map
- Appendix B-6 Top Upper Confining Structure
- Appendix B-7 Top Injection Zone Structure
- Appendix B-8 Top Lower Confining Structure
- Appendix B-9 Upper Confining Isochore
- Appendix B-10 Injection Zone Isochore
- Appendix B-11 Lower Confining Isochore
- Appendix B-12 Injection Zone Net Sand
- Appendix B-13 Fault Slip Potential Model

1.13. References

"Frequency of Damaging Earthquake Shaking Around the U.S." (retrieved 2023). *USGS sources include Earthquake Hazards Program*. https://www.usgs.gov/media/images/frequency-damaging-earthquake-shaking-around-us.

Aird, P. (2019). *Deepwater Geology & Geoscience*. ScienceDirect: https://www.sciencedirect.com/topics/engineering/overburden-stress.

Bretan, P. (2022). Assessing the predictive capability of the empirical Shale Gouge Ratio–buoyancy pressure calibration: implications for estimating CO2 column heights. The Geological Society of London.

Bretan, P. Y. (2003). Using calibrated shale gouge ratio to estimate hydrocarbon column heights. AAPG.

Brunn, B., Jackson, K., Peter, L., and Walker, J. (2016). Texas Aquifers Study. *Groundwater Quantity, Quality, Flow, and Contributions to Surface Water*.

Bump, A. P., Bakhshian, S., Ni, H. et al. (2023). Composite confining systems: Rethinking geolgic seals for permanent CO2 sequestration. *International Journal of Greenhouse Gas Contro* 126. https://doi.org/10.1016/j.ijggc.2023.103908.

Burke, L. A., Kinney, S. A., Dubiel, R., and Pitman, J. K. (2013). Regional Maps of Subsurface Geopressure Gradients of the Onshore and Offshore Gulf of Mexico Basin. USGS.

Crone , A., and Wheeler, R. (2000). *Data for Quaternary faults, liquefaction features, and possible tectonic features in the Central and Eastern United States, east of the Rocky Mountain front.* U.S. Geological Survey.

Eaton, B. A. (1969). Fracture Gradient Prediction and Its Application in Oilfield Operations. SPE-AIME.

Galloway, W. E. et al (2000). Cenozoic Depositional History of the Gulf of Mexico Basin. AAPG.

Galloway, W. E. (2008). *Sedimentary Basins of the World*, Chapter 15: Depositional Evolution of the Gulf of Mexico Sedimentary Basin, 505-549.

Galloway, W. E., Ganey-Curry, P. E., Li, X., and Buffler, R. T. (2000). Cenozoic depositional history of the Gulf of Mexico basin. AAPG.

Heidbach, O., Rajabi, M., Cui, X. (2016). World Stress Map database release 2016: Crustal stress pattern across scales. *Tectnophysics*, 484-498.

Hovorka, S. D., Holtz, M. H., Sakurai, S. et al. (2003). Frio Pilot in CO2 Sequestration in Brine-Bearing Sandstones. Gulf Coast Carbon Center.

Jolley, S., Stuart, G., and Freeman, S. (2007). Progressive evolution of a late-orogenic thrust system, from duplex development to extensional reactivation and disruption: Witwatersrand Basin, South Africa. In: Deformation of the Continental Curst. *Geologic Society*, 543-569.

Karolyte, R., Johnson, G., Yeilding, G., and Gilfillan, G. (2020). Fault Seal modelling – the influence of fluid properties on fault sealing capacity in hydrocarbon and CO2 systems. *Petroleum Goescience*, 481-497.

Kasmarek, M., and Robinson, J. (2004). Hydrogeology and simulation of groundwater flow and land-surface subsidence in the northern part of the Gulf Coast aquifer system, Texas: U.S. Geological Survey. *Scientific Investigations Report*.

Loucks, R. F., Bebout, D., and Galloway, W. E. (1977). Relationship of porosity formation and preservation to sandstone consolidation history- Gulf Coast Lower Tertiary Frio Formation. Gulf Coast Association of Geological Societies Transactions.

McGuire, K. A. (2009). CO2 injection and reservoir characterization: an integrated petrographic and geochemical study of the Frio formation, Texas. Ball State University.

Meckel, T. P., and Trevino, R. (2014). *Gulf Of Mexico Miocene Co2 Site Characterization Mega Transect, Final Scientific/technical Report (Revised).* U.S. Department of Energy National Energy Technology Laboratory.

Meckel, T., and Trevino, R. (2014). Gulf of Mexico Miocene CO2 Site Characterization Mega Transect. Bureau of Economic Geology.

Molina, O., Vilarrasa, V., and Zeidouni, M. (2016). Geologic carbon storage for shale gas recovery. *Elsevier*.

National Risk Index FEMA, Jefferson County, Texas. (2023, 04). https://hazards.fema.gov/nri/learn-more.

Olariu, M. I., DeAngelo, M., Dunlap, D., and Treviño, R. H. (2019). High frequency (4th order) sequence stratigraphy of Early Miocene deltaic shorelines, offshore Texas and Louisiana. *B*ureau of Economic Geology.

Palandri, J. L., and Kharaka, Y. K. (2004). A Compilation of Rate Parameters OF Water-mineralL Interaction Kinectics for Application to Geochemical Modeling. USGS.

Peel, F. J., Travis, C., and Hossack, J. (1995). Genetic structural provinces and salt tectonics of the Cenozoic offshore U.S. Gulf of Mexico: a preliminary analysis. AAPG, 153-175.

Petersen, M., Shumway, A., Powers, P. et al. (2019). The 2018 update of the US National Seismic Hazard Model: Overview of model and implications. *Earthquake Spectra* 36, 6-36. doi:10.1177/8755293019878199.

Roberts-Ashby, T. L., Brennan, S. T., Buursink, M. L. et al. (2012). Geologic framework for the national assessment of carbon dioxide storage resources: U.S. Gulf Coast. USGS.

Savvaidis, A. (2022). *2022 Biennial Report on Seismic Monitoring and Research in Texas.* Austin: Bureau of Economic Geology.

Snedden, J. W., and Galloway, W. E. (2019). The Gulf of Mexico Sedimentary Basin. Cambridge University Press.

Texas Department of Water Resources (1981). *Sabine-Neches Estuary: A Study of the Influence of Freshwater Inflows*.

Treviño, R. H., and Rhatigan, J.-L. T. (2017). Regional Geology of the Gulf of Mexico and the Miocene Section of the Texas Near-Offshore Waters. Bureau of Economic Geology.

U.S. Geological Survey and Texas Bureau of Economic Geology (2023, 10). Quaternary fault and fold database for the United States. https://www.usgs.gov/natural-hazards/earthquake-hazards/faults.

U.S. Quaternary Faults (2023, 04). USGS. https://usgs.maps.arcgis.com/apps/webappviewer/index.html?id=5a6038b3a1684561a9b0aadf88412fcf.

Weaver, C. E. (1977). Fine-Grained Sheet Silicate Rocks. USDOE.

Weber, K., and van Geuns, L. (1990). Framework for Constructing Clastic Reservoir Simulation Models. SPE.

Yassir, N., and Zerwer, A. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana: Data from Well-Bore Breakout Analysis. AAPG, 293-307.

Yeilding , G. (2002). Shale gouge ratio— Calibration by geohistory, in A. G. Koestler and R. Hunsdale, Hydrocarbon seal quantification. *Norwegian Petroleum Society Special Publication*, 1-15.

Yielding, G., Freeman, B., & Needham, D. T. (1997). Fault seal quantitative prediction: shale smear factor, shale gouge ratio, and smear gouge ratio. *AAPG*.

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 2 – PLUME MODEL

February 2024

LONQUIST
SEQUESTRATION LLC

SECTION 2 – PLUME MODEL

TABLE OF CONTENTS

2.1 Introduction 4
2.2 Project Summary 4
2.2.1 Software 4
2.2.2 Data Sources 5
2.3 Trapping Mechanisms 8
2.3.1 Structural/Stratigraphic Trapping 8
Residual Trapping 9
2.3.2 Solubility Trapping 9
2.3.3 Mineral Trapping 11
2.4 Conceptual Site Model 11
2.4.1 Geologic Model Development 11
2.4.2 Structural Framework 12
2.4.3 Rock Property Distribution 16
2.5 Dynamic Plume Model 27
2.5.1 Model Orientation and Gridding Parameters 27
2.5.2 Initial Conditions 32
2.5.3 Rock Properties Hysteresis Modeling 36
2.6 Well Operations Setup 40
2.7 Model Results 42
2.7.1 Active Injection Operations of Proposed CO_2 Injector 42
2.8 CO_2 Plume Migration for AOR Delineation 46
2.8.1 Trapping Summary 53
2.9 Critical Pressure Front for AOR Delineation 54
2.10 Final AOR 59
2.11 References 61

Figures

Figure 2-1 – Major stratigraphic units in the geologic model displayed in southwest-northeast section. .. 6
Figure 2-2 – CO_2 Storage Mechanisms (Metz et al., 2005) 8
Figure 2-3 – Map of the project area showing the Titan acreage outline 12
Figure 2-4 – Structural model displayed in a 3D view as seen from a southwest perspective. 13
Figure 2-5 – Structural Map for the Top of Amph B – Top of the Upper Confinement Zone [redacted] in brown). 14
Figure 2-6 – Structural Map for the Top of Siph Dav – Top Lower Confining Zone [redacted] 15
Figure 2-7 – Northwest-southeast well section displaying SP logs and interpreted lithofacies results (map location shown in Figures 2-8 and 2-10). 17
Figure 2-8 – Base map displaying northwest-southeast well section (from Figures 2-7 and 2-10) 18
Figure 2-9 – Typical vertical and horizontal variograms, calculated in this study for the Lower Miocene – Rob L interval. 19

Figure 2-10 – K layer 293 from the injector zone (just above Marg Asc) through the model displaying seismic amplitude sampled to the cells in the model. 20
Figure 2-11 – Facies model in a 3D window. The location of the cross section from Figure 2-12 is represented by the gray plane. 21
Figure 2-12 – Southwest-to-northeast cross section through the facies model shown in Figure 2-11. Perforation stages are displayed in the injector wells. 22
Figure 2-13 – Base map showing the location of the six wells with porosity logs included in the distribution of the porosity model. 23
Figure 2-14 – Southwest-northeast section through the porosity model. 24
Figure 2-15 – Histogram comparing porosity from raw logs, upscaled cells, and porosity property model. 25
Figure 2-16 – Porosity-Permeability Relationship Implemented Into the Geocellular Model 26
Figure 2-17 – Model Pre-cutoff at Rhea No. 1, West-East Cross-Sectional View 28
Figure 2-18 – Model Resizing for Improved Efficiency at Rhea No. 1, West-East Cross-Sectional view 30
Figure 2-19 – [redacted] 31
Figure 2-20 – Plot of pore pressure gradient vs. depth calculated from log data at the [redacted] 34
Figure 2-21 – Pore-Volume Compressibility vs. Initial Sample Porosity (Newman, 1973) 37
Figure 2-22 – Porosity vs. Residual Gas Saturation Relationship 38
Figure 2-23 – Two-phase relative permeability curves implemented in the model. 39
Figure 2-24 – Depiction of Completion Strategy 41
Figure 2-25 – Modeled BHP and Injection Rate for Cronos No. 1 43
Figure 2-26 – Modeled BHP and Injection Rate for Rhea No. 1. 43
Figure 2-27 – Pressure Buildup for Cronos No. 1 During Active Injection Operations 45
Figure 2-28 – Pressure Buildup for Rhea No. 1 During Active Injection Operations 45
Figure 2-29 – Pressure Buildup for the Life of Cronos No. 1 46
Figure 2-30 – Pressure Buildup for the Life of Rhea No. 1. 46
Figure 2-31 – A vertical 3D representation (left) and aerial view (right) of supercritical CO_2 plume in [redacted], colored by CO_2 saturation. 47
Figure 2-32 – West-east cross-sectional view at Cronos No. 1 [redacted], colored by CO_2 saturation. 48
Figure 2-33 – West-east cross-sectional view at Rhea No. 1 [redacted], colored by CO_2 saturation. 49
Figure 2-34 – South-north cross-sectional view at Cronos No. 1 [redacted], colored by CO_2 saturation. 50
Figure 2-35 – South-north cross-sectional view at Rhea No. 1 [redacted] colored by CO_2 saturation. 51
Figure 2-36 – Aerial View of Supercritical CO_2 Front [redacted], Outlined in Black 52
Figure 2-37 – Modeled Trapping Mechanisms (the red line designating end of injection) 53
Figure 2-38 – Plume Growth Over Time 54
Figure 2-39 – Greatest Extent of Critical Pressure Front, Outlined in Pink. 58
Figure 2-40 – Cronos No. 1 and Rhea No. 1 (Titan Project) Final AOR 60

Tables

Table 2-1 – Facies Variograms and Target Percentages from Well Logs 20
Table 2-2 – Initial-Conditions Inputs Summary. 32
Table 2-3 – Fracture Gradient Calculation Assumptions – Eaton's Method. 35

Table 2-4 – Well Hydraulics Input Summary 40
Table 2-5 – Summary of Completion Stages for Cronos No. 1 42
Table 2-6 – Summary of Completion Stages for Rhea No. 1 42
Table 2-7 – Cronos No. 1 Model Outputs 44
Table 2-8 – Rhea No. 1 Model Outputs 44
Table 2-9 – Critical Pressure Calculation Parameters 55
Table 2-10 – Cronos No. 1 Critical Threshold Pressure for Each Completion Stage 56
Table 2-11 – Rhea No. 1 Critical Threshold Pressure for Each Completion Stage 56

2.1 Introduction

The following discussion of the plume model used for Cronos No. 1 and Rhea No. 1, the proposed injection wells of the Titan Carbon Sequestration Project (Titan Project), was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC) **§**5.**203(d)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84**]. This section describes the key details of the reservoir model. The plume defines the pore space rights, area of review (AOR) for the well, monitoring plans, corrective action plan as necessary, and overall viability of the project. Both *Section 3 – AOR and Corrective Action Plan* and *Section 5 – Testing and Monitoring Plan* use 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 to do the following:

1. Select the strategically best well locations for CO_2 storage.
2. Optimize the available pore space for supercritical CO_2 storage.
3. Minimize the impact of offset injection through completion-strategy implementation and well design.
4. Assess CO_2 migration and pressure increase to avoid adverse impact on major subsurface structures.

2.2 Project Summary

The Titan Project, located in Jefferson County, Texas, will be developed by Titan Carbon Sequestration, LLC (Titan), through underground storage easements. [redacted] Two injection wells are currently planned for the Titan Project, Cronos No. 1 and Rhea No. 1, located in the western portion of the easement area. The plume modeling is specific to these proposed injection wells. The two injection wells were included in the reservoir model to capture their interaction with each other. Each well injects [redacted] million metric tons annually (MMT/yr). Cronos No. 1 and Rhea No. 1 are planned to inject for [redacted] years concurrently, resulting in [redacted] million metric tons (MMT) of supercritical CO_2 being safely sequestered. Figure A-4 in *Appendix A* provides a detailed description of the property.

2.2.1 Software

2.2.1.1 Petrel™ Software Suite

Schlumberger's Petrel software was chosen to create a detailed geocellular model for the CCS site. This state-of-the-art software is used worldwide and combines information from logs and seismic data to build an accurate representation of the underground reservoir. The Petrel-developed geocellular model shows the different layers of the site, including the *Amphistegina B* (Amph B) (upper seal), Lower Miocene Sands (injection zone), and *Siphonina davisi* (Siph Dav)

(lower seal). Using Petrel, the permeability and porosity properties of the injection zone were distributed, considering well-log analysis and established methods. These methodologies ensure a representative depiction of the reservoir in the model.

2.2.1.2 Computer Modelling Group's Software Suite

The geocellular model was developed in Petrel and then input into CMG's GEM 2023.20 (GEM) simulator, a widely recognized tool for modeling compositional fluid flow in conventional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state (EOS) algorithms to evaluate compositional and chemical processes to produce a reliable CCS simulation. The software can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

2.2.2 Data Sources

Constructing the geocellular and dynamic model involved the use of 3D seismic data, offset well logs, core data, and publicly available literature, such as peer-reviewed papers of the Society of Petroleum Engineers (SPE) and the American Association of Petroleum Geologists (AAPG).

A comprehensive review of public databases and literature was carried out at both regional and site-specific levels. At the regional level, major trends within the project area and its surroundings were identified. These trends were then compared to more site-specific data to increase confidence in the reservoir properties. Using nearby offset well data, trends in reservoir salinity and temperature were estimated. Additionally, regional data pointed towards analogous reservoirs to incorporate into the model. Key properties like rock compressibility and relative permeability were gathered from the publicly available literature. These assumptions are further discussed in *Section 2.5.2*.

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

To enhance the characterization of the reservoir, 3D seismic data was used in conjunction with formation tops identified through log analysis—to identify major structural horizons as shown in Figure 2-1. The 3D seismic data also offered improved clarity of the subsurface, aiding in the identification of major structural horizons, as well as any structural alterations like faults, salt domes, or other subsurface changes. This data enhanced the accuracy of the geocellular model by providing a clearer understanding of the targeted stratigraphy.

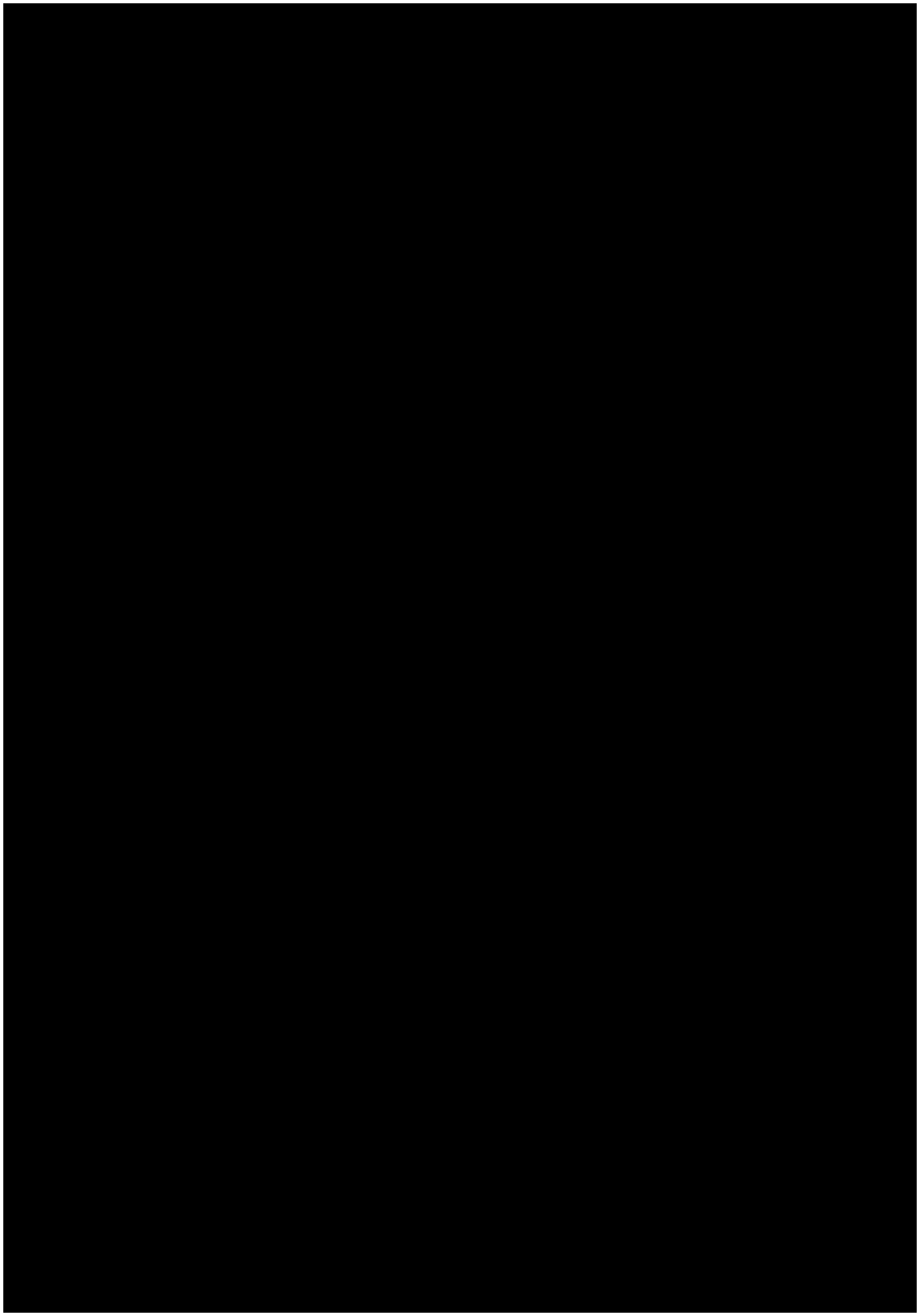


Figure 2-1 – Major stratigraphic units in the geologic model displayed in southwest-northeast section.

Analogous core data was used to determine the porosity-permeability relationship in the Lower Miocene. The core data comes from the [redacted] of the injection site. Site-specific data will be collected after submittal of this permit application. A stratigraphic test well is planned to gather core, fluid samples, and geophysical logs. The inclusion of the additional data will further increase the accuracy of the model and simulation results.

2.3 Trapping Mechanisms

In the context of a CCS project, four mechanisms are key for trapping and storing supercritical CO_2, as illustrated in Figure 2-2. The following sections will cover structural and stratigraphic trapping, residual trapping, solubility trapping, and mineral trapping mechanisms. All mechanisms except for mineral trapping are present in the current model.

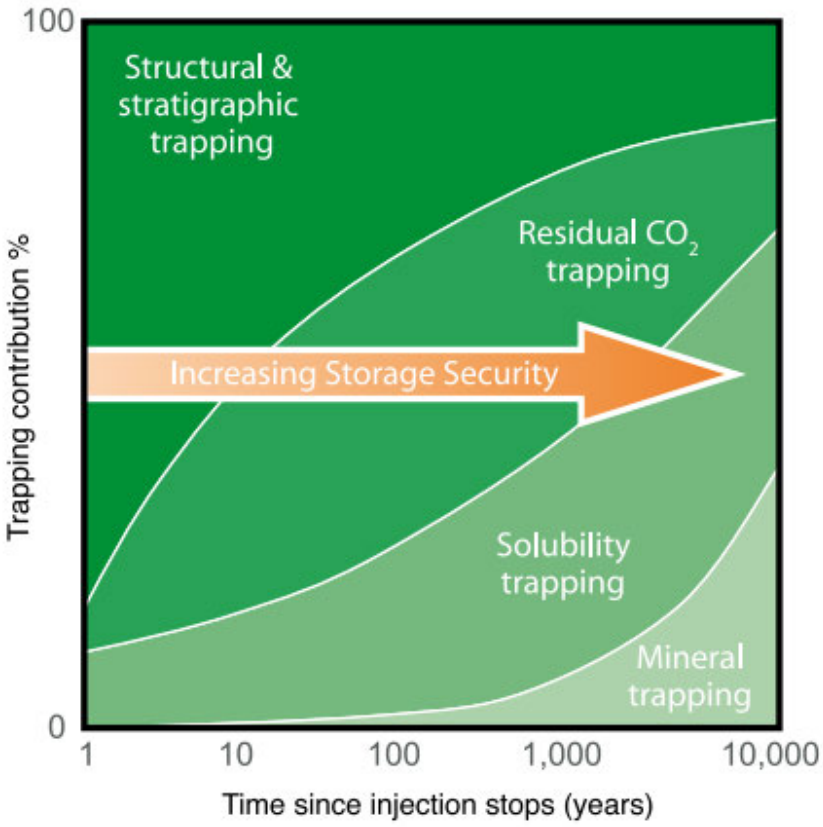


Figure 2-2 – CO_2 Storage Mechanisms (Metz et al., 2005)

2.3.1 Structural and Stratigraphic Trapping

Structural and stratigraphic trapping involves the physical immobilization of injected supercritical CO_2 through the presence of geological features like sealing faults, pinchouts, or other forms of geologic traps. Like naturally occurring hydrocarbon reservoirs, CO_2 can commonly be stored in anticlinal folds. Structural and stratigraphic trapping play a key role in trapping the injected supercritical CO_2 during and in the initial period after injection, but overtime is overtaken by more permanent trapping mechanisms. In this project specifically, the CO_2 is structurally trapped by the confining zone and thick interbedded shales. These features prevent any further vertical migration of the injected CO_2. Supercritical CO_2 is a low-viscosity fluid, less dense than the surrounding brine found in the injection zone. The CO_2 will continue to rise until its buoyant forces are no longer greater than the capillary entry pressure of the confining zone. For this

model, the CO_2 mass density ranges [redacted] The surrounding brine density is [redacted]

To determine the CO_2 phase and associated properties, EOS calculations are performed using formulas that can predict the density of the injected fluid at any location based on pressure and temperature. The GEM uses several well-known EOS formulas, including the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong (SRK) 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 Trapping

Residual trapping is a physical form of trapping where discontinuous CO_2 is left behind and becomes trapped in the pore space as the plume continues to migrate. As water is displaced in the rock, the CO_2 fills the space. However, depending on the movement of CO_2 and the aqueous phase through saturation and capillary forces, CO_2 will remain residually trapped within the pore space. Within the Miocene sandstone environment, larger quantities of sand are available for the CO_2 to migrate to and become residually trapped. Laboratory testing shows that residual trapping of CO_2 accounts for the majority of the overall trapping within high permeability sandstones during the proposed monitoring period (Burnside and Naylor, 2014). Based on dynamic plume modeling, residual trapping is the main trapping mechanism during the proposed monitoring period (Figure 2-37).

To accurately predict the amount of supercritical CO_2 that remains residually trapped, the model employs hysteresis modeling. The GEM software offers several methods to determine residual trapping, such as the Carlson and Land model and the Larsen and Skauge model. The Carlson and Land model was implemented for this simulation due to (1) its use being validated for water-alternating-gas (WAG) injection and (2) its ability to model a two-phase system. The critical parameter—residual (trapped) gas saturation—will be discussed in *Section 2.5.3*.

2.3.3 Solubility Trapping

Solubility trapping is a form of chemical trapping between the injected supercritical CO_2 and surrounding formation brine. In brine, CO_2 is highly soluble, resulting in a solution that has a higher density than the connate brine. This action causes the higher density brine to sink within the formation and traps the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration. The salinity, pressure, and temperature of the surrounding brine all affect the solubility of CO_2 and the rate at which the dissolution occurs. While solubility trapping takes place in the dynamic plume model, this trapping mechanism can take hundreds to thousands of years to overtake residual trapping as the main mechanism for trapping CO_2 (Figure 2-2). During the project's proposed monitoring period, solubility trapping is second to residual trapping as the main trapping mechanism, based on the dynamic plume model (Figure 2-37).

For solubility modeling, GEM offers the options of the Harvey and Li-Ngheim methods. The Li-Ngheim method was chosen due to its accuracy in modeling CO_2 solubility at high salinities. This method also incorporates solubility parameters specific to CO_2, as defined by the constant correlations of Henry's law.

2.3.4 Mineral Trapping

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

Mineral trapping can also occur due to the adsorption of CO_2 onto clay minerals. Once hysteresis and solubility trapping are included in the model, geochemical formulas can be added through an internal geochemistry database to describe mineral-trapping reactions. For aqueous reactions, the following formulas were used:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

These three reactions are common ionic reactions that can occur in the reservoir between water and CO_2. The following formulas show the mineral reactions used within the model. Each mineral is commonly found within sandstone in an underground aquifer and causes the precipitation of carbon oxides in a solid state:

$$Anthorite\ (CaAl_2Si_2O_8) + 8H^+ = 4H_2O + Ca^{2+} + 2Al^{2+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO_3^-$$
$$Kaolinite\ (Al_2Si_2O_5(OH_4)) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

While geochemical trapping can have a greater impact on CO_2 over hundreds or thousands of years, the short-term effects of these trapping mechanisms are small, and fluid movement is 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 geochemical properties of the reservoir, sensitivities could be run to determine the relative importance of this trapping mechanism over time.

2.4 Conceptual Site Model

2.4.1 Geologic Model Development

Using Petrel, the model incorporated [redacted] to define the structural framework. A horizontal cell dimension of [redacted] t was applied. [redacted]

[redacted]. Lithofacies were then interpreted from the well logs and scaled up to the 3D grid-cell dimensions. Next, the data was analyzed using seismic attributes and geostatistics to help define the vertical and lateral continuity and orientation of the facies. These results were used to populate the facies well control throughout the 3D model, using the sequential indicator simulation algorithm. The generated facies model was then used to condition the distribution of the porosity, resulting in the porosity model. The geocellular model is referenced to the North American Datum of 1927 (NAD 27) and was projected into the Texas State Plane before being exported to GEM.

The sources of data incorporated into the geocellular model were seismic surveys and well data, such as locations, elevations, deviation, well tops, and well logs. Seismic surveys and well logs were used for interpretation and for the depth-conversion process.

2.4.2 Structural Framework

The geocellular model covers an area of [redacted] square miles (sq mi) as represented by the black polygon in Figure 2-3. A 3D seismic survey exists within the model area that covers [redacted] sq mi of that area, as represented by the red polygon. The outline for the Titan acreage is displayed in blue. The structural model was built on [redacted] (Figure 2-4).

Figure 2-3 – Map of the project area showing the Titan acreage outline (indicated in blue) and the 3D geomodel outline (in black).

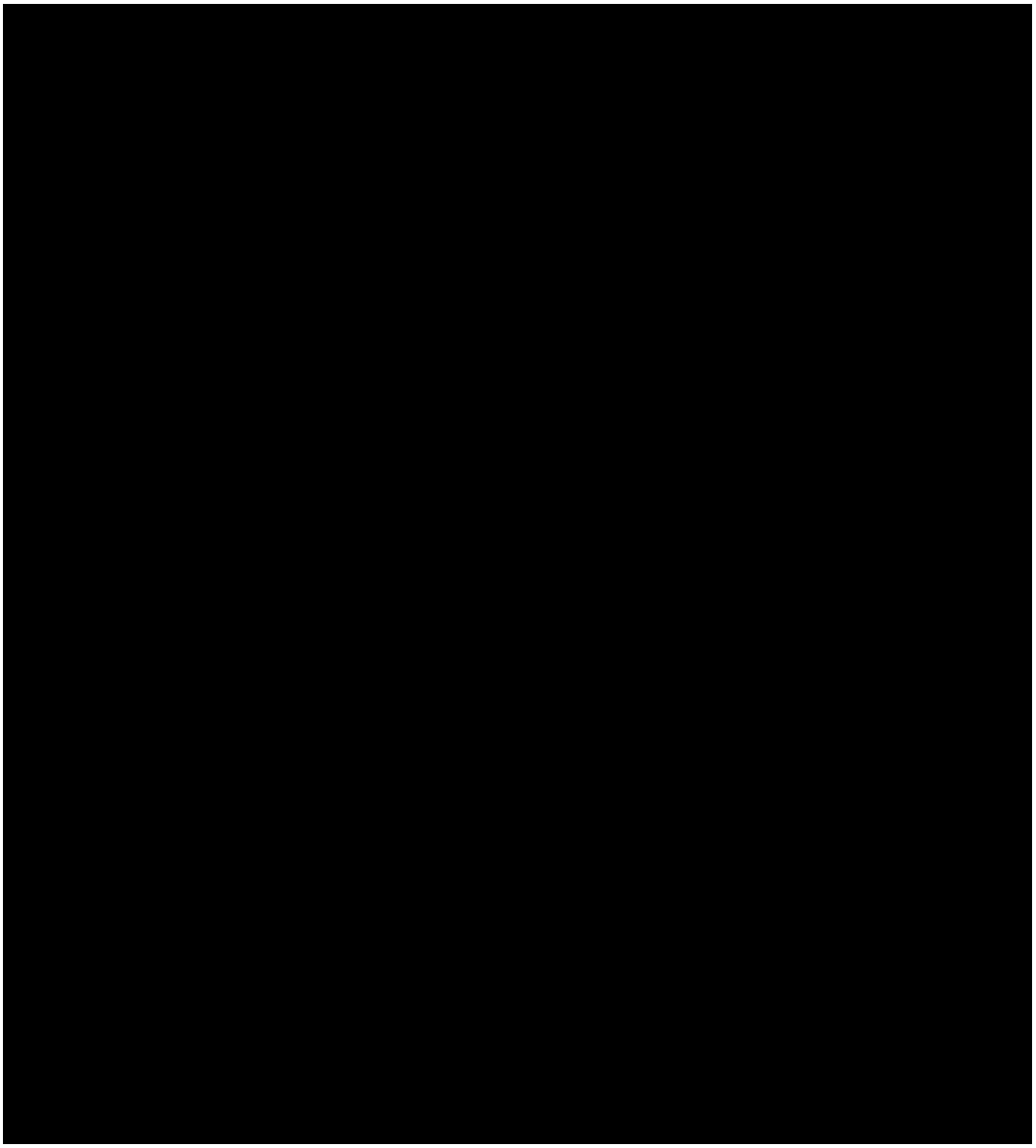


Figure 2-4 – Structural model displayed in a 3D view as seen from a southwest perspective.

Figures 2-5 and 2-6 illustrate [redacted] the tops of the upper and lower confining surfaces, Amphistegina B (Amph B) and Siphonina Davisi (Siph Dav), respectively. [redacted]

Figure 2-5 – Structural Map for the Top of Amph B – Top of the Upper Confinement Zone [redacted]

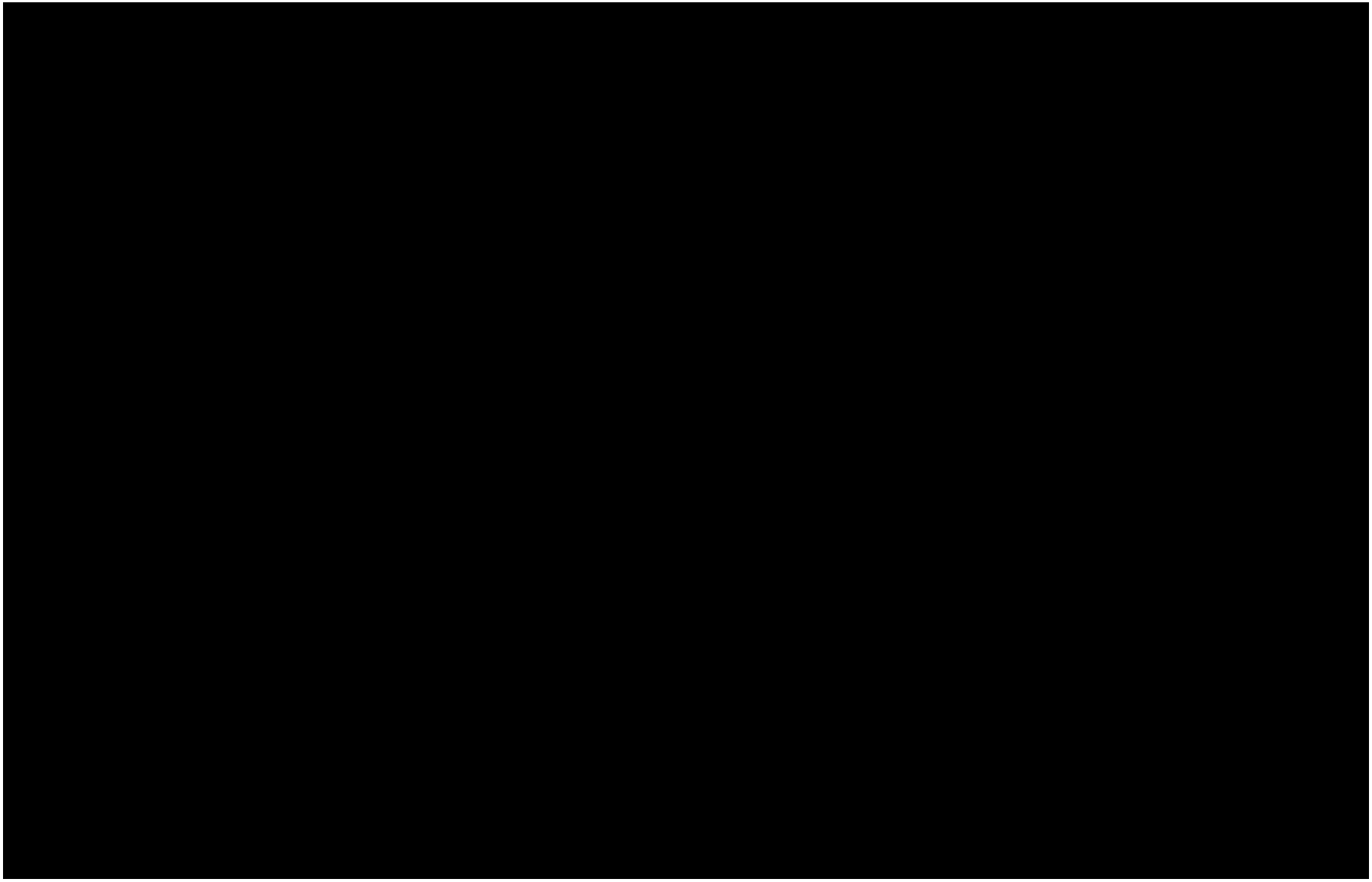


Figure 2-6 – Structural Map for the Top of Siph Dav – Top Lower Confining Zone [redacted]

2.4.3 Rock Property Distribution

2.4.3.1 Lithofacies Distribution

Lithofacies were interpreted for [redacted] wells with spontaneous potential (SP) or gamma ray (GR) logs. Figure 2-7 displays the northwest-to-southeast well section showing the SP/GR logs and interpreted facies. The reference map is provided in Figure 2-8 (page 15). If an SP log was not available, a GR one was used. A shale baseline was selected for each SP or GR log based on log character for individual wells. This baseline was used to separate the sand from the shale. The cutoff values varied since they were chosen according to the shale baseline determined for each well. The interpreted facies logs based on the results obtained were then upscaled into the 3D grid and distributed to create a facies model using geostatistics.

Figure 2-7 – Northwest-southeast well section displaying SP logs and interpreted lithofacies results (map location shown in Figures 2-8 and 2-10).

Figure 2-8 – Base map displaying northwest-southeast well section (from Figures 2-7 and 2-10).
The wells were used for the lithofacies interpretation. The Cronos No. 1 and Rhea No. 1 injection wells are displayed in black.

The geostatistical analysis included the generation of vertical, major, and minor variograms from upscaled facies logs derived from the defined SP/GR cutoffs. The variograms were calculated for each one of the zones in the model. An example of a typical variogram from this study is shown in Figure 2-9, displaying the vertical, major, and minor variograms for the Lower Miocene sands. The anisotropy observed has [redacted] This [redacted] trend is also observed in the seismic attributes and the other injection interval, as shown in Figure 2-10. The K Slice from this figure is from the injection zone and overlies the Marg Asc. Table 2-1 displays the variogram ranges and target-facies fractions for each of the sand intervals in the project. The target-facies fractions are derived from the upscaled-facies log.

Figure 2-9 – Typical vertical and horizontal variograms, calculated in this study for the Lower Miocene – Rob L interval.

Figure 2-10 – K layer 293 from the injector zone (just above Marg Asc) through the model displaying seismic amplitude sampled to the cells in the model.

Table 2-1 – Facies Variograms and Target Percentages from Well Logs

Zone	Vertical Range (ft)	Major Range (ft)	Minor Range (ft)	Facies Fraction
Amph B – Lower Mio				
Lower Mio – Rob L				
Rob L – Siph Dav				

The sequential indicator simulation algorithm was used to populate the facies distribution, using the variograms and target-facies fractions listed in Table 2-1. The vertical-facies proportions from the upscaled log were also used to capture the vertical trends.

The facies model is observed in Figure 2-11, and a southwest-to-northeast cross section through the model is shown in Figure 2-12. Sand lithofacies are represented in yellow and shale in gray.

Figure 2-11 – Facies model in a 3D window. The location of the cross section from Figure 2-12 is represented by the gray plane.

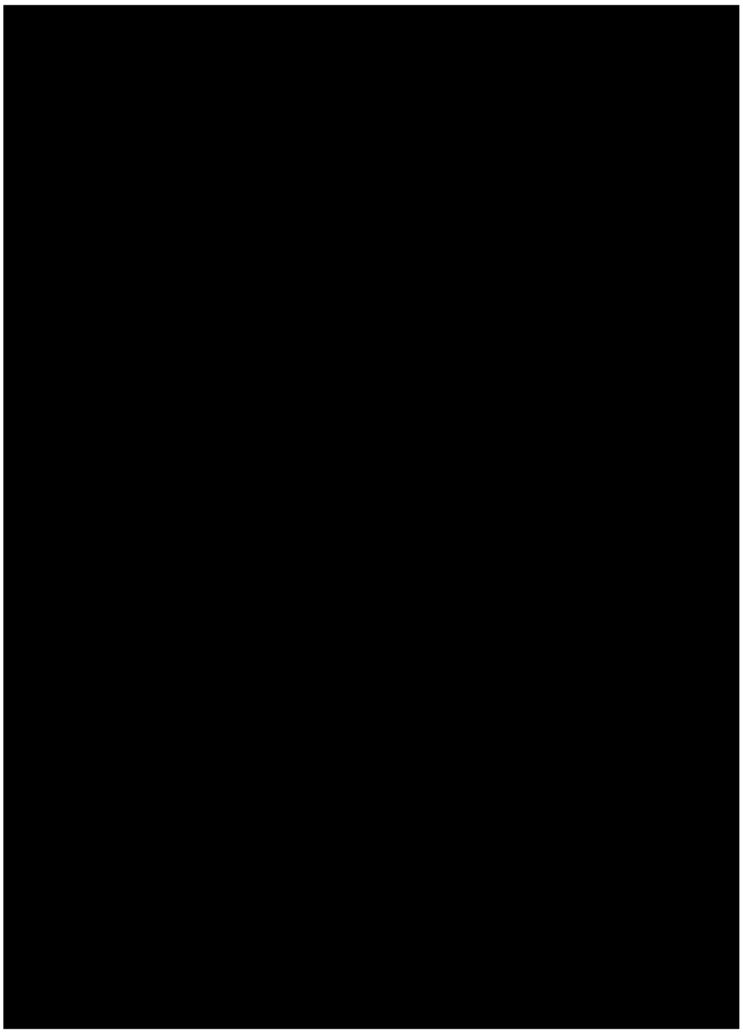


Figure 2-12 – Southwest-to-northeast cross section through the facies model shown in Figure 2-11. Perforation stages are displayed in the injector wells.

2.4.3.2 Permeability/Porosity Distribution

A porosity model was also generated using [redacted] porosity log curves that were upscaled to the 3D grid. The values were distributed using the sequential Gaussian simulation algorithm and conditioned to the facies model already created. Figure 2-13 shows the location for the wells with porosity logs, while Figure 2-14 shows a southwest-northeast section through the porosity model and injector locations. The results of the porosity-distribution histogram are shown in Figure 2-15 (page 23).

Figure 2-13 – Base map showing the location of the [redacted] wells with porosity logs included in the distribution of the porosity model.

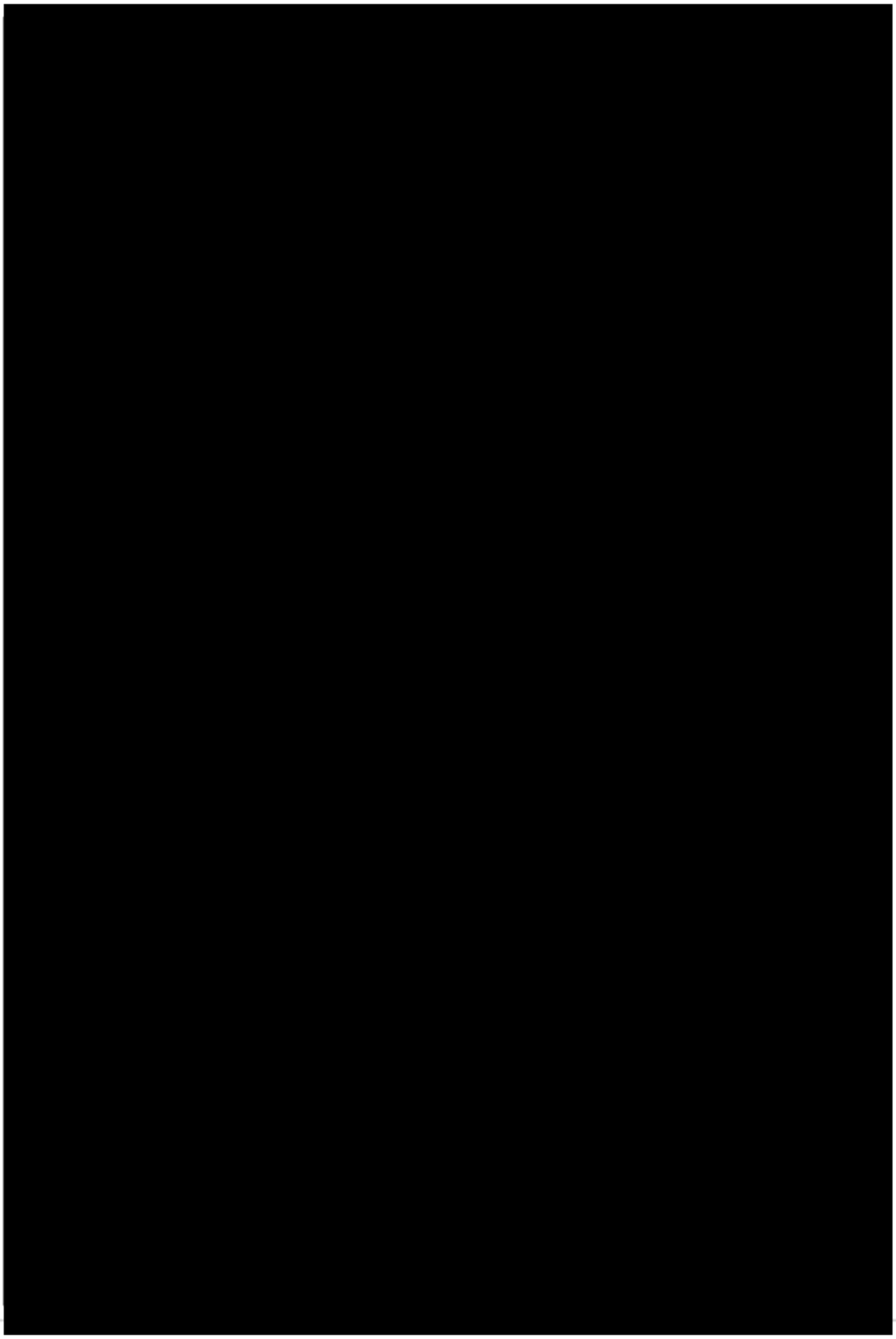


Figure 2-14 – Southwest-northeast section through the porosity model.
The location of the section is represented by the polygon in Figure 2-13.

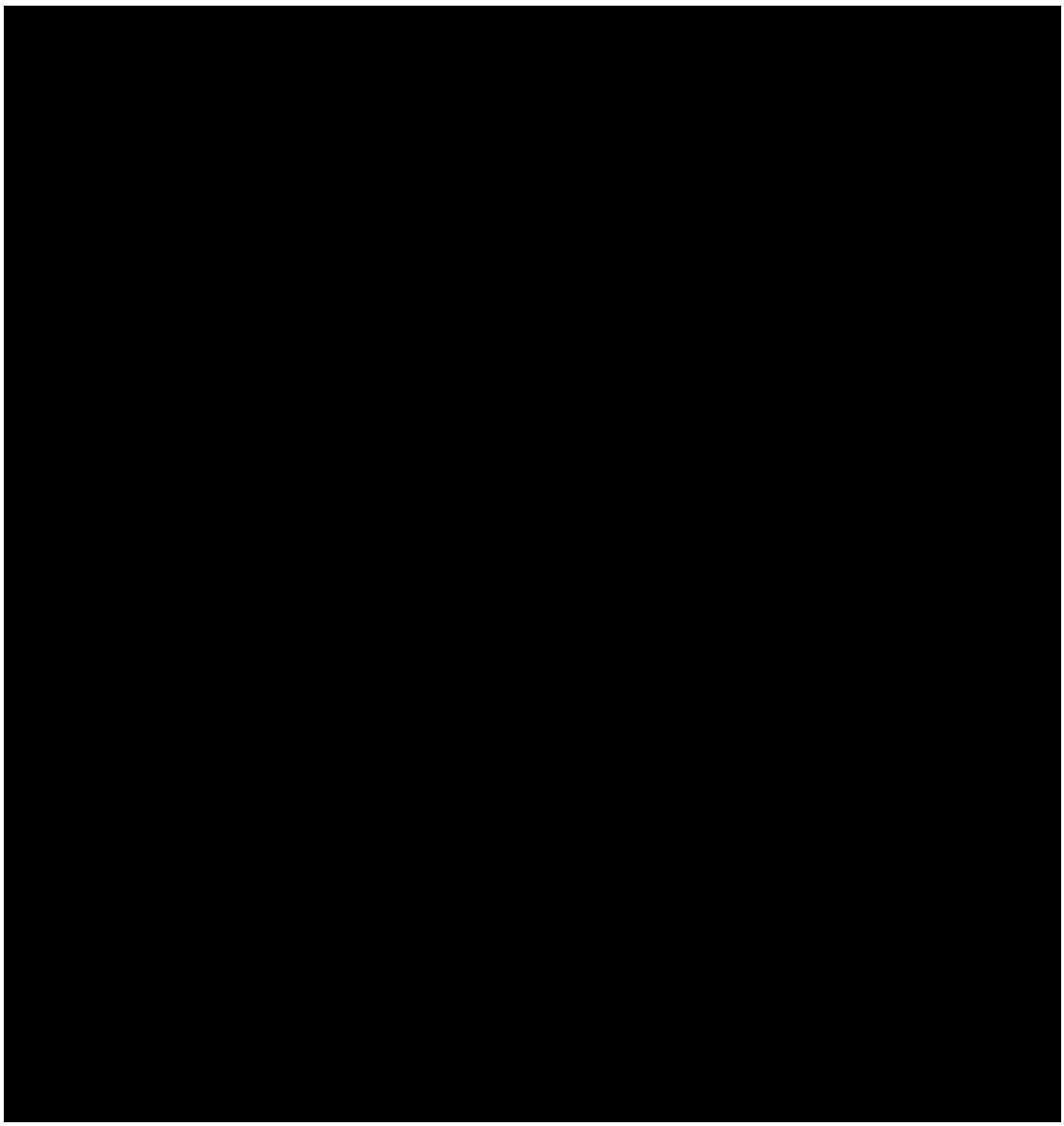


Figure 2-15 – Histogram comparing porosity from raw logs, upscaled cells, and porosity property model.

A porosity-permeability relationship was derived from offset core samples of one nearby well, the [redacted] Using these samples, a relationship was identified as displayed in Figure 2-16. This relationship was then applied to the porosity model to determine the permeability of the Lower Miocene sands. *Section 1.5.1* provides a more detailed explanation of this relationship.

Figure 2-16 – Porosity-Permeability Relationship Implemented Into the Geocellular Model

A regression equation was derived from Figure 2-16 and used to calculate the permeability property depicted in Equation 1:

(Eq. 1) $K(mD) =$ [redacted]

Where:
K(mD) is the resulting permeability model.
Φ_{eff} *is the porosity property discussed above, converted to percentage instead of fractions.*

All properties, facies, porosity, and permeability were exported to GEM for simulation.

2.5 Dynamic Plume Model

2.5.1 Model Orientation and Gridding Parameters

Spatial Conditions

As discussed in *Section 2.2.1.2*, CMG uses as an input the Petrel geocellular model, which encompasses approximately [redacted] The geocellular model is built in Petrel to capture available well control and seismic data in and around the Titan Project boundary. By incorporating information from well logs and seismic data encompassing an area larger than the project boundary, the geologic characterization of the reservoir is enhanced. Once the geocellular model is imported into CMG for dynamic modeling purposes, the large grid size allows for the pressure and plume extents to be fully captured and not constrained by the lateral extent of the grid. At its greatest extent, the grid extends [redacted] Figure 2-17 shows the porosity and permeability in the west-east cross-sectional view at Rhea No. 1, as it was imported from Petrel pre-cutoffs.

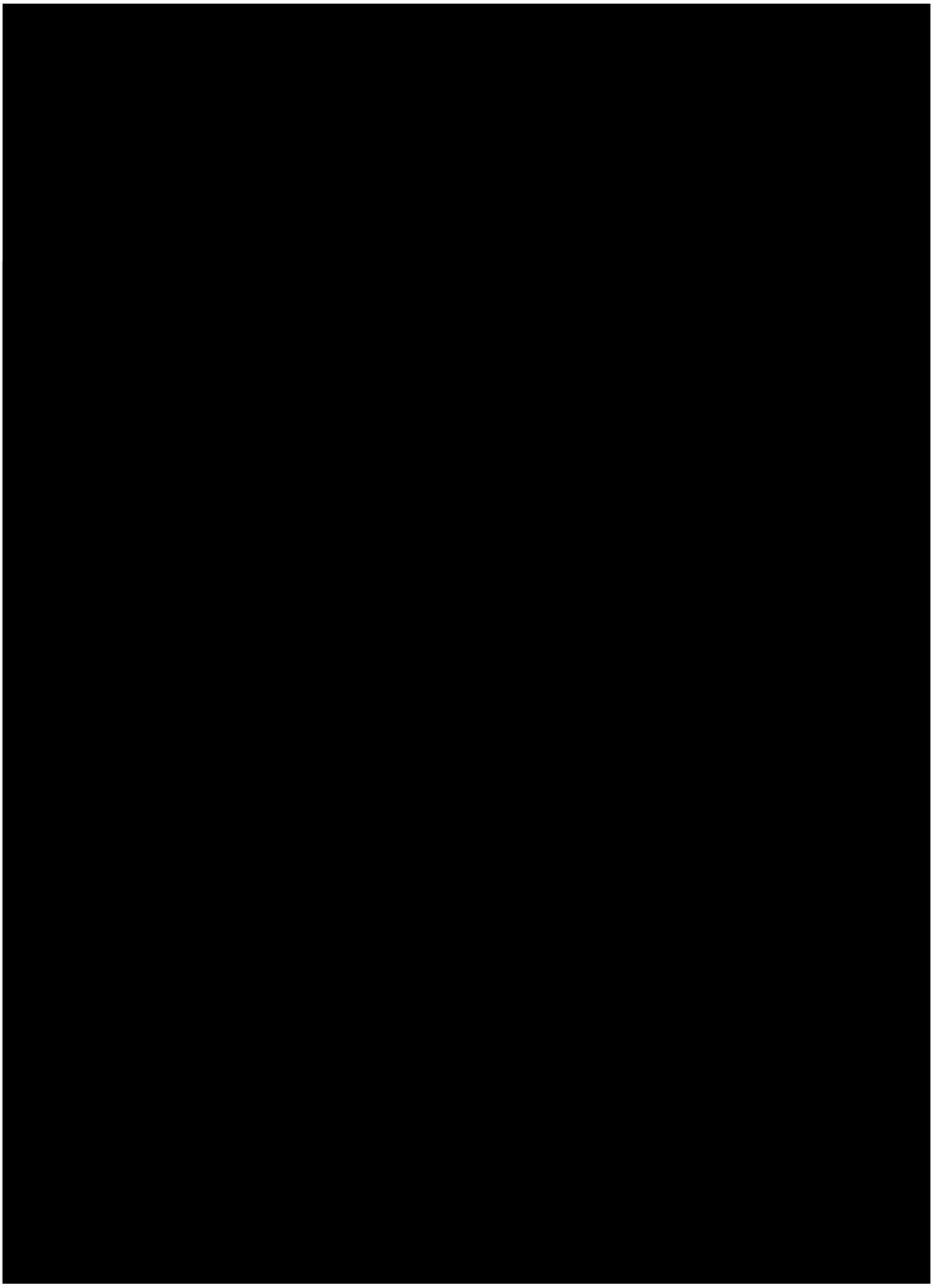


Figure 2-17 – Model Pre-cutoff at Rhea No. 1, West-East Cross-Sectional View

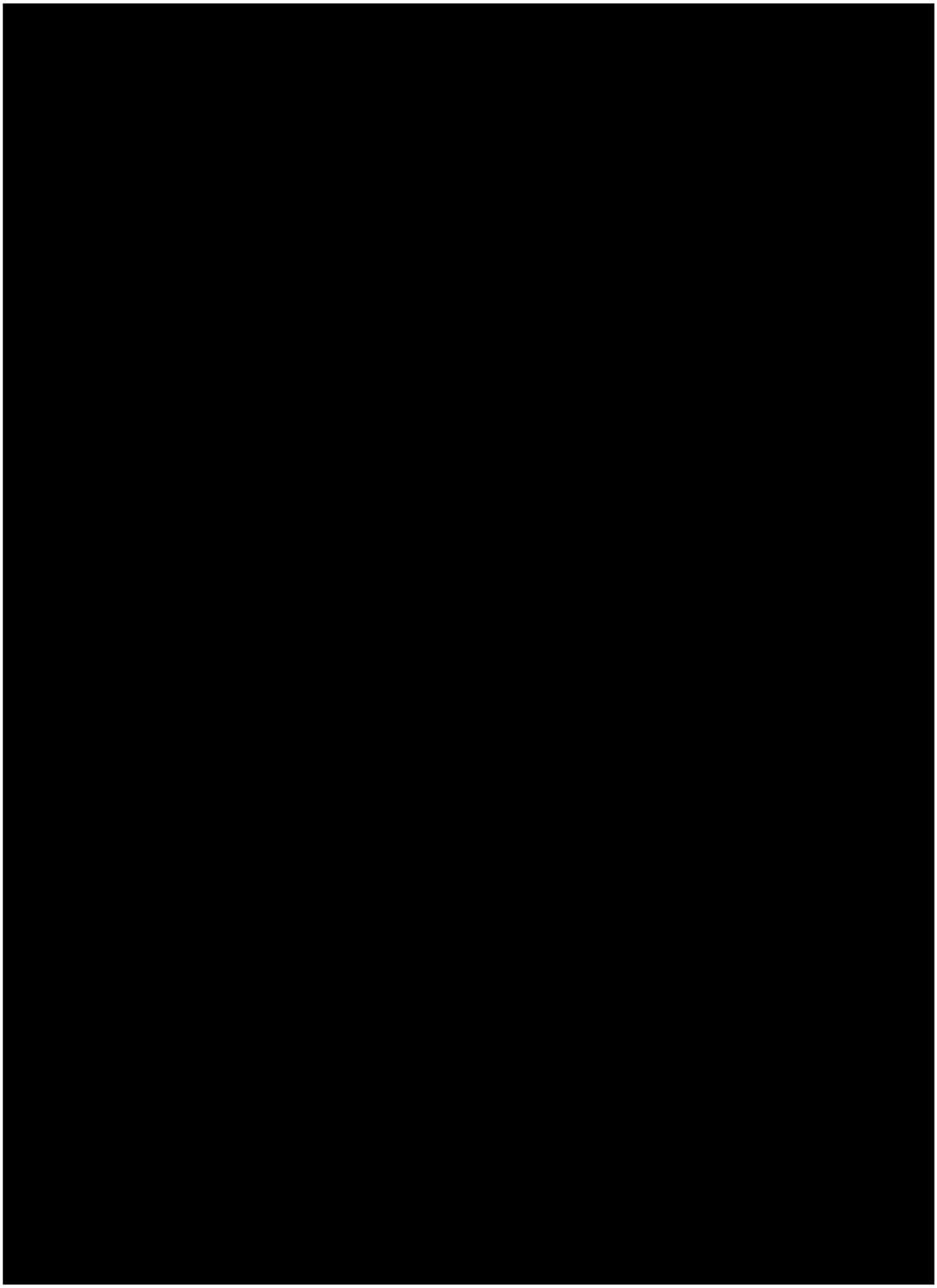


Figure 2-18 – Model Resizing for Improved Efficiency at Rhea No. 1, West-East Cross-Sectional view

Multiple distinct sand packages are identified as potential targets for supercritical CO_2 injection. Each package is separated by interbedded shales and shale baffles that may act as barriers that impede CO_2 movement. [redacted] To represent the sand packages more accurately between large gaps of well data and further validate the geocellular model, 3D seismic was used.

Boundary Conditions

The Miocene sands in the Gulf Coast exhibit extensive connectivity across the entire area. [redacted]

[redacted]

Figure 2-19 – [redacted]

Model Time Frame

[redacted] This duration allows for a comprehensive demonstration of plume stabilization. Details of the model's results are discussed in *Section 2.7.*

2.5.2 Initial Conditions

The geocellular model served as an input for constructing the dynamic plume model. The assumptions in Table 2-2 were also used to initialize the model. Porosity is geostatistically distributed and exported from Petrel, with values ranging from [redacted] in the injection zone. Applying the porosity-permeability relationship derived from petrophysical analysis for offset cores, the permeability ranges from [redacted] The pore and fracture pressure gradients were calculated to be [redacted], respectively. A regional and well log review estimated the temperature gradient to be [redacted] Salinity within the injection zone was determined to be approximately [redacted] as discussed in the brine salinity subsection (*Section 2.5.2.4*).

Table 2-2 – Initial-Conditions Inputs Summary

Inputs	Values
Average Porosity (%)	[redacted]
Average Permeability (mD)	
Average Kv/Kh Ratio	
Pore Pressure Gradient (psi/ft)	
Frac Pressure Gradient (psi/ft)	
Mean Surface Temperature (°F)	
Temperature Gradient (°F/100 ft)	
Salinity (ppm)	

[redacted]

2.5.2.1 Porosity/Permeability

As discussed in *Section 2.4*, porosity is determined through the analysis of openhole logs, and permeability is calculated using a porosity-permeability relationship (Figure 2-16, *Section 2.4.3.2*), derived from core data taken from a nearby offset well within the Lower Miocene. The permeability relationship implemented in the dynamic model is depicted in Equation 1 in *Section 2.4.3.2*.

Porosity is geostatistically distributed throughout the model. The porosity-permeability equation is then applied to all sand facies grid cells to determine reservoir permeability. This process results in a porosity range of [redacted] and a permeability range of [redacted] in all sands. Shales are expected to be clay-rich in this depositional environment. Clay-rich shales show permeability values in the range of 0.1 nano-darcy to 100 nano-darcy (Backeberg et al., 2017). In the dynamic model, a permeability value of [redacted] is assumed for the shale facies. These distributions are shown west to east in Figure 2-18 (*Section 2.5.1*).

The vertical permeability [redacted]

2.5.2.2 Pressure Gradient

The reservoir simulation model for Cronos No. 1 and Rhea No. 1 assumes a reservoir filled with 100% brine. The formation is assumed to be in hydrostatic conditions. Pore pressure for the injection zone was estimated from log data of the [redacted] A total dissolved solids (TDS) curve was prepared using resistivity data. The TDS values were used to calculate fluid density and pore pressure, using McCain's Correlation (McCain, 1991) in half-foot intervals. The resulting pore pressure vs. depth curve is included in Figure 2-20, and the equation used to calculate the pore pressure gradient is given in Equation 2. The pressure gradient used in this model is [redacted] psi/ft, which correlates to the calculated density. This value is used to help initialize GEM's reservoir model to internally calculate the fluid density across the entire modeled area.

(Eq. 2) $$PPG\left(\frac{psi}{ft}\right) = 0.433 \cdot \left(1 + TDS_{Inj\,Zone} \cdot 10^{-6}\right)$$

Where:
PPG is the resulting pore pressure gradient in psi/ft.
0.433 is the pressure gradient of freshwater in psi/ft.
$TDS_{Inj\ Zone}$ is the total dissolved solids in the injection zone in ppm.

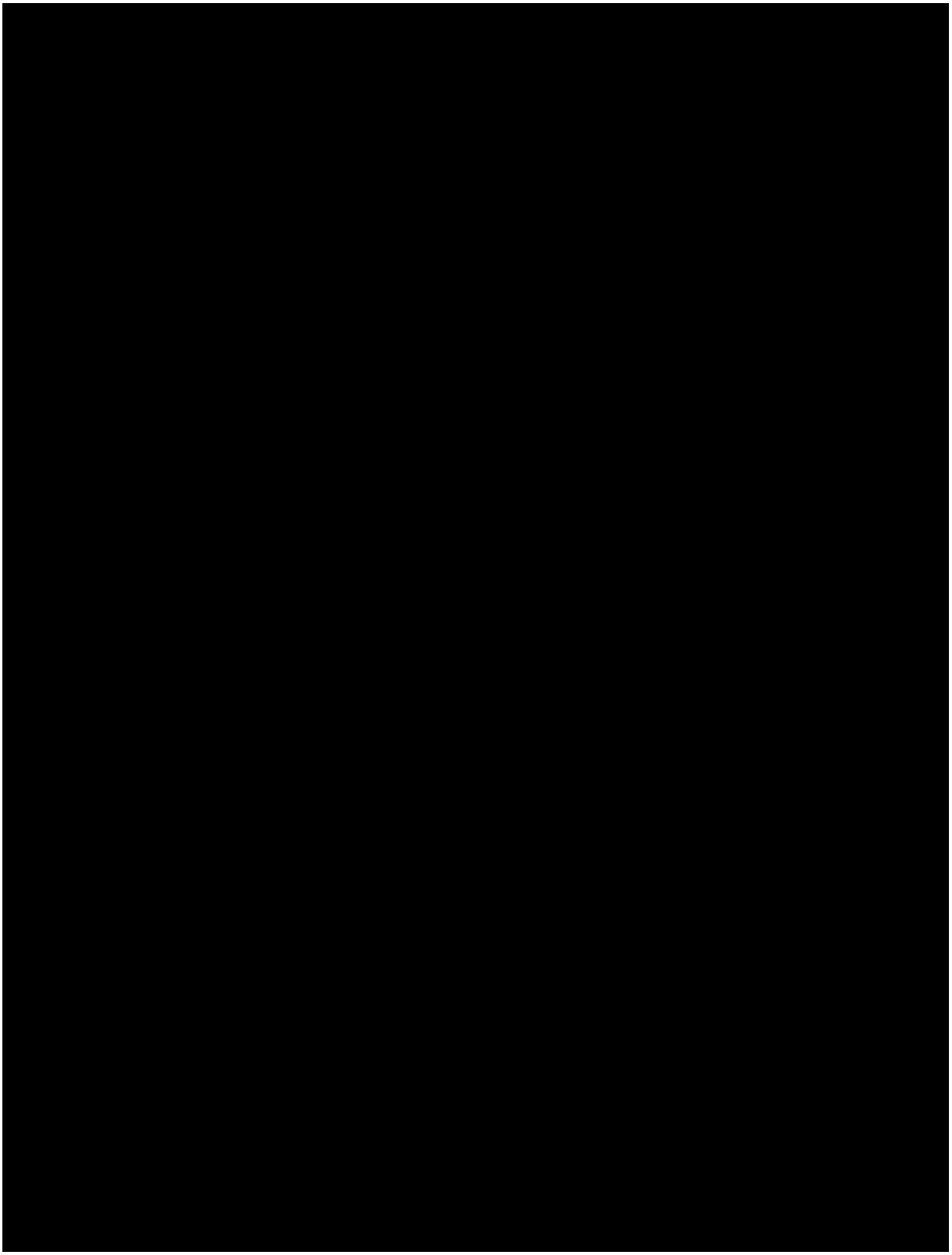


Figure 2-20 – Plot of pore pressure gradient vs. depth calculated from log data at the [redacted]

2.5.2.3 Fracture Gradient

Eaton's method (Eaton, 1969), widely acknowledged as the standard practice for the determination of fracture gradients, was used to calculate the pressure required to fracture the injectable rock. The method requires Poisson's ratio (v), overburden gradient (OBG), and pore gradient (PG) to be [redacted] psi/ft, to determine the fracture gradient. Table 2-3 provides the values of each input.

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

Inputs	Values
Poisson's Ratio	[redacted]
Overburden Gradient (psi/ft)	
Pore Gradient (psi/ft)	

Poisson's ratio was determined through an extensive literature review on unconsolidated sandstones and core data. 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 Miocene sands. In 2014, a case study was done to model fracture initiation in poorly consolidated sandstone, resulting in a ratio of 0.27 (Sun et al., 2015). Further research showed that soft sandstones can have a range of 0.2–0.35 (Molina, Vilarras, and Zeidouni, 2017). [redacted]

With the inputs, it is possible to calculate a fracture gradient (FG). Equation 3 highlights the necessary steps for calculating the gradient. Per TAC **§5.203(f)(2)(C)** [40 CFR **§146.88(a)**], the well may not exceed 90% of the FG during injection operations. Therefore, the model applied a pressure constraint of [redacted] psi/ft to all injectors.

(Eq. 3) $$FG = \frac{\nu}{1-\nu}(OBG - PG) + PG$$

[redacted]

2.5.2.4 Reservoir Fluid Properties

Reservoir Temperature

An evaluation of well logs near the Titan Project was conducted to estimate the reservoir temperature. From this evaluation, the nearest well log was chosen to provide the most analogous data point to the target formation. [redacted] This gradient is added onto a surface temperature of 70°F, the mean annual surface temperature.

Brine Salinity

A constant salinity value of [redacted] TDS was input into the model. This value is based on the average salinity estimates of the injection zone taken from well log analysis of the [redacted] This method of estimating salinity entails determining an apparent water resistivity (R_{wa}) by applying Archie's equation to porosity and resistivity data. Subsequently, the R_{wa} value is transformed into salinity using conventional petrophysical charts, provided by service companies such as SLB (previously known as Schlumberger).

2.5.3 Rock Properties Hysteresis Modeling

Rock (Pore Space Volume) Compressibility

A literature review was conducted to determine the rock compressibility of the Gulf Coast Miocene sands. Due to the lack of regional rock compressibility data, an expanded search for data into poorly sorted, unconsolidated sandstones was undertaken. The literature review analysis indicates that this type of formation can have compressibility values within a range of 10–40 microsips, as highlighted in Figure 2-21. [redacted] This assumption is subject to revision as additional data from the stratigraphic test well becomes available.

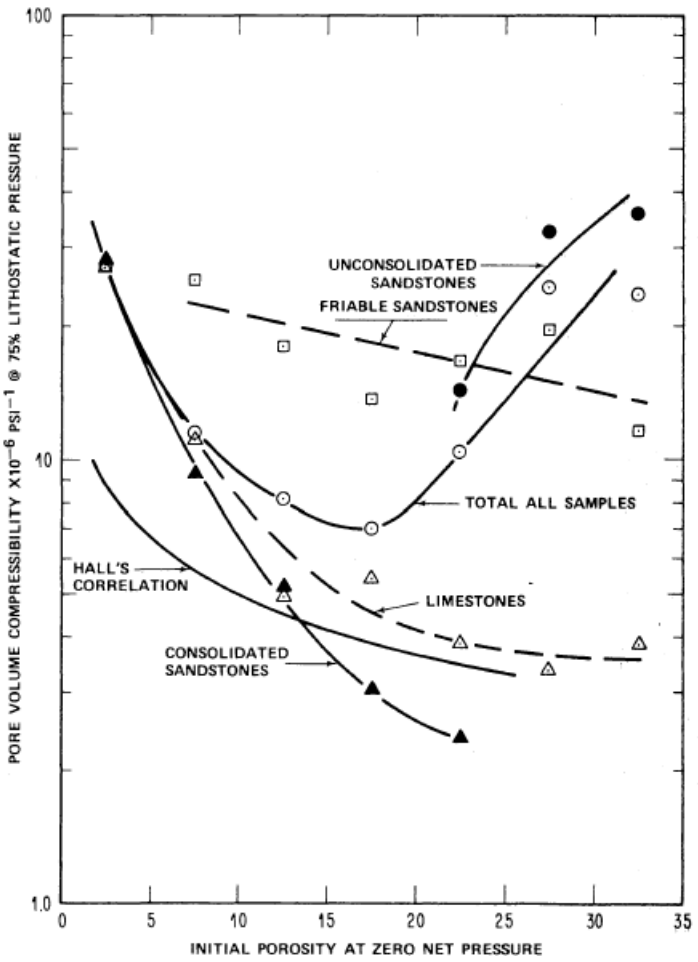


Figure 2-21 – Pore-Volume Compressibility vs. Initial Sample Porosity (Newman, 1973)

Residual Gas (Nonwetting Phase) Saturation

A comprehensive literature review was conducted to determine the maximum residual-gas saturation (S_{grm}). Numerous studies were reviewed to find a value that most accurately represents the target formation. One report (Holtz, 2005) established a correlation between porosity and S_{grm}. Another report (Hovorka, 2003), based on one of the first CCS pilots within the United States, used a relationship between porosity and S_{grm} similar to the first report. A chart illustrating the relationship between porosity and the maximum residual-gas saturation for unconsolidated Miocene sands is displayed in Figure 2-22 (Holtz, 2005). [redacted]

Figure 2-22 – Porosity vs. Residual Gas Saturation Relationship (Holtz, 2005)

Relative Permeability Curves

The absolute permeability of a porous medium is the permeability when only a single fluid is present within the pore space. When only one fluid is present within the reservoir, the effective permeability is equal to the absolute permeability. However, the effective permeability decreases as new fluids are introduced into the reservoir. This phenomenon is depicted by relative permeability curves, which illustrate the effective permeability of two or more fluids as they flow through a porous medium.

The GEM utilizes hysteresis modeling to establish the amount of supercritical CO_2 that is residually trapped. The hysteresis model enables the simulation of both drainage and imbibition processes. *Drainage* is the process of a nonwetting fluid (supercritical CO_2) displacing the wetting fluid (brine) as it is injected into and migrates through the reservoir. *Imbibition* refers to the reentry of the brine into the pore space, during which a certain amount of CO_2 becomes effectively trapped within the pore space.

In the absence of site-specific core data, relative permeability curves were constructed based on a literature review of similar depositional environments. The Corey-Brooks equations were used to generate the relative permeability curves used in the model. [redacted] iterature suggests that the K_{rw0} endpoint can be as high as 1.0 for analogous formations (Benson et al., 2013). [redacted]

[redacted]

[redacted] The data pertaining to the construction of the relative permeability curves are based on multiple references from the literature review (Bachu and Bennion, 2008; Bachu, 2012; Krevor et al., 2012). Subsequently, the imbibition curves were internally computed in GEM using the Carlson and Land method. Figure 2-23 shows the drainage and imbibition relative-permeability curves used in the model.

Figure 2-23 – Two-phase relative permeability curves implemented in the model.

[redacted] The model and subsequent curves will be updated after the cores have been tested and analyzed.

2.6 Well Operations Setup

For the Titan Project, the wellbore models for both wells were set up using the proposed wellbore schematics (WBS) along with assumptions provided in Table 2-4. Three primary constraints were imposed in GEM to limit the pressure response and CO_2 plume growth: (1) a maximum injection rate of [redacted] MMT/yr, (2) a maximum bottomhole pressure (BHP) gradient of [redacted] psi/ft, and (3) an injection period [redacted] years for both the Cronos No. 1 and Rhea No. 1 injection wells. Based on the proposed WBS, Titan plans to implement a [redacted] inch (in.) tubing string. This tubing size was considered when calculating the wellhead pressure (WHP) in GEM.

Table 2-4 – Well Hydraulics Input Summary

Inputs	Cronos No. 1 Values	Rhea No. 1 Values
Maximum Injection Rate (MMT/yr)	[redacted]	
Pressure Constraint Gradient (psi/ft)		
Injection Duration (yrs)		
Tubing Inner Diameter (in.)		
Tubing Setting Depth (ft)		
Roughness Factor		
Compressor Outlet Temperature (°F)		
Compressor Outlet Pressure (psi)		

Each injection well is divided into multiple completion stages to optimize the usage of available pore space. Each completion stage represents a portion of the reservoir that will be injected into at a given time. Figure 2-24 provides a theoretical depiction of the completion strategy planned for carbon sequestration. At each new completion, the pressure constraint is updated based on the upper perforation depth. This strategy is done to ensure that the BHP never exceeds the calculated fracture gradient. [redacted] A general description of the completion strategies is summarized in Tables 2-5 and 2-6.

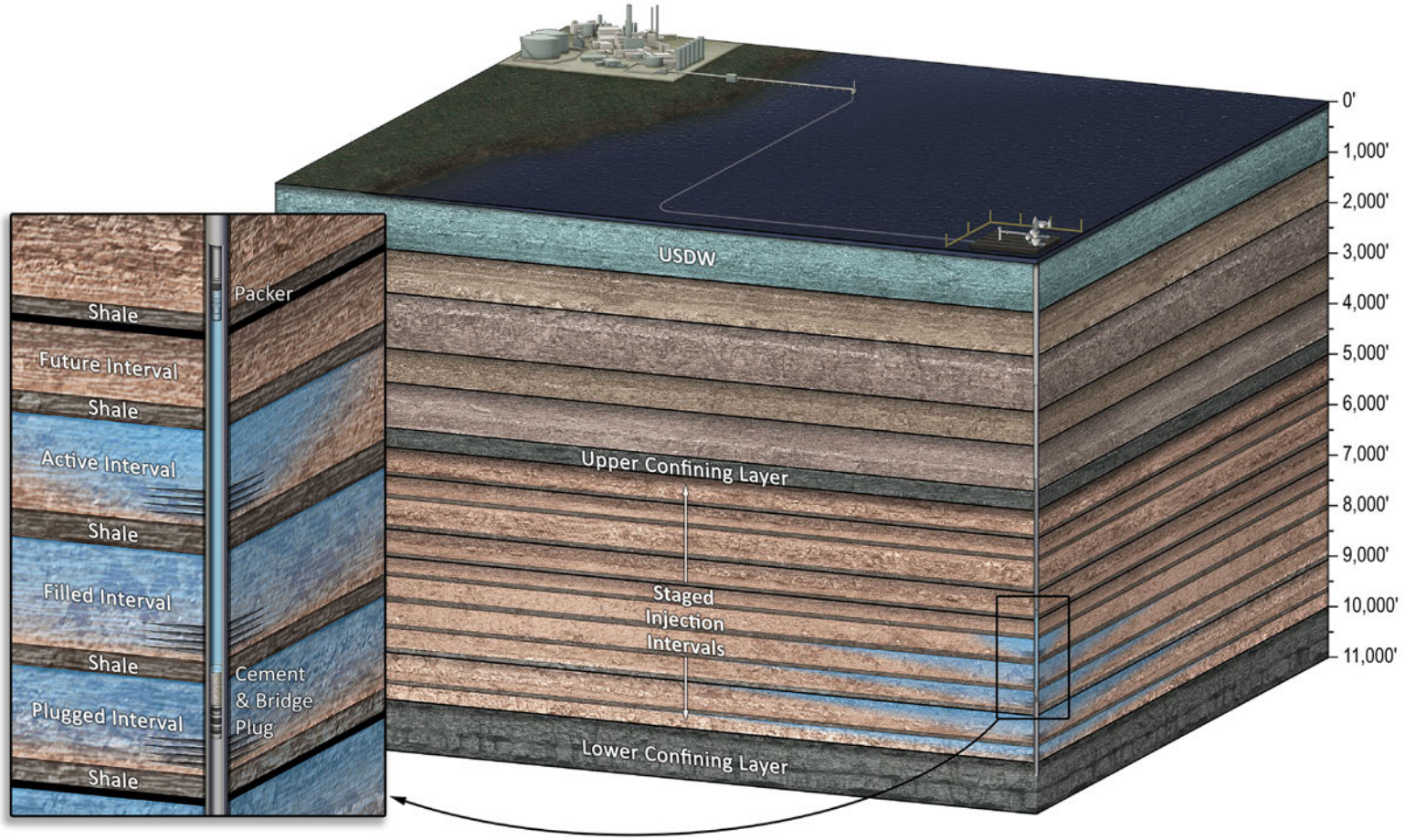


Figure 2-24 – Depiction of Completion Strategy

Table 2-5 – Summary of Completion Stages for Cronos No. 1

Stage	Top Perf (ft)	Bottom Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]					

Table 2-6 – Summary of Completion Stages for Rhea No. 1

Stage	Top Perf (ft)	Bottom Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]					

[redacted]

2.7 Model Results

2.7.1 Active Injection Operations of Proposed CO_2 Injector

During the life of the CO_2 injectors, the BHP and injection rate are simulated for each completion stage. Figures 2-25 and 2-26 depict the injection rates and BHP responses during operational activities. The rates are held at a constant rate of [redacted] MMT/yr for the injection periods for both wells, and the BHP never exceeds 90% of the fracture gradient. Because of the relative permeability, the BHP "spikes" at the start of each stage of injection. Once the CO_2 flow is established, the reservoir pressure declines to the expected values.

Figure 2-25 – Modeled BHP and Injection Rate for Cronos No. 1

Figure 2-26 – Modeled BHP and Injection Rate for Rhea No. 1

The WHP was calculated using GEM. Values such as tubing inner diameter, tubing setting depth, roughness factor, and compressor outlet pressure and temperature from Table 2-4 (*Section 2.6*)

were used as inputs for the wellbore model. The calculations used BHP outputs from GEM to estimate the WHP.

Based on the model simulation, the maximum expected BHP of Cronos No. 1 is [redacted] psi during the life of the project, evaluated at [redacted]. On average, the BHP of the well will be [redacted] psi. The maximum WHP is calculated to be [redacted] psi with an average of [redacted] psi. Table 2-7 highlights the outputs for this injection well as modeled in GEM.

Table 2-7 – Cronos No. 1 Model Outputs

Stage	Year	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Based on model simulation, the maximum expected BHP of Rhea No. 1 is [redacted] psi during the life of the Titan Project, evaluated at [redacted] ft. On average, the BHP of the well will be [redacted] psi. The maximum WHP is calculated to be [redacted] psi with an average of [redacted] psi. Table 2-8 provides the outputs for this injection well as modeled in GEM.

Table 2-8 – Rhea No. 1 Model Outputs

Stage	Year	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Reservoir pressure is expected to increase from initial conditions during the active injection period. The highest increase is expected at the wellbore and then propagates throughout the formation rock, resulting in a general increase of pressure within the aquifer region. This pressure-increase phenomenon is referred to as "pressure buildup," which is monitored by the rise of reservoir pressure as well as its associated gradient based on the top of the perforated interval.

Figures 2-27 and 2-28 represent the maximum pressure buildup at the two injection wells—the BHP result—which represents the maximum pressure seen within the reservoir at any given time. In addition, since these pressure values are retrieved at different depths, the pressure gradient is also calculated as pressure divided by depth (i.e., the calculated pressure gradient). [redacted] As shown in Figures 2-27 and 2-28, the pressure gradient never exceeds the constraint (90% of FG) imposed on the wells, to allow for the safe injection of supercritical CO_2.

Figure 2-27 – Pressure Buildup for Cronos No. 1 During Active Injection Operations

Figure 2-28 – Pressure Buildup for Rhea No. 1 During Active Injection Operations

The elevated pressure in the saline aquifer quickly dissipates once active injection operations cease. [redacted] Figures 2-29 and 2-30, for the two wells respectively, show the pressure buildup throughout the life of the project.

Figure 2-29 – Pressure Buildup for the Life of Cronos No. 1

Figure 2-30 – Pressure Buildup for the Life of Rhea No. 1

2.8 CO_2 Plume Migration for AOR Delineation

According to TAC **§5.203(d)** [40 CFR **§146.84**], the AOR must be determined by the maximum extent of either the supercritical CO_2 plume or critical pressure front—or both. The first review starts with the extent of the CO_2 plume. The Occupational Safety and Health Administration (OSHA) has set an acceptable exposure limit of CO_2, indicating that up to 30,000 ppm over a 10-minute period is within safe guidelines. Both Titan injection wells were used to determine the plume extent. Injection of CO_2 into the two wells results in a combined supercritical CO_2 plume.

Due to the geologic structure of the reservoir and presence of channels, the CO_2 plume may migrate in different directions from the injector wells. Channels may act as a high permeability conduit that CO_2 can migrate further through. Structural dip also influences the migration of the CO_2 plume. The less dense CO_2 migrates upward due to buoyancy effects until it reaches an impermeable layer, like an interbedded shale. The formation's upward dip then facilitates migration. [redacted] Figure 2-31 provides a 3D view of the stabilized plume in the year [redacted] highlighting the different directions in which the plume migrates, while also illustrating the concept of structural trapping. Interbedded shales and shale baffles serve as traps for the supercritical CO_2 to prevent further upward and lateral migration. The largest extent of the plume is determined by the maximum saturation experienced in all the modeled layers at a specified point in time.

Figure 2-31 – A vertical 3D representation (left) and aerial view (right) of supercritical CO_2 plume in [redacted] colored by CO_2 saturation.

The CO_2 plume [redacted] for both injection wells. Figures 2-32 through 2-35 show the cross-sectional view of the plumes and highlight how the shape and size of the plumes vary in each sand package. Between each sand package, interbedded clay-rich shales exist that help structurally trap CO_2 and inhibit vertical migration. The current completion strategy is designed to use these interbedded shales, to help permanently sequester CO_2 between completion stages while minimizing the plume footprint.

Figure 2-32 – West-east cross-sectional view at Cronos No. 1 [redacted] colored by CO_2 saturation.

Figure 2-33 – West-east cross-sectional view at Rhea No. 1 [redacted], colored by CO_2 saturation.

Figure 2-34 – South-north cross-sectional view at Cronos No. 1 [redacted], colored by CO_2 saturation.

Figure 2-35 – South-north cross-sectional view at Rhea No. 1 [redacted] colored by CO_2 saturation.

The CO_2 plume in Figure 2-36 is delineated from the maximum CO_2 saturation seen in each layer of the model. The plume extent is taken in [redacted]

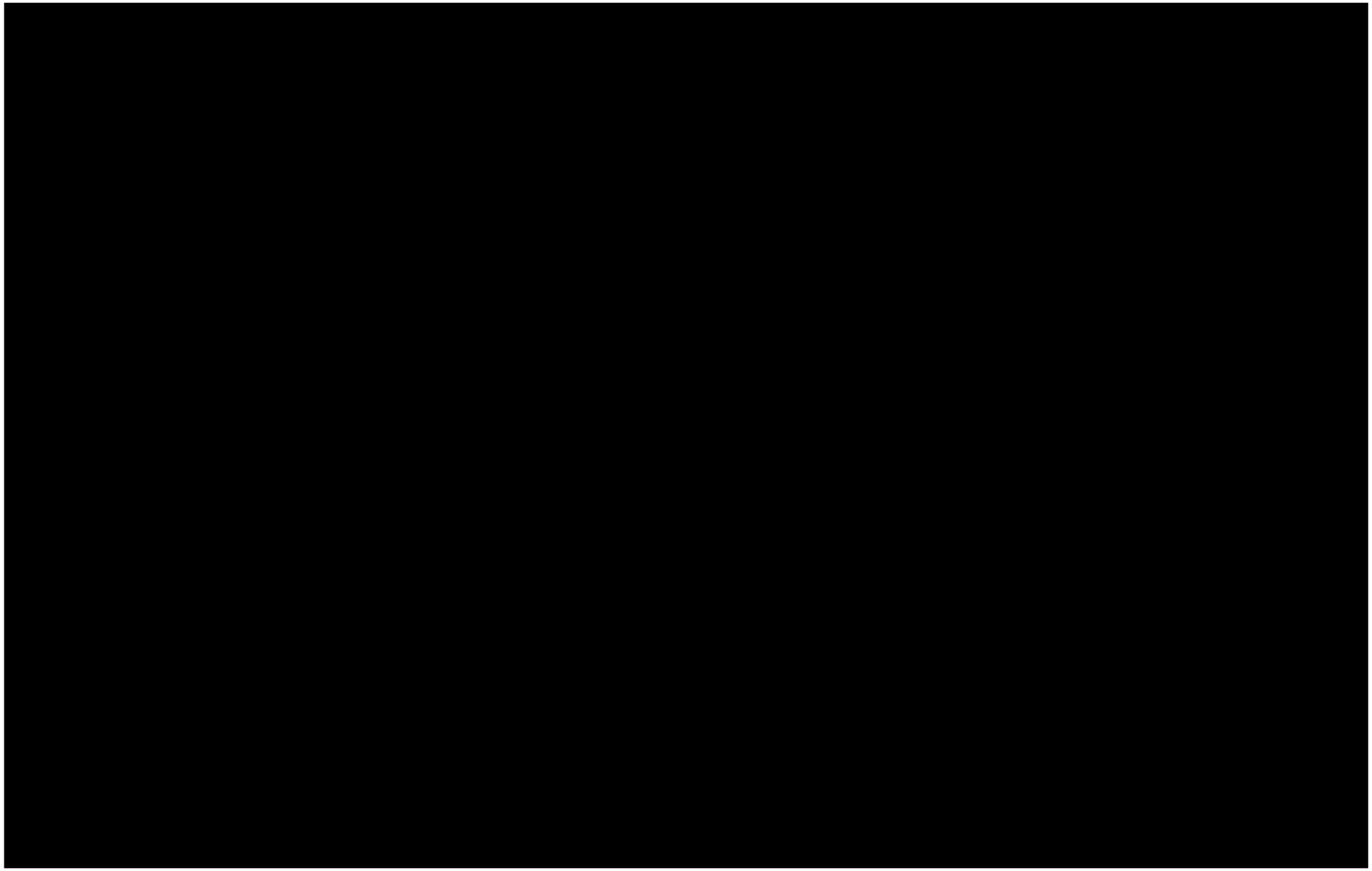


Figure 2-36 – Aerial View of Supercritical CO_2 Front [redacted] Outlined in Black

2.8.1 Trapping Summary

Figure 2-37 shows the breakdown of the trapping mechanism. Once injection stops [redacted] the mobile CO_2 quickly decreases as supercritical phase CO_2 migrates through pore space and is trapped. Over the life of the project, [redacted] These percentages of trapped CO_2 agree with data from literature based on the maximum residual gas saturation value implemented in the model (Metz et al. 2005; Holtz 2002).

Figure 2-37 – Modeled Trapping Mechanisms (the red line designating end of injection)

2.8.1.1 Stabilized Plume

Plume stabilization occurs when the rate of growth or positional change has slowed to a nearly imperceptible change per year. At that point, the CO_2 plume is considered hydrodynamically trapped in the pore space. This stabilization point is determined by the model output, where the areal growth rate is [redacted]

The reservoir model determines that plume stabilization occurs by the [redacted] To be conservative and in accordance with [40 CFR **§146.93(b)(1)**], the plume is monitored for 50 years after injection ceases, even though stabilization has occurred. Because of the proximity of the two injection wells, the plumes of both coincide with one another to create one plume. The

plume growth therefore considers the one combined plume. While incidental plume movement may occur after this period, the reservoir model indicates that the plume will continue to remain on acreage that Titan has secured by underground storage easements. Figure 2-38 demonstrates that the rate of plume movement decreases to [redacted] post-injection.

Figure 2-38 – Plume Growth Over Time

2.9 Critical Pressure Front for AOR Delineation

In accordance with TAC **§5.203(d)** [40 CFR **§146.84**], the AOR was delineated by the critical pressure front created by the injection of supercritical CO_2 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 first step to predict the pressure front is to calculate the critical pressure for each completion stage. Once critical pressure is determined, a numerical simulation is used to predict the size and shape of the critical pressure front. A conservative approach on determining the critical pressure front was used [redacted]

[redacted] This case allows for a larger and therefore more conservative strategy of calculating the critical pressure front.

The EPA has outlined three potential methodologies to calculate the critical pressure. Method 2, which uses Nicot's method to calculate the critical pressure, was used in this model. Nicot assumes that the reservoir is in hydrostatic equilibrium, neither under- nor overpressurized, and that a direct path between the two zones exists. This path could be in a hypothetical incorrectly plugged-and-abandoned wellbore or some other subsurface feature.

For the purpose of the critical pressure calculations, the base of the USDW was estimated to be at [redacted] true vertical depth (TVD), as stated in *Section 1.8*. This depth is based on analysis of offset wells nearest to the proposed injector locations [redacted] that indicate the depth of the USDW's base within plugging and abandonment reports of [redacted] TVD. Said plugging and abandonment reports are in alignment with the Bureau of Economic Geology (BEG) estimations for the area, as stated in *Section 1.8.4*. The USDW base will be confirmed by the Groundwater Advisory Unit of the Texas Railroad Commission (TRRC). The critical pressure was calculated for each completion of each injection well, with the top of injection [redacted] The fluid in the injection zone is assumed to be brine, with [redacted] TDS, which results in a [redacted] psi/ft pressure gradient. The fluid within the USDW was assumed to be fresh water (less than 10,000 ppm), with a pressure gradient of 0.436 psi/ft. The inputs used in the calculation are provided in Table 2-9.

Table 2-9 – Critical Pressure Calculation Parameters

Parameter	Symbol	Value
Depth to Base of USDW	(D_u)	[redacted]
Depth to Top of Injection Zone	(D_i)	
Gradient of USDW	(G_u)	
Gradient of Injection Zone	(G_i)	

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

(Eq. 4) $$\xi = \frac{G_i - G_u}{D_i - D_u}$$

[redacted]

The critical pressure rise (ΔP_c) is then calculated using Equation 5. The inputs include the coefficient (ξ) calculated in Equation 4 and the depths for the base of the USDW (D_u) and top of the injection zone (D_i).

(Eq. 5) $$\Delta P_c = \frac{1}{2} * \xi * (D_i - D_u)^2$$

[redacted]

The resulting critical pressure rise for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by approximately [redacted] psi, without risk of fluid migration to the USDW. The calculated critical pressure rise for each of the completion stages for both injection wells is included in Tables 2-10 and 2-11.

Table 2-10 – Cronos No. 1 Critical Threshold Pressure for Each Completion Stage

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

Table 2-11 – Rhea No. 1 Critical Threshold Pressure for Each Completion Stage

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

Due to the complex and heterogeneous nature of the reservoir, the critical pressure front may propagate in different directions. The critical pressure front is delineated by the maximum extent of the pressure front from each completion stage. [redacted]

[redacted]

The AOR is, in part, determined by the [redacted] 1. Figure 2-39 provides a snapshot of the largest extent of the critical pressure front experienced in the model.

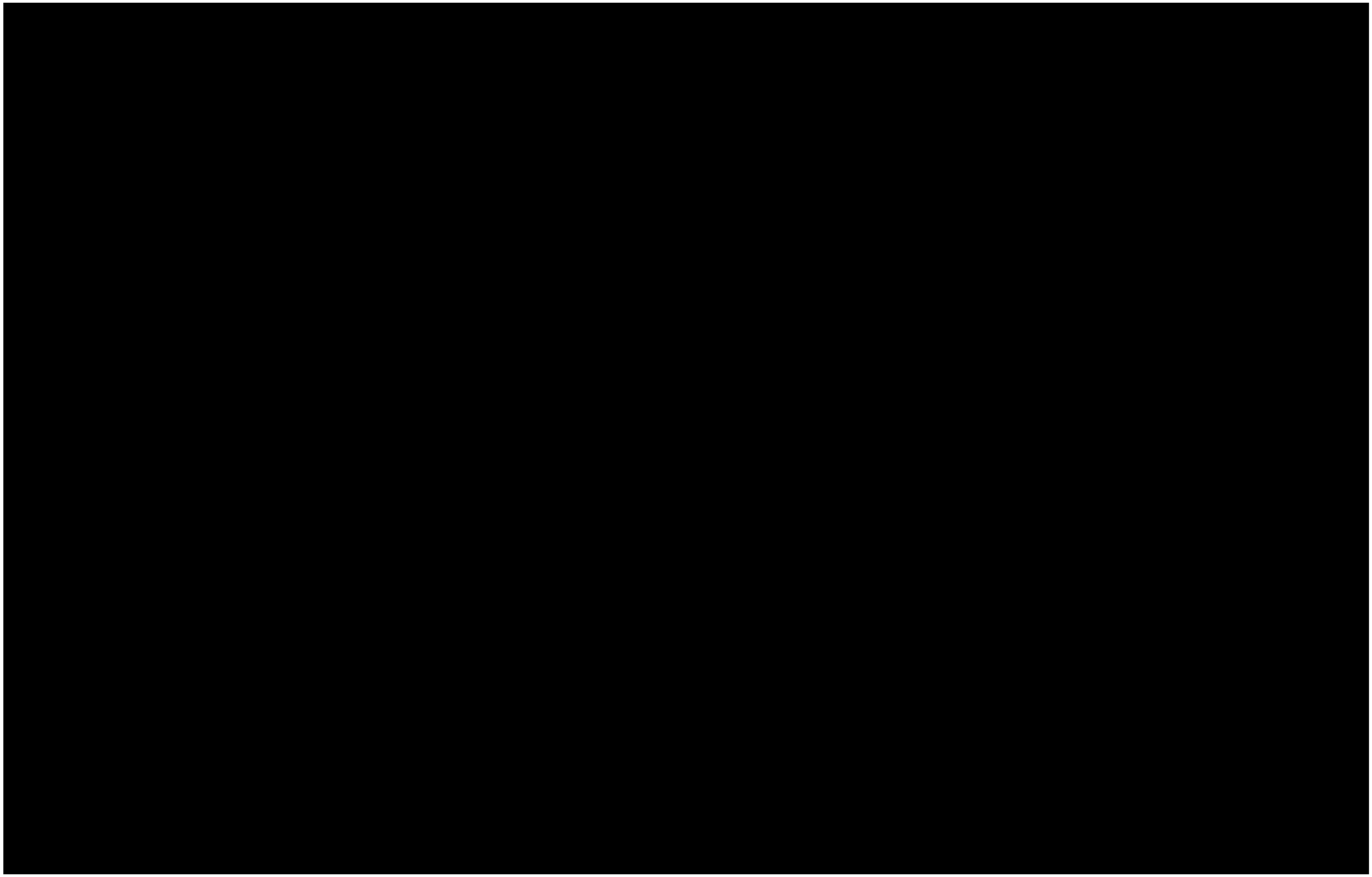


Figure 2-39 – Greatest Extent of Critical Pressure Front, Outlined in Pink

2.10 Final AOR

The maximum CO_2 plume and critical pressure front delineate the AOR, which determines the necessary evaluation of, and potential corrective action needed for, any offset wells. The CO_2 saturation front is determined by the greatest extent of the fluid in any direction throughout the injection zone. The acceptable exposure limit of CO_2 set by OSHA indicates that up to 30,000 ppm over a 10-minute period is within safe guidelines [redacted]. The critical pressure front was determined from the greatest areal extent of all completion stages for both injection wells. Figure 2-40 provides the final AOR outlines for the project.

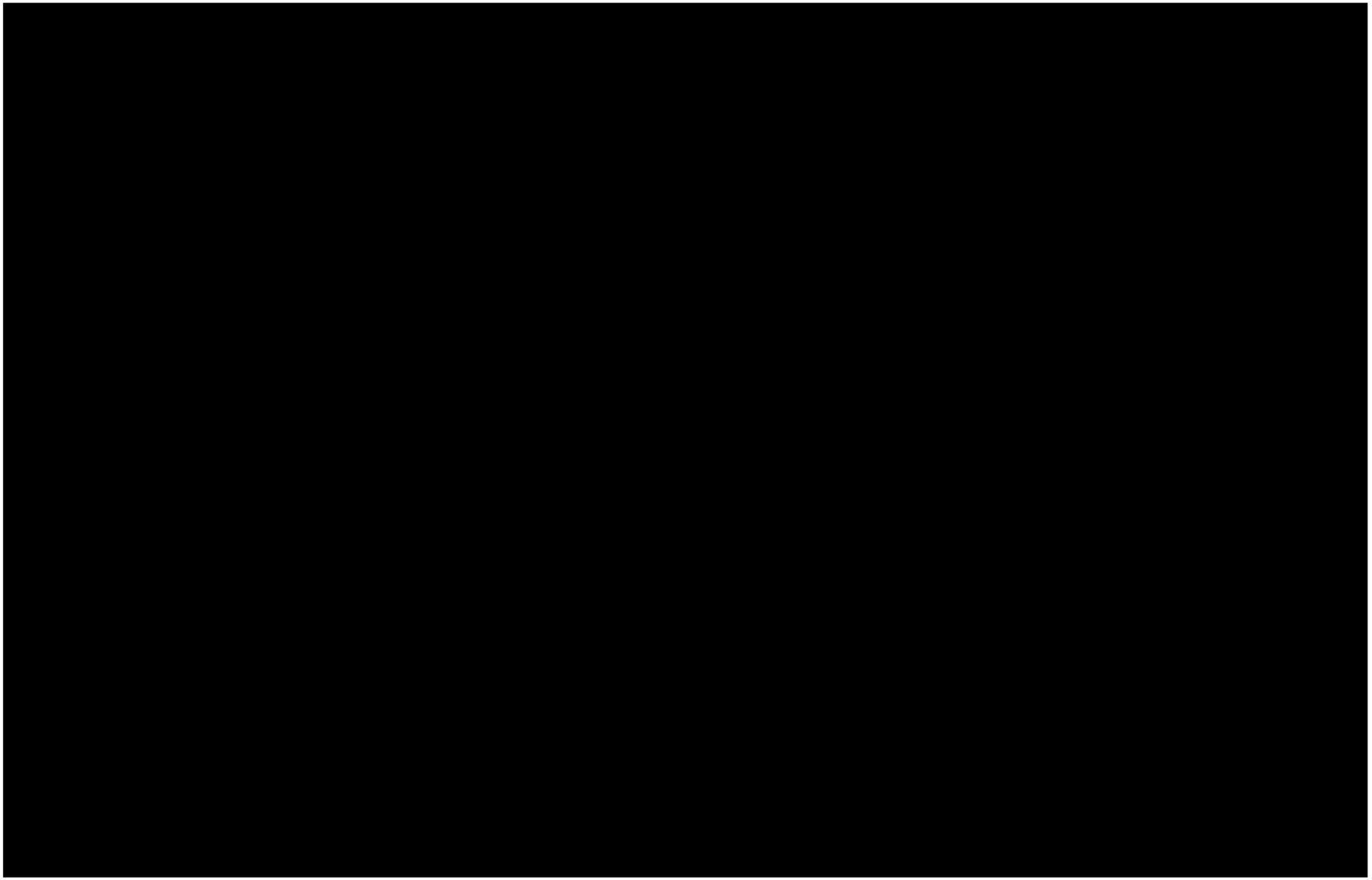


Figure 2-40 – Cronos No. 1 and Rhea No. 1 (Titan Project) Final AOR

2.11 References

Bachu, S. (2012). Drainage and Imbibition CO2/Brine Relative Permeability Curves at In Situ Conditions for Sandstone Formations in Western Canada. *Energy Procedia* 37. 10.1016/j.egypro.2013.07.1

Bachu, S., and Bennion, B. (2008). Effects of in-situ conditions on relative permeability characteristics of CO2-brine systems. *Environ Geol* 54: 1707–1722.

Backeberg, N., Iacoviello, F., Rittner, M. et al. (2017). Quantifying the anisotropy and tortuosity of permeable pathways in clay-rich mudstones using models based on X-ray tomography. *Scientific Reports*, 7. 10.1038/s41598-017-14810-1.

Benson, S., Pini, R., Reynolds, C., and Krevor, S. (2013). Relative Permeability Analysis to Describe Multi-Phase Flow in CO2 Storage Reservoirs; No. 2; Global CCS Institute: Melbourne, Australia.

Burnside, N. M., and Naylor, M. (2014). Review and implications of relative permeability of CO2/brine systems and residual trapping of CO2, *International Journal of Greenhouse Gas Control*, Volume 23.

Chen, X., Gao, S., Kianinejad, A., and DiCarlo, D. A. (2017). Steady-state supercritical CO2 and brine relative permeability in Berea sandstone at different temperature and pressure conditions. *Water Resources Res.* 53: 6312– 6321. https://doi:10.12/2017WR020810.

Chudi, O. K., Lewis, H., Stow, D. A. V., and Buckman, J. O. (2016). Reservoir quality prediction of deep-water Oligocene sandstones from the west Niger Delta by integrated petrological, 61petrophysical and basin modelling. In: Armitage, P.J., Butcher, A. et al., ed., Reservoir Quality of Clastic and Carbonate Rocks: Analysis, Modelling and Prediction. Geological Society, London, Special Publications, 435. https://doi.org/10.1144/ SP435.8.

Eaton, B. A. (1969). Fracture Gradient Prediction and Its Application in Oil Field Operations. *Journal of Petroleum Technology*, 25-32.

Holtz, M. H. (2002). "Residual Gas Saturation to Aquifer Influx: A Calculation Method for 3-D Computer Reservoir Model Construction." Paper presented at the SPE Gas Technology Symposium, Calgary, Alberta, Canada, April 2002. https://doi.org/10.2118/75502-MS.

Holtz, M. H. (2005). “Reservoir Characterization Applying Residual Gas Saturation Modeling, Example From the Starfak t1 Reservoir, Middle Miocene Gulf of Mexico.”

Hovorka, S. D., Holtz, M. H., Sakurai, S. et al. (2003). Frio pilot in CO2 sequestration in brine-bearing sandstones: The University of Texas at Austin, Bureau of Economic Geology, report to the Texas Commission on Environmental Quality to accompany a Class V

application for an experimental technology pilot injection well. *GCCC Digital Publication Series No. 03-04*.

Krevor, S. C. M., Pini, R., Zuo, L., and Benson, S. M. (2012). Relative permeability and trapping of CO2 and water in sandstone rocks at reservoir conditions. *Water Resources Res.*

McCain, W. D. (1991). Reservoir-Fluid Property Correlations—State of the Art. *SPE Res Eng* 6: 266–272. https://doi.org/10.2118/18571-PA.

Metz, B., Davidson, O., de Connick, H., Loos, M., and Meyer, L. ed. (2005). IPCC Special Report on Carbon Dioxide Capture and Storage. Cambridge, United Kingdom: Cambridge University Press.

Molina, O., Vilarrasa, V., and Zeidouni, M. (2017). Geologic Carbon Storage for Shale Gas Recovery. *Energy Procedia* 114: 5748-5760. 10.1016/j.egypro.2017.03.1713.

Müller, N. (2011). Supercritical CO2-Brine Relative Permeability Experiments in Reservoir Rocks—Literature Review and Recommendations. *Transp Porous Med* 87: 367–383.

Newman, G. H. (1973). Pore-volume compressibility of consolidated, friable, and unconsolidated reservoir rocks under hydrostatic loading. *Journal of Petroleum Technology* 25(02): 129–134. https://doi.org/10.2118/3835-pa.

Sun, J., Deng, J., Yu, B., and Peng, C. (2015). Model for fracture initiation and propagation pressure calculation in poorly consolidated sandstone during waterflooding. *Journal of Natural Gas Science and Engineering* 22: 279-291. 10.1016/j.jngse.2014.12.004

Taylor, T. R., Kittridge, M. G., Winefield, P. et al. (2015). Reservoir quality and rock properties modeling – Triassic and Jurassic sandstones, greater Shearwater area, UK Central North Sea. *Marine and Petroleum Geology* 65: 1–21. https://doi.org/10.1016/j.marpetgeo.2015.03.020.

Weber, K., and van Geuns, L. (1990). Framework for Constructing Clastic Reservoir Simulation Models. *Journal of Petroleum Technology*, 1248-1253, 1296-1297.

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

February 2024

LONQUIST
SEQUESTRATION LLC

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

TABLE OF CONTENTS

3.1 Facility Information 2
3.2 Computational Modeling 2
3.3 Area of Review Discussion 3
3.3.1 Area of Review: Pore Occupancy Plume 3
3.3.2 Area of Review: Pressure Front 4
3.3.3 Operating Strategies Influencing Reservoir Modeling Results 8
3.3.4 Area of Review Results 14
3.4 Corrective Action Plan and Schedule 18
3.5 Area of Review Reevaluation Plan and Schedule 18
3.5.1 Proposed Reevaluation Cycle 19

Figures

Figure 3-1 – Critical Pressure Front 7
Figure 3-2 – West-east cross-sectional view at Cronos No. 1, colored by CO_2 saturation. 9
Figure 3-3 – West-east cross-sectional view at Rhea No. 1, colored by CO_2 saturation. 10
Figure 3-4 – A 3D representation of supercritical CO_2 plumes [redacted] colored by CO_2 saturation 11
Figure 3-5 – GEM Plume Model Results, Plan View Maximum Extents 12
Figure 3-6 – Final AOR Map 13
Figure 3-7 – Map of Nearest Offset Artificial Penetrators 15
Figure 3-8 – Map of Nearest Offset Water Wells 16

Tables

Table 3-1 – Model Input Parameters and Assumptions 2
Table 3-2 – Inputs for Critical Pressure Calculation 4
Table 3-3 – Cronos No. 1 Critical Threshold Pressure for Each Completion Stage 5
Table 3-4 – Rhea No. 1 Critical Threshold Pressure for Each Completion Stage 6
Table 3-5 – Triggers for AOR Reevaluations 20

3.1 Facility Information

Facility Name: Titan Carbon Sequestration Project

Injection Well Information:

Well Name and Number	Cronos No. 1
County	Jefferson County, TX
Latitude and Longitude	[redacted]
Well Name and Number	Rhea No. 1
County	Jefferson County, TX
Latitude and Longitude	[redacted]

3.2 Computational Modeling

Model Name: GEM (Ver. 2023.2)

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 Per Well

Input	Value
Injection Rate (MT/yr)	[redacted]
Average Porosity (%)	
Average Permeability (mD)	
Average Kv/Kh Ratio	
Pore Pressure Gradient (psi/ft)	
Frac Pressure Gradient (psi/ft)	
Mean Surface Temperature (°F)	
Temperature Gradient (°F/100 ft)	
Salinity (ppm)	

*MT/yr – metric tons per year
mD – millidarcy

3.3 Area of Review Discussion

Title 16, Texas Administrative Code (16 TAC) **§5.203(d)**[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. The EPA defines the AOR as the greater of either (1) the maximum extent of the separate-phase plume (pore occupancy plume) or (2) the pressure front—where the pressure buildup is of sufficient magnitude (i.e., pressure front plume) to force fluids from the injection zone into the formation matrix of an Underground Source of Drinking Water (USDW). The Titan Carbon Sequestration Project (Titan Project) AOR was determined under both definitions.

3.3.1 Area of Review: Pore Occupancy Plume

The pore occupancy plume area was delineated using computational modeling, which considers the physical and chemical properties of all phases of the injected CO_2 stream. This modeling process is based upon the data obtained from site characterization, monitoring, and operational data. *Section 2 – Plume Model* comprehensively discusses this modeling effort and establishes the boundaries of the pore occupancy plume area.

In the investigation of the pore occupancy plume AOR, three key elements were identified and assessed: (1) artificial penetrations, (2) subsurface characteristics, and (3) pore space rights.

Within this AOR, artificial penetrations such as wellbores were reviewed for suitable completions, plugging strategies, and construction materials. To comply with Class VI regulations, these wellbores must be constructed or plugged using materials appropriate for storing carbon oxides. Consequently, any wellbore located within the pore occupancy plume, that penetrates the primary injection zone and was not appropriately plugged, necessitates a corrective action or contingency plan. This approach ensures that no wellbore serves as a conduit for the escape of stored CO_2 or reservoir fluids from containment. Conversely, any wellbore situated within the AOR boundary that does not penetrate the primary injection zone will be deemed to have no impact on containment integrity, and therefore will not factor into any corrective action or contingency plan considerations.

Subsurface characteristics within this AOR will undergo an assessment to determine their influence on the primary injection zone. These features encompass a range of elements, including but not limited to faults, mapped fractures, folds, steeply dipping formations, and salt diapirs. Certain features can function as barriers, establishing no-flow boundaries that enhance the containment of stored CO_2. Conversely, some of these subsurface attributes could serve as conduits out of the containment zone. Nevertheless, Titan Carbon Sequestration, LLC (Titan) has determined that any such structures should not permit the escape of CO_2 to the surface.

Reservoir modeling simulations indicate that the CO_2 plume growth and extent will remain on Titan-controlled fee acreage at the Titan Project.

3.3.2 Area of Review: Pressure Front

The second AOR to be examined is the pressure front generated during the injection of fluids into a reservoir that was previously in a state of equilibrium. The boundaries of the pressure front AOR are established through a combination of calculated values and simulation modeling. The critical pressure buildup that might lead to potential fluid migration is assessed for inadequately plugged-and-abandoned artificial penetrations and any subsurface features identified that breach the upper confining zone (UCZ) of the primary injection zone.

Titan has established that the most adverse situation for the migration of reservoir fluids into the USDW would involve an open or improperly sealed-and-abandoned wellbore that remains open at both the upper boundary of the injection zone and the lower boundary of the USDW. The pressure threshold at which this becomes possible is called the critical pressure. The analysis assumes that the injection zone is in a state of hydrostatic equilibrium, meaning it is neither overpressured nor underpressured. The approach used to determine the critical pressure draws from EPA guidance, relying on calculations that consider the displacement of the initially present borehole fluid under hydrostatic conditions. Because the reservoir is in hydrostatic equilibrium, EPA Method 2 is used to determine the critical pressure.

The base of the USDW is expected to be at [redacted] as observed on offset well logs [redacted], as discussed in *Section 1.9*. The critical pressure was calculated for each of the injection stages, with the top depth of each stage ranging from [redacted] ft. The fluid in the injection zone is assumed to be brine with [redacted] parts per million (ppm) total dissolved solids, which results in a [redacted] pounds per square inch (psi)/ft pressure gradient. The fluid within the USDW was assumed to be fresh water with a pressure gradient of [redacted] psi/ft. Table 3-2 summarizes the calculation inputs.

Table 3-2 – Inputs for Critical Pressure Calculation

Inputs for Critical Pressure Calculation	
Depth to Base of USDW	[redacted]
Depth to Top of Injection Zone	
Gradient of USDW	
Gradient of Injection Zone	

The calculations, using EPA Method 2, for the uppermost stage are shown in detail below as an example. The coefficient (ξ) is first calculated in Equation 1 using the pressure gradients and depths for the base of the USDW and the top of the injection zone.

(Eq. 1) $$\xi = \frac{G_i - G_u}{D_i - D_u}$$

[redacted]

The critical pressure rise (ΔP_c) is then calculated using Equation 2. The inputs include the coefficient (ξ) calculated in Equation 1 and the depths for the base of the USDW (D_u) and the top of the injection (D_i).

(Eq. 2) $$\Delta P_c = \frac{1}{2} * \xi * (D_i - D_u)^2$$

[redacted]

The resulting critical pressure rise for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by [redacted] without the risk of fluid migration to the USDW. The calculated critical pressure rise for each of the completion stages for both wells is included in Tables 3-3 and 3-4. The resulting maximum critical pressure front extent is shown in Figure 3-1. Each stage of injection is considered when delineating the maximum critical-pressure front extent. Indicated by the pink outline in the figure, the critical pressure front is the maximum extent for all stages of injection.

Table 3-3 – Cronos No. 1 Critical Threshold Pressure for Each Completion Stage

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

Table 3-4 – Rhea No. 1 Critical Threshold Pressure for Each Completion Stage

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

[redacted]

The comprehensive AOR for the Titan Project encompasses the combined region of both the pore space and pressure front areas. Any feature detected within either of these zones has been assessed for its ability to adequately safeguard the USDW.

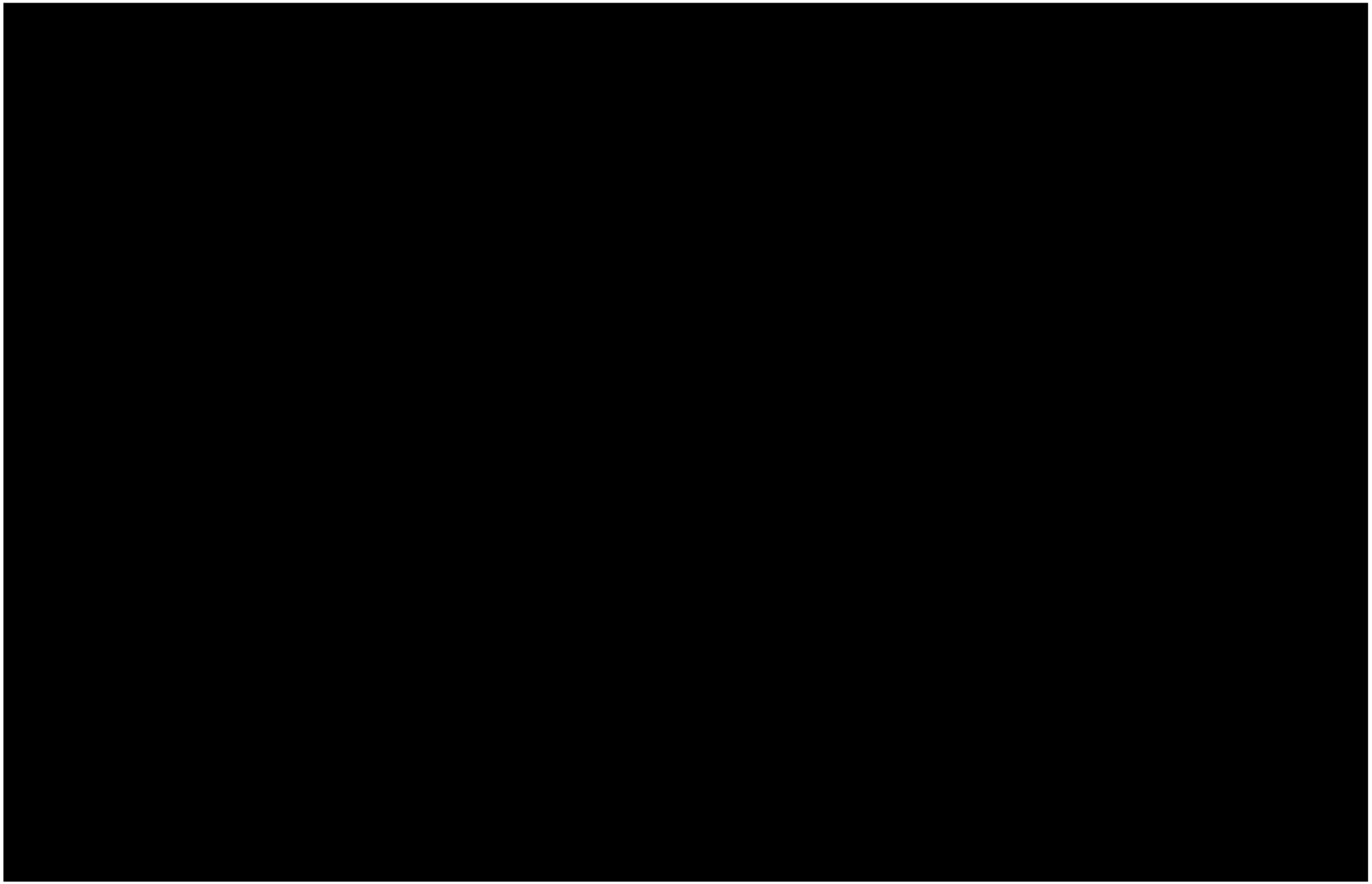


Figure 3-1 – Critical Pressure Front

3.3.3 Operating Strategies Influencing Reservoir Modeling Results

To prevent the plume from extending into artificial penetrations or encountering unfavorable subsurface features, a well-designed completion and operational strategy is imperative in the Miocene sands of the Gulf Coast depositional environment. [redacted]

For this project, approximately [redacted] net feet of usable sand formations are targeted for injection for Cronos No. 1 and approximately [redacted] net feet for Rhea No. 1. These Miocene-age sand formations will be selectively targeted in discrete completions, staged out over the proposed active life of the project. Each sand package is isolated by shale layers that will help control the migration of the CO_2 plumes within each discrete injection zone.

The completion strategy aims to achieve two primary objectives: to create multiple plumes, stacked on top of each other and separated by shale beds; and to control the lateral extent of the resulting plumes, thereby confining them within the controlled pore space. The GEM model has provided the following outputs for this reservoir management program. Figures 3-2 and 3-3 show a cross section for each well, and Figure 3-4 shows the oblique cross section of these stacked injection layers as modeled by GEM.

Figure 3-2 – West-east cross-sectional view at Cronos No. 1 in [redacted] colored by CO_2 saturation.

Figure 3-3 – West-east cross-sectional view at Rhea No. 1 in [redacted], colored by CO_2 saturation.

Figure 3-4 – A vertical 3D representation (left) and aerial view (right) of supercritical CO_2 plumes [redacted] colored by CO_2 saturation.

Figure 3-5 depicts the shape and lateral extent of the largest of the stacked injection plumes. [redacted] The extent of these plumes was digitized from the GEM model's output and subsequently imported into ArcGIS™ to delineate the area of influence, which served as the foundation for the AOR assessment for the Titan Project. In accordance with TAC **§5.203(d)(V)** [40 CFR **§146.84(c)(iii)**], a comprehensive examination was conducted to identify any artificial penetrations or potential hazards to the lowermost USDW arising from injection activities or operations. This assessment involved creating maps illustrating the AOR and any human-made structures located within it. Any artificial penetrations or other artifacts were then subjected to evaluation—considering factors such as the depth of completion, construction specifications, and plugging and abandonment procedures—to ascertain their potential impact on the containment integrity of the storage zone.

The maps and associated lists generated during this effort are contained in *Appendix C*. Figure 3-6 (page 13) identifies the Titan Project AOR.

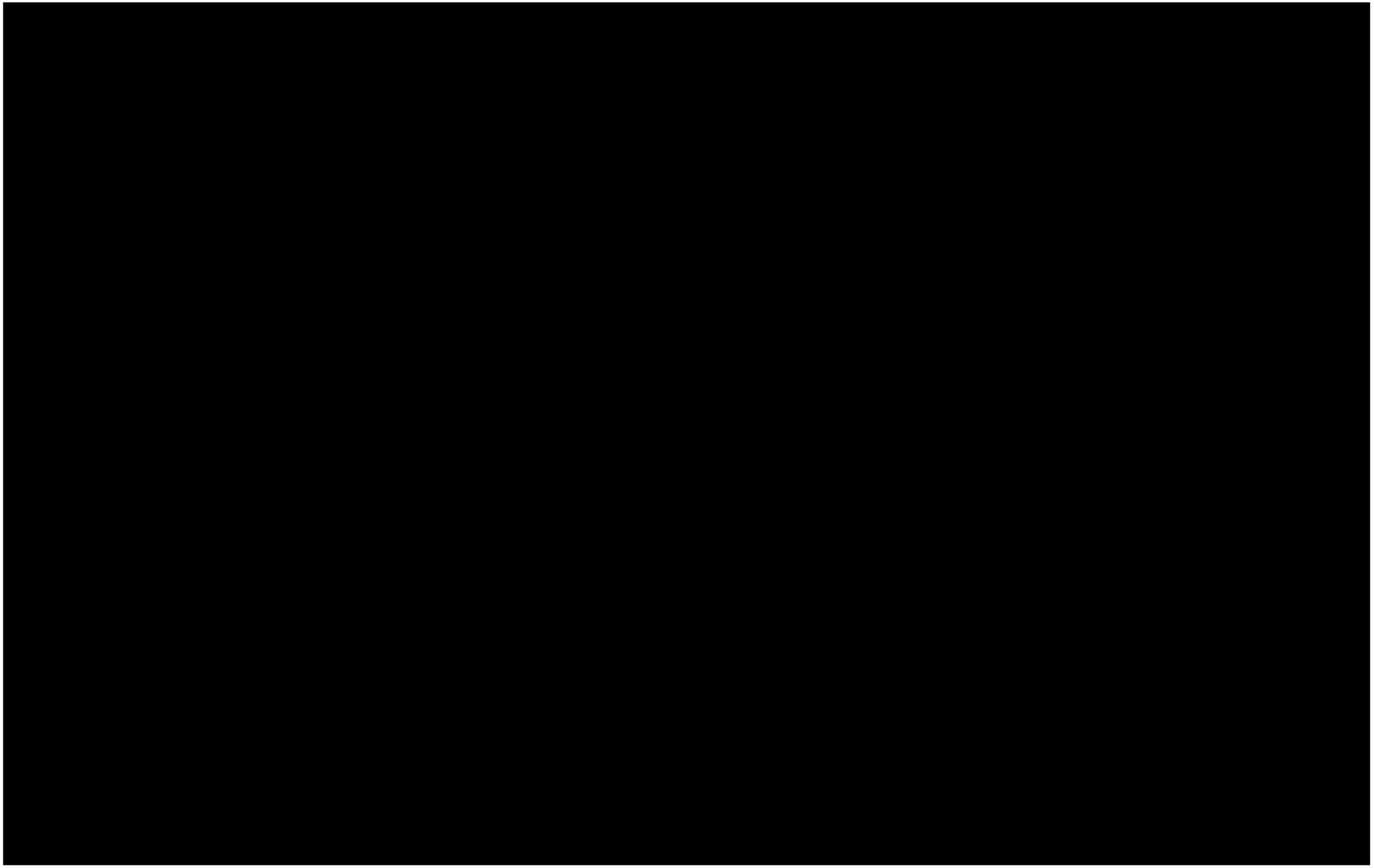


Figure 3-5 – GEM Plume Model Results, Plan View Maximum Extents

Figure 3-6 – Final AOR Map

3.3.4 Area of Review Results

A comprehensive multi-database analysis was performed to search for artificial penetrations into the injection zone within the AOR. Oil-and-gas well data for the AOR is primarily gathered from the Texas Railroad Commission (TRRC). Supplemental well data from additional databases, including IHS and Enverus, was then incorporated and assessed to reduce potential historical well omissions and data inaccuracies. All water well data was accessed directly from the Texas Water Development Board's statewide water-well registration database. The Texas Commission on Environmental Quality (TCEQ) and EPA websites were reviewed for additional artificial penetration records and any environmental cleanup sites in the AOR.

The results of the AOR evaluation yielded no artificial penetrations within the pore occupancy boundaries. The pressure front AOR evaluation also yielded no artificial penetrations; therefore, no corrective action is required for artificial penetrations for this project. A map showing the nearest offset artificial penetrators is displayed in Figure 3-7. Titan plans to perform an aerial magnetometer survey, explained in *Section 3.3.4.1*, to confirm that no wellbores exist within the AOR.

[redacted] Also, no existing water wells have been found within the AOR. A map showing the nearest offset water wells is featured in Figure 3-8 (page 16). A review of TCEQ records was conducted as well, to identify Class I wells within the AOR boundaries—a search that yielded no such wells in the AOR.

Moreover, no existing active or inactive hazardous waste sites, mines, or quarries have been identified within the AOR. Because the wells are in a marshy area, Titan will ensure that operations are designed to protect all surface water resources. A map showing the surface water bodies and nearest hazardous waste sites, mines, and quarries is featured in Figure 3-9 (page 17).

3.3.4.1 Aerial Magnetometer Survey

To ensure that no orphan wells exist in the AOR, Titan will contract with a third party to perform an aerial magnetometer survey across the Titan Project area. The survey will be conducted by an unmanned aerial vehicle (UAV) to indicate the potential presence of abandoned wells across the AOR. The data will be processed, and magnetic field intensity contour maps provided, in a report summarizing the survey methodology, results, and anomaly locations representing potential the locations of oil and gas wells.

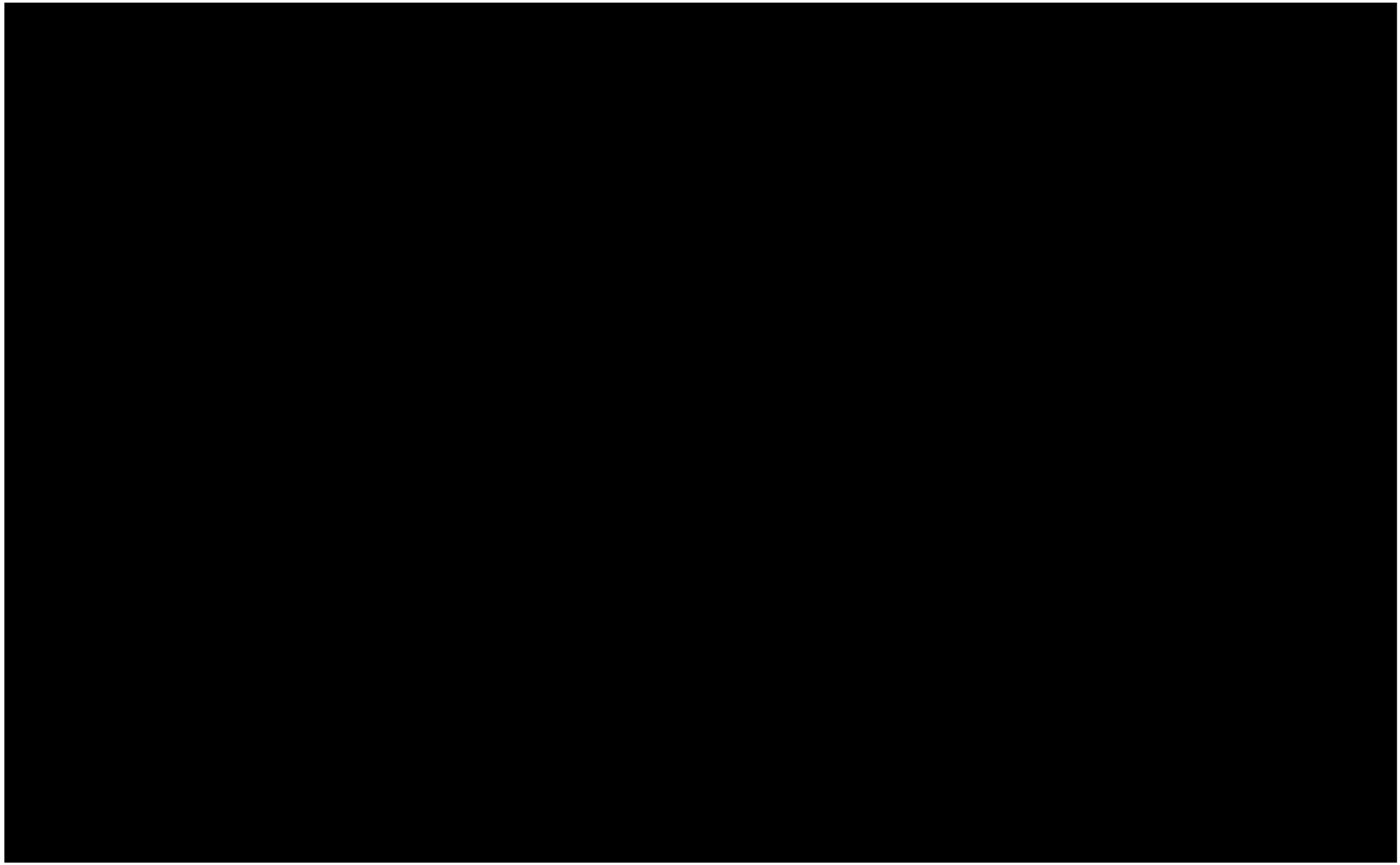


Figure 3-7 – Map of Nearest Offset Artificial Penetrators

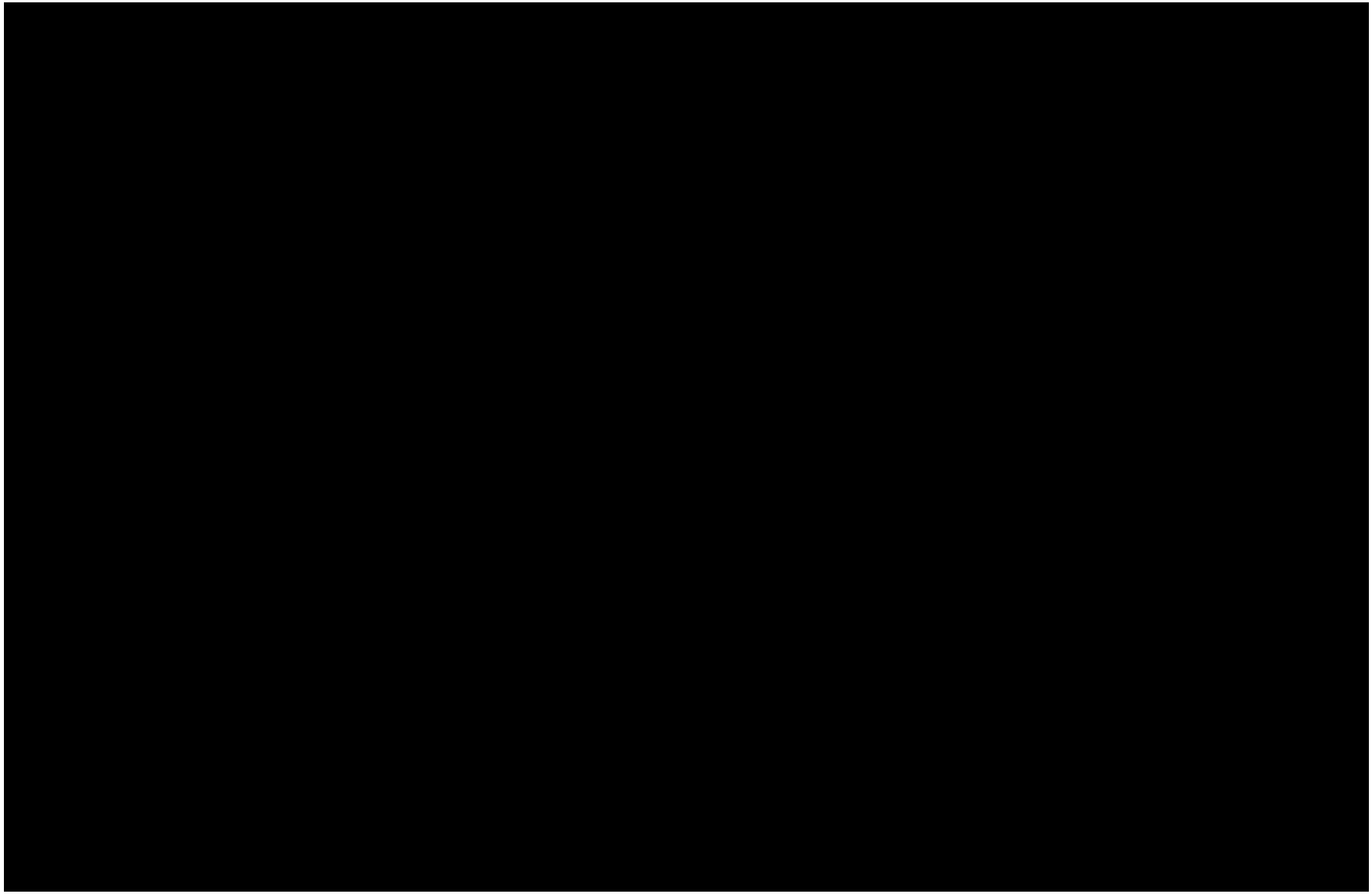
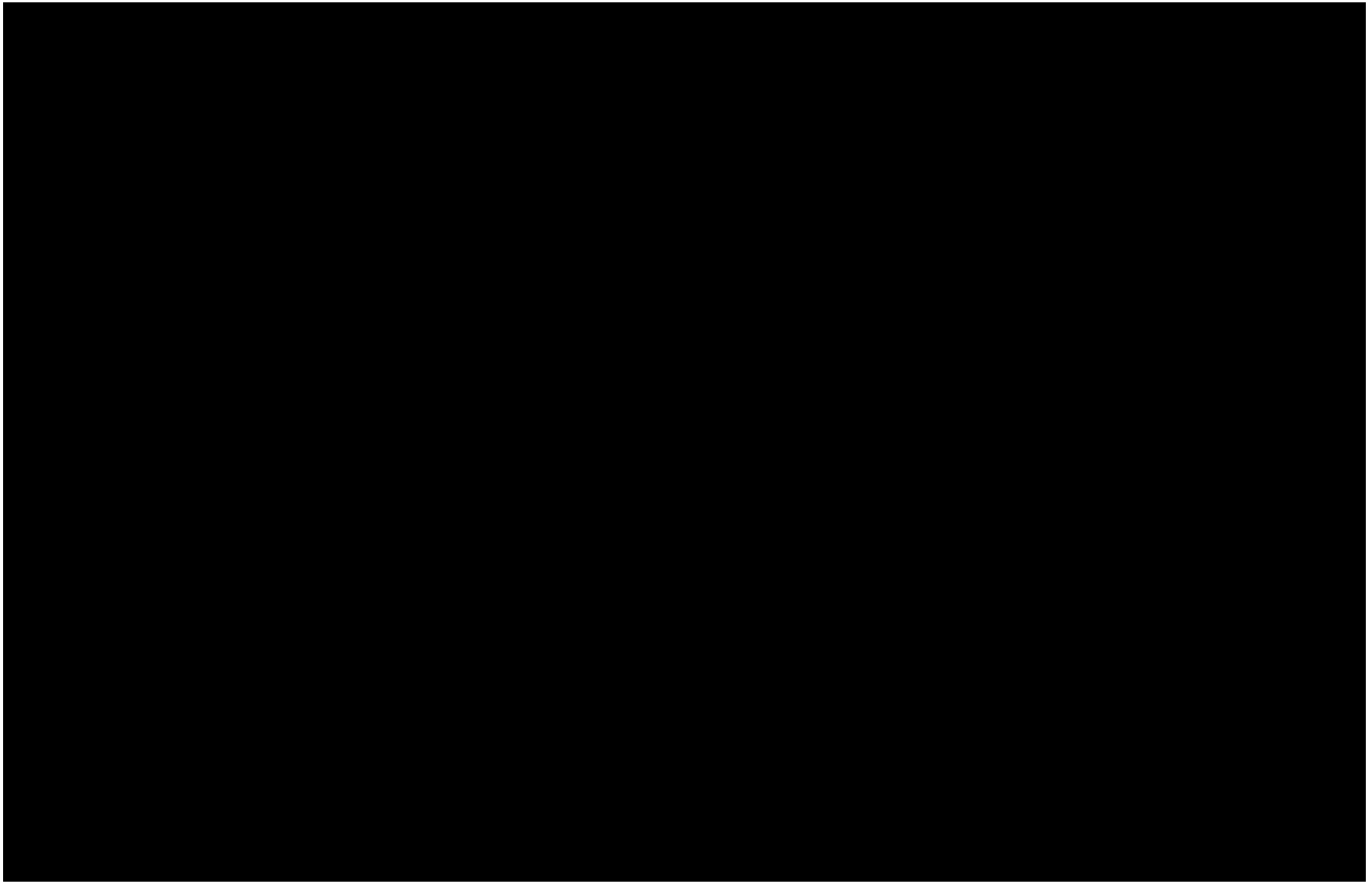


Figure 3-8 – Map of Nearest Offset Water Wells



3.4 Corrective Action Plan and Schedule

The primary objective of a corrective action plan is to ensure the proper containment of CO_2 and other resulting fluids involved in a carbon sequestration project. This plan is strategically crafted to guarantee that neither CO_2 nor other formation fluids will migrate from the injection zone, beyond the impermeable shale barrier of the upper confinement layer.

No wells have been identified within the CO_2 plume and pressure front boundaries that require corrective action. Consequently, there are no planned remediation activities scheduled before the commencement of injection, as no existing wellbores penetrate the UCZ. If a new well were to be identified in the AOR that required corrective action, Titan will ensure that site access is secured for any future work needed.

The growth and extent of the CO_2 plume will undergo continuous monitoring and periodic assessments. A reevaluation is scheduled for every 5 years, and if it is deemed essential, adjustments to the corrective action plan will be made to encompass additional wells.

3.5 Area of Review Reevaluation Plan and Schedule

As mentioned, the establishment of the AOR was guided by three main objectives:

1. Identify artificial penetrations or human-made structures that could impact the long-term storage of sequestered CO_2.
2. Identify subsurface geological features that could influence the capacity for indefinite sequestration of CO_2.
3. Identify pore space rights affected by the expansion of the injection plume over the modeled time frame.

In accordance with TAC and EPA requirements, Titan 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

Wells identified within the reevaluated AOR necessitating corrective action will be addressed with an amended AOR and corrective action plan that will be submitted to the Underground Injection Control (UIC) Program director (UIC Director) for approval. All amendments and corrective action plans will be approved and incorporated into the permit, and subject to permit modification requirements per 40 CFR **§144.39.**

Upon reexamination, if it is determined that no additional wells are affected, Titan will demonstrate to the UIC Director, supported by monitoring data and modeling outcomes, that no

modifications are required. All modeling inputs and data utilized for the substantiation of AOR reevaluations will be retained for a period of 10 years.

3.5.1 Proposed Reevaluation Cycle

Titan will reevaluate the AOR at least every 5 years, per TAC **§5.203(d)(2)(B)(i)** [40 CFR **§146.84(b)(2)(i)**]. The ongoing monitoring of plume growth and migration may necessitate more frequent reevaluations of the AOR than the scheduled 5-year intervals.

Intermittent surveys will be carried out to enable Titan to adapt the selection of discrete sand formations for injection, thereby influencing the evolution of the plume during the operational life span of the wells. As time progresses, the migration model and the results from plume surveys are expected to align more closely, permitting a reduction in survey frequency. These surveys will be conducted at least once every 5 years from the start of injection operations.

If the injection rates fall short of the modeled capacity, it is likely that the actual plume migration may not reach the extents initially modeled. [redacted] However, if the observed plume behavior exceeds the initially modeled boundaries, the model will be revised and a reevaluation of the AOR carried out.

Table 3-5 lists some of the possible triggers for an AOR reevaluation.

Table 3-5 – Triggers for AOR Reevaluations

Reevaluation Trigger	Measure to be Taken	Schedule for Reevaluation
TAC §5.203(d)(2)(B)(i) [40 CFR §146.84(b)(2)(i)]	Reevaluate the AOR as required by statute.	At least once every 5 years
Annual plume migration survey identifies a greater extent than modeled.	Re-run the reservoir plume model with new data. If plume extents increase, reevaluate the AOR.	Within 1 month of detection
Annual plume migration survey identifies the plume direction is different than modeled.		Within 1 month of detection
Operational Change: Injection rate increases to a rate greater than modeled.		Within 1 month of rate change
Operational Change: Injection pressures are significantly higher than modeled.		Within 1 month of significant pressure change
Operational Change: Injectate composition changes to a new mixture.		Within 1 month of composition change
New site-characterization data is produced.		Within 1 month of data production
New operations are being brought online within or near the plume extents.		Within 1 month of commencement of new operations
Seismic event or other emergency occurs.	Perform a plume migration survey. If plume increases in shape or extents, reevaluate the AOR.	Within 1 month of event

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

- Appendix C-1 Oil and Gas Wells AOR Map
- Appendix C-2 Oil and Gas Wells AOR List
- Appendix C-3 Freshwater Wells AOR Map
- Appendix C-4 Freshwater Wells AOR List
- Appendix C-5 Site Review AOR Map

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

February 2024

LONQUIST
SEQUESTRATION LLC

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

TABLE OF CONTENTS

4.1 Introduction 3
4.2 Engineering Design 3
4.2.1 Detailed Discussion of Injection Well Design 10
4.2.2 Completion/Stimulation Plans 24
4.3 Testing and Logging During Drilling and Completion Operations 24
4.3.1 Coring Plan 24
4.3.2 Logging Plan 24
4.3.3 Formation Fluid Testing 27
4.3.4 Step-Rate Test 27
4.4 Injection Well Operating Strategy 29
4.5 Injection Well Construction and Operation Summary 33
4.6 Discussion of Above-Zone Monitoring Wells 34
4.6.1 General Outline of Atlas No. 1 Well Design 37
4.7 Discussion of USDW Monitoring Wells 43
4.7.1 General Outline of USDW Monitoring Wells Design 46
4.8 Engineering Design and Operations Summary 47

Figures

Figure 4-1 – Cronos No. 1 Wellbore Schematic 6
Figure 4-2 – Rhea No. 1 Wellbore Schematic 7
Figure 4-3 – Injection Pressure Plot for Cronos No. 1 11
Figure 4-4 – Injection Pressure Plot for Rhea No. 1 11
Figure 4-5 – [redacted] 21
Figure 4-6 – Titan Injection Wells Cronos No. 1 and Rhea No. 1 Preliminary Wellhead Design 23
Figure 4-7 – Typical Plume Profile in High Permeability Formations 32
Figure 4-8 – Operational Completion Strategy 33
Figure 4-9 – Atlas No. 1 Monitoring Wellbore Schematic 35
Figure 4-10 – Andes No. 1 Monitoring Wellbore Schematic 36

Tables

Table 4-1 – Cronos No. 1 Operational Strategy 4
Table 4-2 – Rhea No. 1 Operational Strategy 4
Table 4-3 – CO_2 Inlet Conditions 10
Table 4-4 – Injectate Parameters 12
Table 4-5 – Input Injection Parameters for Cronos No. 1 and Rhea No. 1 13
Table 4-6 – Calculated Injection Parameters for Cronos No. 1 13
Table 4-7 – Calculated Injection Parameters for Rhea No. 1 13
Table 4-8 – Surface Casing Engineering Calculations for Cronos No. 1 and Rhea No. 1 15
Table 4-9 – Surface Casing Annular Geometries for Cronos No. 1 and Rhea No. 1 15
Table 4-10 – Surface Casing Volume Calculations for Cronos No. 1 and Rhea No. 1 15

Table 4-11 – Long String Casing Engineering Calculations for Cronos No. 1 17
Table 4-12 – Long String Casing Engineering Calculations for Rhea No. 1 17
Table 4-13 – Long String Casing Annular Geometries for Cronos No. 1 18
Table 4-14 – Long String Casing Annular Geometries for Rhea Well No. 1 18
Table 4-15 – Long String Casing Volume Calculations for Cronos No. 1 18
Table 4-16 – Long String Casing Volume Calculations for Rhea No. 1 18
Table 4-17 – Tubing Engineering Design Calculations – Cronos No. 1 19
Table 4-18 – Tubing Engineering Design Calculations – Rhea No. 1 20
Table 4-19 – Openhole Logging Plan 25
Table 4-20 – Cased-Hole Logging Plan 26
Table 4-21 – Proposed Step-Rate Injection Test 28
Table 4-22 – Injection Parameters 29
Table 4-23 – Injection Pressures and Volumes by Stage, Cronos No. 1 30
Table 4-24 – Injection Pressures and Volumes by Stage, Rhea No. 1 30
Table 4-25 – Injection Intervals – Cronos No. 1 30
Table 4-26 – Injection Intervals – Rhea No. 1 31
Table 4-27 – Atlas No. 1 and Andes No. 1 Surface Casing Engineering Calculations 38
Table 4-28 – Atlas No. 1 and Andes No. 1 Surface Casing Annular Geometries 38
Table 4-29 – Atlas No. 1 and Andes No. 1 Surface Casing Cement Calculations 39
Table 4-30 – Atlas No. 1 Long String Casing Engineering Calculations 40
Table 4-31 – Andes No. 1 Long String Casing Engineering Calculations 40
Table 4-32 – Atlas No. 1 Long String Casing Annular Geometries 40
Table 4-33 – Andes No. 1 Long string Casing Annular Geometries 40
Table 4-34– Atlas No. 1 Long String Casing Cement Calculations 41
Table 4-35 – Andes No. 1 Long String Casing Cement Calculations 41
Table 4-36 – Openhole Logging Plan, Atlas No. 1 and Andes No. 1 42
Table 4-37 – Cased-Hole Logging Plan, Atlas No. 1 and Andes No. 1 43

4.1 Introduction

The following section describes the engineering design details and operational strategies employed during the planning of the Titan Carbon Sequestration Project's (Titan Project) proposed injection wells Cronos No. 1 and Rhea No. 1. The engineering design details meet the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(e)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**].

The design, construction, and operation of injection wells fall under the jurisdiction of the EPA Underground Injection Control (UIC) program. Class VI injection wells are designed for the sole purpose of safely injecting and storing CO_2 into selected injection zones. The wells are designed to ensure protection of all Underground Sources of Drinking Water (USDWs) through the drilling, completion, injection, and plugging phases.

The two proposed injection wells of the Titan Project are centrally located near various surrounding industrial companies whose facilities produce high levels of CO_2 as a by-product. Titan Carbon Sequestration, LLC (Titan) proposes to inject CO_2 into the Lower Miocene sands. The approximately [redacted] feet (ft) of gross vertical sands are highly porous, highly permeable, saline-filled, and interbedded with shale layers to isolate each potential zone of injection. These reservoir properties make it an excellent candidate for the safe injection and containment of CO_2.

The specific requirements for the design of a carbon capture and sequestration (CCS) Class VI well are described in the following sections.

4.2 Engineering Design

The design of Titan's proposed Cronos No. 1 and Rhea No. 1 injection wells was developed to consider the volumes and rates of injection, chemical composition, and physical properties of the injectate fluid, corrosion and metallurgical evaluations, and operational requirements to maintain reservoir management for the duration of the wells.

Carbon sequestration wells are designed along parameters and considerations similar to those for acid-gas injection wells, including special metallurgies. While CO_2 is not inherently hazardous, when it is mixed with water under the right conditions, carbonic acid can form with a pH as low as 3. As with all classes of injection wells, the protection of USDWs is critically important. These wells are designed to prevent CO_2 from migrating above the upper confining zone (UCZ).

Additionally, these injection wells must ensure the protection of other subsurface natural resources. For this reason, the proposed CO_2 sequestration components of the wells, including the casing, tubing, packer, wellhead equipment, and downhole tools, are designed to withstand the corrosive environment to which they will be exposed. The cement slurries used in the wells and products selected are designed to fill the annuli from total depth to surface, create a good bond between the casing and formations, provide good compressive strengths, and withstand the nature of the corrosive fluids.

The CO_2 injectate will be sequestered in the Miocene sands, where the upper and lower confining shale zones will contain the CO_2 injectate. Intermittent layers of shales exist throughout the injection interval that will also act as additional vertical barriers to help control the migration of CO_2 plumes within each discrete injection stage. The injection interval sands are located from approximately [redacted] ft true vertical depth (TVD). The sand formations are porous, permeable, and unconsolidated—making them favorable for CO_2 injection and storage.

Once injection operations have ceased in a stage of the injection zone, that injection stage will be plugged back to isolate that stage. The next sand interval above that stage will then be perforated. The injectate will then be injected into and stored in that new stage until the predetermined amount of time—or the adjusted time—is reached. The above process will be repeated until the uppermost injection stage below the UCZ is reached. The stages and depths for this process are illustrated in Tables 4-1 and 4-2 for Cronos No. 1 and Rhea No. 1, respectively. The CO_2 plume will be monitored during and after injection to ensure that the plume follows the expectations of the model.

Table 4-1 – Cronos No. 1 Operational Strategy

Stage	Top Perf (ft)	Bottom Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]					

Table 4-2 – Rhea No. 1 Operational Strategy

Stage	Top Perf (ft)	Bottom Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]					

The wellbore will be designed with [redacted] inch (in.) long string casing to a depth of approximately [redacted] ft. That casing will then be crossed over to [redacted] casing at approximately [redacted] above the top of the UCZ. That casing will be run to total depth (TD) and set at approximately [redacted] ft into the lower confining zone. The injection tubing will be [redacted]

[redacted]. The tubing will be run in conjunction with a subsurface injection valve (SSIV) and a [redacted] packer with tail pipe. The packer will be located approximately [redacted] ft above the lowest stage that will be perforated. The SSIV, packer and tail pipe will be [redacted] material or equivalent.

The plugging of the lower stage and recompletion of the next highest stage will be performed using a workover rig and wireline unit. The fiber optic/electric cable lines with temperature and pressure gauges will be installed to allow for the continuous monitoring of the casing and tubing annulus. This will help to ensure that wellbore and mechanical integrity are maintained.

Figures 4-1 and 4-2 show the proposed wellbore designs for the Titan Project.

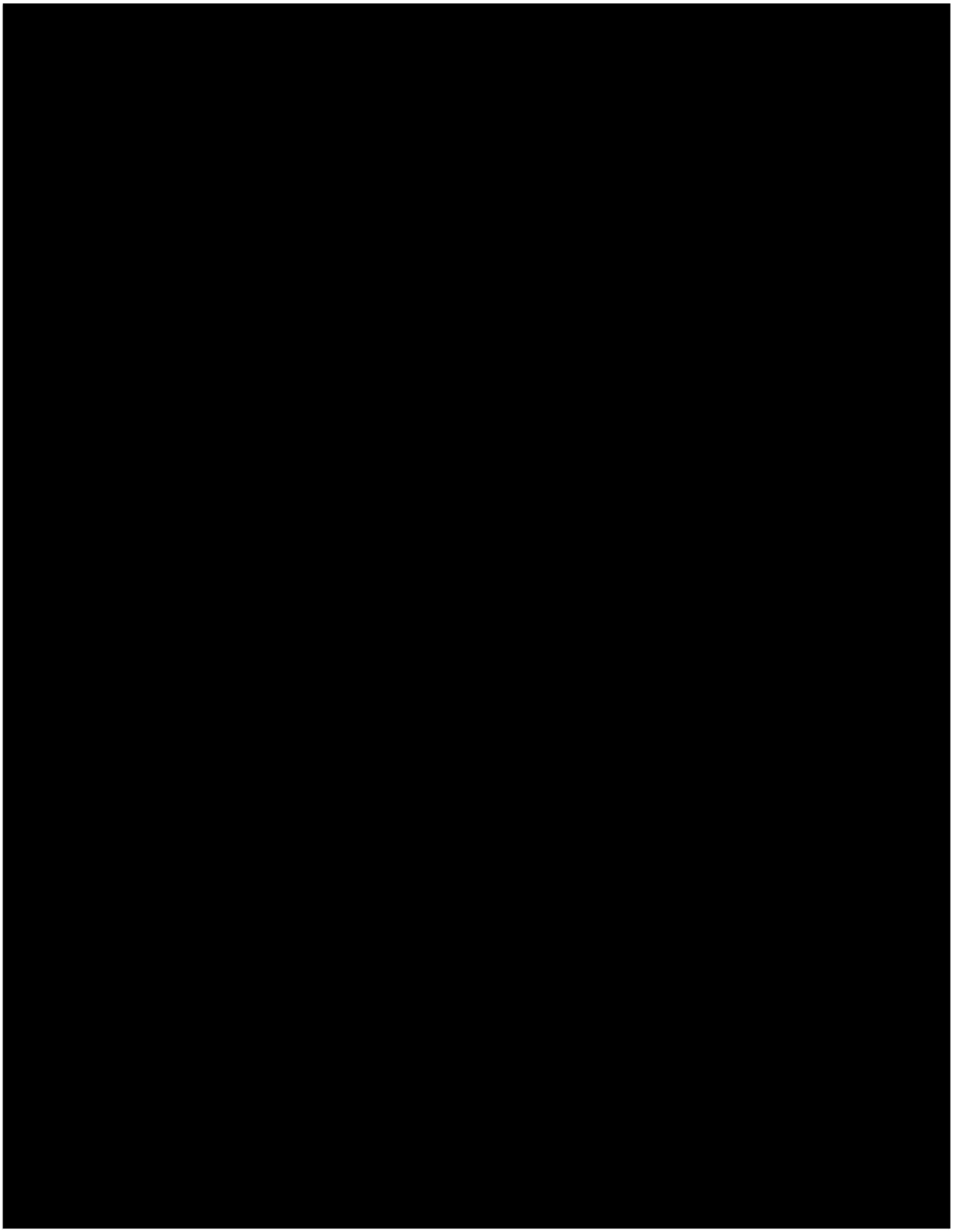


Figure 4-1 – Cronos No. 1 Wellbore Schematic

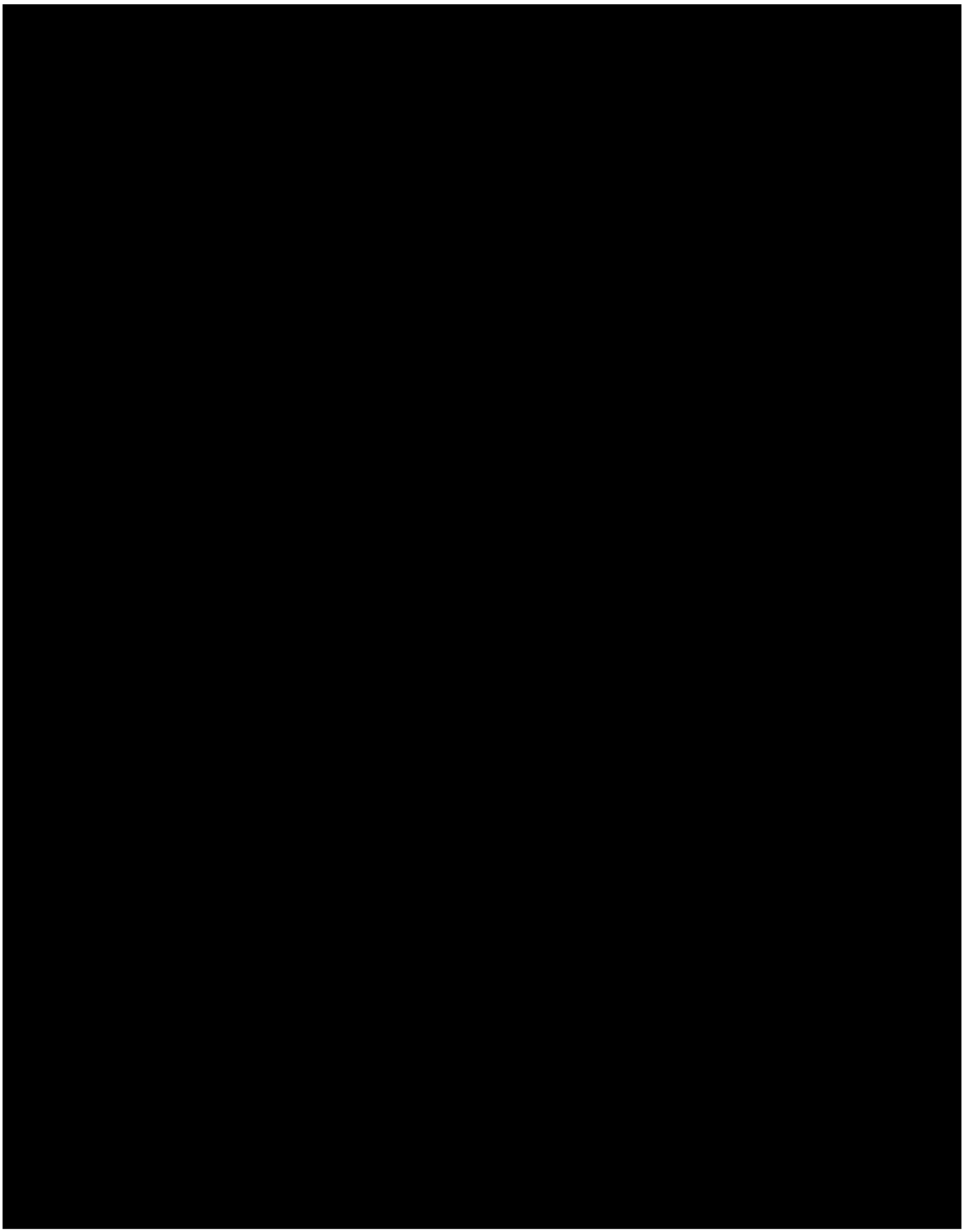


Figure 4-2 – Rhea No. 1 Wellbore Schematic

The drilling and completion design for Cronos No. 1 is as follows:

- Drive Pipe
  - [redacted] ft (or 200 blows/ft)
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of openhole logging during the drilling of the well. If necessary, the final setting depth will be adjusted.
    - The current estimated setting depth is [redacted] ft TVD. [redacted]
  - [redacted]
  - Cemented to surface
- Long string Casing
  - [redacted] in. hole size
  - [redacted] in. outer diameter (OD) casing set to TD of well [redacted]
  - Cemented back to surface
    - Cement to be comprised of: [redacted]
- Injection Tubing [redacted]
  - Tubing annulus will be filled with a noncorrosive fluid [redacted]
- njection Packer
  - [redacted]
- Wellhead [redacted]

- Figure 4-1 illustrates the above and additional details.

The drilling and completion design for Rhea No. 1 is as follows:

- Drive Pipe
  - (or 200 blows/ft)
- Surface Casing
  - To be set below the lowermost USDW
  - Cemented to surface
- Long string Casing
  - OD casing set to TD of the well
  - Cemented back to surface
    - Cement to be comprised of:
- Injection Tubing
  - Tubing annulus will be filled with a non-corrosive fluid.
- acker configuration
- Wel head

- Figure 4-2 illustrates the above and additional details.

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

4.2.1 Detailed Discussion of Injection Well Design

Titan plans to inject a maximum volume of [redacted] million metric tons per year (MMT/yr) of captured CO_2 into each of the proposed wells. At standard conditions, this mass translates to a rate of approximately [redacted] million standard cubic feet per day (MMscf/D). Detailed reservoir modeling was performed by considering the properties of the injectate, rate of injection, and injection pressures to determine the size, weight, and grade of the tubing to be used in the well.

Table 4-3 shows the standard conditions of CO_2 used in the modeling and flow calculations.

Table 4-3 – CO_2 Inlet Conditions

Temperature (°F)	Pressure (psia)	Density (lbm/ft³)	Enthalpy (Btu/lbm)	Entropy (Btu/lbm-°R)
60	14.7	0.11666	214.18	0.64759

*psia – pounds per square inch absolute
lbm – pound mass | ft^3 – cubic foot

A tubing design sensitivity was run that considered calculated pipe-friction losses, exit velocities, compression requirements, and economic evaluations. Bottomhole pressures (BHPs) were calculated from detailed reservoir-engineering model runs as shown in Figures 4-3 and 4-4. The data identifies when the maximum BHP occurs during the life of the project, and the resulting maximum flowing pressure at the surface—allowing for the proper design of the casing, tubing, and wellhead configurations.

Figure 4-3 – Injection Pressure Plot for Cronos No. 1

Figure 4-4 – Injection Pressure Plot for Rhea No. 1

For the reservoir model, 100% CO_2 was used for the injectate stream. The anticipated chemical composition of the pipeline CO_2 is outlined in Table 4-4.

Table 4-4 – Injectate Parameters

Component	Value
[redacted]	

The input injection parameters from the model, for both injection wells, are shown in Table 4-5. The calculated injection parameters are shown in Table 4-6 for Cronos No. 1 and Table 4-7 for Rhea No. 1.

Table 4-5 – Input Injection Parameters for Cronos No. 1 and Rhea No. 1

Inputs	Cronos No. 1	Rhea No. 1
Maximum Injection Rate (MMT/yr)	[redacted]	
Pressure Constraint Gradient (psi/ft)		
Injection Duration (yrs)		
[redacted] Tubing Inner Diameter (ID) (in.)		
[redacted] Tubing Setting Depth (ft)		
Absolute Roughness Factor		
Wellhead Temperature (°F)		

Table 4-6 – Calculated Injection Parameters for Cronos No. 1

Stage	Year	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Stage	Year	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

The results from running the model, using the inputs listed, indicate that [redacted] tubing is the appropriate size to inject the desired volumes of supercritical CO_2 into each well. The results also verified that the CO_2 injectate would continue to remain in a supercritical state within the wellbores.

Based on appropriate bit-size selection, pipe-clearance considerations, and recommended annular spacing for assurance of proper cementing, the following casing sizes are appropriate to accommodate the [redacted] injection tubing.

[redacted]

Drive Pipe

Because of the loose, unconsolidated nature of the sediments found immediately beneath the waterline, drive pipe will be needed to ensure that the hole integrity is maintained during the initial drilling of Cronos No. 1 and Rhea No. 1. A [redacted] drive pipe will be used in both wells and driven either to [redacted] ft or to refusal (at approximately 200 blows/ft of advancement) by a hydraulic ram.

The drive pipe size was selected to facilitate the desired bit size requirement for the drilling of the surface casing. With an ID of [redacted] bit can be used for developing the next section of the well. Once the drive pipe is installed, the inner portions of the pipe will be flushed out and cleaned, and drilling will commence.

Surface Casing

The surface hole will be drilled t [redacted] casing will be run and cemented with the casing centered using centralizers in the open hole. The selected hole size and centralizers will provide a consistent thickness of cement between the casing and the open hole. Cement returns will be circulated to surface. [redacted] This process provides a good cement bond from the surface-casing setting depth to the surface, protecting the USDW. After cementing, a cement bond log will be run to evaluate and verify good bonding throughout the surface hole.

Summaries of engineering calculations for the surface casing are displayed in Tables 4-8 to 4-10. The engineering calculations for both injection wells in this project were performed assuming identical wellbore conditions and setting depth for surface casing.

Table 4-8 – Surface Casing Engineering Calculations for Cronos No. 1 and Rhea No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Table 4-9 – Surface Casing Annular Geometries for Cronos No. 1 and Rhea No. 1

Section – Surface	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-10 – Surface Casing Volume Calculations for Cronos No. 1 and Rhea No. 1

Section – Surface	Footage (ft)	Capacity (ft^3)	Excess (%)	Cement Volume (ft^3)
[redacted]				

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

Long String Casing

Due to the unconsolidated nature of the Miocene sands targeted for injection in these wells, the long string casing will be run all the way to each well's TD. The long string casing will be cemented from the casing-shoe setting depth back to surface.

The following are key design criteria to be used for the long string of casing:

- [redacted]
- Integration of tools such as float equipment, and centralizers

- CO_2-compatible cement systems from [redacted]

A detailed metallurgical analysis was performed that considered the chemical composition of the injectate and downhole conditions as shown in Table 4-3 (*Section 4.2.1*) and included in *Appendix E*. The injectate stream is made up of [redacted] Based on the analysis of the injectate stream and downhole conditions, the long string casing will be [redacted] material to prevent corrosion and downhole failures, should any fluids enter the wellbore from the reservoir.

The long string will be cemented with CO_2-compatible cement from [redacted] above the UCZ—to provide a good barrier across the UCZ and the top of the injection level, to prevent CO_2 migration out of the injection interval. Above the CO_2-compatible cement, the well will be cemented from that point to the surface with a high-quality blended Portland cement.

The Miocene sand for Cronos No. 1 and Rhea No. 1 is approximately [redacted] ft thick. The sand is interbedded with layers of shale above each sand layer that will act as barriers to confine the CO_2 injectate below the UCZ. The completion strategy for both wells will be designed to start injecting at the lowest stage selected. The CO_2 injectate will be injected for a predetermined amount of time derived from the reservoir-injection plume modeling. Once that stage has reached its maximum injection time, that stage will be plugged. The plugging of the lower stage and recompletion of the next highest stage will be performed using a workover rig and wireline unit.

Each stage will be permanently plugged by setting a corrosion-resistant bridge plug [redacted] A 50-ft plug of CO_2-compatible cement will then be placed on top of the [redacted] e plug or cement retainer. The [redacted] casing will be perforated into the next stage above [redacted] This process will be repeated throughout the life of each wel[redacted] til the uppermost stage is completed. [redacted] are planned for Cronos No. 1 and [redacted] for Rhea No. 1, as determined from type logs and injection-modeling results.

Throughout the life of both wells, a FOC, TEC and sensor package will be installed behind the long string casing and cemented into place. This equipment will be used to perform vertical seismic profile (VSP) surveys of the plume and record formation temperatures and pressures in each injection interval. This ability is considered part of the overall long-term monitoring system of the wells. As the life of the wells progresses, the installed system can monitor data from the plugged zones as well as each new injection zone that will be completed.

The engineering and design parameters for the long string casing are summarized in Tables 4-11 through 4-16.

Table 4-11 – Long String Casing Engineering Calculations for Cronos No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Table 4-12 – Long String Casing Engineering Calculations for Rhea No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Table 4-13 – Long String Casing Annular Geometries for Cronos No. 1

Section – Long string	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-14 – Long String Casing Annular Geometries for Rhea Well No. 1

Section – Long string	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-15 – Long String Casing Volume Calculations for Cronos No. 1

Section – Long string	Footage (ft)	Capacity (ft^3)	Excess (%)	Cement Volume (ft^3)
[redacted]				

*An excess of 30% of openhole volumes was used to calculate cement volum

Table 4-16 – Long String Casing Volume Calculations for Rhea No. 1

Section – Long String	Footage (ft)	Capacity (ft^3)	Excess (%)	Cement Volume (ft^3)
[redacted]				

*An excess of 30% of openhole volumes was used to calculate cement volume.

Centralizers

The bow-spring centralizer design for the [redacted] in. surface casing is planned to protect any shallow aquifer zones per state regulations. The specific placement is to ensure that a continuous, uniform column of cement is present throughout the [redacted] in. annular void. The recommended locations are as follows:

[redacted]

Centralizer placement for the [redacted] in. long string casing is designed for the installation of the FOC and TEC. Clamped centralizers and eccentric centralizers will both be utilized to ensure the FOC and TEC are not damaged. The recommended procedure is as follows:

[redacted]

Injection Tubing

The [redacted] in. injection tubing size and material were selected for use in both wells based on modeling results from planned injection volumes, rates, and injectate composition. [redacted]. A complete summary of the metallurgical analysis is included in *Appendix E*. Tables 4-17 and 4-18 provide the design calculations for Cronos No. 1 and Rhea No. 1, respectively.

Table 4-17 – Tubing Engineering Design Calculations – Cronos No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Table 4-18 – Tubing Engineering Design Calculations – Rhea No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Packer Discussion

The [redacted] in. injection tubing will engage a [redacted] packer. A subsurface injection valve will be placed [redacted]. Several joints of [redacted]ail pipe will be run directly below the packer. Once the packer and tubing are installed, the tubing/casing annulus will be pressure tested for verification.

Figure 4-5 provides a schematic of the planned packer assembly.

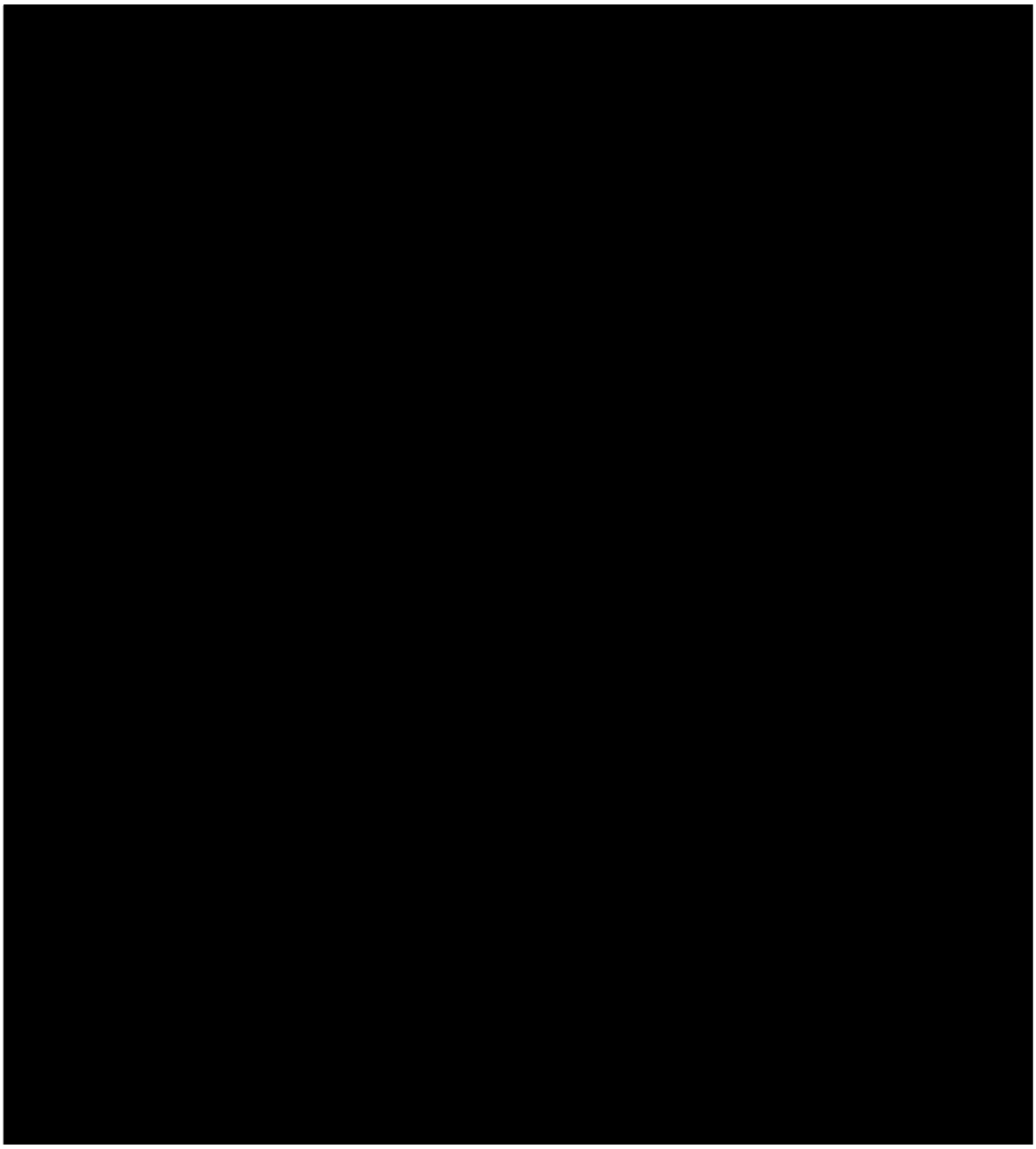


Figure 4-5 – [redacted] Packer Illustration

Prior to setting the packer, the tubing/long string casing annulus will be filled with a noncorrosive fluid as approved by the UIC Director. Pressure will be maintained on the annulus at a pressure that exceeds the operating injection pressure of the well.

Safety Injection Valve

In accordance with TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted] in. tubing just above the packer.

Pressure Gauge Array

Pressure and temperature gauges will be installed across the active injection interval to provide continuous data in real time for reservoir monitoring purposes. A TEC will be installed on the exterior of the long string casing to power the gauges and provide communication to the surface for both wells. A FOC will be installed on the exterior of the long string casing to provide temperature measurement, acoustic measurement and VSP survey capability for both wells.

Wellhead Discussion

The wellhead is designed to control working pressures and corrosion complications. The wellhead equipment will be manufactured to be National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) compliant using a combination of stainless-steel components and Inconel lining across the tubing hanger, casing adapter spool and lower master valve. The final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as illustrated in Figure 4-6. The wellhead design and manufacturer shown may change based on well and commercial factors determined before drilling.

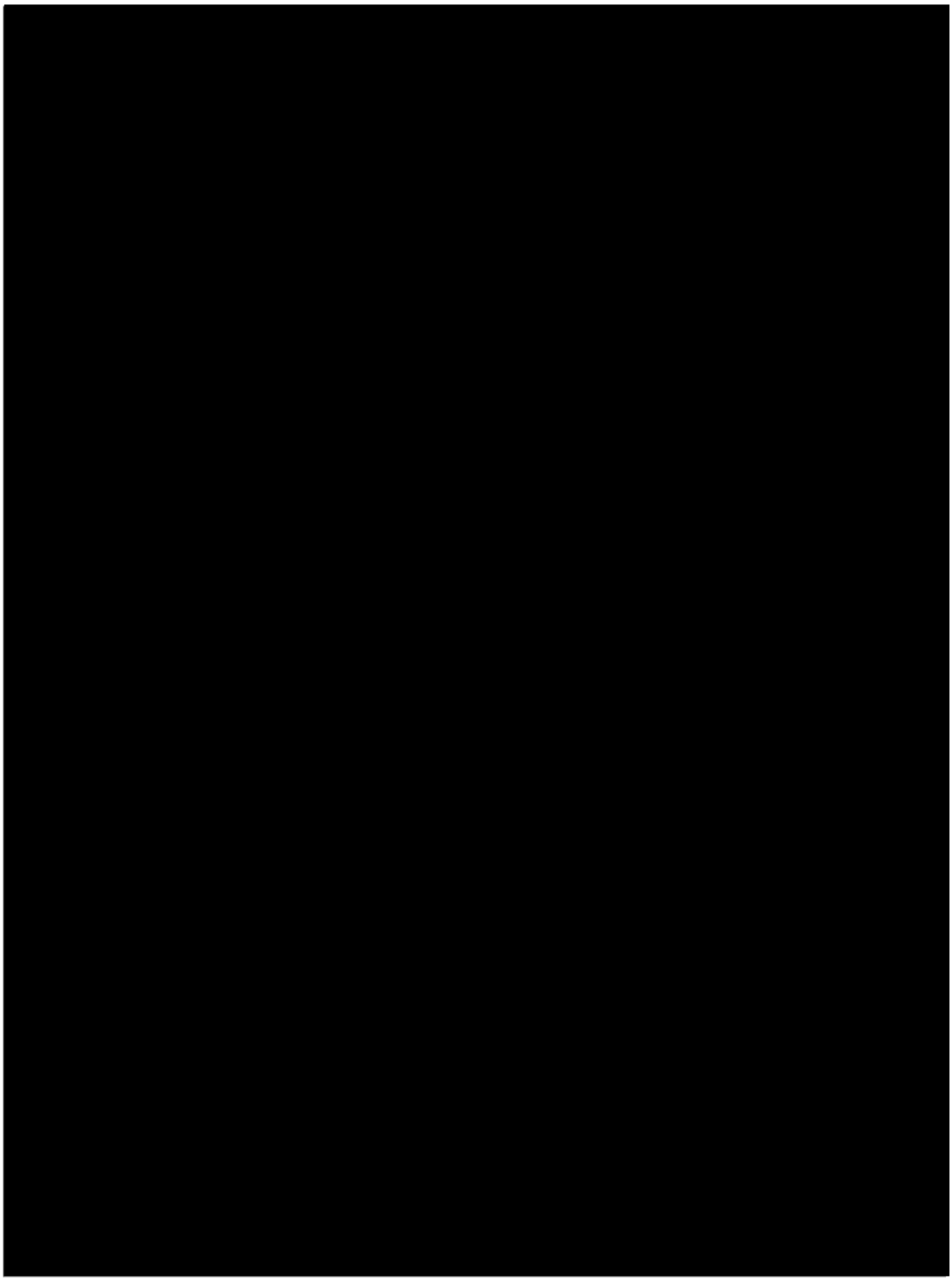


Figure 4-6 – Titan Injection Wells Cronos No. 1 and Rhea No. 1 Preliminary Wellhead Design

4.2.2 Completion/Stimulation Plans

Titan's proposed injection wells, Cronos No. 1 and Rhea No. 1, may be stimulated during completion operations, to clean up the well after drilling and/or to improve injection performance. Final stimulation designs will be determined based on the conditions met during drilling. Titan will submit proposed stimulation procedures to the UIC Director at least 30 days prior to beginning such operations. Such procedures may include the following activities:

[redacted]

4.3 Testing and Logging During Drilling and Completion Operations

In accordance with 16 TAC **§5.206(i)** [40 CFR **§146.87(f)**], Titan will submit a proposed schedule to the UIC Director for any planned testing and logging at least 30 days prior to conducting the first such activity. Titan will submit notice at least 48 hours in advance of any actual activity.

4.3.1 Coring Plan

[redacted] Core samples will be collected using [redacted] core barrels and engineering best practices, to attempt to recover high quality samples in the unconsolidated formations. If needed, sidewall cores may be collected during the drilling and testing of the injection wells to supplement the whole core analysis.

4.3.2 Logging Plan

An extensive suite of electric logs will be run in both the openhole and cased-hole sections of Cronos No. 1 and Rhea No. 1. The openhole logging plan is detailed in Table 4-19. The cased-hole logging plan is detailed in Table 4-20.

Table 4-19 – Openhole Logging Plan

Trip	Hole Section	Logging Suite	Openhole Diameter (in.)	Cronos No. 1 Depths (ft)	Rhea No. 1 Depths (ft)
[redacted]					

Table 4-20 – Cased-Hole Logging Plan

Trip	Hole Section	Logging Suite	Casing Dimension (in.)	Use	Cronos No. 1 Depths (ft)	Rhea No. 1 Depths (ft)
[redacted]						

Deviation checks will also be performed every 100 ft during drilling operations. The overall maximum allowable deviation of the wellbore is 3 degrees, and the maximum allowable deviation for any 100-ft segment is 1 degree.

4.3.3 Formation Fluid Testing

Prior to setting the long string casing string, samples of the formation fluid will be obtained by running an openhole fluid recovery tool (MDT). Recovery sections will be determined based on openhole evaluations. Parameters to be measured include formation fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone as required by 16 TAC **§5.203(f)(3)(A)** [40 CFR **§146.87(c)**].

4.3.4 Step-Rate Test

Prior to the commencement of CO_2 injection, Titan will conduct a step-rate injectivity test to attempt to measure the fracture gradient of the proposed injection wells in compliance with 16 TAC **§5.203(f)(2)(A)** [40 CFR **§146.87(d)(1)**] and 16 TAC **§5.203(f)(2)(C)** [40 CFR **§146.87(e)(3)**]. A bottomhole pressure gauge and temperature gauge will be run to the bottom of the wellbore. A surface gauge with continuous readout will also be installed. All gauges will be calibrated prior to the test. Initial bottomhole pressure and temperature readings must be taken prior to beginning injection.

The step-rate test will be performed using brine/water. Brine/water injection rates observed during step-rate testing can be converted to the equivalent CO_2 injection rate by accounting for the difference in fluid properties. The injection rate can be converted from a volumetric rate to a mass rate (i.e., barrels per day (bbl/D) to standard cubic feet per day (scf/D)). The mass rate is more suitable for measuring a compressible fluid, such as CO_2.

The densities of the CO_2 at standard conditions and in the reservoir are modeled using the Reference Fluid Thermodynamic and Transport Properties Database (REFPROP, Ver. 10.0), a software program developed by the National Institute of Standards and Technology. This program references the thermodynamic, physical, and transport properties of various fluids and fluid mixtures, and implements fluid models to calculate properties at variable temperatures and pressures throughout the liquid, gas, and supercritical states. The most accurate available models are included for 147 industrially important fluids. A wide range of tables and plots can be created within the software to display fluid properties at varying conditions.

Equation 1:

(Eq. 1.0) $$Qm = \frac{Qv * \rho BH}{\rho SC}$$

(Eq. 1.1) $$\rho_{BH} = (T_{BH}, P_{BH}, Fluid\ Composition) \leftarrow \text{from } REFPROP\ software$$

(Eq. 1.2) $\rho_{SC}=(T_{BH},P_{BH},Fluid\ Composition)\leftarrow$ from $REFPROP\ software$

Where:

Qv = Volumetric flow rate (bbl/day)

Qm = Mass flow rate (SCF/day)

T_{BH} = Temperature at bottomhole (°F)

ρ_{BH} = Pressure at bottomhole (°F)

ρ_{BH} = CO_2 density at bottomhole conditions pound per cubic foot (lb/ft^3)

ρ_{SC} = CO_2 density at standard conditions (lb/ft^3)

Testing Method

Specific wellbore and injection zone properties will define the final test parameters. The following test method outlines the expected test injection rates and times. [redacted] (Table 4-21, which also shows barrels per hour (bph) and per day (bpd)). The injection rates will be stepped up in increments until at least three measurements are taken both below and above the estimated formation fracture initiation pressure, [redacted] *Each stage duration will be based on the time required for the bottomhole pressure for the initial step to stabilize*.

Table 4-21 – Proposed Step-Rate Injection Test

Step	Duration (min)	Rate (bpd)	Rate (bph)	Rate (bpm)	Volume (bbl)
[redacted]					

4.4 Injection Well Operating Strategy

Titan plans to inject [redacted]/yr of CO_2 into each of the proposed injection wells, Cronos No. 1 and Rhea No. 1. This equates to an injection rate of [redacted]/D per well at standard atmospheric conditions. The gas will be compressed at the surface to around [redacted] pounds prior to injection. This pressure will be sufficient to move the gas into the formation and ensure that the gas achieves a supercritical phase or state of being. Because of the injection interval depths, the CO_2 will remain in liquified form until it is either absorbed into the connate fluid of the formation or is chemically bound to the existing geochemistry.

The BHP is calculated to increase by [redacted] psi, which will occur during the initial stages of injection, with the pressure dropping over time. The formation pressure at the extent of the plume migration is expected to rise by [redacted] psi. This relatively low buildup of pressure within the reservoir is a result of the injection intervals having such high porosities and permeabilities. These reservoir properties allow for the formation pressure to balance out and relieve itself much more readily than more restrictive geologies. The operating parameters for the proposed injection wells are provided in Table 4-22.

Table 4-22 – Injection Parameters

Parameter	Cronos No. 1	Rhea No. 1
Gross Injection Interval (ft)	[redacted]	
Average Injection Volume (MMT/yr)		
Average Injection Rate (MMscf/D)		
Maximum Surface Injection Pressure (psi)		
Expected Surface Injection Pressure (psi)		
Maximum Annular Pressure (psi)		

Surface injection pressures will be limited so that the BHP does not exceed 90% of the fracture pressure of the injection reservoir. The anticipated surface and bottomhole injection pressures and injection rates over time for the wells are shown in Tables 4-23 and 4-24.

Table 4-23 – Injection Pressures and Volumes by Stage, Cronos No. 1

Completion Stage	Completion Date	Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowable Bottomhole Pressure (psi)
[redacted]				

Table 4-24 – Injection Pressures and Volumes by Stage, Rhea No. 1

Completion Stage	Completion Date	Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowable Bottomhole Pressure (psi)
[redacted]				

To maximize the use of the available pore space, multiple injection intervals will be used. Each discrete injection interval was selected to maximize the utilization of the pore space and collectively maximize the usage of the acreage position for CO_2 sequestration. A summary of the planned injection strategy is listed in Table 4-25 for Cronos No. 1 and Table 4-26 for Rhea No. 1.

Table 4-25 – Injection Intervals – Cronos No. 1

Completion Stage	Completion Date	Injection Duration (years)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
[redacted]					

Table 4-26 – Injection Intervals – Rhea No. 1

Completion Stage	Completion Date	Injection Duration (years)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
[redacted]					

The operating plan was devised to optimize reservoir pore space and plume expansion management. The loosely consolidated Miocene sands, while ideal for carbon sequestration due to their significant thicknesses and high porosities and permeabilities, also pose complications to operational considerations. Miocene sands require substantial reservoir management practices to facilitate a controlled injection operation. Unlike typical injection wells, the plume growth will be controlled by a complex series of injection operations over multiple intervals over time.

Because of the differences in physical properties between CO_2 and the connate brine in the formation, plume modeling indicates that the injectate will rush to the shallowest portions of the opened sand packages first, with the small amounts of supercritical fluid migrating upward, to the uppermost portion of the injection interval. This effect is because the CO_2 is less dense than brine. Typical densities for the injectate range from [redacted]

The result is a significant "mushroom cap" effect, with the top of the mushroom expanding outward in a nearly uncontrolled fashion (Figure 4-7).

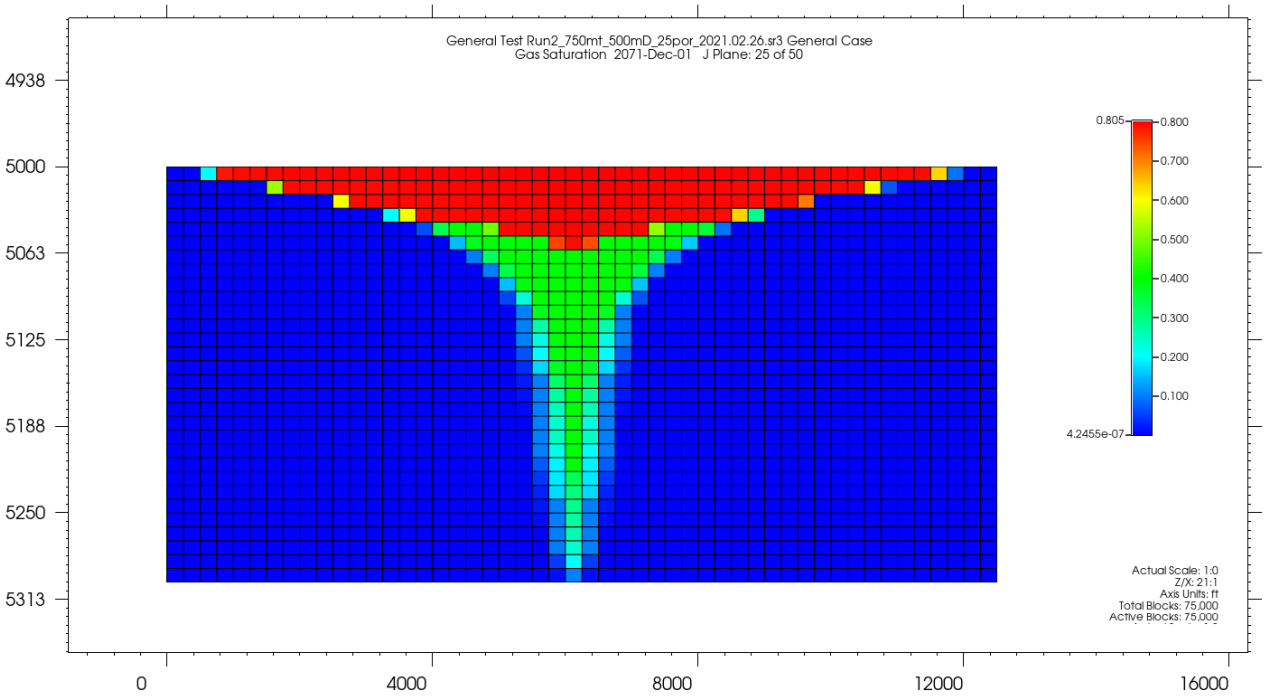


Figure 4-7 – Typical Plume Profile in High Permeability Formations

Figure 4-7 shows that injected fluids occupy only approximately 5%–10% of the total pore space—an inefficient use of available formation pore space. Also, since pore space rights for carbon sequestration wells are determined by the lateral extent of the farthest-reaching portion of the plume, this result is not desirable.

As such, reservoir management is important for injection wells in thick, loose sand formations. The operating strategy for the proposed injection wells Cronos No. 1 and Rhea No. 1 is as follows:

- The gross injection zone is broken into several discrete injection stages.
- These injection stages are then divided into discrete completion intervals.
- The initial completion stages for each well are perforated.
- The injectate fluids are injected into the discrete stages for a relatively short period of time–no less than 1 year–no greater than 5 years (estimated).
- Plume migration surveys are conducted annually in Years 1 and 5 after injection begins, then every 5 years thereafter to contrast actual plume development with the simulated plume model.
- Once the surveyed plume has reached the model results or caused a sufficient change to cease injection, the stage is isolated and a recompletion to the next stage is performed.
- The completed stage is then plugged with a duplex stainless steel (or equivalent) bridge plug or cement retainer, with [redacted] of corrosion-resistant cement on top of it. The bridge plug with cement plug or cement retainer and casing are then tested.
- If using gauge carrier pressure gauges, the abandoned stage remains open below the

bridge plug to allow for continual monitoring of BHPs and temperatures in the abandoned stages.

- This process is repeated until the entire gross injection zone has been completed.

Figure 4-8 depicts this process in a general form.

Figure 4-8 – Operational Completion Strategy

The actual injection intervals, injection time frame, injection rate, and injection volume for both wells were displayed in Tables 4-25 and 4-26 (page 30).

4.5 Injection Well Construction and Operation Summary

The proposed well design is engineered to address the potential hazards and risks associated with Class VI wells, including protection of the USDW. Casing setting points, materials, and cement meet and exceed the requirements for this classification of injection well. All requirements and regulations are satisfied by the well design. Additionally, the completion strategy efficiently maximizes the use of the available pore space and mitigates issues with sand control while still allowing pressure monitoring throughout the injection interval.

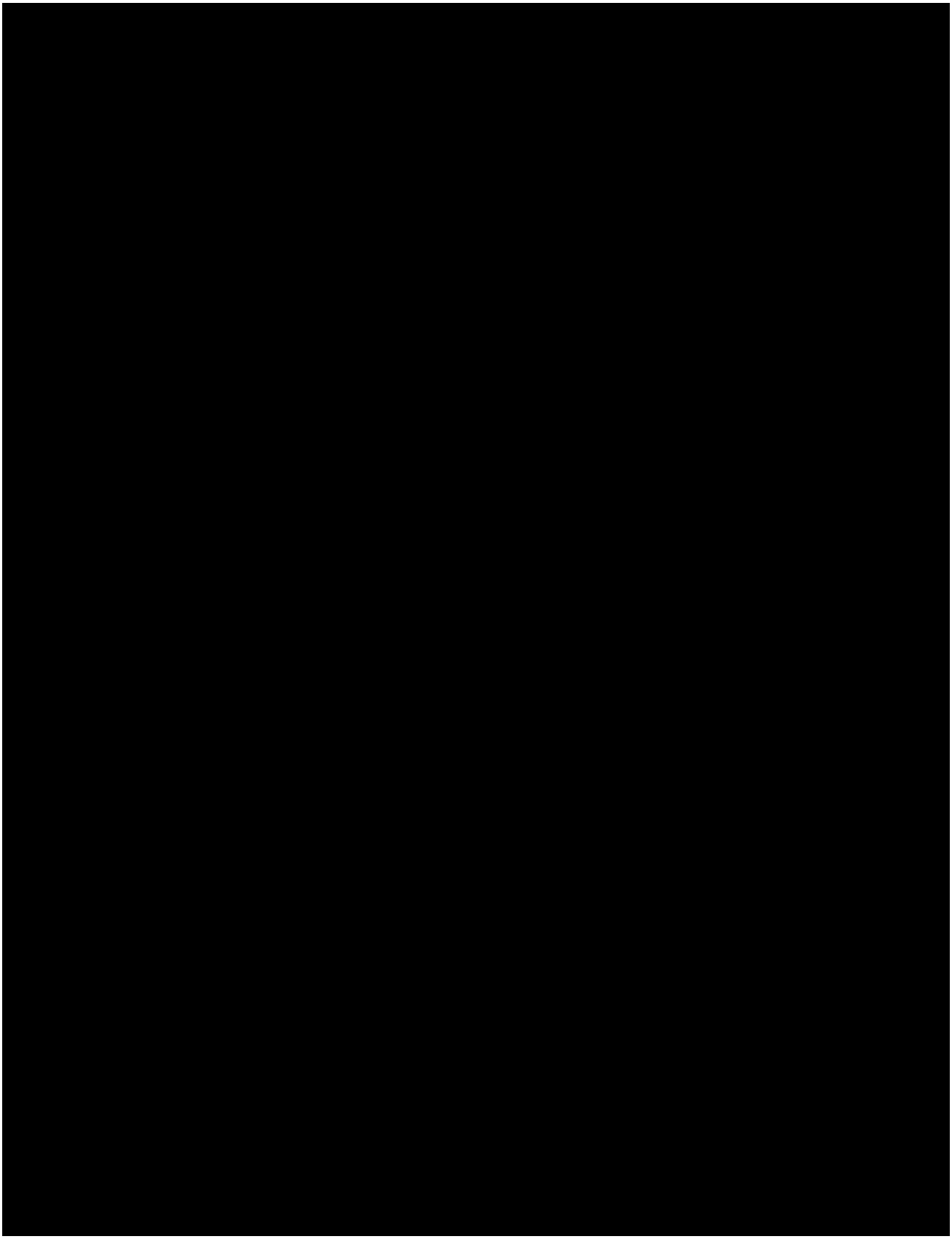
The gross injection interval will be subdivided into stages, which are established based on the designed injection rate. Each stage is then completed in discrete injection intervals, into which CO_2 will be injected for periods of time so that the plume buildup and migration do not exceed

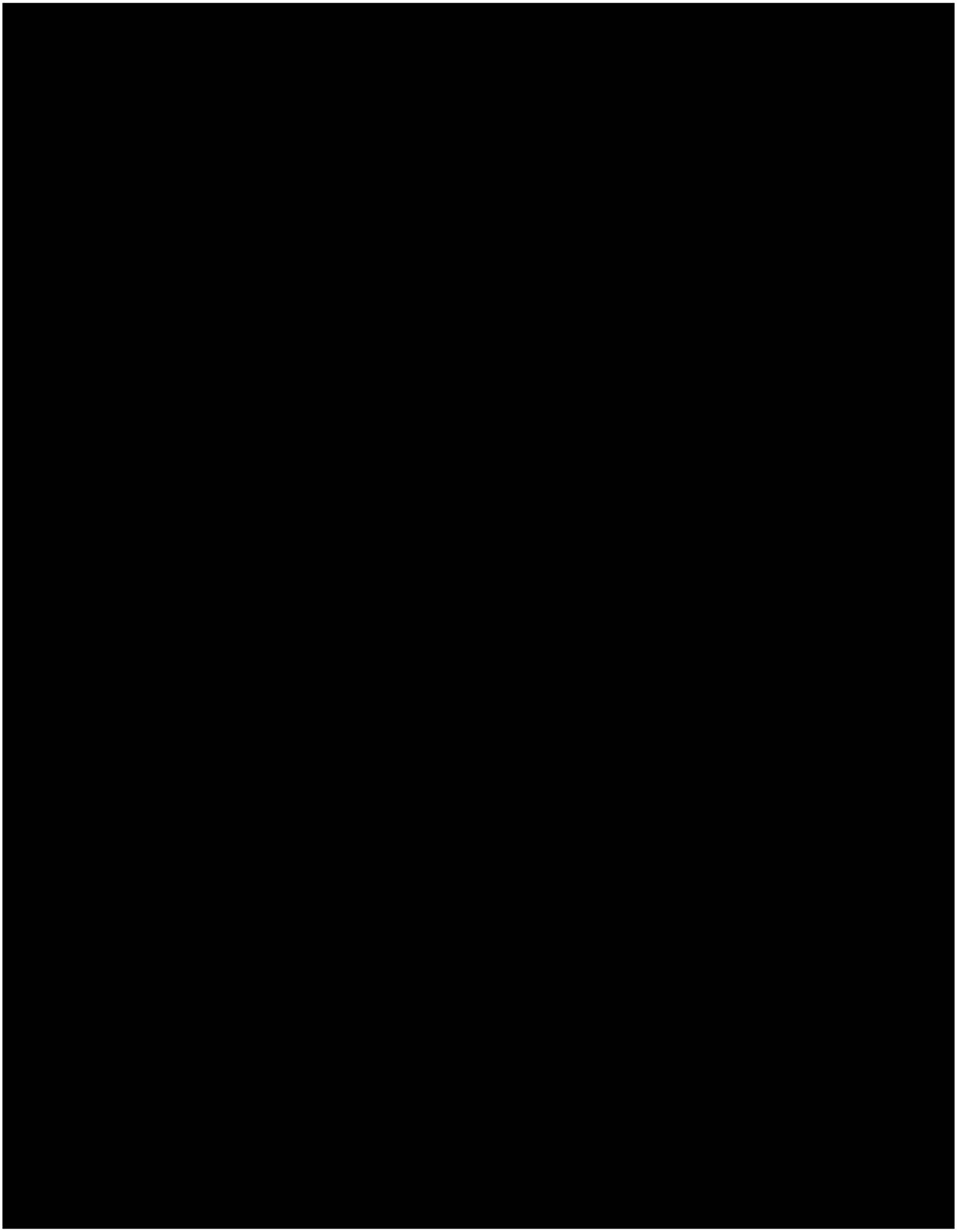
modeled limits.
A VSP survey will initially be performed one year after injection begins, then in year five after the start of injection and every 5 years thereafter to measure actual plume growth within the active injection interval. Once the measured plume reaches modeled extents, the next shallowest sand package will be opened with perforations. The new interval will then be injected into, following the same practices as previously described. Due to the density difference between the injected fluids and connate fluids of the formation, the injected carbon stream will favor the shallowest perforations, with minimal further influence on the deeper sands. Once all the discrete packages within a stage have reached modeled plume extents, the stage will be plugged and abandoned. The next stage will be completed, developed, and operated in the same fashion until all stages have been exploited. Once all stages have been completed, the well will be plugged and abandoned.

This completion and operating strategy is employed to achieve maximum use of available pore space while maintaining control of plume growth and migration. Without this strategy, it is estimated that less than 10% of the entire gross injection interval would be used and the maximum extent of the injection plume would be approximately three times larger than the maximum extent modeled for these wells. As previously discussed, the location for this project is ideally situated for carbon sequestration purposes. Combining the best engineering practices in the design of the well with a state-of-the-art monitoring system and a robust reservoir management strategy, these wells will serve the State of Texas for years to come.

4.6 Discussion of Above-Zone Monitoring Wells

Titan plans to drill and complete two above-zone monitoring (AZM) wells, Atlas No. 1 and Andes No. 1. The AZM wells' surface location will be located [redacted] The AZM wells will be vertically drilled and are intended to monitor the Middle Miocene sand formation. This formation is the first permeable zone above the UCZ of the injection zone. Continuous measurements will be taken with a pressure and temperature sensor run behind casing, or hung off in the wellheads, or other conveyance methods as necessary. If fluid samples need to be taken, the long string casings will be perforated in the Middle Miocene, just above the UCZ. Atlas No. 1 and Andes No. 1 will monitor for indications of CO_2 leaking out of the confining zone. These wells will not penetrate the confining zone and therefore will not need to consider corrosion resistant materials in their construction. Figures 4-9 and 4-10 illustrate the proposed designs for Atlas No. 1 and Andes No. 1, respectively.





4.6.1 General Outline of Atlas No. 1 Well Design

The Atlas No. 1 well was designed with the following specifications (as was illustrated in Figure 4-9):

- Drive Pipe
  - [redacted] (or 200 blows/ft)
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of openhole logging during the drilling of the wells. If necessary, the final setting depth will be adjusted.
  - [redacted]
  - Cemented back to surface
- Long String Casing
  - [redacted] (top of lower confining layer)
  - Cemented back to surface

The Andes No. 1 well was designed with the following specifications (as illustrated in Figure 4-10):

- Drive Pipe
  - [redacted] (or 200 blows/ft)
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of openhole logging during the drilling of the wells. If necessary, the final setting depth will be adjusted.
  - [redacted]
  - Cemented back to surface
- Long String Casing
  - [redacted] (top of lower confining layer)
  - Cemented back to surface

Detailed drilling-and-completion prognoses for Atlas No. 1 and Andes No. 1 are included in *Appendix D*.

Surface Casing

The AZM wells will be drilled vertically from the Cronos No. 1 and Rhea No. 1 injection well pads. The surface holes will be drilled vertically below the lowermost USDW with a [redacted] bit, to casing set [redacted] ft. A string of [redacted] in. casing will be run and cemented, with the casing centered using centralizers in the open hole. The selected hole size and centralizers will provide a consistent thickness of cement between the casing and the open hole. Cement returns will be circulated to the surface. If the cement level falls after it is circulated to the surface, a top-job will be performed to ensure cement at surface—to provide a good cement bond from the surface casing setting depth to the surface, protecting the lowermost USDW. After cementing, a cement bond log will be run to evaluate and verify good bonding throughout the surface hole.

Summaries of engineering calculations for the surface casing are displayed in Tables 4-27 through 4-29.

Table 4-27 – Atlas No. 1 and Andes No. 1 Surface Casing Engineering Calculations

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Table 4-28 – Atlas No. 1 and Andes No. 1 Surface Casing Annular Geometries

Section – Surface	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-29 – Atlas No. 1 and Andes No. 1 Surface Casing Cement Calculations

Section – Surface	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]				

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

Long String Casing

The long string holes will be drilled vertically with a [redacted] in. casing string centered using centralizers in the hole. The long string casing is the final, permanently cemented string of casing installed in the wells, to be run from the surface to the top of the UCZ TD—then cemented back to the surface. As these wells do not penetrate the UCZ, corrosion resistant cements and tubulars were not considered.

The engineering and design parameters for the long string casings are summarized in Tables 4-30 through 4-35.

Table 4-30 – Atlas No. 1 Long String Casing Engineering Calculations

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Table 4-31 – Andes No. 1 Long String Casing Engineering Calculations

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)	Thermal Conductivity (W/m / °C)
[redacted]									

Table 4-32 – Atlas No. 1 Long String Casing Annular Geometries

Section – Long String	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-33 – Andes No. 1 Long string Casing Annular Geometries

Section – Long String	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-34– Atlas No. 1 Long String Casing Cement Calculations

Section – Long String	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]				

Table 4-35 – Andes No. 1 Long String Casing Cement Calculations

Section – Long String	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]				

Centralizers

The bow-spring centralizer design for the [redacted] in. surface casing is planned to protect any shallow aquifer zones per state regulations. The specific placement is to ensure that a continuous, uniform column of cement is present throughout the [redacted] in. annular void. The recommended locations are as follows:

[redacted]

The solid body centralizer design for the [redacted] in. long string casing is designed to protect all shallow aquifer zones per state regulations. The specific placement ensures that a continuous, uniform column of cement is present throughout the [redacted] in. annular void. The recommended locations are as follows:

[redacted]

[redacted]

Tubing

There will be no tubing run in this well as discussed in *Section 4.6*. Tubing may be used as a contingency to run additional instrumentation in the future.

Testing and Logging of Monitoring Well During Drilling and Completion Operations

A basic suite of electric logs will be run in the openhole sections and each casing string. The logging plan is detailed in Tables 4-36 and 4-37. Titan will provide a schedule of all logging plans to the UIC Director at least 30 days prior to conducting the first test. Notice will be provided at least 48 hours in advance of such activity.

Table 4-36 – Openhole Logging Plan, Atlas No. 1 and Andes No. 1

Trip	Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter (in.)	Depths of Survey (ft)
[redacted]					

Table 4-37 – Cased-Hole Logging Plan, Atlas No. 1 and Andes No. 1

Trip	Hole Section	Logging Suite	Target Data Acquisition	Casing Dimension (in.)	Depths of Survey (ft)
[redacted]					

Overview of Atlas No. 1 and Andes No. 1 Completion Program

The completion program includes the following:

- Make bit and scraper run to TD.
- Run cased-hole logs as described in Table 4-44.
- Test the casing.
- [redacted]

Monitoring Well Operational Strategy Summary

The Atlas No. 1 and Andes No. 1 monitoring wells are designed to be above-zone monitoring wells. Continuous monitoring will be implemented with the use of a Supervisory Control and Data Acquisition (SCADA) system to monitor the reservoir pressure. The Middle Miocene formation is the first porous interval above the UCZ. Temperature and pressure anomalies within the Middle Miocene are potential early warning signs of injectate from the proposed Titan Project injection wells moving out of the injection zone. If pressure or temperature anomalies consistent with loss of containment are observed, injection will be stopped, and the incident will be assessed as described in *Section 8 – Emergency and Remedial Response Plan*. After injection ceases in Cronos No. 1 and Rhea No. 1, the monitoring wells will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*.

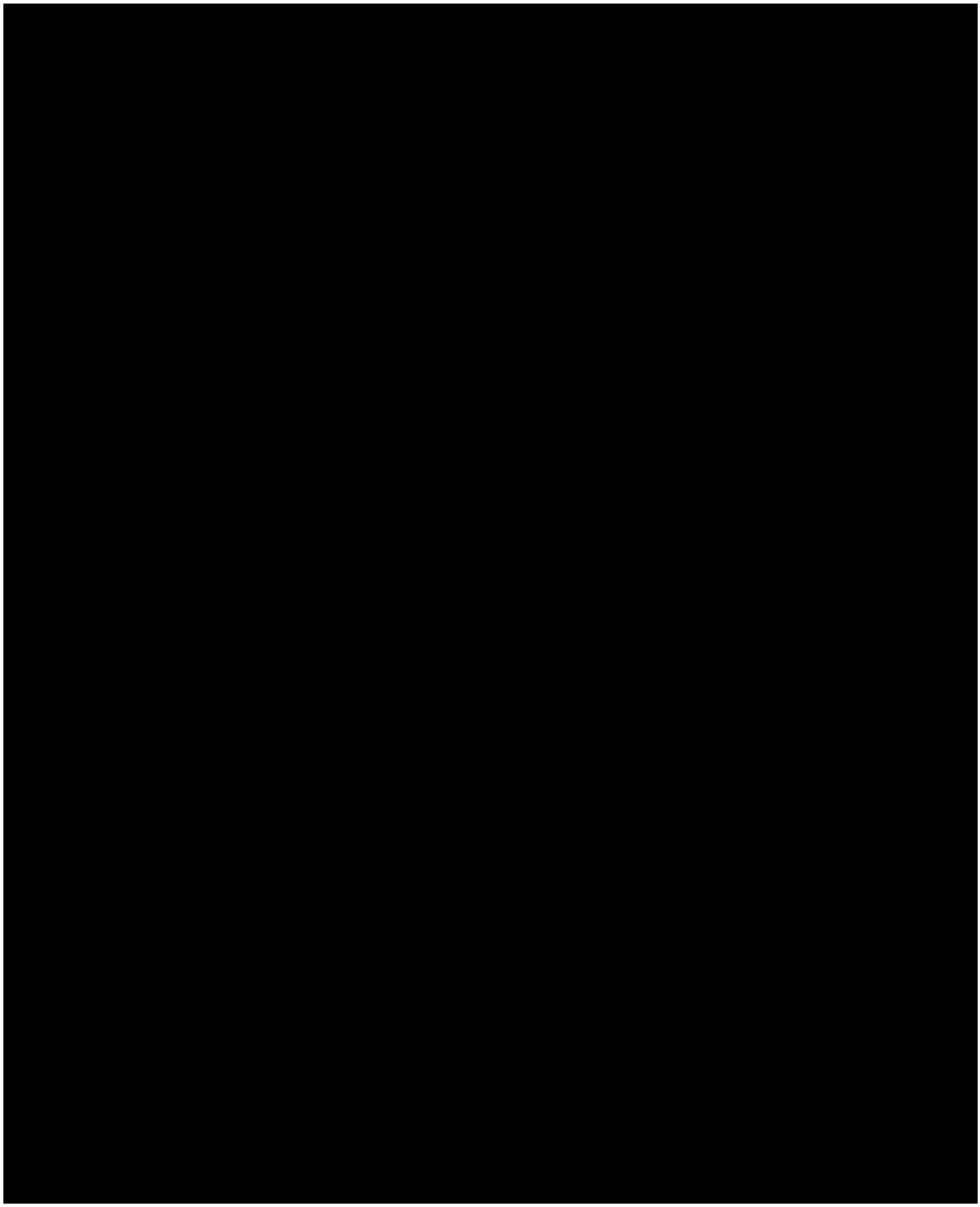
4.7 Discussion of USDW Monitoring Wells

Titan plans to drill and complete two USDW monitoring wells, TCS WM No. 1 and TCS WM No. 2. The USDW monitoring wells will be located on the planned injection well pads. Long string casing will be set, gravel packed and cemented back to surface with 20 ft of screen/slotted pipe just above the TD of the well to enable the taking of fluid samples. These wells will monitor for indications of CO_2 leaking out of the confining zone. These wells will not penetrate the confining zone; therefore, corrosion resistant materials will not need to be considered in their construction.

The specific depths will be updated for each well after the stratigraphic test well is drilled and the aquifer depths better identified.

Representative aquifer water samples will be obtained two times each year and compared against baseline sampling and fluid testing results, to verify that injectate is not leaking into the USDW. If fluid sample anomalies are detected, injection will be stopped, and the incident will be assessed as described in *Section 8 – Emergency and Remedial Response Plan*. After injection ceases in Cronos No. 1 and Rhea No. 1, the monitoring wells will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*. Figure 4-11 shows the proposed design for TCS WM No. 1.

Figure 4-11 – TCS WM No. 1 Wellbore Schematic



4.7.1 General Outline of USDW Monitoring Wells Design

The Titan USDW monitoring wells are designed with the following specifications (as illustrated in Figure 4-11):

Conductor Casing

The conductor casing will be run from the surface to [redacted] then cemented back to the surface with Portland Cement.

- Conductor Casing

Long String Casing

Casing to be run from the surface to [redacted] below the USDW at [redacted] then cemented back to the surface. As these wells do not penetrate the UCZ, corrosion resistant cements and tubulars were not considered.

- Long string Casing
  -

Long string Centralizers

The bow-spring centralizer design for the [redacted] long string casing is designed to protect all shallow aquifer zones per state regulations. The specific placement ensures that a continuous, uniform column of cement is present throughout the [redacted] annular void. The recommended locations are as follows:

- [redacted]

[redacted]

Overview of USDW Well Completion Program

After setting and cementing the long string casing, the completion program includes the following:

- Perform pump-in test to ensure fluid and pressure communication with the formation.
- Install tubing and electric pump
- Install wellhead.

4.8 Engineering Design and Operations Summary

The Titan Project site is ideally situated for carbon sequestration and monitoring purposes. By combining the best engineering practices in each well design with a state-of-the-art monitoring system and robust reservoir management strategy, these proposed injection wells will safely permanently sequester CO_2.

Detailed drilling and completion procedures are provided in *Appendix D.*

Appendix D – Well Construction Schematics and Procedures:

- Appendix D-1 Injection Wellbore Schematics
- Appendix D-2 Injection Well Drilling and Completion Prognoses
- Appendix D-3 Monitoring Wellbore Schematics
- Appendix D-4 Monitoring Well Drilling and Completion Prognoses
- Appendix D-5 USDW Monitoring Wellbore Schematics
- Appendix D-6 Supporting Well Construction Programs

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 5 – TESTING AND MONITORING PLAN

February 2024

SECTION 5 – TESTING AND MONITORING PLAN

TABLE OF CONTENTS

5.1 Introduction 3
5.2 Record Keeping and Reporting Requirements 3
5.3 Testing Plan Review and Updates 5
5.4 Testing Strategies 5
5.4.1 Initial Step-Rate Injectivity Test 5
5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test 8
5.4.3 External Mechanical Integrity Testing – Temperature Log 9
5.4.4 Pressure Falloff Testing 10
5.4.5 Cement Evaluation and Casing Inspection Logs 11
5.5 Monitoring Programs 13
5.5.1 Monitoring Overview 13
5.5.2 Continuous Injection Stream Physical Monitoring 14
5.5.3 Injection-Stream Composition Monitoring 16
5.5.4 Corrosion Coupon Monitoring 17
5.5.5 Groundwater Quality Monitoring 18
5.5.6 Above-Zone Monitoring Well 23
5.5.7 Injection Plume and Pressure Front Tracking 27
5.5.8 Monitoring Schedule 36
5.5.9 Wellbore Overview 36
5.5.10 VSP Monitoring Conclusion 52
5.6 Conclusion 53
5.7 References 54

Figures

Figure 5-1 – Example Step-Rate Injectivity Test 8
Figure 5-2 – Location of the Titan Project Monitoring Wells 19
Figure 5-3 – TCS WM No. 1 Schematic 21
Figure 5-4 – Proposed Atlas No. 1 Schematic 25
Figure 5-5 – Proposed Andes No. 1 Schematic 26
Figure 5-6 – Shell Canada Quest Project VSP Acquisition Patterns (Bacci et al., 2017) 28
Figure 5-7 – RokDoc Well Viewer 30
Figure 5-8 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation 31
Figure 5-9 – Illustration of a Vertical Seismic Profile Survey 32
Figure 5-10 – Illustration of a Checkshot Survey 33
Figure 5-11 – A 4D Processing Workflow Diagram 34
Figure 5-12 – Baseline and subsequent VSP used to determine the difference in amplitude 35
Figure 5-13 – Proposed Wellbore Schematic for Cronos No. 1 38
Figure 5-14 – Proposed Wellbore Schematic for Rhea No. 1 39
Figure 5-15 – [redacted] 41
Figure 5-16 – Subsurface Injection Valve 42

Figure 5-17 – Halliburton Array Pressure Temperature Sensor 43
Figure 5-18 – SureVIEW with CoreBright Optical Fiber 44
Figure 5-19 – SureVIEW WIRE Well Integrity Evaluation 47
Figure 5-20 – Tubing Encapsulated Conductor 48
Figure 5-21 – SureSENS QPT Elite Gauge 49
Figure 5-22 – External Sensor 50
Figure 5-23 – SureSENS QPT Gauge Carrier Illustration 52
Figure 5-24 – Steel Blast Protector Illustration 52
Figure 5-25 – Cross Coupling Protector 52

Tables

Table 5-1 – Proposed Step-Rate Injection Test 7
Table 5-2 – PEC Tool List 12
Table 5-3 – Testing and Monitoring Plan Measurements 14
Table 5-4 – Injection Stream Measurements 16
Table 5-5 – USDW Monitoring Well Details 20
Table 5-6 – USDW and AZM Monitoring-Well Sampling Parameters Measured 22
Table 5-7 – AZM Well Location Details 23
Table 5-8 – SureVIEW Downhole Specifications 44
Table 5-9 – SureVIEW DTS Surface Interrogator Specifications 45
Table 5-10 – SureVIEW DAS VSP Specifications 45
Table 5-11 – SureVIEW WIRE Cable Specifications 47
Table 5-12 – TEC Specifications, Part I 49
Table 5-13 – TEC Specifications, Part II 49
Table 5-14 – QPT Elite Pressure Interface – Pressure-Test Manifold Specifications 51

5.1 Introduction

The operating plans for the proposed Titan Carbon Sequestration Project (Titan Project) injection wells Cronos No. 1 and Rhea No. 1 include robust testing and monitoring programs in accordance with promulgated regulations, which are designed to satisfy the requirements of 16 Texas Administrative Code (16 TAC) ***§*5.203(j)** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**. This plan will begin before CO_2 injection 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 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. An in-depth summary of plume-growth monitoring, using time-lapse seismic imaging technology, is also presented.

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. The monitoring 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 CO_2 is not endangering the USDWs. This section discusses the key details of this plan.

5.2 Record Keeping and Reporting Requirements

In compliance with 16 TAC **§5.207** [40 CFR **§146.91**], Titan Carbon Sequestration, LLC (Titan) will provide routine reports to the Underground Injection Control (UIC) Program director (UIC Director). The report contents and submittal frequencies are as follows.

Per-Occurrence Reporting:

- 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 the event
- Any evidence that the injected CO_2 stream or associated pressure front may endanger a USDW
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 5 working days of the event
- Any failure to maintain mechanical integrity
    - Verbal Notification – Reported within 24 hours of the event
- Any significant data that indicate the presence of leaks in the well or lack of confinement to the injection zone
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 5 working days of the event

- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
    - Written Notification – Reported within 72 hours of composition change
- Any new wells installed at the facility and the type, location, number and information required by 16 TAC **§5.203(e)**
- 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 the event
    - Written Notification – Reported within 72 hours of the event
- Description of any event that triggers a shutoff device either downhole or at the surface and the response taken
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 72 hours of the event
- Results of injection pressure and injection rate monitoring of each injection well on TRRC Form H-10, Annual Disposal/Injection Well Monitoring Report

Semiannual Reports:

- Summary of wellhead pressure monitoring
- Any changes to the source of the CO_2 stream
- Any significant changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
- Monthly average, maximum and minimum values of injection pressure, flow rate, temperature, volume, and annular pressure
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
- Monthly volume and/or mass of the CO_2 stream injected during the reporting period, and the volume injected cumulatively during the life of the project
- Monthly annulus fluid volume added
- Results of any monitoring, as described in this section

Annual Reports:

- Any corrective action performed
- Recalculated area of review (AOR) or statement confirming that monitoring and operational data supports the current delineation of the AOR on file with the regulatory authority
- Proof of good faith claim to sufficient property rights for storage facility operation
- Metric tons of CO_2 injected

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

- Any well workover

- Any test of the injection wells conducted, if required by the UIC Director
- Any periodic mechanical integrity tests

Notification to the UIC authority [16 TAC **§5.206(c)**], in writing, 30 days in advance of the following:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of the injection wells

Titan will submit the above reports, submittals, and notifications to the Environmental Protection Agency (EPA) and Texas Railroad Commission (TRRC) and ensure that such records are retained throughout the life of the project. In accordance with 16 TAC **§5.207(e)** [40 CFR **§146.91(f)**], these records will be maintained for 10 years after site closure. The records will be delivered to the UIC Director upon request after the retention period. Monitoring data will be retained for 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 16 TAC **§5.207(a)(3)** [40 CFR **§146.90(j)**], the Testing and Monitoring Plan will be reviewed and revised at least every 5 years or as otherwise required to incorporate collected monitoring data. Plan amendments will also be submitted within 1 year of an AOR reevaluation, following significant facility changes—such as the development of offset monitoring wells or newly permitted injection wells within the AOR—or as the UIC Director requires.

5.4 Testing Strategies

5.4.1 Initial Step-Rate Injectivity Test

Prior to the commencement of CO_2 injection, Titan will conduct a step-rate injectivity test to measure the fracture gradient of the proposed injection wells, Cronos No. 1 and Rhea No. 1, in compliance with 16 TAC **§5.203(f)(2)(A)** [40 CFR **§146.87(d)(1)**] and 16 TAC **§5.203(f)(2)(C)** [40 CFR **§146.87(e)(3)**]. Pressure and temperature gauges, plus fiber optic temperature and acoustic sensing, will be run and cemented behind the [redacted] casing from surface to the total depth of the wellbore. A surface gauge with continuous readout will also be installed. All gauges will be calibrated prior to the test. Initial bottomhole pressure and temperature readings must be taken prior to beginning injection.

The step-rate test will be performed using brine. Brine injection rates observed during step-rate testing can be converted to the equivalent CO_2 injection rate by accounting for the difference in fluid properties. The injection rate can be converted from a volumetric rate to a mass rate (i.e., barrels per day (bbl/D) to standard cubic feet per day (scf/D). The mass rate is more suitable for measuring a compressible fluid such as CO_2.

The densities of the CO_2 at standard conditions and in the reservoir are modeled using the Reference Fluid Thermodynamic and Transport Properties Database (REFPROP, Ver. 10.0), a software program developed by the National Institute of Standards and Technology. This program references thermodynamic, physical, and transport properties of various fluids and fluid mixtures, and implements fluid models to calculate properties at variable temperatures and pressures throughout the liquid, gas, and supercritical states. The most accurate available models are included for 147 industrially important fluids. A wide range of tables and plots can be created within the software to display fluid properties at varying conditions. Equations 1 through 3 are key equations used within the REFPROP software.

(Eq. 1) $$Qm = \frac{Qv * \rho BH}{\rho SC}$$

(Eq. 2) $$\rho_{BH} = f(T_{BH}, P_{BH}, Fluid\ Composition) \leftarrow \text{from } REFPROP\ software$$

(Eq. 3) $$\rho_{SC} = f(T_{SC}, P_{SC}, Fluid\ Composition) \leftarrow \text{from } REFPROP\ software$$

Where:

Qv = volumetric flow rate (bbl/day)

Qm = mass flow rate (scf/day)

T_{BH} = temperature at bottomhole (°F)

P_{BH} = pressure at bottomhole, pounds per square inch (psi)

ρ_{BH} = CO_2 density at bottomhole conditions, pounds per cubic foot (lb/ft^3)

T_{SC} = temperature at standard conditions (°F)

P_{SC} = pressure at standard conditions (psi)

ρ_{SC} = CO_2 density at standard conditions (lb/ft^3)

5.4.1.1 Testing Method

Specific wellbore and injection zone properties will define the final test parameters. The following test method outlines the expected test injection rates and times. Brine injection will begin at less than 1 barrel per minute (bpm) and be held for a [redacted]. The injection rates will be stepped up in increments until at least three measurements are taken, both below and above the estimated formation fracture-initiation pressure—or to a maximum rate of [redacted]. *Each stage duration will be based on the time required for the bottomhole pressure for the initial step to stabilize*. Table 5-1 lists the proposed rates and total volumes planned for the step-rate test.

Table 5-1 – Proposed Step-Rate Injection Test

Step	Duration (min)	Rate (bpd)	Rate (bph)	Rate (bpm)	Volume (bbl)
[redacted]					

bph – barrels per hour

A plot of stabilized injection pressure vs. injection rate at each step should graphically represent a linearly sloped line, until the fracture initiation pressure is exceeded. Figure 5-1 is a graphical representation of an example step-rate test.

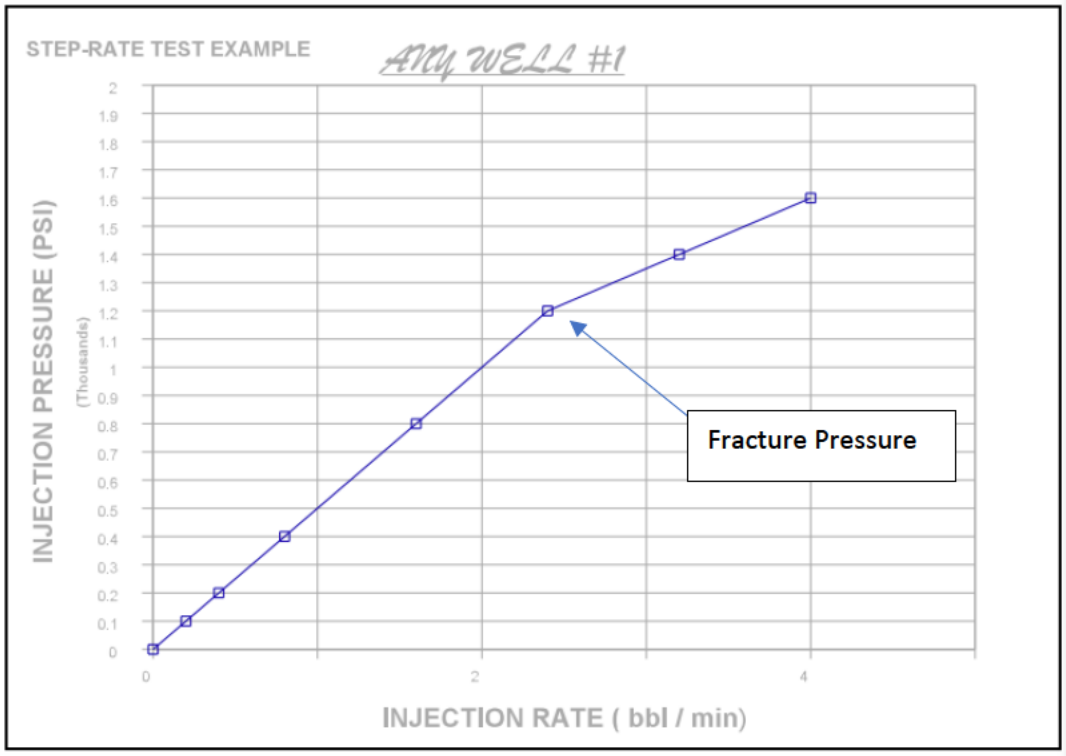


Figure 5-1 – Example Step-Rate Injectivity Test[1]

Upon reaching a stabilized pressure after completing the final step, pressures will be recorded at the highest frequency of the gauge for a period indicated by the step-up phase of testing, to calculate the rate of pressure bleed-off.

5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 16 TAC **§5.203(h)(1)(C)** [40 CFR **§146.89(b)**], Titan will ensure the mechanical integrity of both injection wells by performing annulus pressure tests (1) after the wells have been completed, (2) prior to injection, and (3) every five years afterwards. This annular pressure test specifically verifies the integrity of the annulus between casing and tubing above the packer. During well construction, prior to completion, the casing will also be pressure tested to the maximum anticipated annulus-surface pressure to verify its integrity.

After the wells are completed, an annular pressure test will be performed prior to the start of injection, to demonstrate the mechanical integrity of the casing, tubing, and packer. An annulus pressure test will also be performed after any workover operation involving the removal and replacement of the tubing and packer. The annulus will be pressured to a minimum of 500 psi fluid pressure. A block valve will be used to isolate the test pressure source from the test pressure gauge once the test has begun. All ports into the casing annulus—other than the one monitored by the test pressure gauge—will be closed. The test pressure will be monitored and recorded for

[1] https://www.epa.gov/sites/default/files/documents/INFO-StepRateTest.pdf

a minimum of 30 minutes. The test pressure gauge will be of sufficient sensitivity to indicate a loss of 5%. Any loss of test pressure more than 5% during the minimum 30 minutes will indicate a lack of mechanical integrity.

All annulus pressure test results will be submitted to the TRRC/EPA on Form H-5 within 30 days of log run completion. This test will be performed at least every 5 years.

5.4.3 External Mechanical Integrity Testing – Temperature Log

Titan will perform external mechanical integrity tests (MITs) annually, to meet the requirements of 16 TAC **§5.203(h)(2)** [40 CFR **§146.89(c)**], by running a temperature log through tubing or by using the distributed temperature sensing (DTS) system installed on the fiber optic system. Temperature logs will be run prior to beginning injection operations, to establish the baseline to compare against future logs. Prior to running the temperature logs, the wells will be shut in long enough— approximately 36 hours—to stabilize temperatures. Satisfactory mechanical integrity is demonstrated by the proper correlation between the baseline and subsequent logs. All temperature logs will be reported to the UIC Director within 30 days of the log run.

Temperature Log Procedure

Prior to injection, the wells will be shut in for at least 36 hours, and a temperature log will be run in the wells to establish a baseline temperature survey. This baseline survey will be compared against temperature surveys throughout the life of the wells, to determine fluid flow outside the casing. In all future temperature logs, a stabilization period will be reached to compare any differences in the log. Distributed temperature sensing fiber may also be used for the required temperature analysis.

When conducting a temperature survey via wireline, the tool will log from the surface to the total depth (TD) of the wells. No logging runs should precede the temperature log, to ensure static conditions in the wellbore. The recommended logging speed is 30 feet (ft) per minute, and all depths should be zeroed to the bradenhead flange. The following list highlights the general procedure for the wireline-temperature logging operation for the proposed injection wells:

1. Allow the well to stabilize for 36 hours.
2. Rig up the wireline unit to the wellhead and make up the logging tool (temperature probe and casing collar locator (CCL)).
3. Zero the end of the tool string at the bradenhead flange.
4. Run in the hole while logging from surface to TD at 30 ft per minute. Correlate collar depths to the CCL.
5. Pull out of hole and rig down wireline unit.

Once the temperature log is processed, the data will be analyzed in conjunction with the baseline and other temperature logs. A differential temperature trend will be calculated and reported. Include the new log and the baseline log on a report as well as a track—to calculate the differential temperature.

5.4.4 Pressure Falloff Testing

Titan will perform a required pressure falloff test at least every 5 years to meet the requirements of 16 TAC **§5.203(j)(2)(G)** [40 CFR **§146.90(f)**]. This test will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases. Parameters obtained from the falloff tests will be compared to those determined from the computational modeling and previous tests, for indications of fluid leakage during the test.

5.4.4.1 Testing Method

The CO_2 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 wells are shut in, continuous pressure measurements will be taken with a downhole pressure gauge array installed across each injection stage. This array consists of a tubing encapsulated conductor (TEC) cable equipped with pressure gauges. 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.

Detailed Pressure Falloff Test Procedure:

1. Prior to testing, keep the injection rate and pressure as constant as practical and continuously recorded.
    a. The injection rate should be high enough and maintained for a duration sufficient to produce a measurable pressure transient that will result in a valid falloff test.
    b. Offset wells should be shut in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
    c. [redacted]
2. Stop injection and shut in the wells completely.
    a. This shut-in should occur over the shortest time possible.
3. During the shut-in period, continue to record temperatures and pressures at the highest obtainable frequency.
    a. The shut-in period should be long enough to observe a straight line of pressure decay on a semi-log plot (i.e., radial flow is achieved). The radial flow portion of the test is the basis for all pressure transient calculations. Therefore, the falloff portion of the test should be designed to reach radial flow, and to sustain a time frame sufficient for analysis of the radial flow period.
    b. A general rule of thumb is to run the test for three to five times the amount of time required to reach radial flow conditions.

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 will also be considered. The 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. Results of the pressure falloff test will be reported to the UIC Director within 30 days of the test.

5.4.4.3 Quality Assurance/Quality Control

All surface field equipment will undergo inspection and testing prior to operation. The pressure gauges used in the falloff test will be calibrated according to manufacturers' instructions. Documentation certifying proper calibration will also be enclosed with the test results. [redacted]

5.4.5 Cement Evaluation and Casing Inspection Logs

In accordance with 16 TAC **§5.203(h)(2)** [40 CFR **§146.89(d)**], a comprehensive cased-hole logging suite will be run on the long-string casing at the time of initial well completion. This suite of logs will include a cement bond log and a multiple-armed caliper to establish the condition of the casing metal. This survey will characterize the original state of the wellbore materials.

Casing inspection logs will be run at least every five years if a log has not been obtained in the interim. These logs will be performed, through tubing on wireline if tubing and packer are not moved and whenever tubing is removed for workover operations. The following tools will be run at that time:

- A 5-year casing inspection:
    - Casing section below the packer:
        - Multiple-armed calipers to measure the inner diameter (ID) of the casing as the tool is raised or lowered into the well
        - Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing as well as cement bonding
        - Electromagnetic tools that measure the magnetic flux of the tubular and can provide mapped circumferential images to indicate potential pitting
    - Casing section without tubing in the hole
    - Casing section from packer to surface:
        - Through-tubing casing inspection log
- Conventional casing inspection logs will be run if tubing is removed, consisting of the following:

- Multiple-armed calipers to measure the ID of the casing as the tool is raised or lowered into the well
- Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing as well as cement bonding
- Electromagnetic tools that measure the magnetic flux of the tubular and can provide mapped circumferential images to indicate potential pitting

Titan will provide a schedule of all logging plans to the UIC Director at least 30 days before conducting the first test. Notice will be provided at least 48 hours in advance of such activity.

5.4.5.1 Casing-Log Equipment Overview

Through-tubing logging technology provides the ability to evaluate casing deformation and curve-deviation measurements in conjunction with other well-integrity tools, such as multi-finger calipers and multiple pipe-thickness logging tools. This technology provides quality measurements without requiring the removal of the tubing and packer (Yang et al., 2021).

The following descriptions of the through-tubing logging tools that will be run are provided for informational purposes. The final vendor will be selected before operations, based on availability and commercial considerations.

The instruments listed in Table 5-2 use pulsed eddy current (PEC) decay technology to measure the thicknesses of multiple concentric tubulars. Basic PEC decay technology theory is discussed further below. These tools can be run stand-alone or combined with other well-integrity and correlation instruments—such as multi-finger imaging caliper, temperature, noise, pressure, fluid density, capacitance, flowmeter, gamma ray, and CCL.

The through-tubing PEC decay measurements are not affected by wellbore fluid types, chemical precipitates, or other foreign material deposits. They are also not affected by the type or distribution of annular materials, such as cement, mud, liquid, or gas.

Table 5-2 – PEC Tool List

Pulsed Eddy Current Decay Thickness Instruments					
Tool	Tool O.D.	Max # concentric pipes	Max O.D.	Max Combined Wall Thicknesses	Ratings (degF/K psi)
MTD-B/C	1-11/16"	2	10-3/4"	1.75"	350/15
MTD-G	1-11/16"	3	16"	2.5"	350/15
ePDT-II	2" / 1-11/16"	3-5	30" / 18-5/8"	3.5"	350/20

"O.D." = outer diameter
degF/K = degrees Fahrenheit per thousand pounds per square inch

Logging speeds depend on the size and number of tubulars to be logged. In general, multiple tubulars and larger sizes will necessitate slower data-acquisition speeds, which range from 30 ft per minute to 5 ft per minute, based on the complexity of the wellbore configuration.

The through-tubing PEC decay instruments measure the increase or decrease of metal thickness for each concentric tubular. The PEC decay data combined with inspection of the tubular's ID, using an imaging caliper or other methods, can reliably predict the inside vs. outside location of corrosion or flaws on the innermost tubular. Internal wear based on drilling or other known causes of internal damage is readily assessed, assuming that the measured metal loss in such cases is "internal."

The degree of penetration is reported in percentage of wall loss from both the nominal and absolute values of metal thickness, expressed in inches or millimeters. Because of well-understood, long-established PEC decay physics principles, reported metal gain or loss is assumed to be distributed evenly around the pipe's circumference.

The through-tubing PEC decay instruments measure the increase or decrease of metal thickness, due to both internal and external corrosion effects. This overall metal thickness/degree of penetration is valid in identifying areas of concern with well integrity. Additionally, integrity assessment of the injection tubulars (i.e., tubing[s] and first casing) is only part of whether a wellbore and its associated tubulars are in such a condition as to be protective of public health, safety, and the environment. The newer-generation through-tubing PEC decay instruments provide an opportunity to assess the state of the protection tubulars (i.e., second casing, surface casing, etc.).

5.4.5.2 Logging and Testing Reporting

A report that includes log and test results obtained during the drilling and construction of the proposed Titan injection wells Cronos No. 1 and Rhea No. 1—and interpreted by a knowledgeable log analyst—will be submitted to the UIC Director in accordance with 16 TAC **5.203(h)(2)** [40 CFR **§146.87(a)**].

5.5 Monitoring Programs

5.5.1 Monitoring Overview

Table 5-3 summarizes the various measurements discussed in the Testing and Monitoring Plan.

Table 5-3 – Testing and Monitoring Plan Measurements

Monitoring Type	Monitoring Program	Location	Frequency
CO_2 Injection Stream Composition	• CO_2 sampling station	CO_2 meter run	Quarterly
Corrosion Monitoring	• Corrosion coupon system	Facility flowline	Quarterly
Continuous Recording of Injection Pressure, Rate, and Volume	• Surface pressure and temperature gauges • Coriolis mass flowmeter	Wellhead	Continuous
Well Annulus Pressure Between Tubing and Casing	• Annular pressure gauge	Wellhead	Continuous
Groundwater Monitoring	• USDW monitoring wells • Groundwater monitoring wells	Facility	Annually first 5 years, then every 5 years until plume stabilizes
Above Confining Zone (ACZ) Monitoring	• Fluid samples • Pressures	Above-zone monitoring (AZM) wells	Pressure – continuously; fluid – as needed, if indicated from pressure response
Direct Reservoir Monitoring	• Pressure/temperature gauges on TEC cable installed on outside of casing	Cronos No. 1 and Rhea No. 1	Continuously
Indirect Reservoir Monitoring	• Vertical seismic profile (VSP) surveys	Facility	Years 1 and 5 after injection begins, then every 5 years until plume stabilizes
Internal and External Mechanical Integrity	• Annulus pressure test • Temperature and/or pulsed neutron logs • Casing pressure test • Pressure falloff test • Ultrasonic logs	Cronos No. 1 and Rhea No. 1	• Every 5 years • Annually • 5 years • 5 years • 5 years

5.5.2 Continuous Injection Stream Physical Monitoring

Titan will ensure continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with 16 TAC **§5.203(j)(2)(B)** [40 CFR **§146.90(b)**]. A Supervisory Control and Data Acquisition (SCADA) system will facilitate the operational data collection and monitoring for the full sequestration site—consisting of the pipeline, injection wells, and AZM wells.

The pressure and temperature of the injected carbon dioxide stream will be continuously monitored—using digital pressure gauges installed in the CO_2 pipeline, near its interface with the

wellhead—and connected to the SCADA system on-site. A Coriolis mass flow transmitter will be installed on the injection wells to measure the mass flow rate of CO_2 injected. The flow transmitter will be connected to the CO_2 storage site's SCADA system to continuously monitor and control the rate of CO_2 injection.

Reservoir temperatures and pressures will be measured through gauges installed with a fiber optic system embedded in the cemented annulus behind the long-string casing. Possible gauge designs, which are being evaluated, are described in detail in *Section 5.5.9*.

To meet the requirements of 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], automatic shut-off systems and alarms will be installed to alert the operator and/or shut in the well when operating parameters, such as annulus pressure, injection rate, etc., diverge from permitted ranges or gradients. A change of 10% in the annular pressure during injection operations will result in a shutdown event.

5.5.2.1 Analytical Methods

Continuously monitored parameters will be reviewed and interpreted regularly, to ensure the parameters are within permitted limits. The data will also be reviewed for trends to help identify the need for equipment maintenance or calibration. Monitoring results will be included in the semiannual reports.

5.5.2.2 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

CO_2 Mass Rate to Volumetric Injection-Rate Calculation Methodology

Mass flow rates observed during CO_2 injection can be converted to a volumetric flow rate by considering the density of the fluid. The pressure, temperature, and fluid composition are required to calculate density at specific conditions. REFPROP™ or similar fluid property calculation software may be used to determine density.

Variables Defined:

Q_m = Mass Flow Rate (lb/day)
T_bh = Temperature at Bottom Hole
P_{bh} = Pressure at Bottom Hole
ρ_{bh} = CO2 Density at Bottom Hole Conditions (lb/ft^3)
Q_{vbh} = Volumetric Flow Rate at Bottom Hole (ft^3/day)

Equations:

(Eq. 4) $$\rho_{bh} = f(T_{BH}, P_{BH}, Fluid\ Composition) \leftarrow REFPROP\ software$$

(Eq. 5) $$Q_{vbh} = \frac{Q_m}{\rho_{bh}}$$

5.5.3 Injection-Stream Composition Monitoring

In accordance with 16 TAC **§5.203(j)(2)(A)** [40 CFR **§146.90(a)**] requirements, Titan will determine the chemical composition of the injection stream, with the objective of understanding potential interactions between CO_2 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 of the parameters listed in Table 5-4, plus continuous pressure and temperature analysis.

5.5.3.1 Sampling Methods

In a location representative of injection conditions, CO_2 stream samples will be collected from the CO_2 pipeline. A sampling station will be connected to the pipeline inlet meter at a sampling manifold. Sampling cylinders will be purged with the injectate gas to expel laboratory-added gas, or vacuum cylinders will be used to obtain the samples. The samples will subsequently be sent to a laboratory for analysis.

5.5.3.2 Parameters Measured

Table 5-4 also lists the injection stream parameters that will be measured, plus the frequency and methods used.

Table 5-4 – Injection Stream Measurements

Parameter/Analyte	Frequency	Method
Pressure	Continuous	Pressure gauges at wellhead (downstream of choke) and downhole
Temperature	Continuous	Temperature gauges at wellhead and downhole
CO_2 (%)	Quarterly	Lab analysis
Water (lb/MMscf)	Quarterly	Lab analysis
Oxygen (%)	Quarterly	Lab analysis
Sulfur (ppm)	Quarterly	Lab analysis
Methane (%)	Quarterly	Lab analysis
SO_2 (%)	Quarterly	Lab analysis
NO_x (%)	Quarterly	Lab analysis

Parameter/Analyte	Frequency	Method
Ethane (%)	Quarterly	Lab analysis
Other Hydrocarbons (%)	Quarterly	Lab analysis
Hydrogen Sulfide (ppm)	Quarterly	Lab analysis
Benzene (%)	Quarterly	Lab analysis

*MMscf – million standard cubic feet
ppm – parts per million

5.5.3.3 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

5.5.4 Corrosion Coupon Monitoring

Titan will not only conduct corrosion monitoring of the tubing and the wells' casing materials—to meet 16 TAC **§5.203(j)(2)(C)** [40 CFR **§146.90(c)**] requirements—but also implement a corrosion coupon monitoring system. This system will be evaluated quarterly and casing inspection logs performed at least every 5 years at the time of permit renewal if a log has not been obtained in the interim. If plume surveys indicate it is time to recomplete uphole to a shallower subsection, then the tubing and packer will be removed and inspected, and a casing inspection logging suite will be run. If abandonment of a subsection is not warranted at the time of permit renewal, then a through-tubing inspection will be performed.

5.5.4.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection tubing and production casing, will be exposed to the conditions of the CO_2 flow in the pipeline, in a flow loop installed off the pipeline. 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 calculated by applying a weight-loss calculation method that divides the weight loss recorded during the exposure period by the period duration.

5.5.4.2 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

5.5.5 Groundwater Quality Monitoring

To meet 16 TAC **§5.203(j)(2)(C)** [40 CFR **§146.90(d)**] requirements, groundwater quality and geochemical monitoring above the confining zone will be conducted, the purpose of which is to detect potential changes that may result from fluid leakage out of the injection zone. As discussed in *Section 1.9.2*, [redacted] Titan therefore plans to drill two groundwater monitoring wells on the property, placing them on the same well pad as the injectors, to measure any change from baseline parameters that would indicate the migration of CO_2 into the USDW.

The well locations are shown in Figure 5-2 and listed in Table 5-5. During the final planning of the well pads, the locations of the AZM and USDW monitoring wells could change slightly. Well construction and drilling details, along with schematics, are included in *Appendix F*.

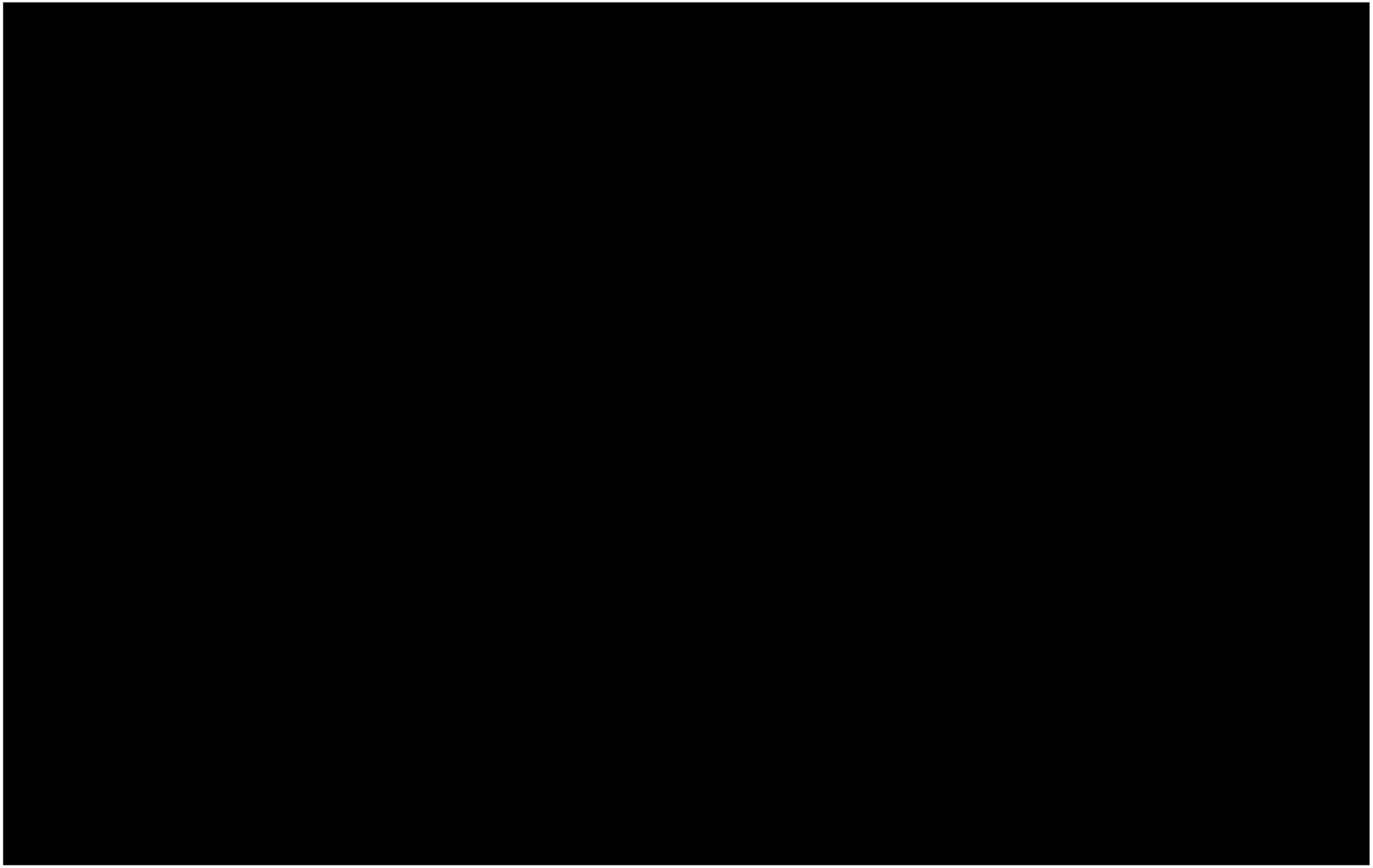


Figure 5-2 – Location of the Titan Project Monitoring Wells

Table 5-5 – USDW Monitoring Well Details

Location Info	TCS WM No. 1	TCS WM No. 2
NAD 83 (2011) Latitude	[redacted]	
NAD 83 (2011) Longitude		
Total Depth (ft)		
Type		

*NAD 83 – North American Datum of 1983

A detailed wellbore schematic for TCS WM No. 1 is displayed in Figure 5-3 as a representative example of such wells. Wellbore schematics of TCS WM No. 1 and No. 2 are provided in *Appendix F*.

As discussed in *Section 3.3.2*, the critical pressure front [redacted]

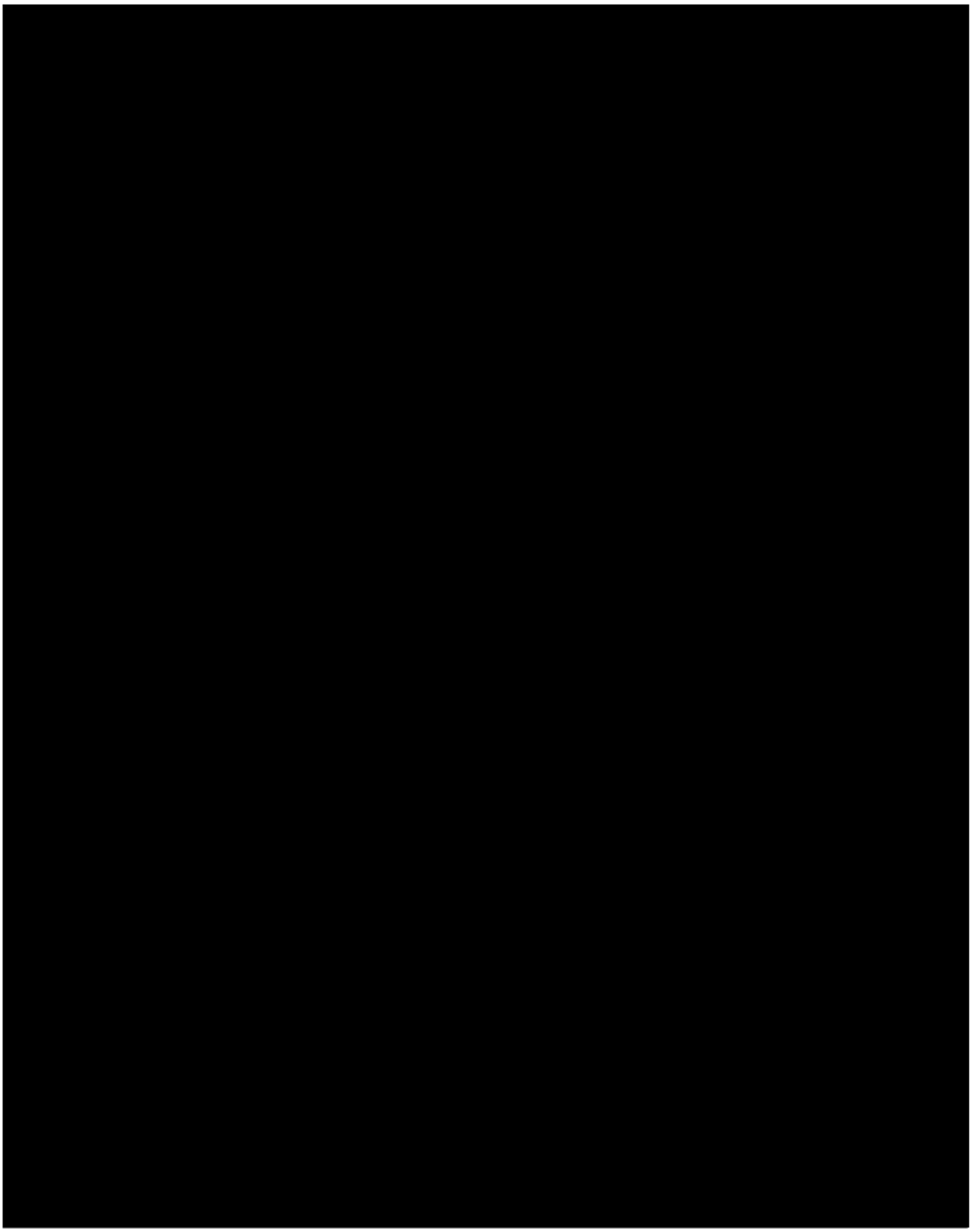


Figure 5-3 – TCS WM No. 1 Schematic

5.5.5.1 Parameters

Samples will be taken annually for the first 5 years, then every 5 years subsequently, with parameters to be measured as shown in Table 5-6.

Table 5-6 – USDW and AZM Monitoring-Well Sampling Parameters Measured

Parameter/Analyte	Frequency
Aqueous and pure-phase carbon dioxide	Annually first 5 years; subsequently, every 5 years
Total dissolved solids (TDS)	
pH	
Specific conductivity (SC)	
Temperature	
Density	
Other parameters, including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds	

5.5.5.2 Sampling Methods

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

5.5.5.3 Analytical Methods

Water samples will be tested and results maintained for the parameters listed above. If any impurities exist in the injectate, testing of those components should be included in the groundwater analysis to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database.

Trends that may indicate fluid leakage include the following:

- Change in TDS
- Changing signature of major anions and cations
- Increasing carbon dioxide concentration
- Decreasing pH
- Increasing concentration of injectate impurities
- Increase concentration of leached constituents
- Increased reservoir pressure and/or static water levels

5.5.5.4 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

5.5.5.5 Laboratory to Be Used/Chain-of-Custody Procedures

Water samples will be sent to an EPA-approved laboratory. Standard chain-of-custody procedures will be followed, and records maintained, to allow a full reconstruction of how the samples were collected, stored, and transported—and will include details of any problems encountered.

5.5.5.6 Quality Assurance and Surveillance Measures

Duplicate samples and trip blanks for quality assurance/quality control (QA/QC) purposes will be collected and used to validate test results and ensure samples are free of contamination.

5.5.5.7 Plan for Guaranteeing Access to All Monitoring Locations

As the locations are in marsh wetlands, access to the wells will be extremely restricted. Nevertheless, the wells will be capped and locked out to prevent any unauthorized access to the well.

5.5.6 Above-Zone Monitoring Well

In addition to the two USDW monitoring wells, two AZM wells—Atlas No. 1 and Andes No. 1—will be drilled to a depth corresponding to the first permeable formation above the upper confining zone (UCZ). [redacted] shown in Figure 5-2 (*Section 5.5.5*)—the details of which are provided in Table 5-7.

Table 5-7 – AZM Well Location Details

Location Info	Atlas No. 1	Andes No. 1
NAD 83 (2011) Latitude	[redacted]	
NAD 83 (2011) Longitude		
Total Depth (ft)		
Type		

5.5.6.1 Pressure Monitoring

Titan will use a downhole pressure gauge to continuously monitor the pressure of the first permeable formation identified above the UCZ in the AZM wells. Deviations from baseline pressures after the start of injection will initiate further review in the area. This review includes both a study to rule out sensor drift, and a comparison to the pressure trend observed prior to injection—the latter providing insights into potential far-field activities in the same zone. [redacted] This benign effect would also be modeled and compared against observations, to further assess the likelihood of the pressure response indicating leakage.

5.5.6.2 Fluid Sampling

While the main purpose of these AZM wells will be to continuously monitor the pressure of the first mappable sand identified above the UCZ, fluid samples can, if necessary, be obtained from this well by perforating at a later date.

A detailed wellbore schematic for Titan's Atlas No. 1 is shown in Figure 5-4; Andes No. 1, in Figure 5-5. The wellbore schematics are also provided in *Appendix F*.

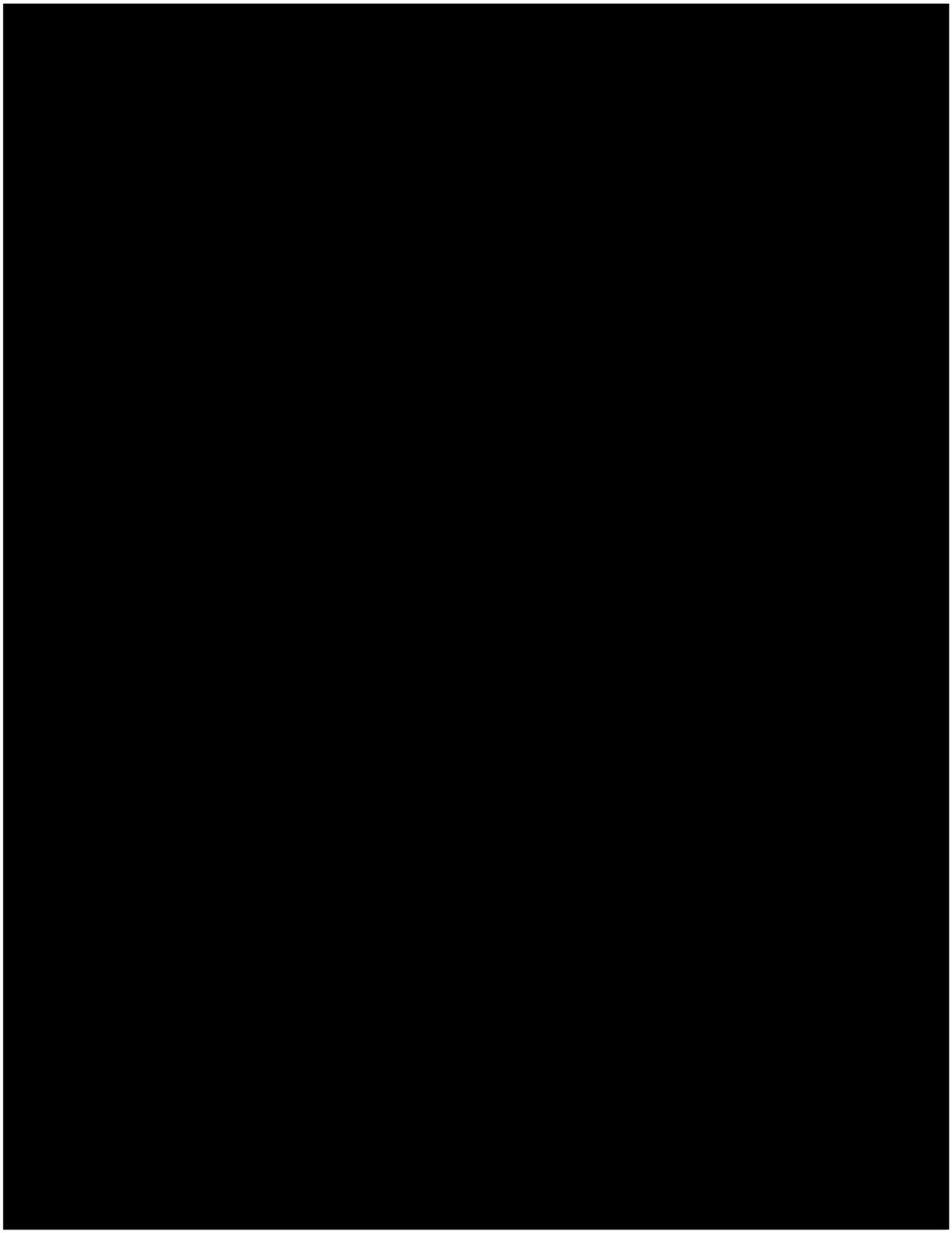


Figure 5-4 – Proposed Atlas No. 1 Schematic

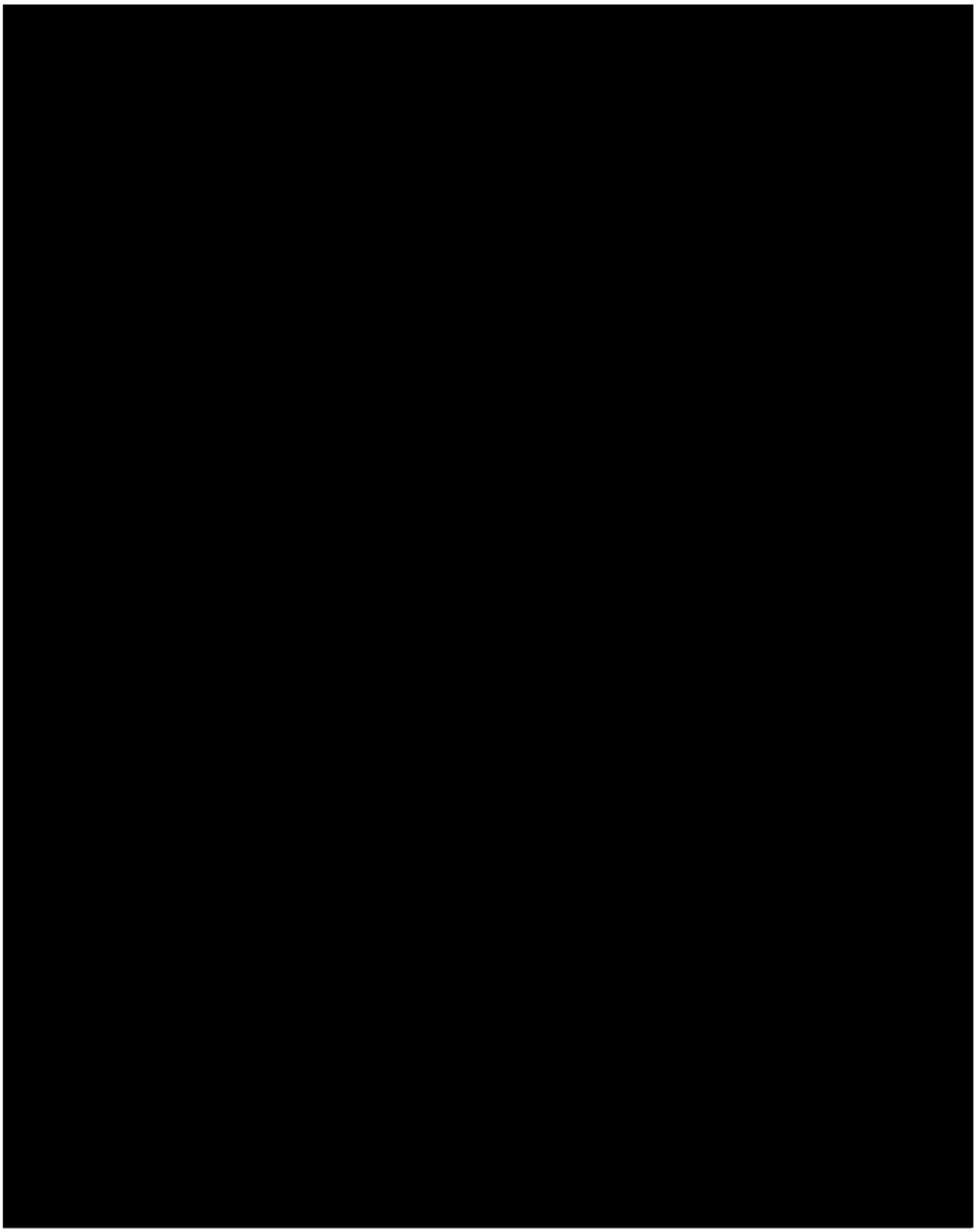


Figure 5-5 – Proposed Andes No. 1 Schematic

5.5.7 Injection Plume and Pressure Front Tracking

Titan proposes a two-tiered system for plume and pressure-front tracking per the operational monitoring requirements of 16 TAC **§5.203(j)(2)(E)** [40 CFR **§146.90(g)**]. The critical pressure front will be directly monitored by continuously recording pressures and temperatures to calculate the extent of this pressure increase. The CO_2 plume will be indirectly monitored using seismic survey technology, such as a VSP.

Titan will use these methods to (1) verify reservoir conditions during injection, (2) track plume and critical pressure front migration, and (3) validate the reservoir model. Continuous pressure and temperature monitoring of the reservoir in the injection zone will allow for monitoring of reservoir conditions and inform calculations, while VSP surveys will determine the actual CO_2 plume migration. The VSP surveys will be run before injection initiation to establish a baseline, then run periodically as needed, at least every 5 years. Additionally, *after* injection has ended, the VSP survey will also be run every 5 years, or until plume stabilization has been verified. In the event that the plume extent exceeds the resolution of the VSP monitoring system, alternative methods may be employed, such as time-lapse 2D surveys.

5.5.7.1 Direct Monitoring: Rate Transient Analysis

Rate transient analysis and reservoir simulations, using known reservoir characteristics, enable more complex parameters to be calculated within the injection intervals. Direct monitoring will be based on continuous pressure, temperature, and injection rate data to calculate the properties of the reservoir and verify the plume model results. Pressure and temperature gauges will be run on TEC cable on the injection wells.

The reservoir model built during the site evaluation phase will be used to predictively monitor the reservoir conditions during injection operations. Through flow simulation and transient flow analyses, the reservoir model will be regularly updated with injection activity, to evaluate the injection stream's effect on reservoir conditions. This analysis can be performed to monitor the magnitude and extent of temperature and pressure changes within the injection zone. Continual monitoring of bottomhole pressures and temperatures combined with known reservoir parameters will be used to calculate reservoir conditions throughout the injection intervals.

Any shut-in periods can be observed and treated as a pressure falloff test. To do this during a shut-in period, the shut-in wellhead pressure, bottomhole pressure, and temperature readings will be recorded and used for pressure transient analysis of the reservoir. The analysis results will include the radius and magnitude of pressure falloff and reservoir performance characteristics, such as permeability and transmissibility. Analysis results will then confirm, and adjust as necessary, the previous model realizations.

Through predictive modeling and analysis of recorded pressure and temperature data, Titan can closely monitor the effect of the injection wells on the subsurface, to help ensure regulatory compliance and safety while contributing to informed decision-making.

5.5.7.2 Indirect Monitoring: Vertical Seismic Profile

Titan will use time-lapse VSP to indirectly monitor the CO_2 plume extent and development in accordance with 16 TAC **§5.203(j)(2)(E)** [40 CFR **§146.90(g)(2)**] requirements. A fiber optic cable with distributed acoustic sensing (DAS) will be installed and cemented in the annulus behind the long-string casing in both injection wells. This system will enable real-time reservoir monitoring using pressure and temperature gauges and the periodic VSP. The DAS fiber optic cable, designed with sensors as closely spaced as 1 meter apart, will be used to generate a VSP at the highest possible resolution. Maps of the carbon dioxide plume will be created from images generated using a walk-away seismic source. The data will be collected by acoustic monitoring in the injection wells and repositioning the surface acoustic source at the surface. The source locations will be determined based on well location and conditions.

As an example of where this technology has proven successful, Shell Canada used it to monitor plume movement at its Quest Project (Bacci et al., 2017). Figure 5-6 illustrates the acquisition pattern strategy employed for plume development surveys from two separate wells.

Figure 5-6 – Shell Canada Quest Project VSP Acquisition Patterns (Bacci et al., 2017)

Reservoir monitoring using time-lapse seismic surveys 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 CO_2. The time-lapse effect is primarily driven by the change in acoustic impedance resulting from compressional changes in velocity between high CO_2 concentrations

and formation gases and fluids. As CO_2 displaces formation fluids, the difference in acoustic impedance with time is an effective proxy for plume shape and can be visualized.

The work steps involved in a time-lapse VSP survey primarily include the following:

1. Rock Physics Model
2. Petro-Elastic Model
3. Feasibility
4. Baseline Survey (Data Acquisition)
5. Repeat/Time-Lapse Survey (Data Acquisition)
6. Interpretation

The following subsections discuss key portions of these work steps.

5.5.7.3 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. It can be produced with high confidence, provided 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 formation fluid impact 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)

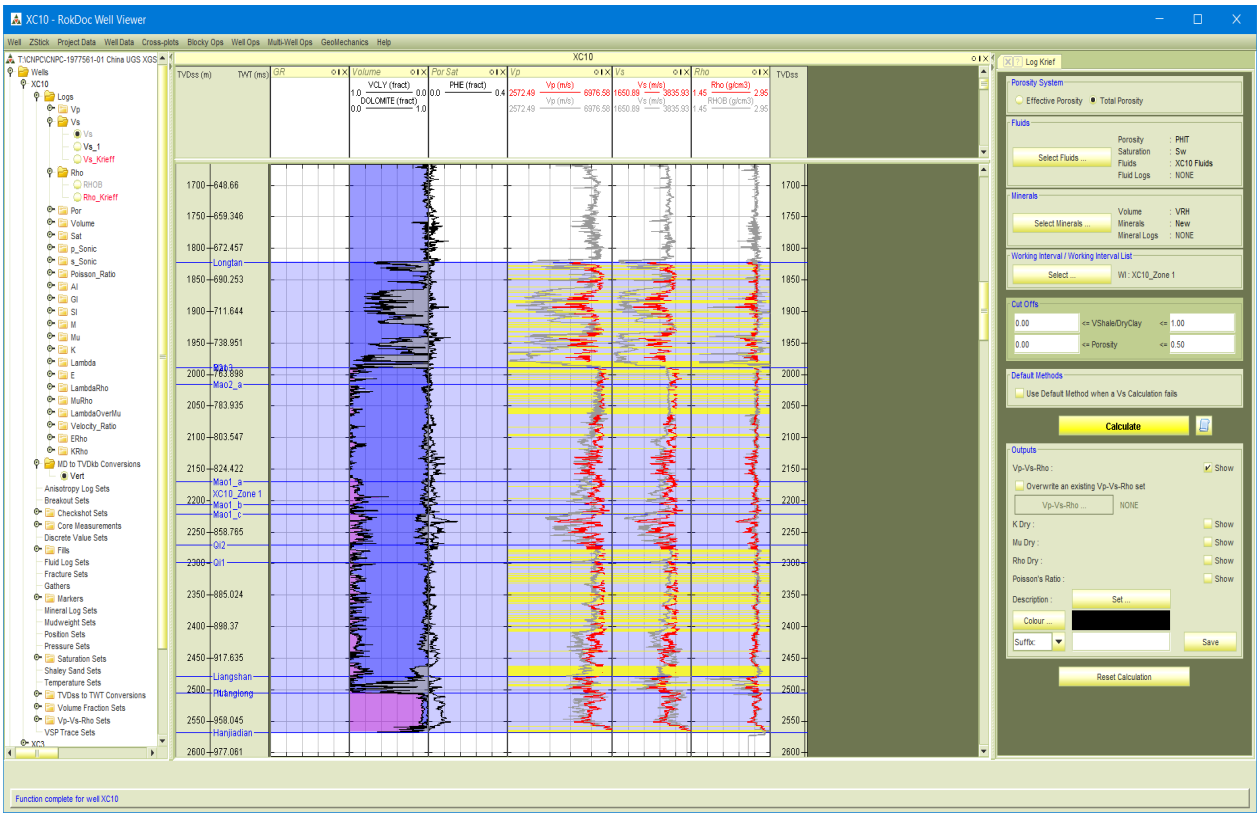


Figure 5-7 – RokDoc Well Viewer

The RokDoc Well Viewer (Figure 5-7), developed by Ikon Science, is an evaluation product that enables QC of the deterministic inversion of the reconstructed mineral content compared to the observed petrophysical response. The inversion allows for stabilizing inverted results, evaluating uncertainty in predicted attributes, and calculating in situ reservoir properties. The image shown here is an example of the software and is not representative of the geology at the Titan site.

5.5.7.4 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.

Predicting velocity and density as functions of injectate saturation is the result of a petro-elastic model, an example of which is shown in Figure 5-8. The seismic response measured during VSP surveys can be determined using the acoustic impedance calculated from both elastic properties. Figure 5-8 is also an example from RokDoc Well Viewer and is not representative of the Titan Project.

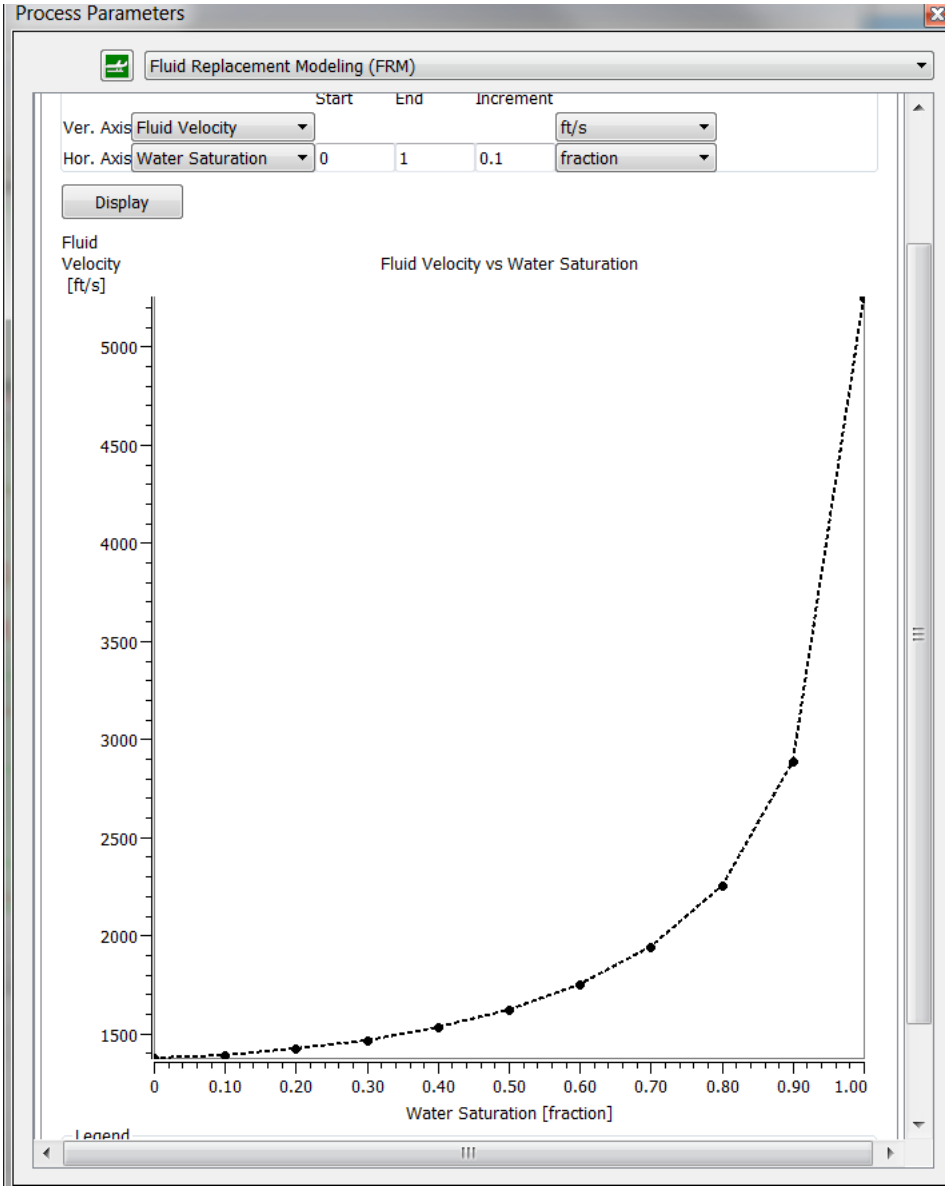


Figure 5-8 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation

A feasibility study will be designed to determine if connate fluids replaced with CO_2 could be detected by the petro-elastic model. This study will be conducted after recovering core material from the stratigraphic test well. The CO_2 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.

5.5.7.5 1D and 2D Models

Changes in the magnitude of the CO_2 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.

Figure 5-9 depicts a standard VSP survey with a geophone configuration.

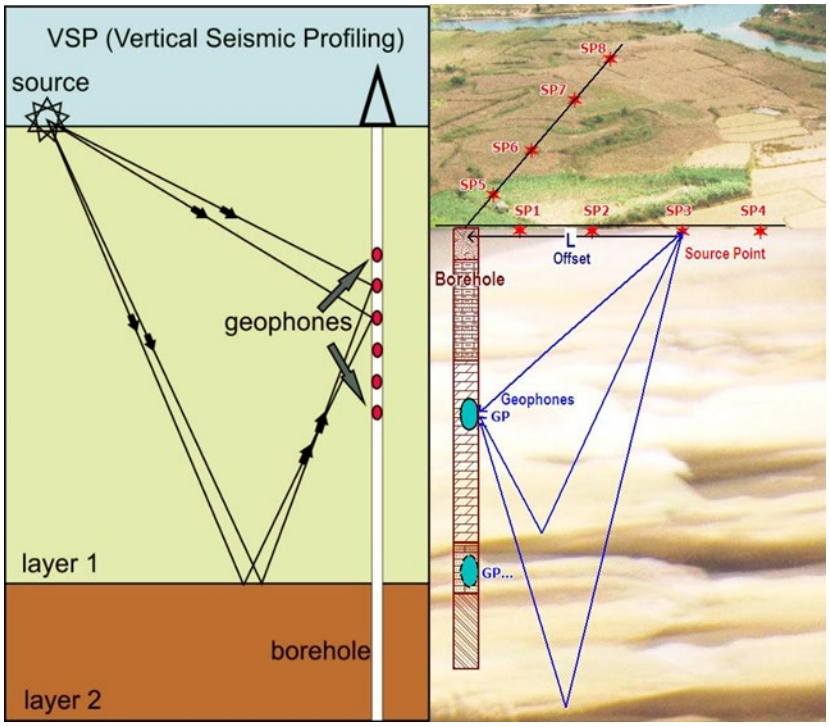


Figure 5-9 – Illustration of a Vertical Seismic Profile Survey

5.5.7.6 1D Model

The previously discussed principles apply to 1D seismic surveys. A standard method of obtaining 1D seismic data is with a checkshot survey, as illustrated in Figure 5-10. Geophones are situated vertically along the wellbore while all shots are fired from the surface. This placement allows the geophones to record seismic waves at different depths and provide measurements—at the highest levels of accuracy—of sonic velocities of the geologic layers affected by wellbore construction. These systems are commonly used to generate more accurate 2D, 3D, VSP, and 4D surveys.

The 1D survey methodology assumes that each formation is homogeneous in the horizontal direction; therefore, the surveys can only provide average sonic velocities. The 1D survey data can also be used to correct the sonic logs and create synthetic seismograms, which are used to

forecast seismic responses of the subsurface. One variation of 1D seismic surveys is an acoustic log, which generates acoustic data along the wellbore using wireline sonic tools. Although the purposes of these logs differ from those of seismic surveys, they can provide a way to a 1D understanding of variation in velocities.

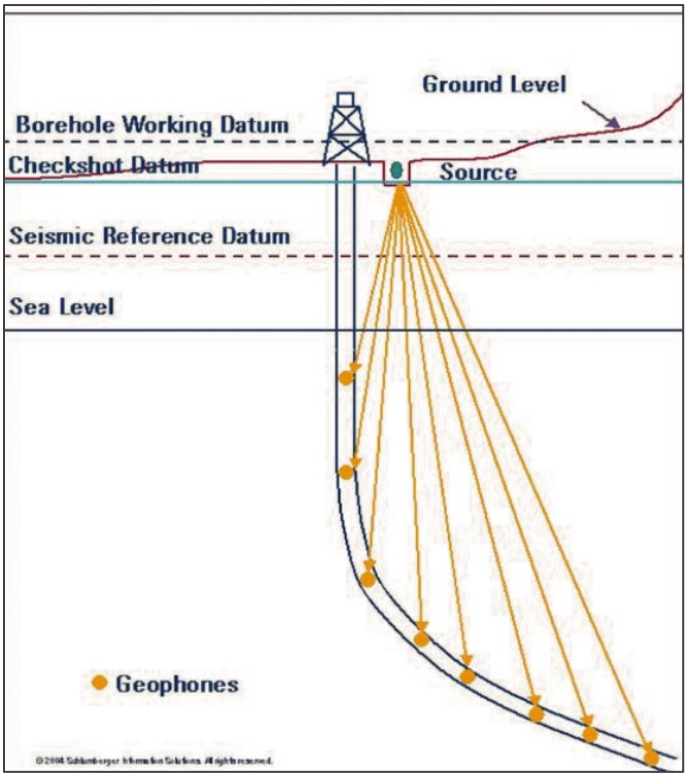


Figure 5-10 – Illustration of a Checkshot Survey

A 1D offset model will be constructed for each case, and differences in reflection amplitudes will be measured.

5.5.7.7 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 CO_2-replaced fluid.

Applying the same principles discussed in the previous section, 2D seismic surveys can provide a snapshot of a thin layer of the Earth's crust. 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. They are commonly used to explore new areas and allow geologists to visualize

the formations lying beneath the surface.

5.5.7.8 Processing Workflow and 4D Seismic Volume Determinations

To produce the final interpretation, CO_2 volume buildups from consecutive surveys will be observed over time. A time lapse or 4D model is created when VSP, 1D, 2D, or 3D dedicated seismic surveys are combined with a time element (i.e., surveys recorded at various time intervals—Year 1, Year 5, Year 10, etc.). The wheel spoke pattern of 2D survey lines, with the injector and VSP receiving fiber optic at its center, will provide coverage in all directions away from the injection well. Changing volumes of gas buildup, represented by either log shifts on the VSP, 1D, or 2D responses, or heat blooms (i.e., change in fluid density) on the 3D model, are identified in the time-lapse/4D interpretation of a seismic survey.

Figure 5-11 illustrates a basic workflow example:

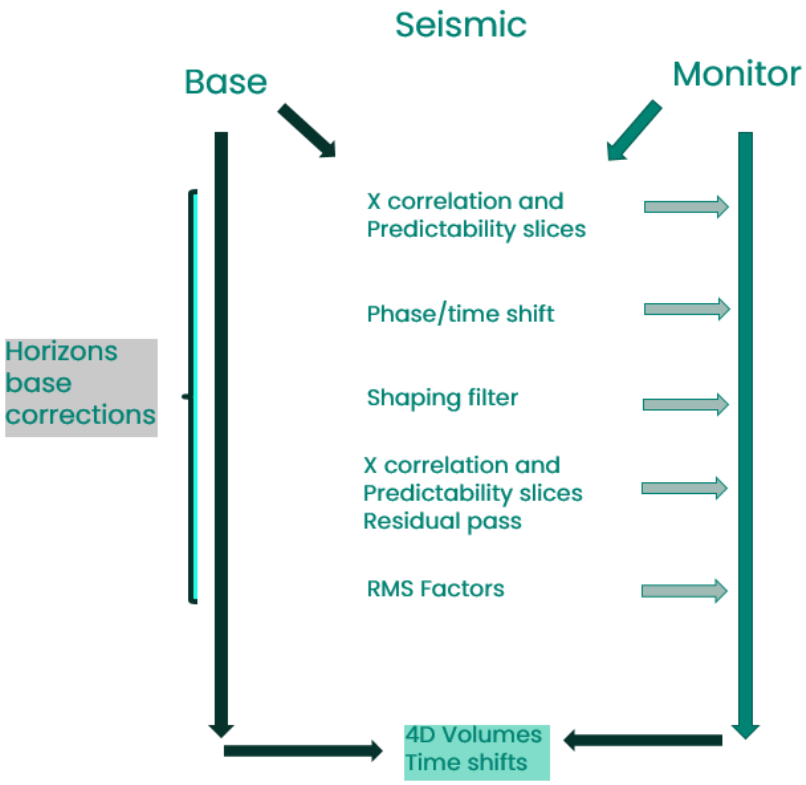


Figure 5-11 – A 4D Processing Workflow Diagram

The 3D horizon model is established from the base survey, and each successive survey creates a reflection differential mapped on the 3D model. The map is used to determine plume geometry, and the process is repeated in time increments to illustrate the time-lapsed development of the injectate plume.

To ensure consistency, all seismic volumes will be processed using the same software and for each workflow step outlined.

5.5.7.9 Inversion Workflow

Log data, post-stack seismic volumes, and a structural model will be used to invert baseline surveys, as Figure 5-12 shows. Later, monitor surveys will employ the same low component and residual corrections for consistency and the detection of changes over time—changes assumed to result from the injection operations.

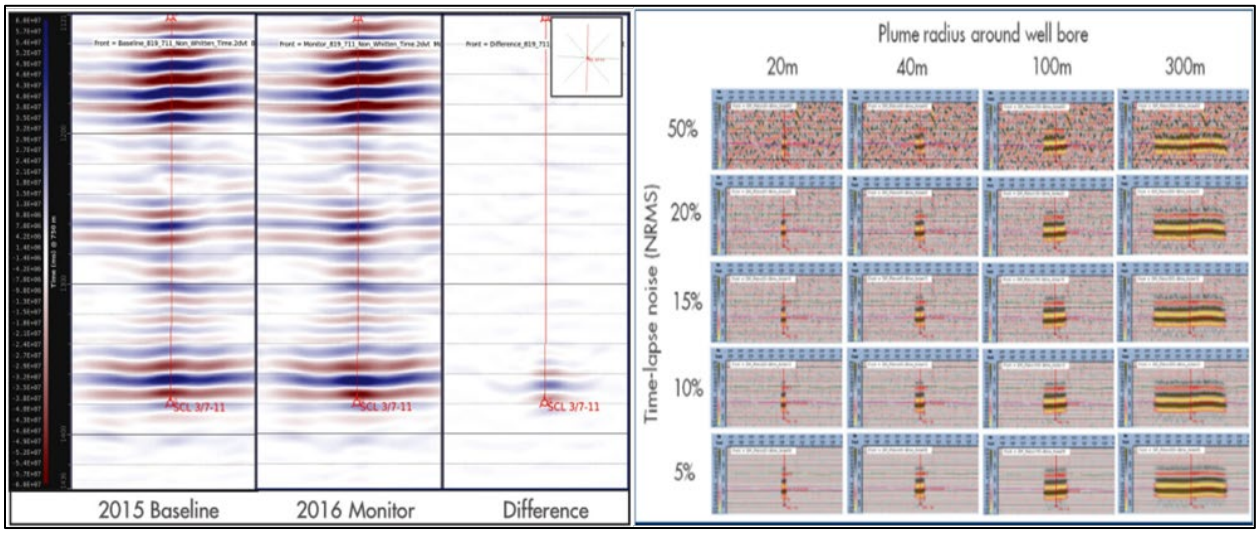


Figure 5-12 – Baseline and subsequent VSP used to determine the difference in amplitude attributed to CO_2 injection measured from the injector well itself. At right, estimation of the plume growth over time (Bacci et al. 2017).

5.5.7.10 Baseline Survey

Conducting a quality VSP baseline survey is critical, because it is the only opportunity to capture an image of the reservoir before injection operations or offset activity—either natural or man-made—impact it. Without this survey, the future interpretation of formation changes cannot be assessed. Also, the size of the baseline survey constrains the extent of plume measurement ability. It is essential to acquire a baseline survey with sufficient coverage if the initial reservoir models are not accurately forecasting plume migration. Titan will be obtaining this baseline survey prior to the commencement of injection.

5.5.7.11 Equipment Design and Setup

The proposed equipment for periodic survey operations to determine the CO_2 plume growth over time includes the time-lapse VSP, which uses a DAS fiber optic cable—to be connected to an interrogator box at the surface. The DAS system is synchronized to the seismic acquisition system controlling both the receiver (the DAS fiber optic array cemented in the injection wells) and the source.

5.5.8 Monitoring Schedule

The plume extent for the proposed Cronos No. 1 and Rhea No. 1 injection wells will be monitored using the DAS-VSP on the following schedule:

- The initial DAS-VSP survey will be conducted prior to the injection phase to capture the starting conditions for the formation brine.
- The first monitoring survey will be performed approximately 1 year after injection begins. The timing for this first survey is based on simulations that predict the plume extent will remain within the DAS-VSP imaging cone. This first survey allows early insights into the actual plume migration relative to the predicted model.
- Subsequent monitoring surveys will be conducted at Year 5 after the start of injection, then additional surveys will be performed at least every 5 years.
- During the PISC phase of the project, surveys will occur immediately after injection ceases into the last injection sand, and every 5 years after injection ceases. If the plume can be shown to have stabilized, additional DAS-VSP surveys will not be required. Pressures and temperatures will continue to be measured from the offset monitoring wells.

If the plume begins to reach the limit of the lateral extent of the VSP-survey resolution required to obtain quality results, time-lapse 2D seismic surveys will be performed to supplement the subsurface image from the VSP results.

5.5.9 Wellbore Overview

The proposed wellbores for both injection wells will have a [redacted]. conductor casing to a depth of about [redacted] ft. The surface casing for both wells will be [redacted] in. and will run below the USDW ([redacted] ft) to a depth of [redacted] ft. The surface casing will be cemented in place per EPA Class VI requirements. The production casing will be a [redacted] in. long-string run to a depth of [redacted] ft for Cronos No. 1 and [redacted] ft for Rhea No. 1. The [redacted] in. casing across the UCZ will be [redacted] material. This long-string casing will be cemented back to surface and comprised of CO_2-compatible cement from TD to [redacted] t for Cronos No. 1, and from TD to [redacted] ft for Rhea No. 1. Both injection wells will then have blended Portland cement from each of the previously mentioned depths to the surface. The injection string will be a [redacted] in. tubing string. The completion and monitoring assembly consists of a [redacted] in. [redacted] in. [redacted] packer (cut to release) that will initially be set at [redacted] ft for Cronos No. 1 and [redacted] ft for Rhea No. 1. Additionally, each well will have a subsurface injection valve (SSIV) just above the packer.

Figures 5-13 and 5-14 display the detailed proposed wellbore schematics for Cronos No. 1 and Rhea No. 1 (pages 38 and 39), respectively.

Pressure and temperature gauges, and distributed temperature and acoustic sensing with fiber optic cable will be installed on the OD of the [redacted] casing to TD. The system will be used to rapidly detect temperature profiles near the [redacted] in. casing, as well as to verify cement circulation during the cement job. The pressure gauges will detect pressure changes within the

reservoir and above/below the active injection zone. A minimum of five gauges will be installed, one for each proposed injection target. The acoustic fiber will be used to monitor the CO_2 plume growth through seismic processing. The fiber monitoring system enables high-density strain monitoring of the wellbore and surrounding formation, to detect, localize, and classify reservoir compaction, shearing, and integrity issues.

[redacted]

[redacted]

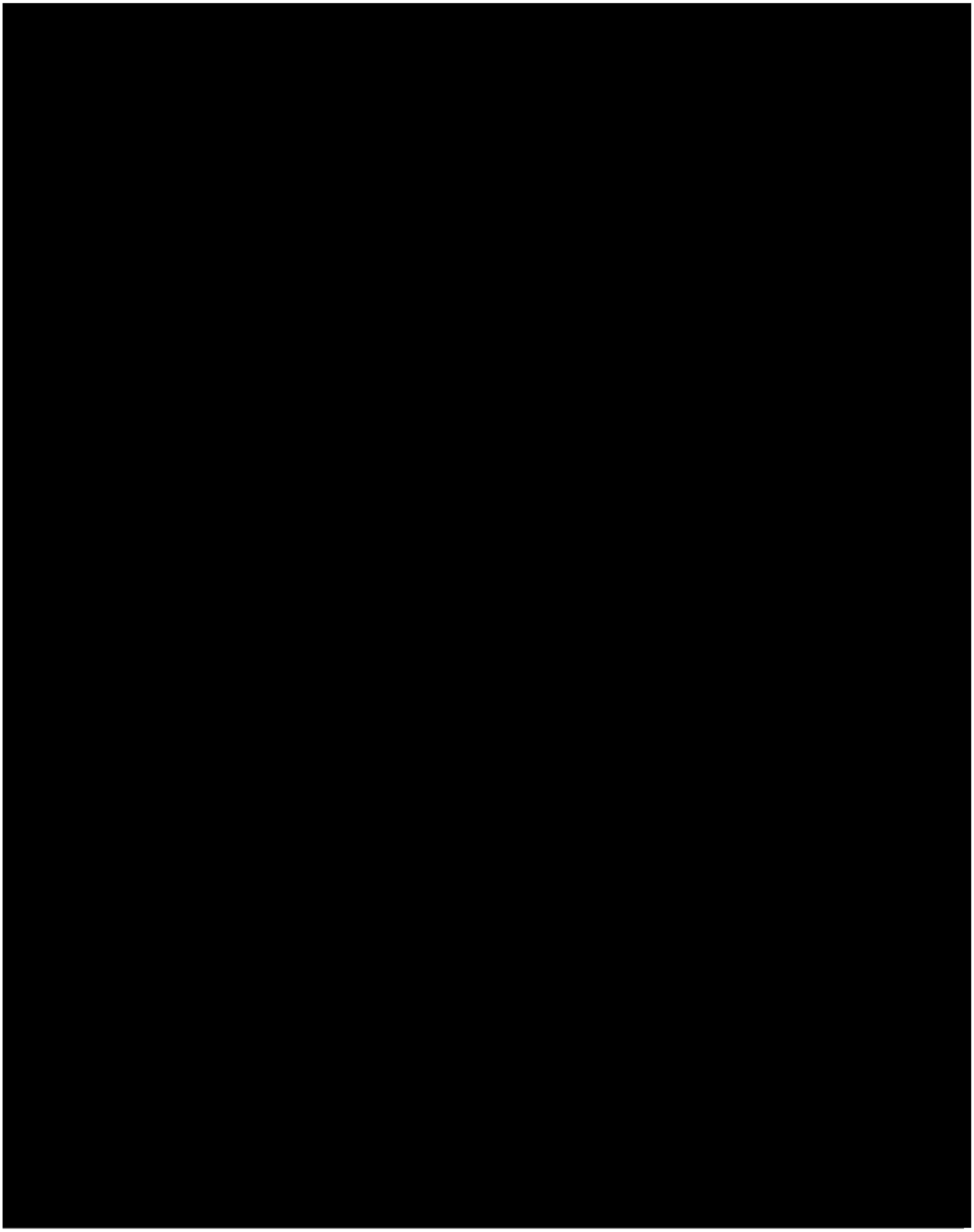


Figure 5-13 – Proposed Wellbore Schematic for Cronos No. 1

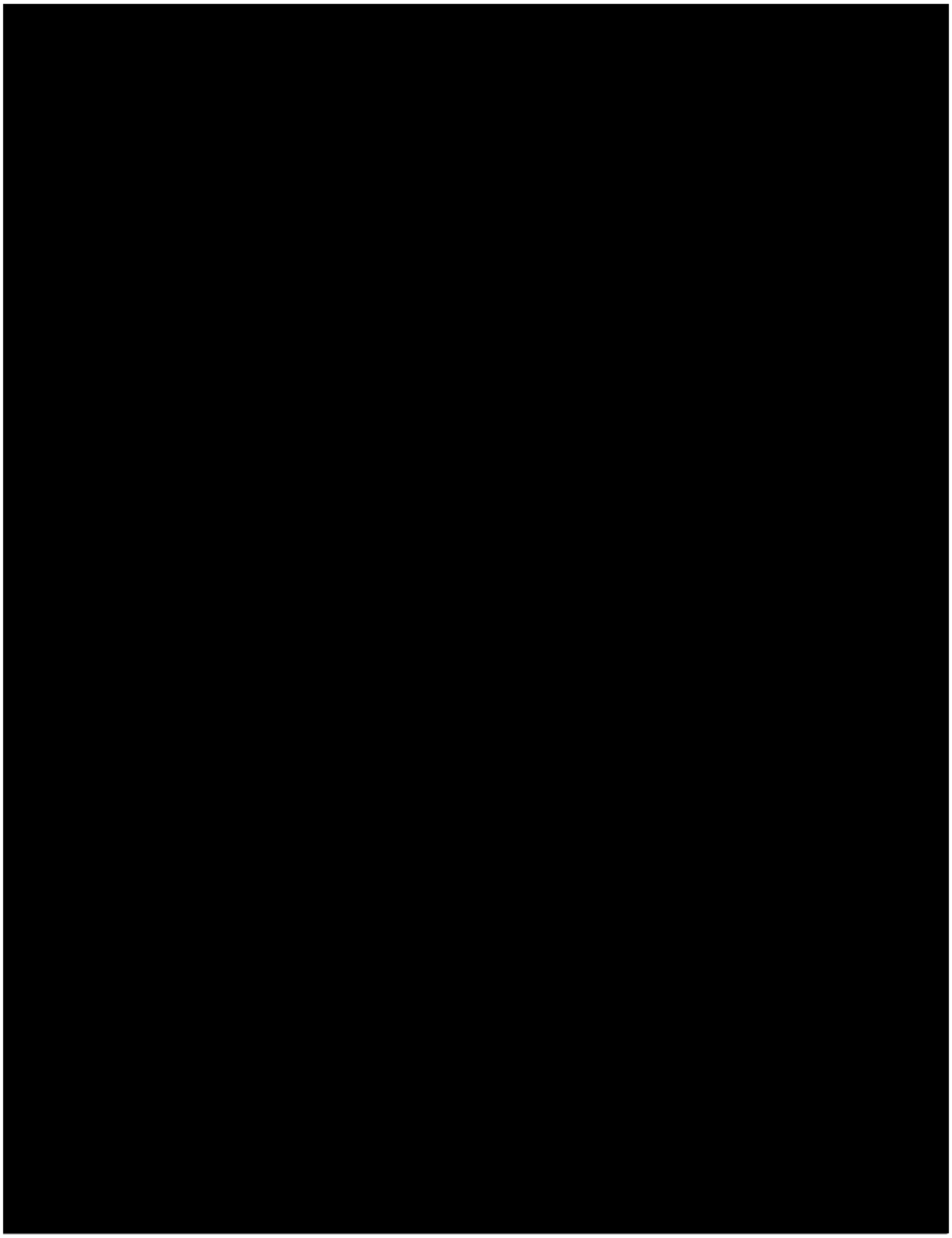


Figure 5-14 – Proposed Wellbore Schematic for Rhea No. 1

5.5.9.1 Equipment Overview

The following discusses the typical hardware setup and use of in situ monitoring equipment for temperature, pressure, and seismic that will employ fiber optic cable to communicate with a surface-located interrogator box, to record real-time or periodic data. The equipment described represents the technology that could be employed. Specific vendor-proprietary equipment details will be provided when the vendor is selected nearer to the time the wells are drilled.

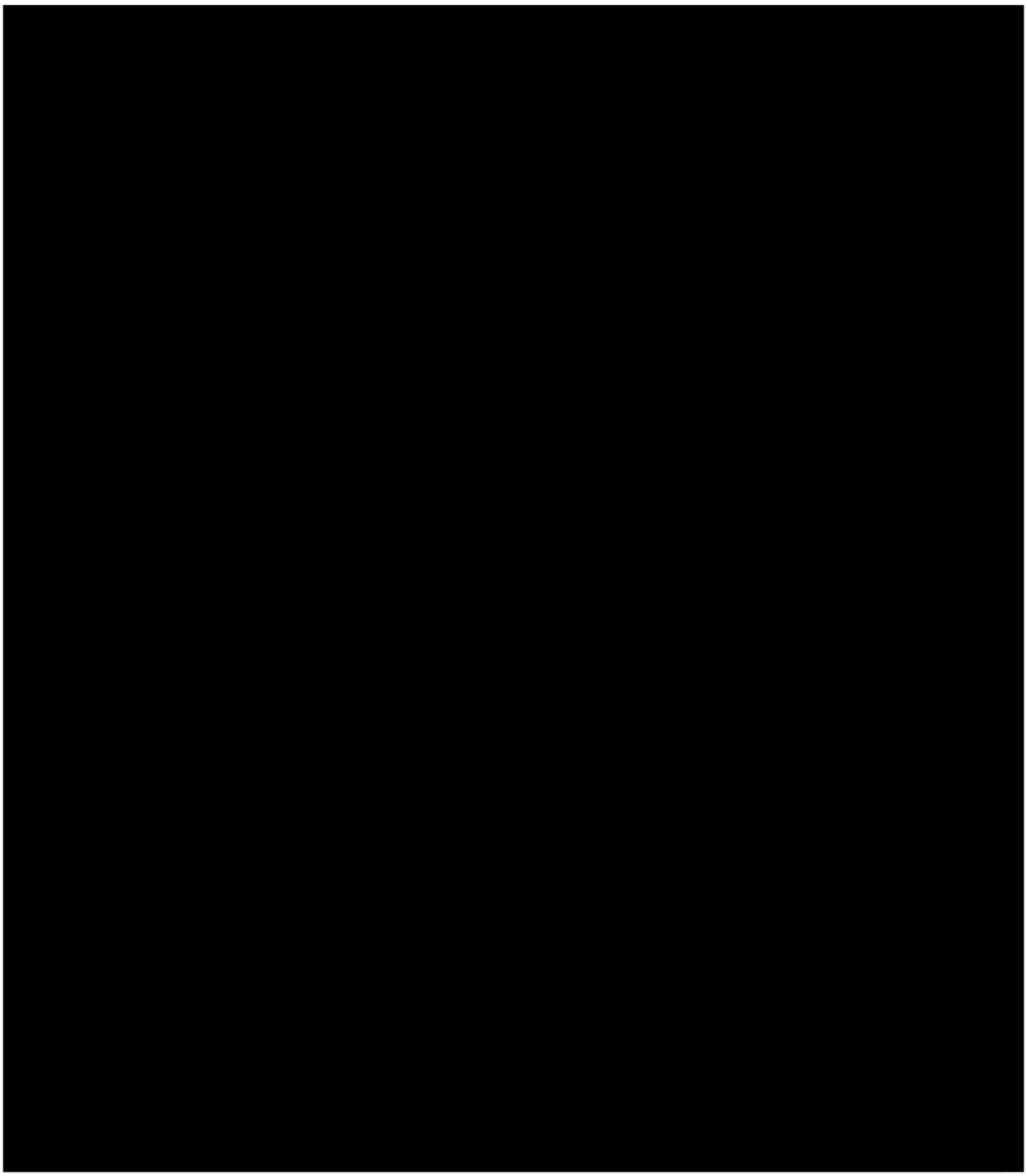


Figure 5-15 – [redacted]

Subsurface Injection Valve

In accordance with TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted] tubing just above the packer. Figure 5-16 provides an illustration and description of the SSIV to be used.

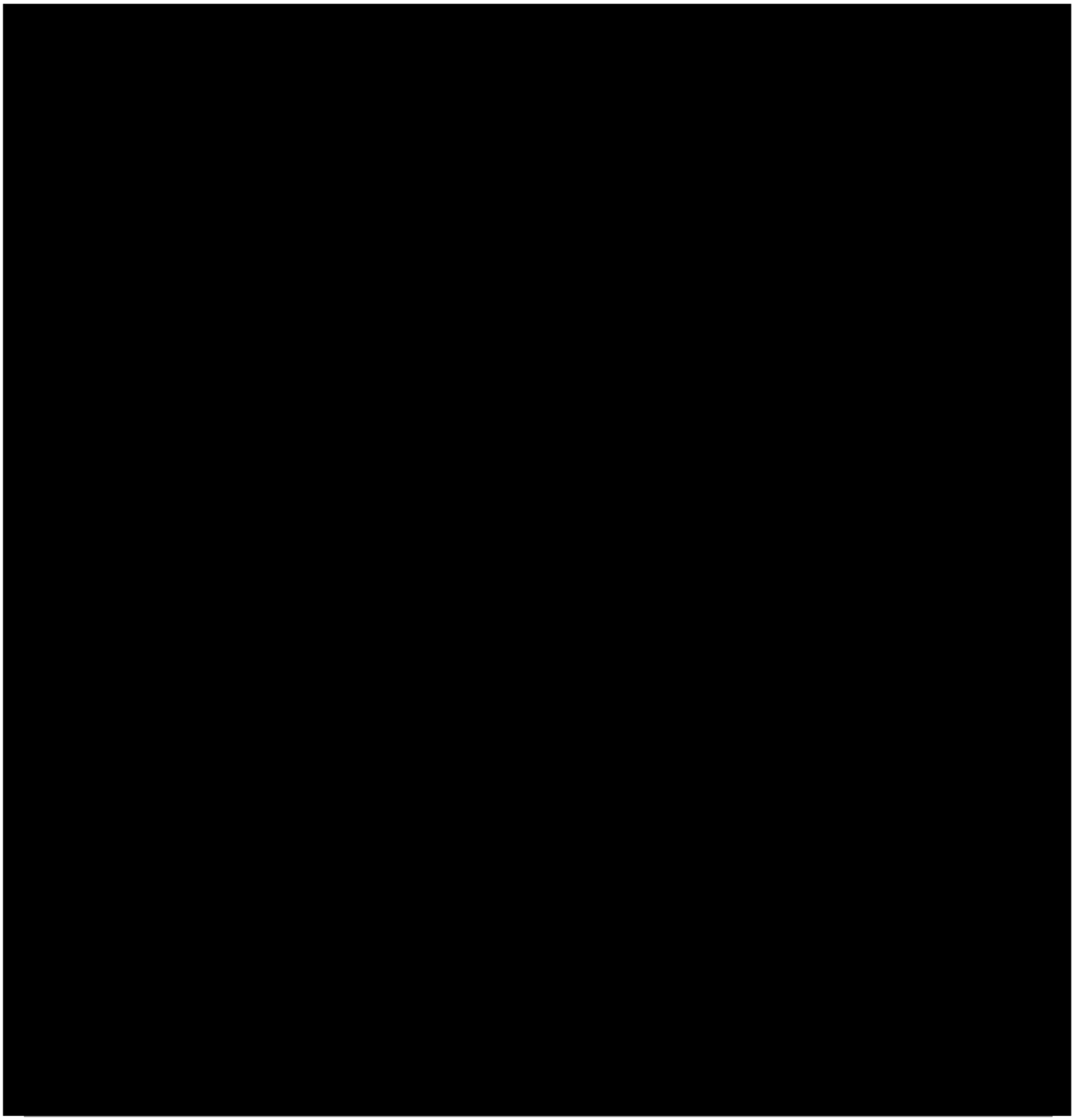


Figure 5-16 – Subsurface Injection Valve

Monitoring Gauges

The following system components and specifications are provided as representative technologies for initial discussion purposes. Final selection of specific monitoring equipment and vendors will be determined prior to commencing drilling operations. Equipment examples are shown for multiple options being evaluated.

Array Pressure Temperature Sensor

The Halliburton Array sensors (Figure 5-17) are welded into the TEC cable when deployed behind casing and have a proven track record of measuring reservoir pressure and temperature through the cement sheath. Between 1 and 25 sensors can be installed on a single TEC line and read independently of each other (e.g., if one sensor is lost the remaining sensors continue reading). (Garcia, E. et al, 2019).

Figure 5-17 – Halliburton Array Pressure Temperature Sensor

SureVIEW with CoreBright Optic Fiber

SureVIEW downhole cable uses CoreBright optical fiber, which leads the industry in resisting hydrogen darkening—the primary cause of failure for fiber optic systems in high-temperature applications. CoreBright is constructed from pure silica—minimizing hydrogen darkening—combined with a layer of hydrogen-absorbing gel. The Baker Hughes and GE Company (BHGE) standard SureVIEW fiber optic cable product is a 0.25-in. OD, heavy wall tubing-armor cable that encloses a 0.125 in. OD, thin wall tubing containing optical fiber. The armor is a corrosion-resistant alloy (CRA) tube, longitudinally welded and cold worked to its final diameter. It contains an extruded plastic filler (belting) that centralizes and provides a level of shock and vibration damping to the inner tube. The inner or fiber-in-metal tube (FIMT) contains up to 12 optical fibers immersed in thixotropic gel. Figure 5-18 illustrates the optical fiber, and Table 5-8 provides the specifications.

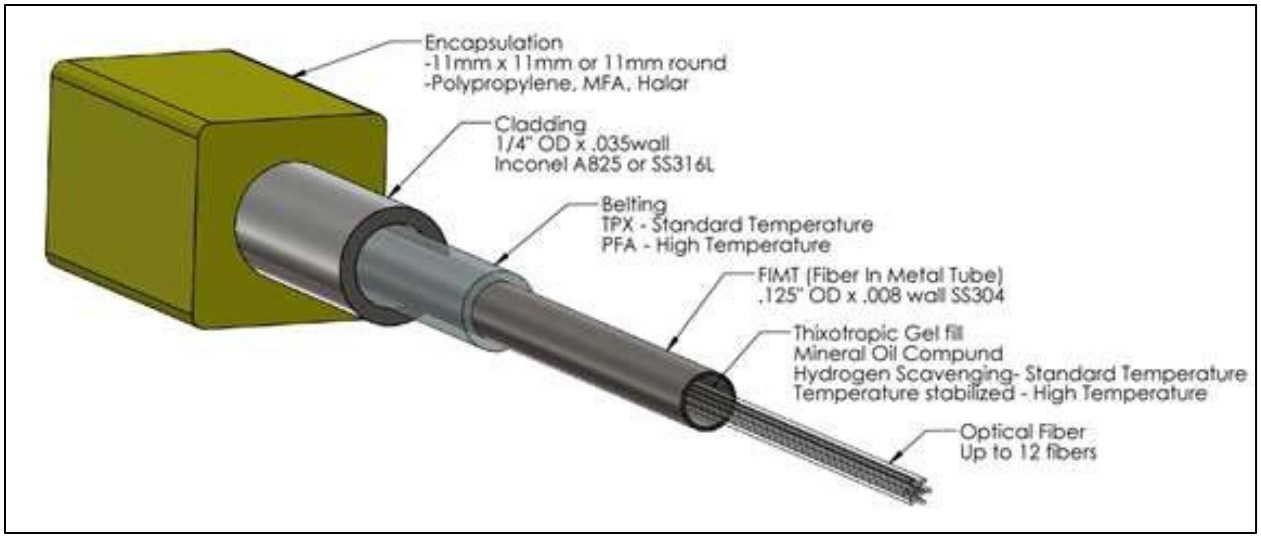


Figure 5-18 – SureVIEW with CoreBright Optical Fiber

Table 5-8 – SureVIEW Downhole Specifications

Description	Value	
Encapsulation	0.433 in.2 (11 mm2) or 0.41 in. round (11-mm OD)	
Cladding	0.250-in. (6.35-mm) OD × 0.035-in. (0.89-mm) wall	
FIMT diameter	0.125-in. (3.18-mm) OD	
Weight with polypropylene 11×11 encapsulation	154 lb/1,000 ft (230 kg/km)	
Weight without encapsulation	101 lb/1,000 ft (150 kg/km)	
Mechanical properties (70°F)*	**A825**	**SS 316L**
Tensile strength (lb)	2,687 (1,219 kg)	2,134 (968 kg)
Yield strength (lb)	2,090 (948 kg)	1,816 (824 kg)
Hydrostatic pressure (kPSI)	25 (17 kg/sq mm)	24 (16.8 kg/sq mm)
Burst pressure (kPSI)	32 (22 kg/sq mm)	22 (15.4 kg/sq mm)
Dynamic bend radius (in.)	14 (355 mm)	25 (635 mm)
Static bend radius (in.)	3 (82 mm)	6.3 (159 mm)
External collapse pressure (kPSI)	24.6 (1729 kg/sq cm)	17 (12.0 kg/sq mm)

*Materials listed should be derated for specific temperature applications. Contact Applications Engineering group for deration factors.

SureVIEW DTS

The SureVIEW DTS interrogator (Table 5-9) provides continuous monitoring, rapidly updating temperature profiles along the length of the completions.

Table 5-9 – SureVIEW DTS Surface Interrogator Specifications

Description	Value
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 µm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

SureVIEW DAS

The SureVIEW DAS interrogator offers all the benefits of fiber-optic acoustic monitoring—from flow monitoring and optimization, sand detection and stimulation optimization, to seismic and microseismic monitoring, combined in a single interrogator (specifications shown in Table 5-10).

Table 5-10 – SureVIEW DAS VSP Specifications

Technical Specifications	
Technology Supported	SureVIEW DAS VSP
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	6U
Certifications	CE, TUV
Supply Voltage	110-240 Volts AC, 50 or 60Hz
Typical Power Consumption	Up to 400W
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Optical Connectors	F3000/APC

Interface Connections	Ethernet, GPS, USB (Geophones) DC Trigger Pulse (GPS Synced)
File Formats	PRODML/HDF5/SEG-Y
Data Storage	960GB (Internal) 8TB (NAS)
Maximum Distance Range	Up to 12 miles (20 km) with CoreBright fiber Up to 50 miles (80 km) with CoreBright EBF
Fiber Type	Single Mode
Spatial Resolution	1.5 meter
Minimum Sampling Interval	0.33 meter
Gauge Length	Selectable 3, 7, 15, 31 meters
Maximum Pulse Rate	10 kHz
Dynamic Range	0.24 nε (over full bandwidth) 1.5pε (narrowband) Up to 1 με

SureVIEW WIRE

The SureVIEW WIRE structural-integrity management system enables high-density strain monitoring of the wellbore and surrounding formation to detect, localize, and classify issues with reservoir compaction, shearing, and well integrity. The cable is deployed along the outside of the casing in the well, where it is cemented into place and brought online. Once online, data can be closely observed across the entire geological interface. An illustration of this technology is shown in Figure 5-19, and the technical specifications are provided in Table 5-11.

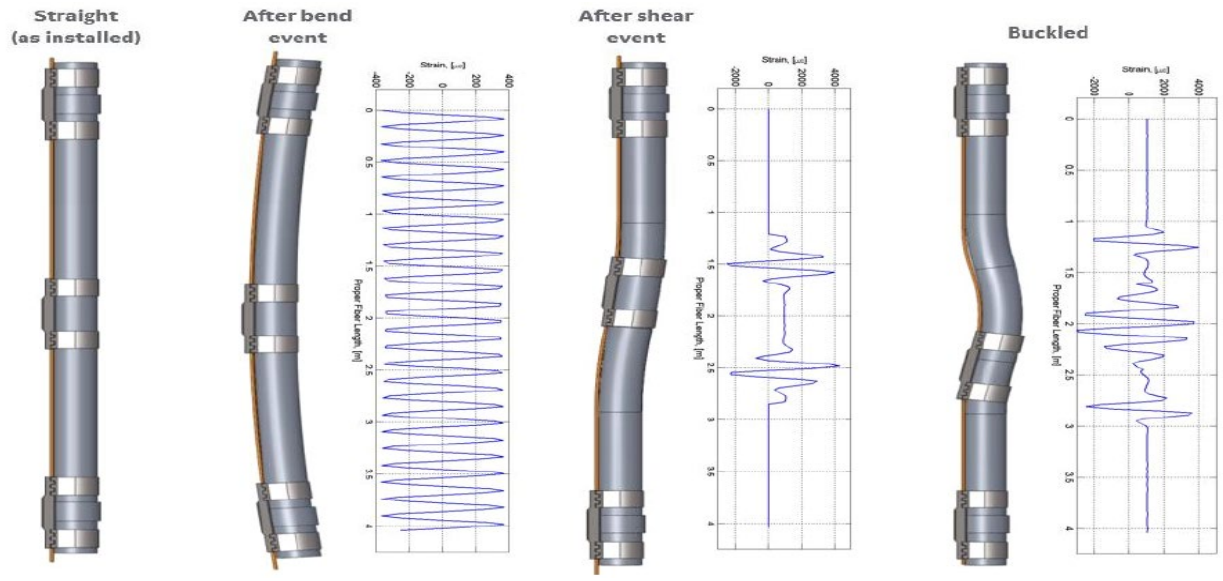


Figure 5-19 – SureVIEW WIRE Well Integrity Evaluation

Table 5-11 – SureVIEW WIRE Cable Specifications

SureVIEW™ WIRE Cable	
Specifications	

Low Temperature Cable	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 120 Deg C Temperature Rating
	• 15,000 psi Pressure Rating

High Temperature	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 225 Deg C Temperature Rating
	• 15,000 psi 15,000 psi Pressure Rating

**may require multiple cables spliced to achieve desired length*	

Tubing Encapsulated Conductor

TEC is a proven technology that the oil and gas industry has used reliably for more than 25 years. The TEC is installed to electrically support the QPT Elite gauges and is designed for prolonged life in the most hostile downhole environments. The TEC's primary function is to transmit both electronic digital signals and power between subsurface components and a surface interface module used for reservoir management. The BHGE-standard TEC product is a 0.25-in. OD tubing-armor cable, which includes an insulated 16-American wire gauge (awg) solid conductor. The armor is a metal-clad CRA tube containing filler materials that centralize the core. An encapsulation material specially designed with safe removal components is recommended to be extruded over the TEC, thereby adding to the metal sheath a layer of protection from abrasion while running downhole. Figure 5-20 illustrates the design of the TEC, and the technical specifications are listed in Tables 5-12 and 5-13.

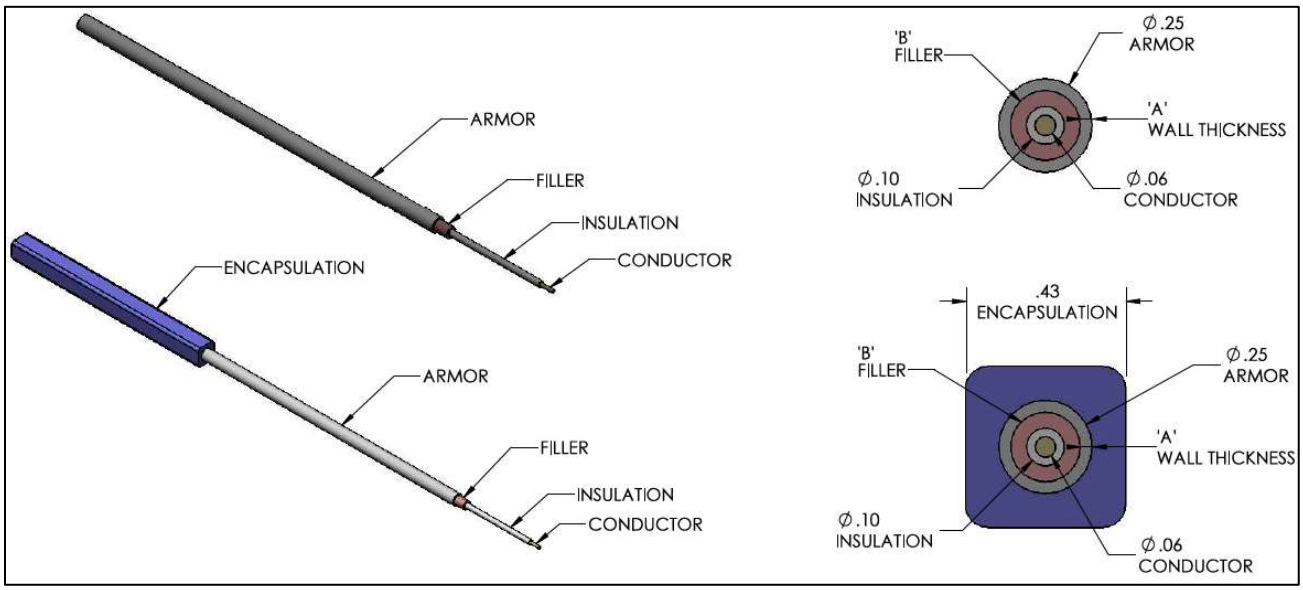


Figure 5-20 – Tubing Encapsulated Conductor

Table 5-12 – TEC Specifications, Part I

Description	Value	
Size 0.035-in. Wall TEC		
Materials	316L stainless UNS S31603	Alloy 825 UNS N08825
Weight	198 kg/km (133 lb/1,000 ft)	199 kg/km (135 lb/1,000 ft)
Armor resistance at 20°C	51.2 Ohms/km (15.6 Ohms/1,000 ft)	73.9 Ohms/km (22.5 Ohms/1,000 ft)
Capacitance at 20°C	98 pF/m	
Collapse pressure rating (psi)*	30,000	

Table 5-13 – TEC Specifications, Part II

Wall (in.)	Alloy	Tensile (psi)				Yield (psi)			
		Minimum	Maximum	Average	STD	Minimum	Maximum	Average	STD
0.035	316L	122,000	178,000	153,000	6,800	100,000	158,000	125,000	8,200
0.049		141,000	154,000	145,000	5,100	113,000	130,000	119,000	6,400
0.035	A825	123,000	182,000	144,000	8,400	108,000	150,000	126,000	7,100
0.049		113,000	157,000	139,000	7,300	89,000	139,000	122,000	7,500

SureSENS QPT Elite Gauge

The reliable, accurate SureSENS QPT Elite gauge (Figure 5-21) measures static and dynamic pressures and temperatures. The highly robust gauge ensures mechanical integrity by deep penetration and high-vacuum, electron-beam fusion welds without filling material. Only two fittings (the pressure port and the TEC) are required to interface the gauge with the carrier. The fittings can be externally tested in the direction that they will experience pressure, eliminating the need for an internal pressure test tool.

Figure 5-21 – SureSENS QPT Elite Gauge

QPT Elite Pressure Interface – Pressure Testable Manifold

The gauge-pressure interface connection to the carrier is through a pressure-testable manifold interface attached to the mandrel. Triple metal-seal rings are pressure tested to ensure integrity before deployment. The three metal seals provide redundant metal-to-metal sealing, tested in the same direction as the applied pressure in the final installation. This sealing provides a true, unique metal-to-metal design that is bidirectional and dual-testable. Figure 5-22 illustrates the design, and Table 5-14 lists the technical specifications.

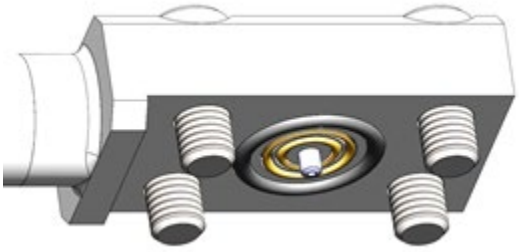


Figure 5-22 – External Sensor

Table 5-14 – QPT Elite Pressure Interface – Pressure-Test Manifold Specifications

Length	25.5 in. to 26.5 in. (64.77 cm to 67.31 cm)					
Height/Width	0.750 in. (19.05 mm) / 1.318 in. to 2.50 in. (33.50 mm to 63.50 mm)					
Seals	Metallic seals and EB welds					
Transducer	Shear mode quartz					
Transducer options	10,000 psi (689.5 bar)	16,000 psi (1103.2 bar)	20,000 psi (1379.0 bar)	25,000 psi (1723.6 bar)	30,000 psi (2068.4 bar)	35,000 psi (2413.7 bar)
Material	Inconel 718	MP35N				
Pressure range	15 psi to 11,000 psi (1 bar to 758.4 bar)	15 psi to 18,000 psi (1 bar to 1241.1 bar)	15 psi to 23,000 psi (1 bar to 1620.3 bar)	15 psi to 28,000 psi (1 bar to 1930.5 bar)	15 psi to 33,000 psi (1 bar to 2275.3 bar)	15 psi to 37,500 psi (1 bar to 2585.5 bar)
Temperature rating (operating)	-99.4°F to 302°F (-73°C to 150°C)	-99.4 to 437°F (-73°C to 225°C)				
Storage temperature	-40°F to 302°F (-40°C to 150°C)					
Temperature shock	5.4°F (3°C) per minute					
Vibration	>10 G, 10 Hz-2 kHz					
Shock	500 G					
Pressure measurement range (calibrated)	200 psi to 10,000 psi (13.8 bar to 689.5 bar)	200 psi to 16,000 psi (13.8bar to 1103.2 bar)	200 psi to 20,000 psi (13.8 bar to 1379.0 bar)	200 psi to 25,000 psi (13.8 bar to 1723.6 bar)	200 psi to 30,000 psi (13.8 bar to 2068.4 bar)	200 psi to 35,000 psi (13.8 bar to 2413.7 bar)
Pressure accuracy	+-0.015% 1.5 psi at full scale	+-0.02% 3.2 psi at full scale	+-0.02% 4.0 psi at full scale	+-0.02% 5.0 psi at full scale	+-0.025% 7.5 psi at full scale	+ -0.03% 10.5 psi at full scale
Pressure resolution	0.0001 psi					
Pressure stability	0.02% full scale, 2.0 psi/year	+-0.02% full scale, 3.2 psi/year	+-0.02% full scale, 4.0 psi/year	+-0.02% full scale, 5.0 psi/year	+-0.02% full scale, 7.5 psi/year	+ -0.03% full scale, 10.5 psi/year
Temperature measurement range (calibrated)	77°F to 302°F (25°C to 150°C)	77°F to 437°F (25°C to 225°C)				
Temperature accuracy	0.27°F (0.15°C)					
Temperature resolution	0.0001°F					
Temperature stability	0.018°F (<0.01°C) per year					
Maximum sample rate/second	>16					
Number of gauges support/TEC	32					
Cable distance transmission	50,000 ft (15,240 m)					

SureSENS QPT Gauge Carriers

The carrier body is machined from a single bar stock without welding or heat-treating processes (Figure 5-23). The gauge assembly is installed into a recessed pocket in the carrier, protecting the gauge without needing a cover plate. The uphole end of the gauge is secured to the carrier by a clamp, which is fastened to the carrier by socket head screws. All tubular completion products are designed to meet or exceed the tubing/casing specifications supplied by the customer. All tubular products are also inspected and tested per American Petroleum Institute (API) 5CT requirements for drift and pressure.

Figure 5-23 – SureSENS QPT Gauge Carrier Illustration

Steel Blast Protectors

The blast protectors are installed above and below each zone over the fiber and TEC lines. The protectors have round steel bars that run the length of and are welded into the channel on both sides of the cables—to increase magnetic mass/signature for detection by the High-Resolution Vertilog (HRVRT) tool, to position the guns away from the cables (Figure 5-24).

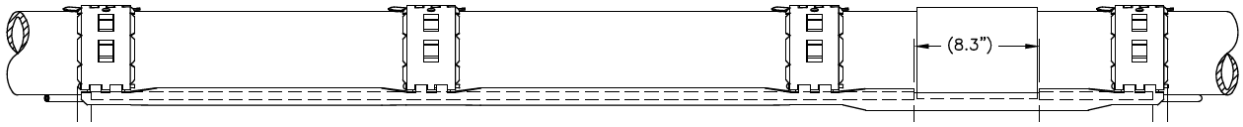


Figure 5-24 – Steel Blast Protector Illustration

Cross-Coupling Protectors

To protect the downhole cable, cross-coupling cable protectors (Figure 5-25) are mounted at each tubing joint coupling to protect the cable transitions across the coupling. A potential exists for the downhole cable to be damaged because of abrasion or crushing between the tubing and casing internal wall during the installation process, thereby resulting in the loss of functionality of the associated downhole equipment.

Figure 5-25 – Cross Coupling Protector

5.5.10 VSP Monitoring Conclusion

Using the VSP method to quantify CO_2 plume development over time has been demonstrated in several cases worldwide. Using this data ensures that implementing this method in a time-lapse format will produce an image of the plume extent and its future development. Also, the use of VSP in the injection wells—using a permanently installed fiber optic sensor—will produce an image centered on the injection spot with a higher resolution than that of a traditional wireline deployed geophone array. Moreover, VSP eliminates the need to create additional penetrations in the ACZ for monitoring purposes.

The fiber optic set-up installed in these wells will also allow for ease of pressure and temperature monitoring in all sections of the wells, the data from which will be used in direct calculations of the pressure plume.

Finally, and most importantly, this VSP system, along with the direct plume calculations, will allow for monitoring the plume migration without the need to create additional artificial penetrations—which could inadvertently form a conduit out of the confinement intervals. Additionally, this approach minimizes the environmental impact of disturbing surrounding wetland areas.

5.6 Conclusion

Monitoring the injection wells and tracking the CO_2 plume and pressure front are key components to the successful sequestration of CO_2 for the Titan Project. Titan is committed to ensuring that best testing and monitoring practices are employed throughout the lifecycle of this project.

Appendix F – Testing and Monitoring:

- Appendix F-1 USDW and AZM Monitoring Well Plan Map
- Appendix F-2 TCS WM No. 1 Schematic
- Appendix F-3 TCS WM No. 2 Schematic
- Appendix F-4 Atlas No. 1 Schematic
- Appendix F-5 Andes No. 1 Schematic

5.7 References

Bacci, V. O., O'Brien, S., Frank, J., and Anderson, M. (2017). Using Walk-away DAS Time-lapse VSP for CO_2 Plume Monitoring at the Quest CCS Project. Shell Canada, Calgary AB, Canada. NADA.

Daley, T. M., Myer, L. R., Hoversten, G. M. et al. (2005). Borehole Seismic Monitoring of Injected CO_2 at the Frio Site. Lawrence Berkeley National Laboratory, Berkeley CA, USA.

Datta-Gupta, A. et al. (2017). Time-Lapse Seismic Monitoring and Performance Assessment of CO_2 Sequestration in Hydrocarbon Reservoirs. Texas A&M Engineering Experiment Station.

Garcia, Elias, Stutes, Gerald , Nåden, Christoffer , and Kjetil Borgersen (2019). "Monitoring Dynamic Reservoir Pressure Responses Through Cement." Paper presented at the SPE Annual Technical Conference and Exhibition, Calgary, Alberta, Canada, September 2019. doi: https://doi.org/10.2118/196168-MS

Huppert, H. E., and Neufeld, J. A. (2013). Fluid Mechanics of Carbon Dioxide Sequestration. Institute of Theoretical Geophysics and Department of Applied Mathematics and Theoretical Physics, University of Cambridge, United Kingdom. *Annual Review of Fluid Mechanics.*

Maurya, S. P. and Singh, N. P. (2019). Seismic modeling of CO_2 fluid substitution in a sandstone reservoir: A case study from Alberta, Canada. *J Earth Syst Sci*, 128: 236.

Rangeti. I., Dzwairo, B., Barratt, G. J., and Otieno, F.A. (2015). Validity and errors in water quality data – A review. *Research and Practices in Water Quality. Durban University of Technology, Durban, South Africa,* 95-112.

Yang, Q., Quin, K., Olson, J., and Rourke, M. (2021). Through-Tubing Casing Deformation and Tubing Eccentricity Image Tool for Well Integrity Monitoring and Plug-Abandonment. SPWLA 62nd Annual Logging Symposium, May 17-20, 2021.

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 6 – PLUGGING PLAN

February 2024

LONQUIST
SEQUESTRATION LLC

SECTION 6 – INJECTION WELL PLUGGING PLAN

TABLE OF CONTENTS

6.1 Introduction 2
6.2 Injection Well Zonal Isolation and Final Plugging and Abandonment 2
6.2.1 Zonal Isolation of Injection Zone / Intermediate Plugback Plan 2
6.2.2 Final Zonal Isolation of Injection Zone / Post Injection Monitoring Plugback Plan 6
6.2.3 Final Plugging and Abandonment 9
6.3 Monitoring Wells Plugging and Abandonment 16
6.3.1 Pre-plugging Activities 16
6.3.2 Plugging Procedure, TCS WM No. 1 and TCS WM No. 2 16
6.3.3 Plugging Procedure, Atlas No. 1 18
6.3.4 Plugging Procedure, Andes No. 1 20

Figures

Figure 6-1 – First Plugging Schematic for Cronos No. 1 4
Figure 6-2 – First Plugging Schematic for Rhea No. 1 5
Figure 6-3 – Final Zonal Isolation Plugging Schematic for Cronos No. 1 7
Figure 6-4 – Final Zonal Isolation Plugging Schematic for Rhea No. 1 8
Figure 6-5 – Final Plugging Schematic for Cronos No. 1 12
Figure 6-6 – Final Plugging Schematic for Rhea No. 1 15
Figure 6-7 – Final Plugging Schematic for TCS WM No. 1 17
Figure 6-8 – Final Plugging Schematic for Atlas No. 1 19
Figure 6-9 – Final Plugging Schematic for Andes No. 1 21

Tables

Table 6-1 – Description of Casing, Tubing, and Other Well-Construction Materials to Be Removed 6
Table 6-2 – Plug Details for Plugs No. 1 to No. 5, Cronos No. 1 10
Table 6-3 – Plug Details for Plugs No. 6 to No. 8, Cronos No. 1 11
Table 6-4 – Plug Details for Plugs No. 1 to No. 5, Rhea No. 1 13
Table 6-5 – Plug Details for Plugs No. 6 to No. 7, Rhea No. 1 14

6.1 Introduction

The plugging plan for the proposed Titan Carbon Sequestration, LLC (Titan) injection wells Cronos No. 1 and Rhea No. 1 has been prepared in accordance with the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(k)** and 16 TAC **§3.14** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.92**. This section provides a general description of the steps that will be taken to plug and abandon each well in the project. For the injection wells, this plan will include the proposed stages of well development through final abandonment. The plugging and abandonment (P&A) of each monitoring well is also covered in this section. Complete P&A prognoses are included in *Appendix H*.

6.2 Injection Well Zonal Isolation and Final Plugging and Abandonment

The injection wells will be completed in multiple intervals within the gross injection zone. Each injection interval will be used for a discrete period as identified in the plume model. Once that period has been completed, the current injection interval will be isolated to prevent crossflow conditions between the new and old injection intervals. Once an injection stage is isolated, a new injection horizon will be opened. This process will be repeated until the entire gross injection interval is fully developed. After [redacted] injection in both wells, the uppermost plug will be set, and the wells will continue to be used for monitoring purposes until the plume monitoring is no longer required. After that, the wells will be permanently plugged. The P&A procedures for the injection wells are designed to prevent CO_2 or formation fluids in the injection interval from migrating to the Underground Source of Drinking Water (USDW).

The details in this section outline the procedures for both types of plugs—described as follows—to be installed in the injection wells:

- Isolation of the active injection section via recompletion operations
- Final P&A of the wellbore

6.2.1 Zonal Isolation of Injection Zone / Intermediate Plugback Plan

When the current, active injection zone has reached the end of its injection period, that zone will be isolated and abandoned. The general procedure for zonal isolation includes the following.

6.2.1.1 Pre-zonal Isolation Activities

1. Titan will comply with all reporting and notification provisions.
    a. Titan will notify the Underground Injection Control (UIC) Program director (UIC Director) 60 days before planned plugging efforts. If any changes are proposed to the original well plugging plan, a revised well plugging plan will be submitted. (16 TAC ***§*5.203(k)(3)(A)** [40 CFR ***§*146.92(c)**])

b. Notice of Intent to Plug will be communicated to the Texas Railroad Commission (TRRC) by submitting Form W-3A with detailed plans at least 5 days prior to the beginning of plugging operations. (16 TAC **§5.203(k)(3)(B)**)

2. Bottomhole reservoir pressure will be measured [redacted] (16 TAC **§5.203(k)(2)(B)** [40 CFR ***§*146.92(a)**]).
3. External mechanical integrity will be demonstrated through approved monitoring methods described in *Section 5*. (16 TAC **§5.203(k)(2)(C)** [40 CFR ***§*146.92(a)**])

Figures 6-1 and 6-2 show schematics of the first intermediate isolation plans for Cronos No. 1 and Rhea No. 1, respectively.

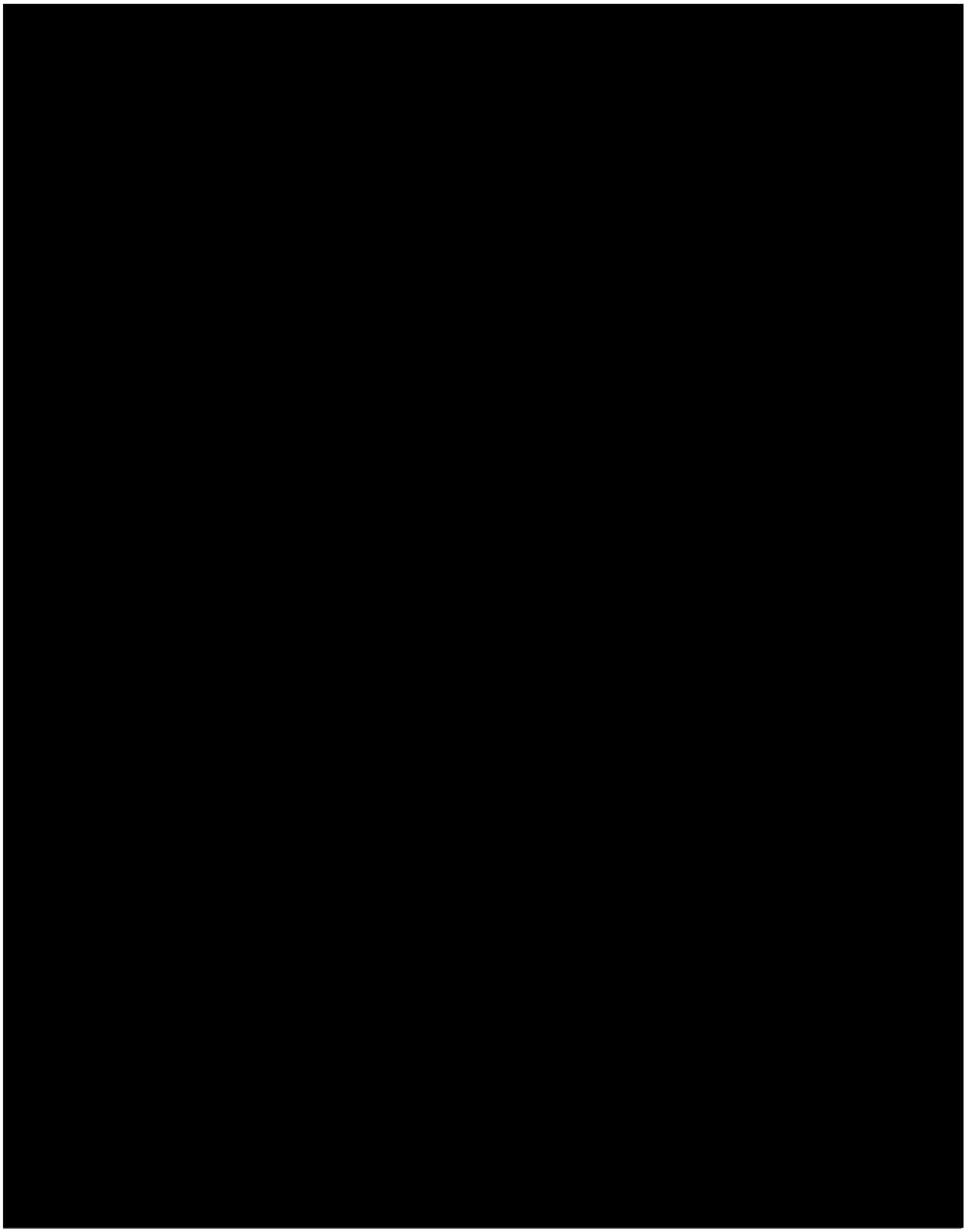


Figure 6-1 – First Plugging Schematic for Cronos No. 1

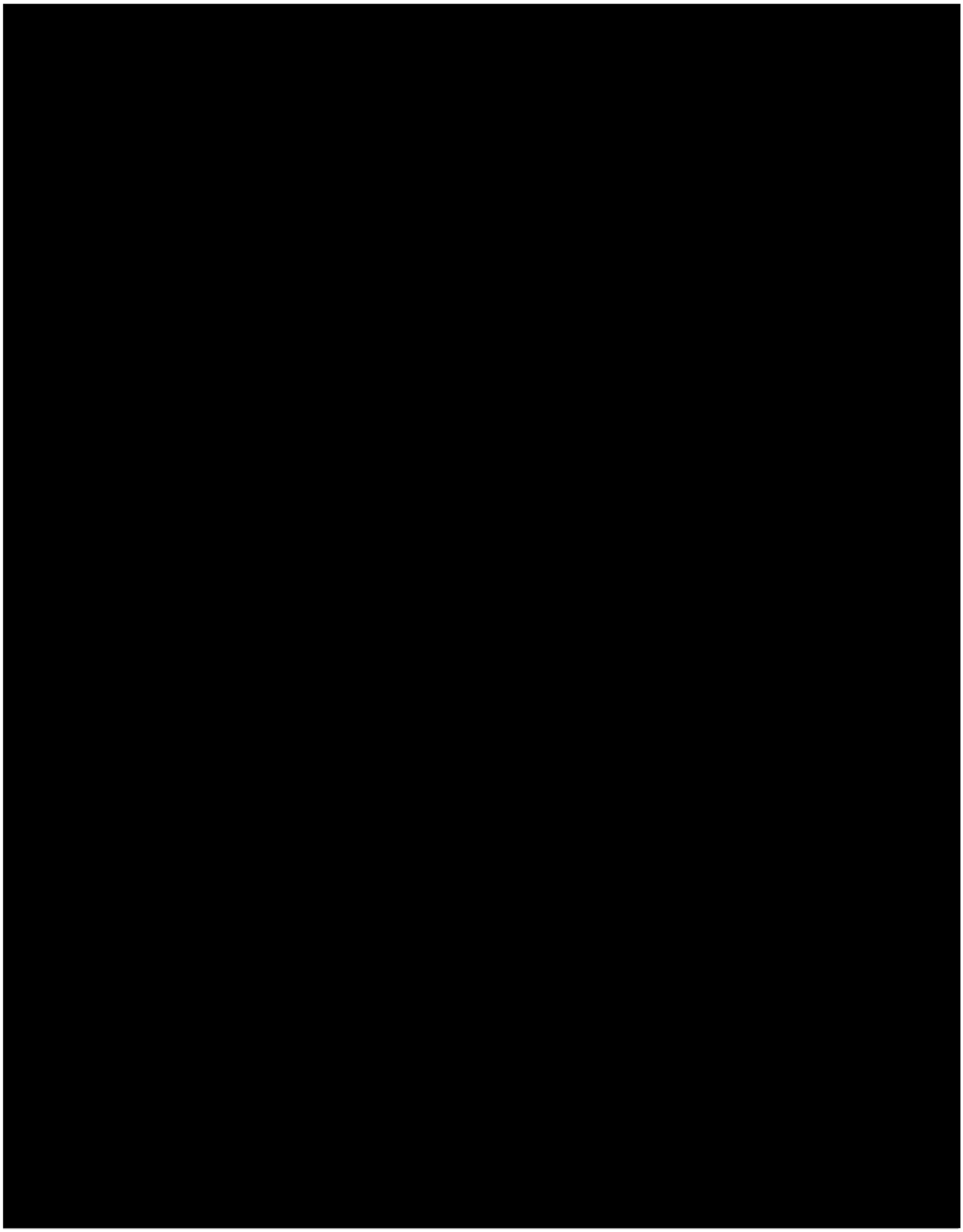


Figure 6-2 – First Plugging Schematic for Rhea No. 1

6.2.1.2 Zonal Isolation Activities

1. A CO_2-compatible barrier will be set above the injection zone to be isolated.
2. The plug will be confirmed by conducting a successful pressure test.
3. The primary plan is to squeeze the perforations. If ported gauge carriers are used, perforations will not be squeezed, which willallow for pressure monitoring of the isolated zone during the life of the Titan Project.

6.2.2 Final Zonal Isolation of Injection Zone / Post Injection Monitoring Plugback Plan

When all active injection zones have reached the end of their injection period, the final injection zone will be isolated and abandoned prior to the post injection monitoring phase. The general procedure for final zonal isolation includes the following.

6.2.2.1 Pre-final Zonal Isolation Activities

1. Titan will comply with all reporting and notification provisions.
    a. Titan will notify the Underground Injection Control (UIC) Program director (UIC Director) 60 days before planned plugging efforts. If any changes are proposed to the original well plugging plan, a revised well plugging plan will be submitted. (16 TAC **§5.203(k)(3)(A)** [40 CFR **§146.92(c)**])
    b. Notice of Intent to Plug will be communicated to the Texas Railroad Commission (TRRC) by submitting Form W-3A with detailed plans at least 5 days prior to the beginning of plugging operations. (16 TAC **§5.203(k)(3)(B)**)
2. Bottomhole reservoir pressure will be measured using the externally mounted pressure-sensing array installed outside the casing as discussed in *Section 5 – Testing and Monitoring Plan*. (16 TAC **§5.203(k)(2)(B)** [40 CFR **§146.92(a)**]).
3. External mechanical integrity will be demonstrated through approved monitoring methods described in *Section 5*. (16 TAC **§5.203(k)(2)(C)** [40 CFR **§146.92(a)**])
4. The injection well will be flushed with a buffer fluid prior to pulling the injection tubing and packer. (16 TAC **§5.203(k)(2)(A)** [40 CFR **§146.92(a)**])
5. All uncemented, nonpermanent components of the well will be removed, as described in Table 6-1.

Table 6-1 – Description of Casing, Tubing, and Other Well-Construction Materials to Be Removed

Well Component	Size	Cronos No. 1 Amount	Rhea No. 1 Amount	Notes / Comments
[redacted]				

Figures 6-3 and 6-4 show schematics of the final zonal isolation plans for Cronos No. 1 and Rhea No. 1, respectively.

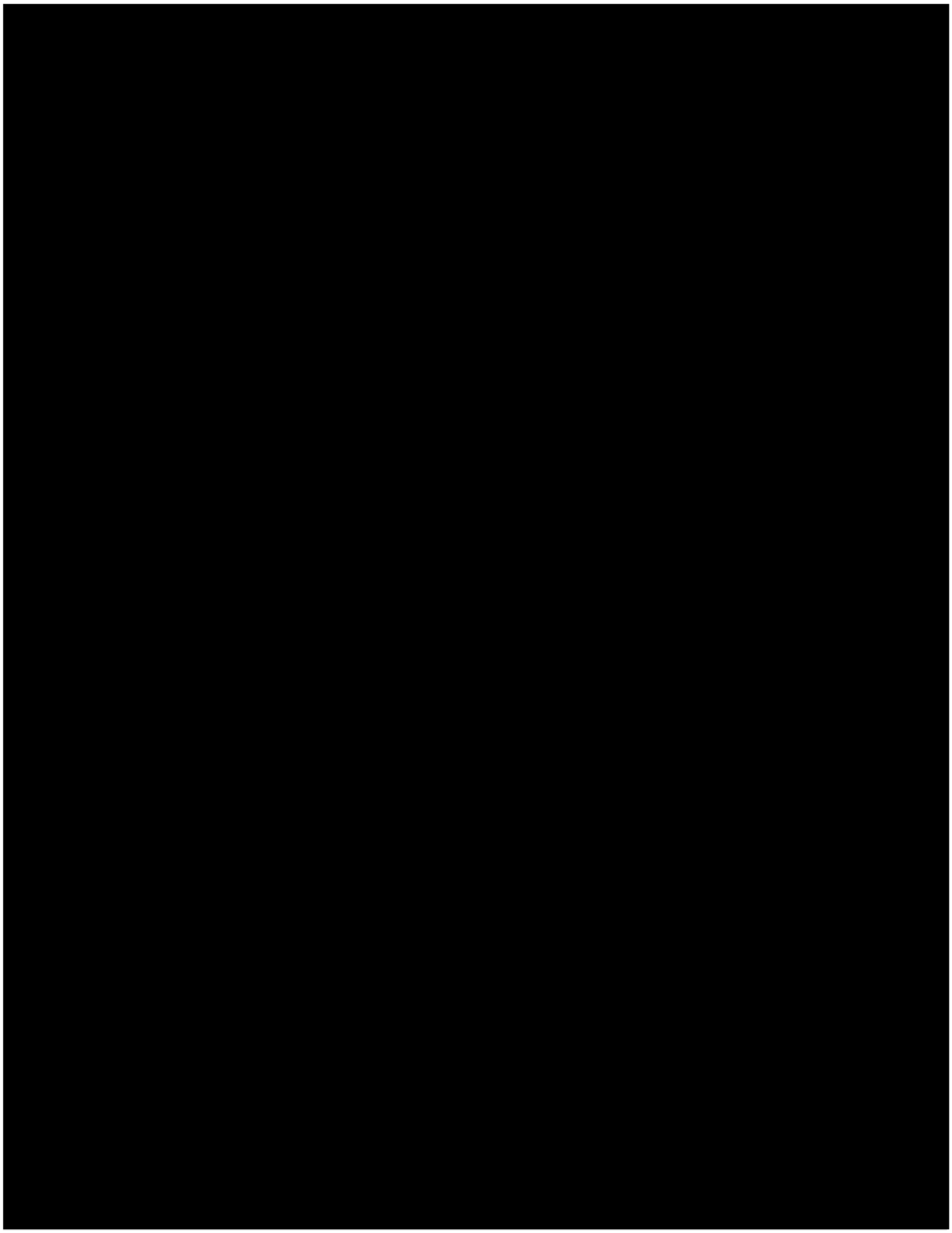


Figure 6-3 – Final Zonal Isolation Plugging Schematic for Cronos No. 1

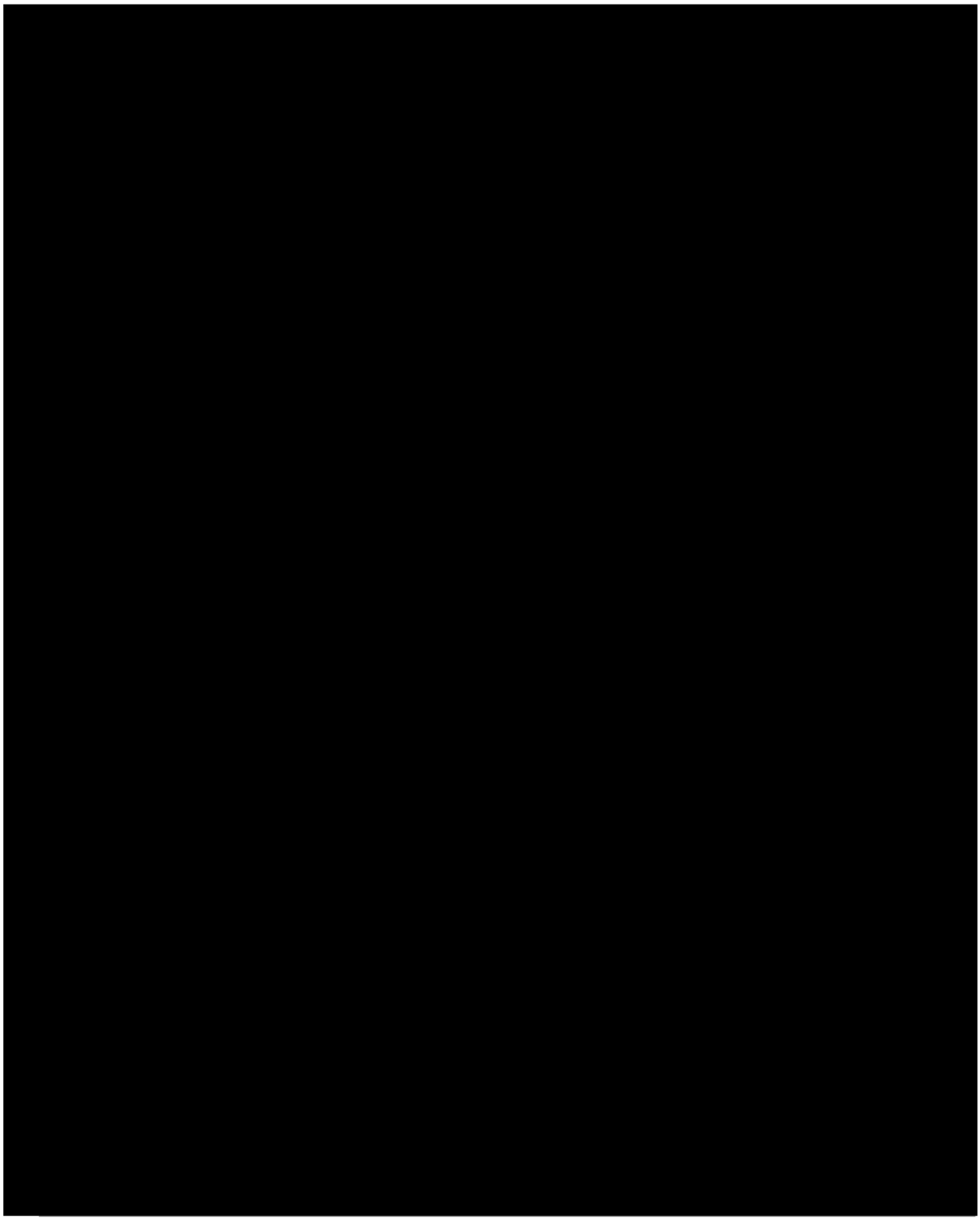


Figure 6-4 – Final Zonal Isolation Plugging Schematic for Rhea No. 1

6.2.2.2 Final Zonal Isolation Activities

1. A CO_2-compatible barrier will be set above the injection zone to be isolated.
2. The plug will be confirmed by conducting a successful pressure test.
3. The primary plan is to squeeze the perforations. If ported gauge carriers are used, perforations will not be squeezed, which willallow for pressure monitoring of the isolated zone during the life of the Titan Project..

6.2.3 Final Plugging and Abandonment

After post injection monitoring is complete the injection wells will be prepared for final P&A, the general procedures for which include the following:

6.2.3.1 Pre-plugging Activities

1. Titan will comply with all reporting and notification provisions.
    a. Titan will notify the UIC Director 60 days before planned plugging efforts. If any changes are proposed to the original well plugging plan, a revised well plugging plan will be submitted. (16 TAC **§5.203(k)(3)(A)** [40 CFR **§146.92(c)**])
    b. Notice of Intent to Plug will be communicated to the TRRC by submitting Form W-3A with detailed plans at least 5 days prior to the beginning of plugging operations. (16 TAC **§5.203(k)(3)(B)**)
2. Bottomhole reservoir pressure will be measured using the [redacted] (16 TAC **§5.203(k)(2)(B)** [40 CFR **§146.92(a)**])
3. External mechanical integrity will be demonstrated through approved monitoring methods described in *Section 5*. (16 TAC **§5.203(k)(2)(C)** [40 CFR **§146.92(a)**])
4. Casing inspection and cement bond logs will be performed before plugging.

6.2.3.2 Plugging Procedure, Cronos No. 1

1. Check wellhead pressures; determine bottomhole pressure (BHP) with sensor and record. (16 TAC **§5.203(k)(2)(B)** [40 CFR **§146.92(a)**])
2. Treated fluid will be circulated at least once to achieve a state of static equilibrium.
3. Set a [redacted] cement plug from [redacted] below the surface casing setting depth to 100 ft into the surface casing shoe.
4. Wait on cement. Tag and test to confirm placement.
5. Set a [redacted] cement plug from [redacted] below the base of the USDW to surface. (16 TAC **§3.14(d)(8)**)
6. Cut and cap the casing to a minimum of 3 ft below the mud line. (16 TAC **§3.14(d)(8)**)
7. Rig down and move off the location.
8. Perform site closure requirements. (16 TAC **§5.203(m)** [40 CFR **§146.93(a)**])

6.2.3.3 Plug Details, Cronos No. 1

Tables 6-2 and 6-3 provide the plugging details for Cronos No. 1 using a bridge plug (BP) or cement retainer (CR).

Table 6-2 – Plug Details for [redacted] Cronos No. 1

Plug Description	Plugback – BP/CR	Plugback – BP/CR	Plugback – BP/CR	Plugback – BP/CR	Plugback – BP/CR
[redacted]					

Table 6-3 – Plug Details [redacted] Cronos No. 1

Plug Description	[redacted]
Plug Number	
Diameter of Boring in Which Plug Will Be Placed (in.)	
Depth to Bottom of Tubing or Drill Pipe (ft)	
Sacks of Cement to Be Used (each plug)	
Slurry Volume to Be Pumped (ft^3)	
Slurry Weight (lb/gal)	
Top of Plug (ft)	
Bottom of Plug (ft)	
Type of Cement or Other Material	
Method of Emplacement	
New Plug?	

Figure 6-5 shows the final plugged schematic for Cronos No. 1.

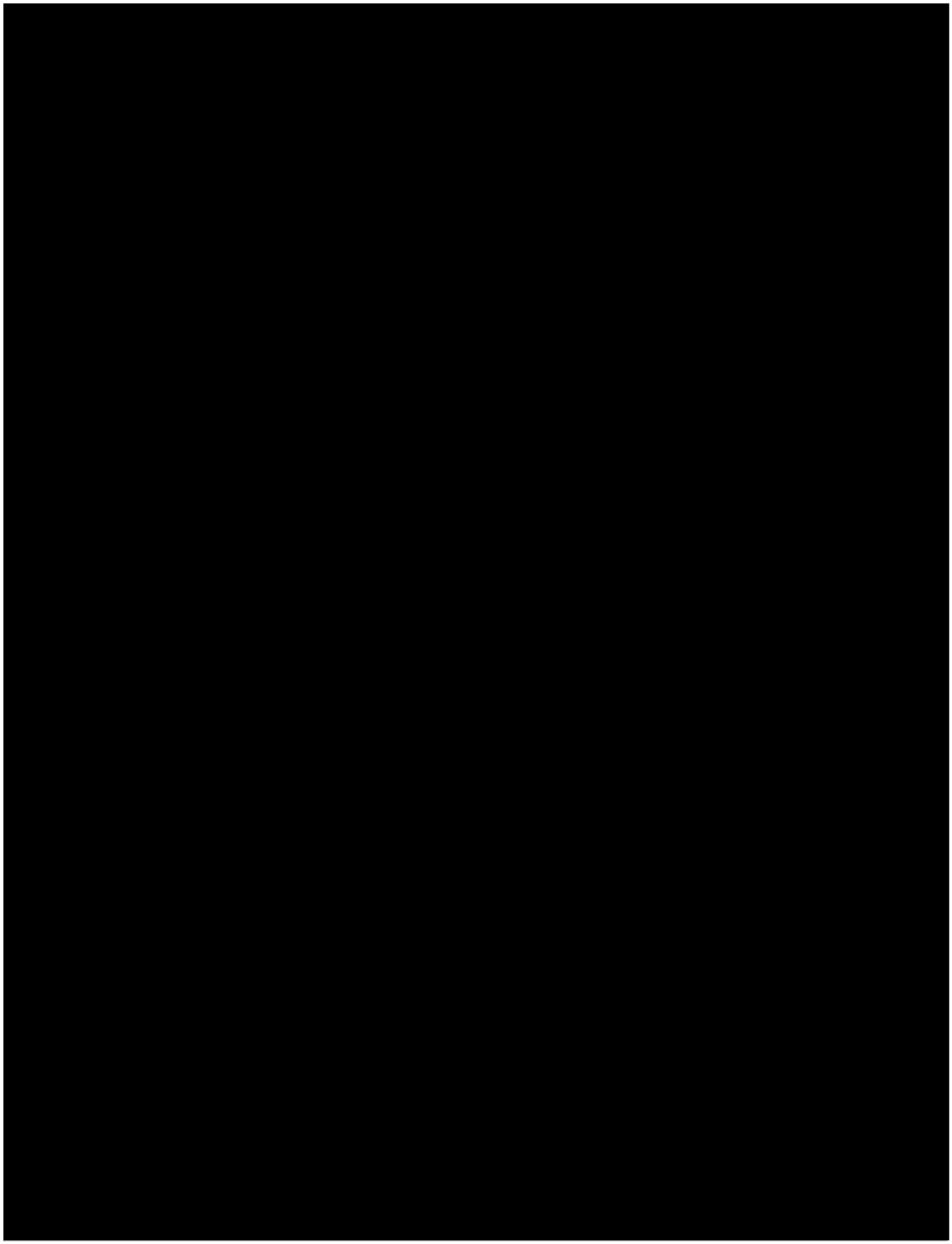


Figure 6-5 – Final Plugging Schematic for Cronos No. 1

6.2.3.4 Plugging Procedure, Rhea No. 1

1. Check wellhead pressures; determine BHP with sensor and record. (16 TAC **§5.203(k)(2)(B)** [40 CFR **§146.92(a)**])
2. Treated fluid will be circulated at least once to achieve a state of static equilibrium.
3. Set a [redacted]-ft cement plug from [redacted] ft below the surface casing setting depth to [redacted] ft into the surface casing shoe.
4. Wait on cement. Tag and test to confirm placement.
5. Set a [redacted]-ft cement plug from [redacted] ft below the base of the USDW to surface. (16 TAC **§3.14(d)(8)**)
6. Cut and cap casing to a minimum of 3 ft below the mud line. (16 TAC **§3.14(d)(8)**)
7. Rig down and move off the location.
8. Perform site closure requirements. (16 TAC **§5.203(m)** [40 CFR **§146.93(a)**])

6.2.3.5 Plug Details, Rhea No. 1

Tables 6-4 and 6-5 provide the plugging details for Rhea No. 1.

Table 6-4 – Plug Details [redacted] Rhea No. 1

Plug Description	[redacted]
Plug Number	
Diameter of Boring in Which Plug Will Be Placed (in.)	
Depth to Bottom of Tubing or Drill Pipe (ft)	
Sacks of Cement to Be Used (each plug)	
Slurry Volume to Be Pumped (ft^3)	
Slurry Weight (lb/gal)	
Top of Plug (ft)	
Bottom of Plug (ft)	
Type of Cement or Other Material	
Method of Emplacement	
New Plug?	

Table 6-5 – Plug Details [redacted] Rhea No. 1

Plug Description	[redacted]
Plug Number	
Diameter of Boring in Which Plug Will Be Placed (in.)	
Depth to Bottom of Tubing or Drill Pipe (ft)	
Sacks of Cement to Be Used (each plug)	
Slurry Volume to Be Pumped (ft^3)	
Slurry Weight (lb/gal)	
Top of Plug (ft)	
Bottom of Plug (ft)	
Type of Cement or Other Material	
Method of Emplacement	
New Plug?	

Figure 6-6 shows the final plugged schematic for Rhea No. 1.

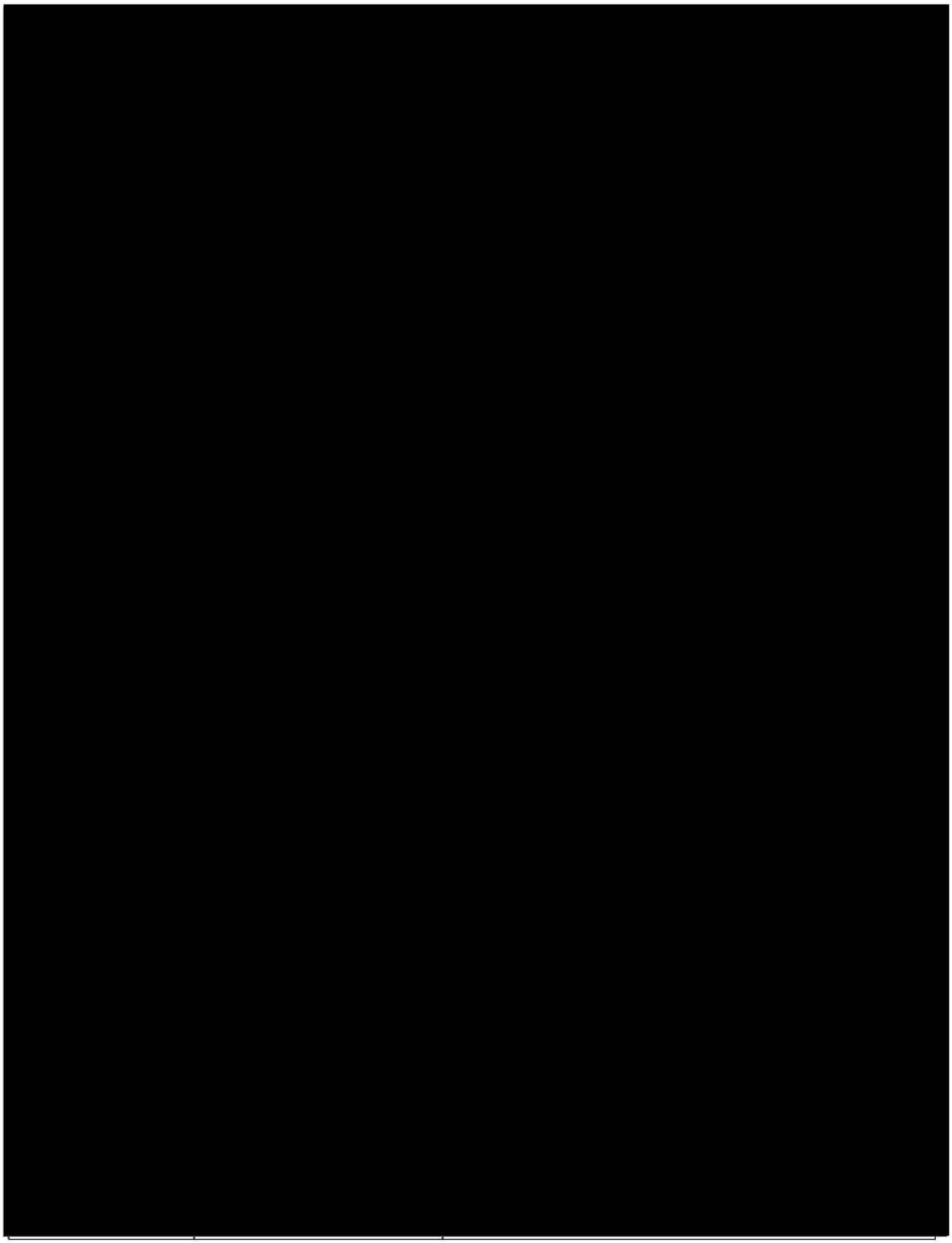


Figure 6-6 – Final Plugging Schematic for Rhea No. 1

6.3 Monitoring Wells Plugging and Abandonment

The following sections outline the plan for the P&A of the monitoring wells associated with the proposed injection wells Cronos No. 1 and Rhea No. 1.

6.3.1 Pre-plugging Activities

Titan will comply with all reporting and notification provisions.

1. Titan will notify the UIC Director 60 days before planned plugging efforts. If any changes are proposed to the original well plugging plan, a revised well plugging plan will be submitted. (16 TAC **§5.203(k)(3)(A)** [40 CFR ***§*146.92(c)**])
2. Notice of Intent to Plug will be communicated to the TRRC by submitting Form W-3A with detailed plans at least 5 days prior to the beginning of plugging operations. (16 TAC **§5.203(k)(3)(B)**)

6.3.2 Plugging Procedure, TCS WM No. 1 and TCS WM No. 2

The two USDW monitoring wells will be plugged by pulling and removing all downhole equipment. Portland cement will then be placed along the entire casing string through a work string. The plugging schematic for TCS WM No. 1 is provided in Figure 6-5, which TCS WM No. 2 will closely follow. The plugging schematics for both wells are provided in *Appendix H-11*.

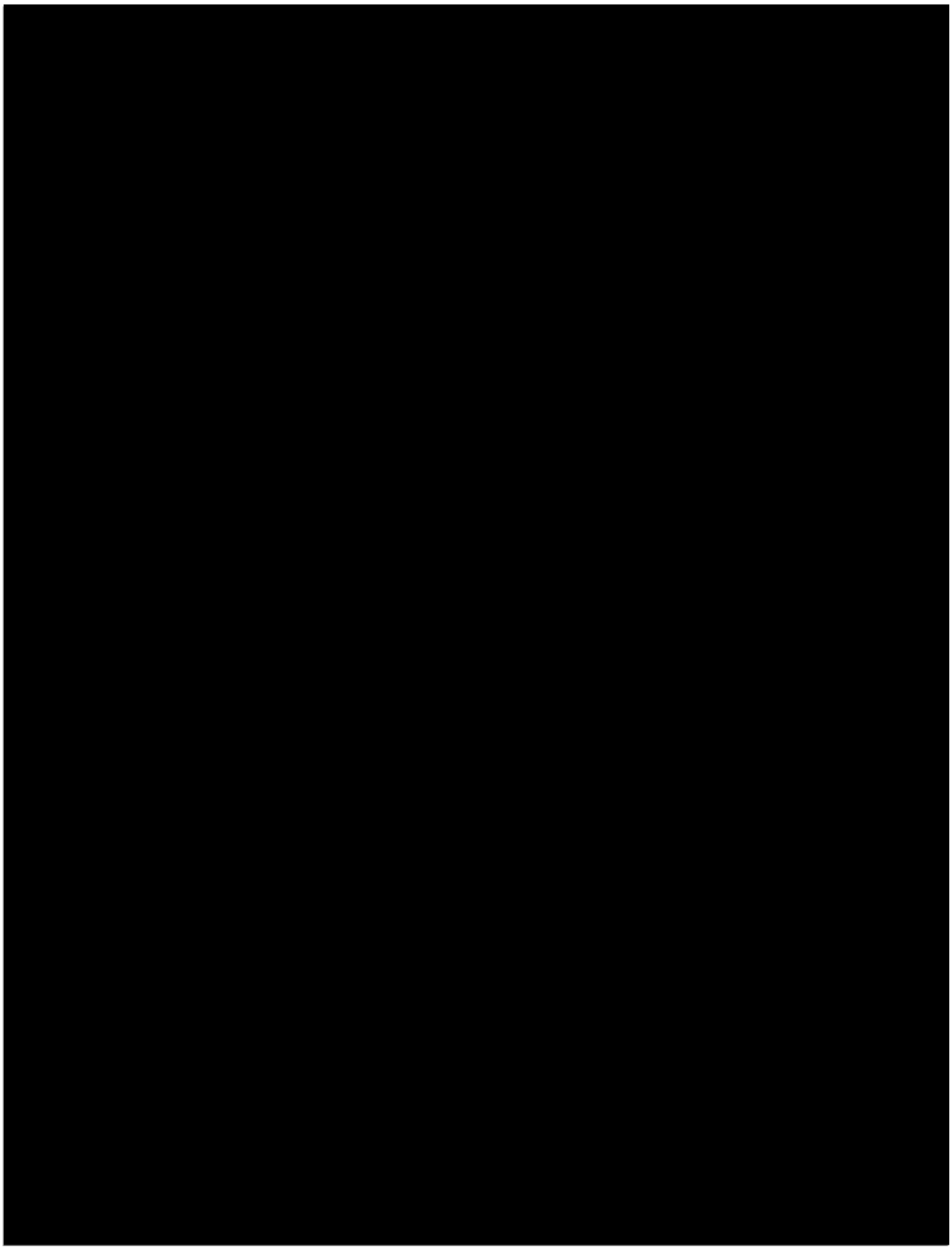


Figure 6-7 – Final Plugging Schematic for TCS WM No. 1

6.3.3 Plugging Procedure, Atlas No. 1

The following is the plugging procedure for above-zone monitoring (AZM) well Atlas No. 1.

1. Move in and rig up workover unit.
2. Check casing and annulus pressures. Record all annuli pressures.
3. Run in hole with work string and circulate the hole clean.
4. If perforations have been used during project life, isolate the open monitoring interval. [redacted]
5. Set a [redacted]-ft cement plug from [redacted] ft below the surface casing setting depth to [redacted] ft into the surface casing shoe.
6. Wait on cement. Tag and test to confirm placement.
7. Set a [redacted]-ft cement plug from [redacted] ft below the base of the USDW to surface. (16 TAC **§3.14(d)(8)**)
8. Cut and cap casing to a minimum of 3 ft below the mud line. (16 TAC **§3.14(d)(8)**)
9. Rig down and move off location.
10. Perform site closure requirements.

Figure 6-8 shows the plugging schematic for Atlas No. 1.

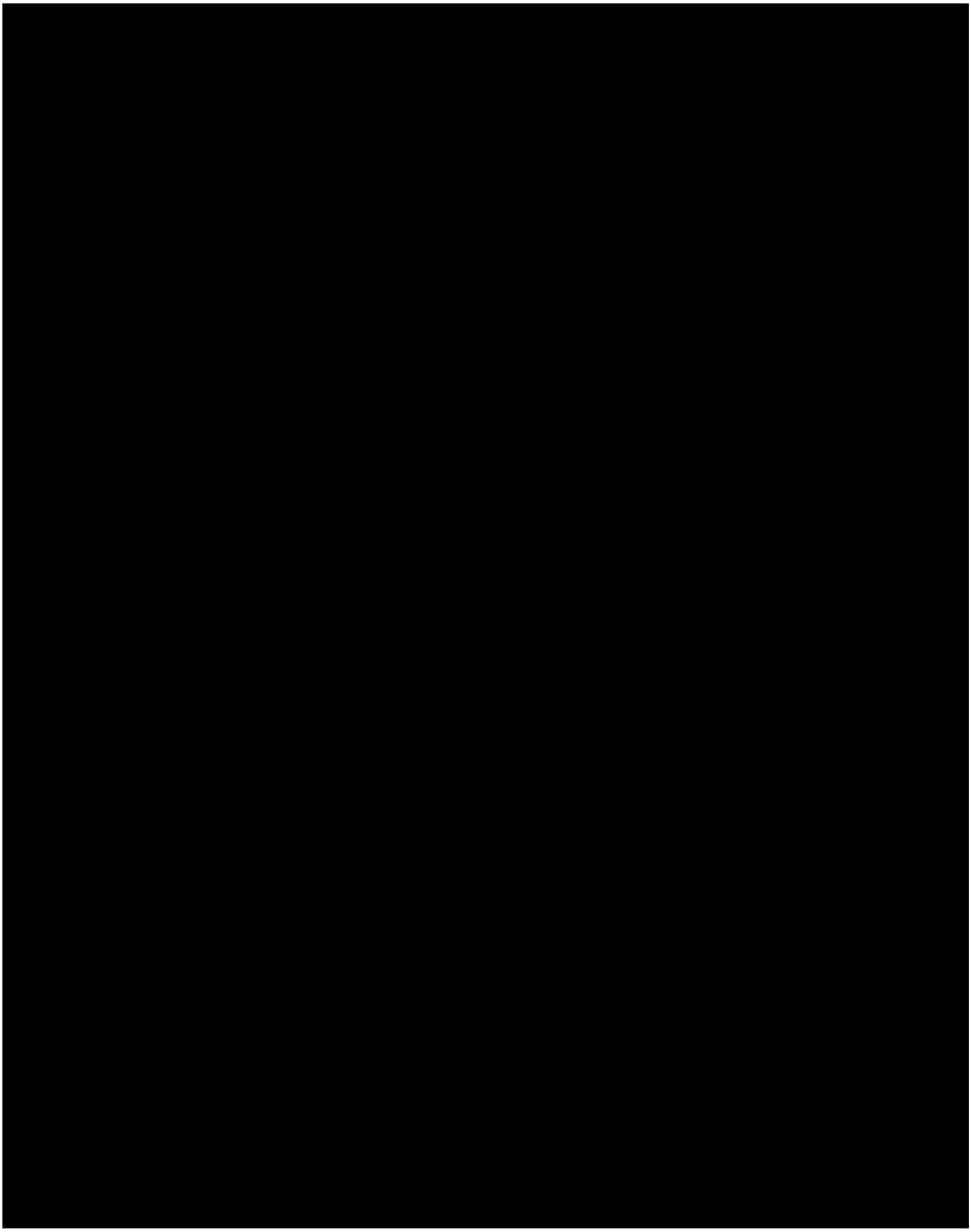


Figure 6-8 – Final Plugging Schematic for Atlas No. 1

6.3.4 Plugging Procedure, Andes No. 1

1. Move in and rig up workover unit.
2. Check casing and annulus pressures. Record all annuli pressures.
3. Run in hole with work string and circulate the hole clean.
4. If perforations have been used during project life, isolate the open monitoring interval. [redacted]
5. Set a [redacted]-ft cement plug from [redacted] ft below the surface casing setting depth to [redacted] ft into the surface casing shoe.
6. Wait on cement. Tag and test to confirm placement.
7. Set a [redacted]-ft cement plug from [redacted] ft below the base of the USDW to surface. (16 TAC **§3.14 (d)(8)**)
8. Cut and cap casing to a minimum of 3 ft below the mud line. (16 TAC **§3.14 (d)(8)**)
9. Rig down and move off the location.
10. Perform site closure requirements.

Figure 6-9 shows the plugging schematic for Andes No. 1.

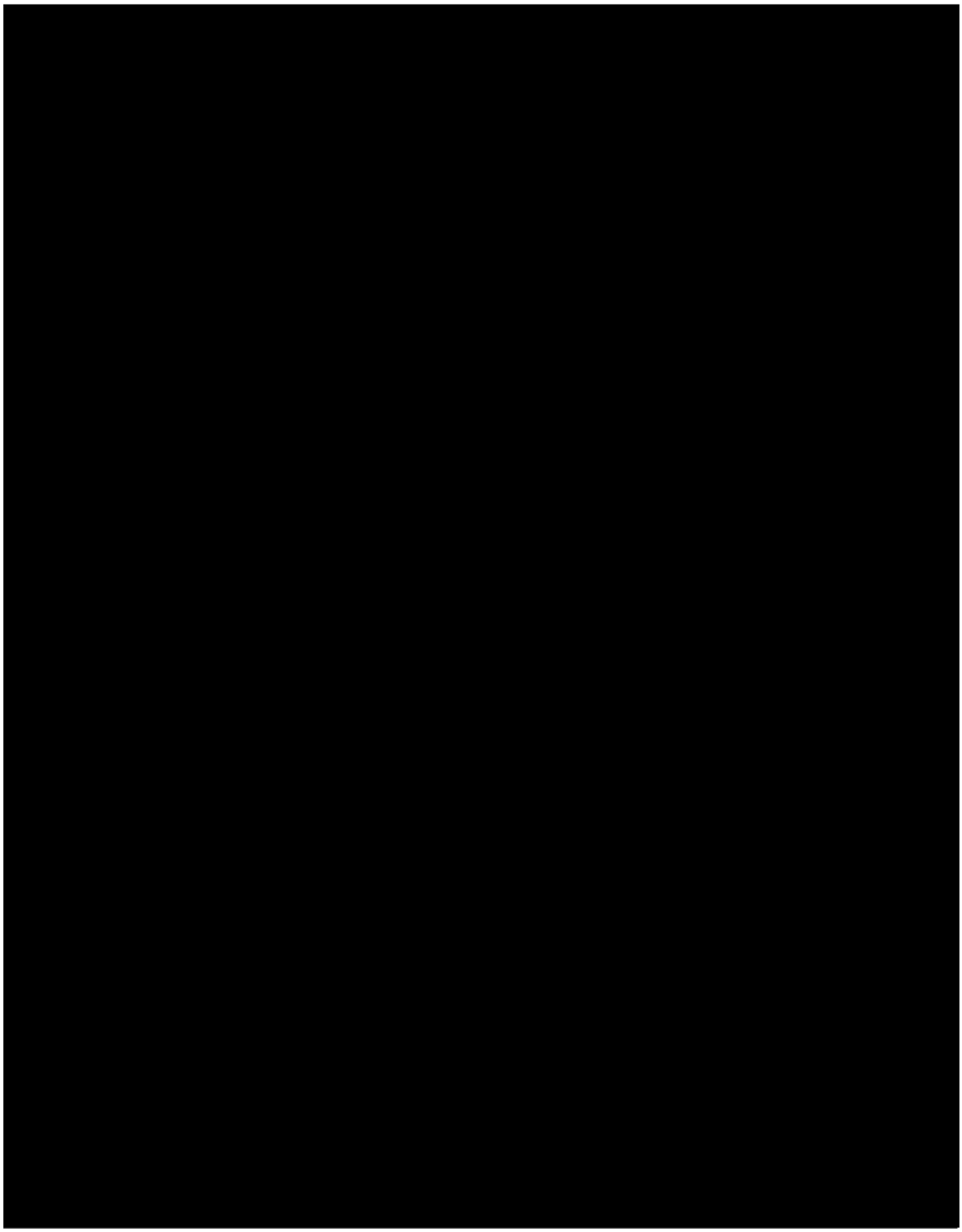


Figure 6-9 – Final Plugging Schematic for Andes No. 1

For each well in the project, final plugging reports—certified by the operator and the person who performed the plugging operation—will be submitted to the UIC Director within 60 days after plugging. Detailed plugging procedures are included in *Appendix H*.

The detailed schematics and procedures in *Appendix H* include the following:

- Appendix H-1 Cronos No. 1 and Rhea No. 1 Zonal Isolation Schematics
- Appendix H-2 Cronos No. 1 and Rhea No. 1 Final Zonal Isolation Schematics
- Appendix H-3 Cronos No. 1 Detailed Plugging Procedure
- Appendix H-4 Rhea No. 1 Detailed Plugging Procedure
- Appendix H-5 Cronos No. 1 and Rhea No. 1 Final P&A Schematics
- Appendix H-6 Atlas No. 1 – Final P&A Procedure
- Appendix H-7 Atlas No. 1 – Final P&A Schematic
- Appendix H-8 Andes No. 1 – Final P&A Procedure
- Appendix H-9 Andes No. 1 – Final P&A Schematic
- Appendix H-10 TCS WM No. 1 and No. 2 – Final P&A Procedures
- Appendix H-11 TCS WM No. 1 and No. 2 – Final P&A Schematics

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

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

February 2024

LONQUIST
SEQUESTRATION LLC

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

TABLE OF CONTENTS

7.1 Introduction 2
7.2 Pre- and Post-Injection Pressure Differentials 2
7.3 CO_2 Plume Position and Pressure Front at End of Closure 4
7.4 Post-Injection Monitoring Plan 6
7.5 Post-Injection Monitoring Activities 7
7.6 Demonstration of Non-Endangerment of USDW 7
7.7 Site Closure Plan 8
7.7.1 Pre-closure 8
7.7.2 Plugging Activities 8
7.7.3 Site Restoration 9
7.7.4 Documentation of Site Closure 9

Figures

Figure 7-1 – Maximum Pressure Differential Over Time for Cronos No. 1 4
Figure 7-2 – Maximum Pressure Differential Over Time for Rhea No. 1 4
Figure 7-3 – 50-Year Maximum Combined Plume 5
Figure 7-4 – Monitoring Well Location Map 6

Tables

Table 7-1 – Maximum Pressure Differential by Year 2
Table 7-2 – Post-Injection Monitoring and Reporting Frequency 7

7.1 Introduction

The Post-Injection Site Care (PISC) and Site Closure Plan for the Titan Project injection wells, Cronos No. 1 and Rhea No. 1, was prepared in accordance with the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(m)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93**]. This plan describes the various activities that will occur once injection has ceased and during the site closure. This plan will be implemented once Titan 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 16 TAC **§5.203(m)(2)** [40 CFR **§146.93(a)(2)(i)**], the following table shows the expected pressure differential between pre- and 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 Titan injection wells will inject into sequentially shallower intervals over the life of the project, resulting in separate pressure profiles for each interval. [redacted] Once injection ceases in each stage, the pressure drops down to near in situ 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) Cronos No. 1	Max Pressure Differential (psi) Rhea No. 1
[redacted]		

Year	Max Pressure Differential (psi) Cronos No. 1	Max Pressure Differential (psi) Rhea No. 1
[redacted]		

Figures 7-1 and 7-2 present graphical representations of the data in Table 7-1, showing the pressure differential over the life of both injection wells. The solid dark-green line represents the buildup from in situ pressure due to injection, and the solid light-green line represents the maximum pressure gradient exhibited in each stage of injection. The dashed light-green line shows the 90% fracture-pressure gradient constraint. The light green line does not exceed the

dashed light-green line, indicating that the model does not surpass the 90% fracture-pressure gradient constraint .

Figure 7-1 – Maximum Pressure Differential Over Time for Cronos No. 1

Figure 7-2 – Maximum Pressure Differential Over Time for Rhea No. 1

7.3 CO_2 Plume Position and Pressure Front at End of Closure

The area of review (AOR) consists of both the CO_2 plume and critical pressure maximum extent. Figure 7-3 shows the AOR and its subcomponents. The CO_2 plumes are indicated by the black polygons, based on the maximum extent of all the differing plume layers in the model, extracted at 50 years post-injection. The CO_2 plumes and pressure front AOR consider both Cronos No. 1 and Rhea No. 1. Once injection has ceased, the pressure in the injection interval will quickly revert to near reservoir pressure, as was shown in Table 7-1.

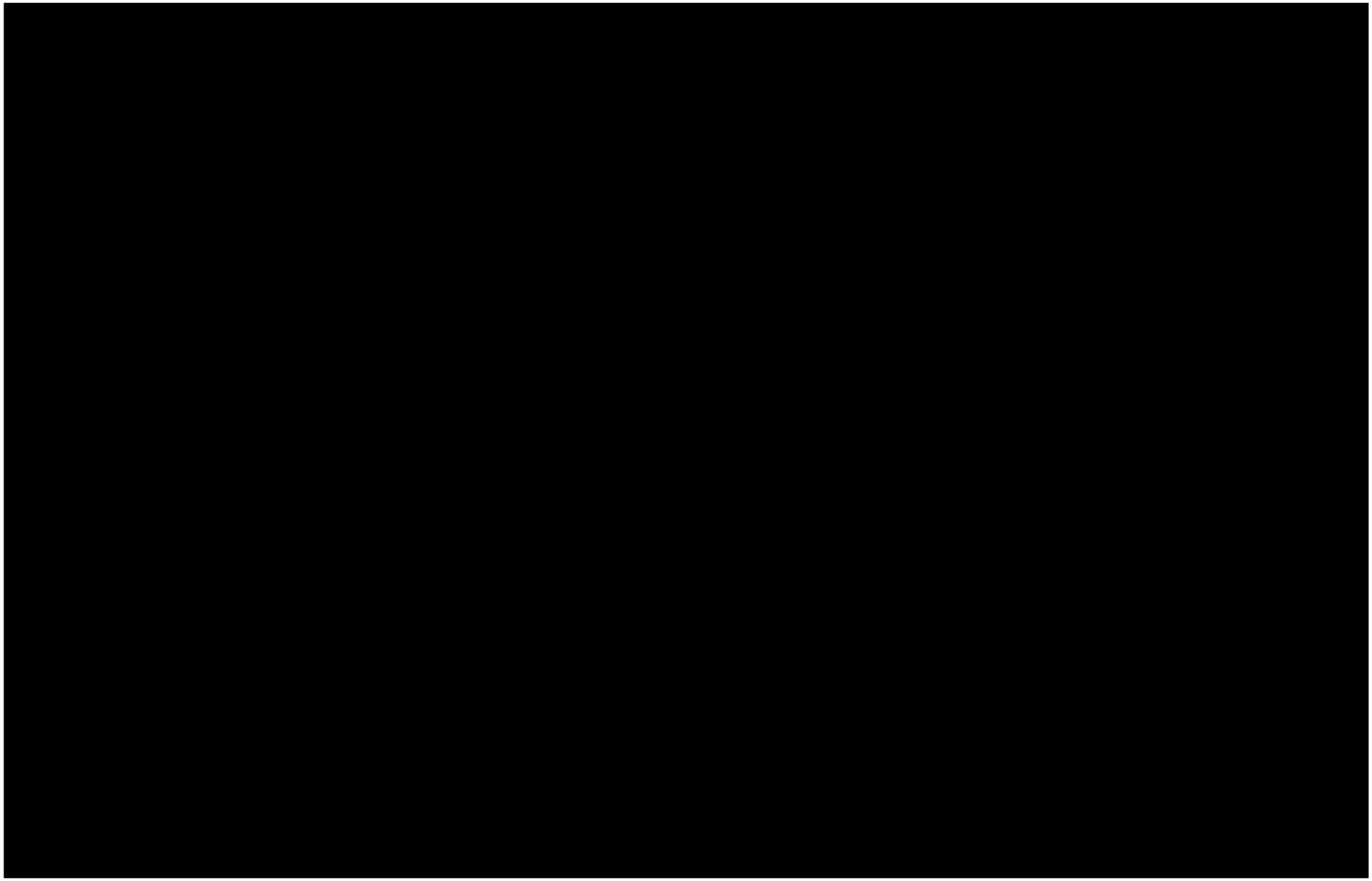


Figure 7-3 – 50-Year Maximum Combined Plume

7.4 Post-Injection Monitoring Plan

As required by 16 TAC **§5.206(k)(2)** [40 CFR **§146.93(b)**], Titan will continue to monitor the site for 50 years or until the UIC director determines that the project no longer poses an endangerment to the USDW, as described in *Section 7.6*. The reservoir model will continue to be updated throughout the project using monitoring observations. Upon cessation of injection, an amended PISC—if needed per the updated model—will be submitted to the Underground Injection Control (UIC) Program director (UIC Director).

Two above-zone monitoring wells and two USDW monitoring wells are proposed, as discussed in *Section 5 – Testing and Monitoring Plan*. The location of these wells is displayed in Figure 7-4.

Figure 7-4 – Monitoring Well Location Map

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.

Table 7-2 – Post-Injection Monitoring and Reporting Frequency

Testing/Monitoring Activity	Frequency	Reporting Schedule	Comment
USDW monitoring well fluid sampling and analysis	Every 5 years	Within 30 days after data collection and analysis	
Above-zone monitoring well fluid sampling and analysis	Only if required	Within 30 days after data collection and analysis	
Above-zone monitoring well pressure measurements	Continuously	Annually	
Injection-well wellhead pressure monitoring (tubing and annulus)	Continuously	Annually	
Injection well in-zone pressure/temperature (P/T) monitoring	Continuously, using P/T gauges in individual injection stages	Annually	Based on the reservoir model, the pressure quickly decays back towards pre-injection pressure.
Indirect plume monitoring (vertical seismic profile)	Every 5 years	Within 30 days after time-lapse seismic processing has finished	Until plume stabilization is verified.
Direct plume calculations based on P/T data	Annually	Annually	

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 Non-Endangerment of USDW

The primary mechanism through which the USDWs are protected is the upper confining zone (UCZ), which is comprised of the *Amphistegina B* (Amph B) shale that ranges from [redacted]

[redacted] 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 improve its ability to accurately predict the movement of CO_2. These calibrated predictions from the simulation model are used to identify any UCZ-penetrating features with which the CO_2 plume may interact prior to final stabilization. Examples of these features of concern are legacy wellbores and fault planes. However, for the Titan Project, no known wellbore paths have been identified. Therefore, the calibration effort ensures that (1) legacy wellbores, if any were found to exist in the AOR, 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 CO_2 does not reach fault planes cutting through the UCZ.

Prior to the approval of the site-closure authorization, as required by 16 TAC **§5.203(m)(1)** [40 CFR **§146.93(c)**], Titan will provide documentation that the USDW is not at risk of further endangerment from the CO_2 plume. While the PISC duration is 50 years, it may be possible to demonstrate USDW non-endangerment earlier. [redacted] Titan will submit a report to the UIC Director demonstrating the 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. The UIC Director will ultimately determine and approve an alternative timeline for closure.

7.7 Site Closure Plan

To meet the requirements of 16 TAC **§5.206(k)(5)** [40 CFR **§146.93(e)**], the following site-closure activities will be performed: plugging of all wells, site closure, and submittal of final site-closure reports.

7.7.1 Pre-closure

To meet the requirements of 16 TAC **§5.206(k)(4)** [40 CFR **§146.93(d)**], notice of the intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

7.7.2 Plugging Activities

The Titan Project injection wells (Cronos No. 1 and Rhea No. 1), AZM wells (Atlas No. 1 and Andes No. 1) and both USDW monitoring wells (TCS WM No. 1 and TCS WM No. 2) will be plugged as discussed in *Section 6 – Plugging Plan*. The plugging and abandonment procedures for the injectors are designed to prevent CO_2 or formation fluids in the injection interval from migrating to the USDW. Prior to plugging the injection and above-zone 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.

7.7.4 Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the UIC Director, per the requirements of 16 TAC **§5.206(k)(6)** [40 CFR **§146.93(f)**], and 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 Texas Railroad Commission (TRRC)
- Records of the nature, composition, and volume of the CO_2 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 CO_2
- The name of the state agency (TRRC) with which the survey plat was filed, and the address of the office of the EPA, Region 6, and the state agency to which it was submitted
- The total volume of fluid injected, the injection zones into which it was injected, and the period over which injection occurred

Titan will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, Titan will deliver all records to the UIC Director for retention at a location designated by the UIC Director for that purpose.

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

February 2024

LONQUIST
SEQUESTRATION LLC

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

TABLE OF CONTENTS

8.1 Introduction 2
8.2 Resources/Infrastructure in Area of Review 2
8.3 Resources/Infrastructure – Specific Events and Response Plans 4
8.3.1 Event Category – Water Quality Impact 4
8.3.2 Event Category – CO_2 Release to or at the Surface 8
8.3.3 Event Category – Entrained Contaminant (Non-CO_2) in Injection Stream 16
8.3.4 Event Category – Accidents/Unplanned Events (Typical Insurable Events) 18
8.4 Risk Activity Matrix 20
8.5 Training 22
8.6 Communications Plan and Emergency Notification Procedures 22
8.7 Flood Hazard Risk 23
8.8 Emergency and Remedial Response Plan Review and Updates 24

Figures

Figure 8-1 – Titan Project Overview Map 3

Tables

Table 8-1 – Risk Activity Matrix 20
Table 8-2 – Risk Mitigation and Threat Scores 21
Table 8-3 – Risk Assessment Scores 21
Table 8-4 – Emergency Services – **CALL 911** 22
Table 8-5 – Government Agency Notification 23
Table 8-6 – Internal Call List 23

8.1 Introduction

This Emergency and Remedial Response Plan (ERRP) for the Titan Carbon Sequestration, LLC (Titan) injection wells Cronos No. 1 and Rhea No. 1, at the Titan Carbon Sequestration Project (Titan Project), was prepared to meet the requirements of Texas Water Code **§27** and Title 16, Texas Administrative Code (TAC) **§5.203 (l)** [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-closure phases of the project and the actions to be taken in the event of such an emergency. This plan will be reviewed and updated annually. Any change in key personnel will also cause the ERRP to be updated immediately.

8.2 Resources/Infrastructure in Area of Review

The Titan Project is [redacted] The proposed location is approximately [redacted] from the nearest freshwater drinking water well (*Appendix C-3*). No permanent structures are in the predicted review area (AOR). If an undocumented artificial penetration is found, the well will be remediated to ensure protection against any possible migration of CO_2. Additionally, two above-zone monitoring (AZM) wells will be installed in the AOR and constructed in a manner to prevent CO_2 from migrating into the Underground Source of Drinking Water (USDW) and surface atmosphere.

The lowermost USDW in the AOR is estimated to be about [redacted] deep in this area. The Groundwater Advisory Unit (GAU) at the Texas Railroad Commission (TRRC) will provide a groundwater determination letter to confirm both the base of usable quality water and the base of the USDW for the specific injection well locations, prior to commencing drilling operations. The GAU determination letter will be obtained prior to the final well design for drilling.

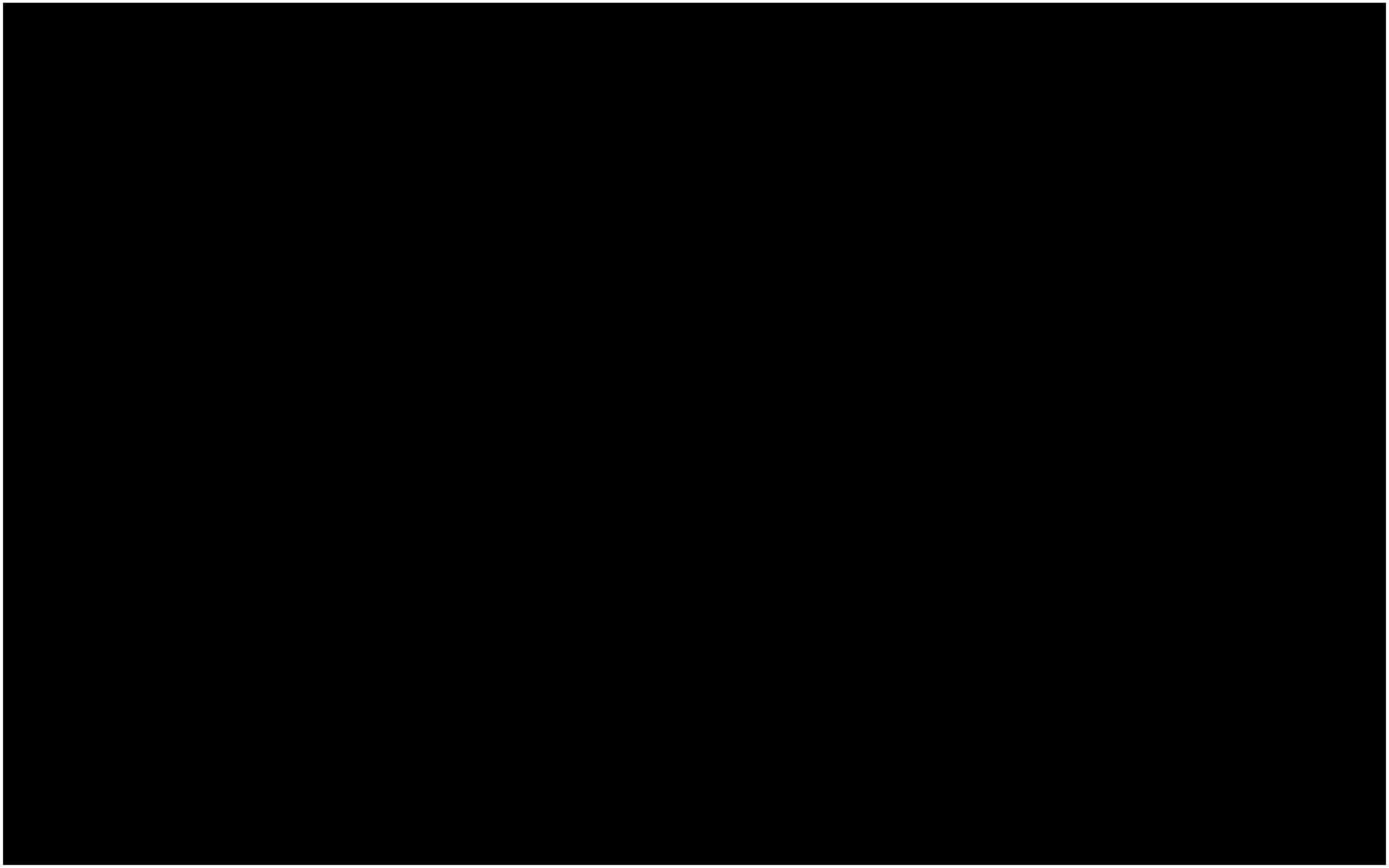


Figure 8-1 – Titan Project Overview Map

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 likely remedial responses.

8.3.1 Event Category – Water Quality Impact

8.3.1.1 Specific Event Description – Leakage of CO_2 outside permitted area into freshwater aquifer

Risk Assessment Matrix, Sections 1.1 and 1.3 (Appendix F-2)

While this event is unlikely to occur during injection facility operations, Titan cannot wholly eliminate the risk of CO_2 leakage. Similarly, analysis and modeling should help to avoid instances of the plume reaching faults or fractures that allow CO_2 migration into another zone, including the USDW, or to the surface.

Likelihood: Remote

Consequence Severity: High

Prevention and Detection:

- The CO_2 plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- The well is specifically designed, constructed, and operated with components such as CO_2-resistant cement, corrosion-resistant alloy tubulars, and other design factors to reduce the likelihood of a CO_2 leak.

Potential Response Actions:

- Cease injection and notify the Underground Injection Control (UIC) Program director (UIC Director) and other pertinent agencies within 24 hours.
- Use vertical seismic profile (VSP) or seismic surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Resume injection at a reduced rate, if possible to do so, with the approval of the UIC Director.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted (Esposito, 2010):
  - Pump CO_2-impacted groundwater to the surface and aerate it to remove the CO_2.
  - Apply "pump and treat" methods to remove trace elements.
  - Drill wells that intersect the accumulations in groundwater and extract CO_2.
  - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
- If surface water is impacted:
  - Shallow lakes will quickly release dissolved CO_2 back into the atmosphere.
  - Create a hydraulic barrier by increasing the reservoir pressure upstream of the

leak.

- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete uphole into the next planned injection stage.

8.3.1.2 Specific Event Description – Leakage of drilling fluid contaminates into potable water aquifer

Risk Assessment Matrix, Section 1.2 (Appendix F-2)

It is possible, albeit unlikely, 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.

Likelihood: Remote

Consequence Severity: Moderate

Prevention and Detection:

- Select a proper drilling-fluids program including freshwater-based muds.
- The well is specifically designed, constructed, and operated with components such as CO_2-resistant cement, corrosion-resistant alloy tubulars, and other design factors to reduce the likelihood of a CO_2 leak.

Potential Response Actions:

- Stop drilling operations and notify the appropriate agencies within 24 hours.
- If groundwater/USDW is impacted (Esposito, 2010):
  - 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.

8.3.1.3 Specific Event Description – Seismic event occurs in project area resulting in plume leakage into the USDW

Risk Assessment Matrix, Section 1.4 (Appendix F-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 CO_2 migration into another zone, including the USDW, or to the surface. Failure of the confining zone caused by a seismic event could also cause CO_2 to migrate and contaminate the USDW.

Likelihood: Remote

Consequence Severity: Moderate

Prevention and Detection:

- The CO_2 plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.

- The chosen project location is both a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.
- The well is specifically designed, constructed, and operated with components such as CO_2-resistant cement, corrosion-resistant alloy tubulars, and other design factors to reduce the likelihood of a CO_2 leak.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Use VSP or seismic surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Resume injection at a reduced rate if possible to do so with the approval of the UIC Director and the appropriate agency.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted (Esposito, 2010):
  - Pump CO_2-impacted groundwater to the surface and aerate it to remove the CO_2.
  - Apply pump-and-treat methods to remove trace elements.
  - Drill wells that intersect the accumulations in groundwater and extract the CO_2.
  - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
- If surface water is impacted:
  - Shallow lakes will quickly release dissolved CO_2 back into the atmosphere.
  - Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete uphole into the next planned injection stage.

8.3.1.4 Specific Event Description – Leakage of brine through artificial penetration into the freshwater aquifer

Risk Assessment Matrix, Section 1.5 (Appendix F-2)

It is possible, albeit unlikely, that brine could leak through an artificial penetration and into the freshwater aquifer. This leakage could occur through a known well included in the AOR, an unknown well that was not in public records, or the injector wells themselves.

Likelihood: Remote

Consequence Severity: Moderate

Prevention and Detection:

- The injector wells and offset USDW wells will be monitored as described in *Section 5*.
- The chosen project location is both a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.

- The well is specifically designed, constructed, and operated with components such as CO_2-resistant cement, corrosion-resistant alloy tubulars, and other design factors to reduce the likelihood of a brine leak.
- Plugging and abandonment operations for applicable artificial penetrations will be designed and executed with CO_2-resistant cement and monitored as described in *Section 5 – Testing and Monitoring Plan*.
- An aeromagnetic survey will be conducted to ensure no undocumented or unknown wellbores are present.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Use VSP or seismic surveys to assess the location and degree of brine movement, as described in *Section 5*.
- Resume injection at a reduced rate if possible to do so with the approval of the UIC Director and the appropriate agency.
- Continue monitoring the USDW at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted (Esposito, 2010):
  - Install additional safety precautions and measurement devices on the USDW monitoring wells.
  - Drill additional wells to monitor brine impact on the USDW.
  - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
  - Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- If surface water is impacted:
  - Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak.
- If the brine continues to migrate out of the zone or beyond the anticipated extent, recomplete uphole into the next planned injection stage.

8.3.1.5 Specific Event Description – Leakage of methane into freshwater aquifer

Risk Assessment Matrix, Section 1.6 (Appendix F-2)

It is possible, albeit unlikely, that methane could leak through an artificial penetration and into the freshwater aquifer. This leakage could occur through a known well included in the AOR, an unknown well that was not in public records, or the injector wells themselves.

Likelihood: Rare

Consequence Severity: Moderate

Prevention and Detection:

- The injector wells and offset USDW wells will be monitored as described in *Section 5 –*

Testing and Monitoring Plan.

- The chosen project location is both a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.
- The well is specifically designed, constructed, and operated with components such as CO_2-resistant cement, corrosion-resistant alloy tubulars, and other design factors to reduce the likelihood of a methane leak.
- Plugging and abandonment operations for applicable artificial penetrations will be designed and executed with CO_2-resistant cement and monitored as described in *Section 5*.
- An aeromagnetic survey will be conducted to ensure no undocumented or unknown wellbores are present.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Use VSP or seismic surveys to assess the location and degree of methane movement, as described in *Section 5*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.
- Continue monitoring the USDW at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted (Esposito, 2010):
  - Install additional safety precautions and measurement devices on the USDW monitoring wells.
  - Drill additional wells to monitor methane impact on the USDW.
  - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
  - Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- If surface water is impacted:
  - Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak.
- If the methane continues to migrate out of the zone or beyond the anticipated extent, recomplete uphole into the next planned injection stage.

8.3.2 Event Category – CO_2 Release to or at the Surface

8.3.2.1 Specific Event Description – Overpressurization (i.e., induced)

Risk Assessment Matrix, Section 2.1 (Appendix F-2)

Although unlikely, overpressurization during injection-facility operations or by operating equipment over designed pressures could cause CO_2 to be released to the surface. This situation could also occur if the maximum allowable operating parameters change due to depreciation or corrosion of equipment, and the changes are not accounted for.

Likelihood: Remote

Consequence Severity: Moderate

Prevention and Detection:

- Proper operation 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 tree will be regularly maintained and tested for integrity.
- Subsurface safety valve will be regularly tested.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions:

- Shut in flow line upon any detection of CO_2 at the surface.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- 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*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.2.2 Specific Event Description – Confining zone/reservoir failure

Risk Assessment Matrix, Section 2.2 (Appendix F-2)

Unforeseen geological complications could result in a release of CO_2 to the surface.

Likelihood: Rare

Consequence Severity: Moderate

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 all be performed according to *Section 5*.
- 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 flow line upon any detection of CO_2 at the surface.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- 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.*
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.2.3 Specific Event Description – Well blowout during drilling operations or loss of mechanical integrity of the well pressure equipment

Risk Assessment Matrix, Section 2.3 (Appendix F-2)

Although highly unlikely, a well blowout could occur during wellbore drilling if unexpected changes in reservoir pressures cause a sudden release of hydrocarbons, water, and/or pressure from the subsurface formations. The integrity of the well may be lost during injection if there is an unexpected failure in well pressure equipment.

Likelihood: Remote

Consequence Severity: Low

Prevention and Detection:

- Maintain appropriate mud weights as required based on offset well data.
- Monitor the rate of drilling-fluid returns vs. rates pumped, penetration rates, pump pressures, etc.
- Proper wellbore design, including proper cement and metallurgy of the casing and tubing, will be implemented in the construction phase.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5*.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions:

- Stop drilling operations and notify the appropriate agencies within 24 hours.
- Activate the proper blowout prevention equipment.

- Read and record stabilized shut-in pressures.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Kill the well by pumping fluid that is heavier than the current fluid down the wellbore until the well stops flowing.

8.3.2.4 Specific Event Description – Well-seal failure of CO_2 sequestration well

Risk Assessment Matrix, Sections 2.4 and 2.5 (Appendix F-2)

A well-seal failure could occur due to the failure of the cement behind the casing, an improperly seated packer, or a tubing leak. This event could also occur due to the corrosive nature of the CO_2 stream causing a break through the casing, allowing for an escape to surface.

Likelihood: Rare

Consequence Severity: Low

Prevention and Detection:

- Proper wellbore design, including proper cement and metallurgy of the casing and tubing, will be implemented in the construction phase.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5 – Testing and Monitoring Plan*.
- Routine cement bond logs and casing inspection logs will be collected and analyzed.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Pull and replace the tubing or the packer.
- Install a chemical-sealant barrier and or attempt a cement squeeze to block leaks.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.2.5 Specific Event Description – Major mechanical failure of flowlines or distribution system
Risk Assessment Matrix, Section 2.6 (Appendix F-2)

Although highly unlikely, a major mechanical failure of the CO_2 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.

Likelihood: Rare

Consequence Severity: Low

Prevention and Detection:

- Operate a closely monitored facility with best operation practices.
- Ensure controls are in place to prevent overpressure and release.
- Proper operation and preventive maintenance of all surface-facility equipment will be carried out.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- Surface wellhead tree will be regularly maintained and tested for integrity.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions:

- Shut in the flow line upon any detection of CO_2 at the surface.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- 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*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.2.6 Specific Event Description – Well-seal failure of adjacent wells (i.e., plugged and abandoned wells, monitoring wells) or orphan wells (i.e., wells not identified prior to injection)

Risk Assessment Matrix, Sections 2.7 and 2.8 (Appendix F-2)

It is possible that well seals in adjacent wells could fail due to improper materials in adjacent wellbores, such as cement inside and behind casing, casing and equipment metallurgy, and plugging materials. This event could also occur due to undiscovered orphan wells that create leak paths to the surface due to improper plugging.

Likelihood: Rare

Consequence Severity: Moderate

Prevention and Detection:

- Perform proper corrective action review and design, including appropriate cement and metallurgy of the plugging materials.
- An aeromagnetic survey will be conducted to ensure that no undocumented or unknown wellbores are present.
- Plugging and abandonment operations for applicable artificial penetrations will be designed and executed with CO_2-resistant cement and monitored as described in *Section 5 – Testing and Monitoring Plan*.
- Continuous pressure monitoring at surface and downhole will highlight potential issues.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5*.
- Operate a closely monitored facility and surrounding area.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if the CO_2 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.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Perform any well reentry and corrective action as necessary to regain isolation of injectate/formation fluids.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.2.7 Specific Event Description – Sabotage/terrorist attack and general security

Risk Assessment Matrix, Section 2.9 (Appendix F-2)

This event could theoretically happen during injection-facility operations by any person or organization wishing to cause harm to life, property, or the environment. This facility itself is not of strategic or cultural importance; therefore, this event has historically been a very low risk. However, given the increasing importance of this region for global energy infrastructure and domestic energy security, the likelihood of this being a target will increase throughout the project life cycle. Titan will have general security measures in place to monitor the injection sites and facilities. This may include, but will not be limited to, fencing, security cameras, gate guards, hired security services, aerial monitoring, etc.

Likelihood: Rare

Consequence Severity: Low

Prevention and Detection:

- Stay current with recent events locally 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 carried out.
- Surface wellhead tree will be regularly maintained and tested for integrity.
- Subsurface safety valve will be regularly tested.
- Proper surface monitoring will be distributed across the facilities.
- Communication with proper authorities regarding threats to the facility or surrounding energy infrastructure will be scheduled on a regular basis.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions:

- Shut in the flow line at the surface.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- 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 attack in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.2.8 Specific Event Description – Induced seismicity directly caused by injection, leading to leakage

Risk Assessment Matrix, Section 2.10 (Appendix F-2)

Although highly unlikely, the process of injection could induce a seismic event that causes the plume to reach faults or fractures that allow CO_2 migration to the surface.

Likelihood: Remote

Consequence Severity: Low

Prevention and Detection:

- The CO_2 plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- The chosen project location is both a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.
- The well is specifically designed, constructed, and operated with components such as CO_2-resistant cement, corrosion-resistant alloy tubulars, and other design factors to reduce the likelihood of a CO_2 leak.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- 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.
- Use VSP or seismic surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete uphole into the next planned injection stage.

8.3.2.9 Specific Event Description – Act of God

Risk Assessment Matrix, Section 2.11 (Appendix F-2)

This would likely occur through the impact of a storm or other natural event that impacts the facility or integrity of the injection system.

Likelihood: Remote

Consequence Severity: Low

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, during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- 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*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.3 Event Category – Entrained Contaminant (Non-CO_2) in Injection Stream

8.3.3.1 Specific Event Description – Change in CO_2 composition/properties from its source

Risk Assessment Matrix, Sections 5.1 and 5.2 (Appendix F-2)

This event could occur due to changes in contamination levels in the CO_2 source. The sources of contaminants may impact dissolution, geochemical reactions, and wellbore integrity. This could have an effect on the reservoir and the metallurgical properties of surface and downhole equipment.

Likelihood: Remote

Consequence Severity: Low

Prevention and Detection:

- Samples of the CO_2 stream will be collected from the injection-source pipeline. The samples will represent injection conditions and be sent to a third-party laboratory for analysis. The analysis will be used to indicate contaminant levels.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies 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*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.3.2 Specific Event Description – Microbial activity initiated by injection process or composition, allowing possible production of H_2S

Risk Assessment Matrix, Section 5.3 (Appendix F-2)

This event could occur due to changes in contamination levels in the CO_2 source that allow microbial activity for possible production of H_2S gas. These sources of contaminants may impact dissolution, geochemical reactions, and wellbore integrity.

Likelihood: Remote

Consequence Severity: Low

Prevention and Detection:

- Samples of the CO_2 stream will be collected from the injection-source pipeline. The samples will represent injection conditions and be sent to a third-party laboratory for analysis. The analysis will be used to indicate contaminant levels.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies 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*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC

Director and the appropriate agency.

8.3.4 Event Category – Accidents/Unplanned Events (Typical Insurable Events)

8.3.4.1 Specific Event Description – Surface infrastructure damage
Risk Assessment Matrix, Section 6.1 (Appendix F-2)

Unforeseen events, such as surface infrastructure damage, pipeline leak, compressor failure, boater or animal damage, or weather-related events, may occur while operating Cronos No. 1 and Rhea No. 1.

Likelihood: Remote

Consequence Severity: Low

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.
- Barricades will be installed to prevent accidental damage to any equipment, and to prevent animals from entering the facility.
- Weather will be continuously monitored, and, during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- 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*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

8.3.4.2 Specific Event Description – Severe weather event
Risk Assessment Matrix, Section 6.2 (Appendix F-2)

Unforeseen weather-related events, such as a hurricane, are likely to occur while operating Cronos No. 1 and Rhea No. 1.

Likelihood: Almost Certain

Consequence Severity: Moderate

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, during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Resume injection at a reduced rate if possible to do so, with the approval of the UIC Director and the appropriate agency.

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. Mitigate through immediate responsive action to reduce likelihood to an acceptable level.
10.0-14.9	Preventive and mitigative (P&M) measures required.
3.5-9.9	P&M measures are optional. Monitoring required.
0-3.4	No P&M measures are required. Monitor situation.

Table 8-3 – Risk Assessment Scores

Risk Assessment Scores						
Likelihood	5 Imminent	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
		Severity				

8.5 Training

Personnel will be trained in their duties and responsibilities related to these facilities during annual on-site or tabletop training exercises. All plant personnel, visitors, and contractors must attend a plant risk orientation before entering any of the facilities. A refresher course on this training is required annually for all personnel according to hurricane response training.

Titan will provide a copy of the ERRP to local first responders that includes potential response scenarios, 24-hour facility contacts, the location of the wells, and schematics/diagrams of the facilities and wells. Titan will also perform internal screening on all site personnel, including third-party contractors, to ensure safety performance and that insurance requirements are met.

8.6 Communications Plan and Emergency Notification Procedures

Prior to commencing injection operations, a site-specific emergency response plan will be developed and implemented. This plan will specify the Incident Command center, muster points, and person-in-charge for any events that might occur. Emergency response numbers are provided in Tables 8-4 through 8-6.

Table 8-4 – Emergency Services – CALL 911

Agency	Telephone Number
Port Arthur and Sabine Pass Fire Department	911 or 409-983-8740
Jefferson County Sheriff	911 or 409-835-8411
Port Arthur Police Department	911 or 409-983-8600
Jefferson County Health Unit #2 (Port Arthur)	409-983-8380
Jefferson County Emergency Preparedness Office	409-835-8757
Texas Department of Public Safety	409-924-5466
Texas Fish and Wildlife Service	512-353-0011

Table 8-5 – Government Agency Notification

Agency	Telephone Number
EPA Region 6	214-665-2102
Class VI Contact	214-665-7252
Texas Commission on Environmental Quality	512-239-6075
Texas Railroad Commission	512-463-3011
National Response Center (NRC)	800-424-8802
Texas General Land Office – Coastal Resources	512-475-0773

Table 8-6 – Internal Call List

Name	Title	Telephone Number
[redacted]		

As appropriate, Titan will communicate with the public and affected surface owners 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

Due to their location near the coast, the Cronos No. 1 and Rhea No. 1 injection wells and surrounding area are designated as a mixture of FEMA flood hazard zones. Flood hazard zone "V19" corresponds to the surface locations and a coastal area within a 1% annual chance flood event, with additional hazards due to storm-induced, velocity-wave action. Both zones are

subject to a 26% chance of flooding over a 30-year life span. Floodplain management standards apply. The well locations and FEMA flood zones are shown in *Appendix F-3*.

8.8 Emergency and Remedial Response Plan Review and Updates

This ERRP will be reviewed and updated annually. Any amendments to the plan must be approved by the UIC Director and will be incorporated into the permit:

- Within one year of an AOR evaluation
- Following any significant changes to the facility, such as the addition of injection or monitoring wells
- After a change in key personnel
- As required by the UIC Director

The following attachments are in *Appendix F*:

- Appendix F-1 Resources and Infrastructure in AOR Map
- Appendix F-2 Complete Risk Assessment Matrix
- Appendix F-3 FEMA Flood Zone Hazards Map
- Appendix F-4 Emergency Operations Plan

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 9 – FINANCIAL ASSURANCE

February 2024

SECTION 9 – FINANCIAL ASSURANCE

TABLE OF CONTENTS

9.1 Facility Information 2
9.2 Introduction 2
9.3 Financial Assurance Demonstration 2
9.3.1 Estimated Coverage Amounts 3
9.4 Corrective Action 3
9.5 Well Plugging 4
9.5.1 Injection Well Plugging 4
9.5.2 Monitoring Well Plugging 4
9.6 Post-Injection Site Care and Site Closure 5
9.6.1 Post-Injection Monitoring 5
9.6.2 Site Closure 5
9.7 Emergency and Remedial Response 6
9.8 Conclusion 6

Figures

None are included in this section.

Tables

Table 9-1 – Summary of GS Activity Project Costs 3
Table 9-2 – Summary of Well Plugging Costs Associated with Financial Security 4
Table 9-3 – Summary of PISC/Site Closure Costs Associated with Financial Security 6

9.1 Facility Information

Facility Name: Titan Carbon Sequestration Project

Facility Contact: [redacted]

Project Site Name: Titan Carbon Sequestration Project

Project Location: Jefferson County, Texas

Cronos No. 1 [redacted]

Rhea No. 1 [redacted]

9.2 Introduction

Under Texas Administrative Code (TAC) Title 16 **§5.205** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.85**], owners or operators of carbon sequestration wells are required to demonstrate financial responsibility for associated activities. Titan Carbon Sequestration, LLC (Titan) plans to construct two Class VI injection wells, Cronos No. 1 and Rhea No. 1, for the purpose of sequestering up to a total of [redacted] million metric tons per year (MMT/yr) of CO_2 at the Titan property. Consistent with these regulatory requirements, Titan has prepared this document to demonstrate financial responsibility for the injection wells that comprise the Titan Carbon Sequestration Project (Titan Project) site.

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

9.3 Financial Assurance Demonstration

Per 40 CFR **§146.85(a)(1)(vii)**, Titan requests approval from the Underground Injection Control (UIC) Program Director (UIC Director), or their designee, to use a corporate guarantee from surety bonds for the purposes of demonstrating financial responsibility for Corrective Action, Injection Well Plugging, and Post-Injection Site Care (PISC) and Site Closure, as well as Emergency and Remedial Response (ERR).

9.3.1 Estimated Coverage Amounts

The total current cost estimate for all sequestration activities necessitating financial assurance at the Titan Project site is [redacted] in 2024 dollars. This total cost estimate assumes the hiring of independent, third-party contractors for key activities, and can be separated into the following project phases:

1. Corrective Action (completed prior to initial injection)
2. Well Plugging: after injection ceases and wells are no longer in use for PISC monitoring
3. PISC: beginning when injection ceases and continuing for 50 years until site closure
4. ERRP: beginning with initial development operations and continuing for 50 years until site closure

Table 9-1 summarizes the total estimated project costs by activity. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the permit application process. Also, the values assume the hiring of third-party contractors to perform the services or to procure the goods associated with the performance of each type of activity. These values are subject to change during the project to account for inflation of costs as well as changes to the project that may affect the cost of covered activities. In accordance with 16 TAC **§5.205(c)(2)** [40 CFR **§146.85(c)**], Titan will adjust the value of its financial assurance instruments in response to any changes in cost estimates and will resubmit its demonstration of financial responsibility to the UIC Director or their designee for review and approval. Titan will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Director or their designee.

Table 9-1 – Summary of Geologic Sequestration Activity Project Costs

Activity	Cost
Corrective Action	N/A
Well Plugging	[redacted]
Post-Injection Site Care and Site Closure	
Emergency and Remedial Response	
TOTAL	

9.4 Corrective Action

The Corrective Action Plan is discussed in detail in *Section 3 – Area of Review and Corrective Action Plan*. The plan specifically outlines both a plugging plan, for the wells found within the critical pressure front and CO_2 pore-occupancy plume, and the recompletion schedule whereby the wellbore modifications will have been completed.

For the planned activities at the Titan Project site, workovers on all wells requiring plugging modifications will have been completed prior to injection. As such, there is no financial risk for these recompleted wells.

The area of review (AOR) will be reevaluated every 5 years to determine if any additional penetrations will be impacted.

9.5 Well Plugging

9.5.1 Injection Well Plugging

Plugging and abandonment (P&A) of the injection wells at the Titan Project site will meet the requirements of 16 TAC **§5.203(k)** [40 CFR **§146.92**]. The P&A of the injection wells will be designed so that no movement of fluids will occur from the injection interval. A more detailed P&A plan is discussed in *Section 6 – Plugging Plan*. The funds for plugging include costs for logs/wireline to be run in the wellbore before cementing occurs. Acid-resistant cement will be used in the initial plug for the well, to ensure that the cement does not react with the injected fluid—resulting in a potentially higher cement expense than traditional cement. All expenses relating to personnel and equipment have been accounted for in Table 9-2. Pressure test costs are also included to account for proving the integrity of the well.

9.5.2 Monitoring Well Plugging

The P&A of the monitoring wells associated with the Titan Project site will also meet the requirements of 16 TAC **§5.203(k)** [40 CFR **§146.92**]. The P&A of these shallow monitoring wells will be designed so that no movement of fluids will occur from the injection interval, nor will fresh, treatable water found within the USDW be threatened. (As noted, a more detailed P&A plan is discussed in *Section 6 – Plugging Plan*.) Because these wells will be completed above the uppermost confining geologic interval, conventional plugging procedures will be utilized. These funds include costs for logs and wireline to be run in the wellbore before cementing occurs. All expenses relating to personnel and equipment have been accounted for in Table 9-2. Pressure test costs are also included to account for proving the integrity of the well.

Table 9-2 – Summary of Well Plugging Costs Associated with Financial Security

Activity	Cost Per Well	Total
Injection Well Plugging (two wells)	[redacted]	
Workover Rig		
Kill/Buffer Fluid		
Personnel		
Wireline		
Downhole Tools		

Activity	Cost Per Well	Total
Other Services	[redacted]	
Cement and Pumping Services		
Equipment Rentals		
Above-Zone Monitoring Well Plugging (two wells)		
Workover Rig		
Kill/Buffer Fluid		
Personnel		
Wireline		
Downhole Tools		
Other Services		
Cement and Pumping Services		
Equipment Rentals		
USDW Monitoring Well Plugging (two wells)		
Workover Rig		
Cement Services		
Auxiliary Services		
TOTAL		

9.6 Post-Injection Site Care and Site Closure

The PISC and Site Closure Plan will be designed to meet the requirements of 16 TAC **§5.206(k)** [40 CFR **§146.93**]. The costs associated with the plan are highlighted in Table 9-3, while the plan itself is discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*.

9.6.1 Post-Injection Monitoring

As discussed in *Section 5 – Testing and Monitoring Plan*, vertical seismic profile (VSP) monitoring will be conducted after the end of injection to ensure the integrity of the well and to track the migration of the plume.

9.6.2 Site Closure

Site closure will occur when the UIC Director has released the owner from all PISC duties. The costs estimated in Table 9-3 reflect the amount expected to decommission and close the site.

Table 9-3 – Summary of PISC/Site Closure Costs Associated with Financial Security

Activity	Cost	Total
Post-Injection Monitoring	[redacted]	
Indirect Plume Monitoring (VSP)		
Other Monitoring (e.g., fluid sampling and analysis, pressure/temperature monitoring)		
Site Closure		
TOTAL		

Indirect plume monitoring (VSP or seismic survey) will be run every 5 years throughout the PISC period, or as agreed to with the UIC director—based on actual plume measurements or until the plume has been determined to have stabilized. The VSP costs are estimated at [redacted] per well and occurring every 5 years during the PISC period. Other monitoring costs such as pressure/temperature monitoring, fluid sampling, etc., are estimated to be [redacted] per year for 50 years.

9.7 Emergency and Remedial Response

The Emergency and Remedial Response Plan (ERRP) is discussed in *Section 8 – Emergency and Remedial Response Plan* and designed to be in compliance with 16 TAC **§5.203(l)** [40 CFR **§146.94**].

The resultant cost for the ERRP is [redacted] in 2024 dollars. This cost assumes coverage for the Titan Project site, including the following risks: water quality impact, CO_2 migration, entrained contaminant (non-CO_2) in the injection stream, and accidents/unplanned events (typical insurable events). Details regarding these cost estimates are explained in *Section 8*.

9.8 Conclusion

State and federal regulations require that the owner and operator of the two proposed Class VI wells demonstrate financial responsibility for the Titan Project site. The information contained in this section displays the instruments that Titan will use to prove their financial assurance to properly execute operations and uphold regulations throughout the life of the project. The owner and operator will secure the appropriate financial assurance instrument(s) prior to beginning construction of the project. These documents, in addition to the information contained in this section, fulfill Titan's responsibilities to ensure financial assurance.

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 10 – ENVIRONMENTAL JUSTICE IMPACT ANALYSIS

February 2024

LONQUIST
SEQUESTRATION LLC

SECTION 10 – ENVIRONMENTAL IMPACT ANALYSES

TABLE OF CONTENTS

10.1 Executive Summary 2
10.2 Environmental Justice 4
10.2.1 EJ Indices 6
10.2.2 EJ Themes 8
10.3 Sensitive Receptors 13
10.4 Social and Economic Benefits 13
10.5 Overview of Environmental Impacts of the Project 14
10.6 Potential Environmental Effects 14
10.6.1 Air Quality 14
10.6.2 Water Quality 15
10.6.3 Sensitive Soils and Vegetation 15
10.6.4 Sensitive Wildlife and/or Habitat 15
10.6.5 Archaeological and Historic Resources 15
10.7 Community Engagement 15
10.8 Environmental Justice Summary 16

Figures

Figure 10-1 – Titan Project Overview Map 3
Figure 10-2 – Census Block Group 48245011600 with 3-mile radius from the Titan injection wells 5

Tables

Table 10-1 – Socioeconomic Indicators for Populations in CBG 4824501160 6
Table 10-2 – EJ Index Measurements for CBG 48245011600 6
Table 10-3 – Supplement EJ Index Measurements for CBG 48245011600 7
Table 10-4 – EJ Guidance Theme Summary 9

10.1 Executive Summary

Large scale capture of anthropogenic CO_2, as previously discussed in this permit application, 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. For example, the International Energy Agency has highlighted a potential need for carbon dioxide storage to increase from around 40 million metric tons per year (MMT/yr) today to more than 5,000 MMT/yr by mid-century[1]. Today, the United States is the global leader in CO_2 capture, utilization, and sequestration (CCUS), holding more than 60% of current CCUS capacity and half of all global CCUS capacity under development.[2] For the global community to have an impact on global greenhouse gas levels, carbon—generally in the form of CO_2—once captured from a source, must be safely disposed in some manner. One of the more common methods of dealing with captured CO_2 is injecting it into porous formations below the Earth's surface.

The U.S. Gulf Coast has long been viewed as suitable for long-term sequestration of CO_2.[3] Titan Carbon Sequestration, LLC (Titan) is proposing to develop a premier carbon capture and sequestration (CCS) facility in Jefferson County, Texas located within close proximity to several liquefied natural gas (LNG) terminals. These LNG terminals operating and under construction in southwest Louisiana and southeast Texas have enabled the United States to become a global leader in natural gas exports to foreign customers. Increasingly, these customers are seeking natural gas sourced through lower-CO_2 processes to meet their energy needs—and are looking to U.S. suppliers for this cleaner product.

Through disciplined, innovative processes and engineering designs, Titan will facilitate the permanent storage of captured CO_2 from the nearby Port Arthur LNG Liquefaction Project (PALNG), as well as potentially other industrial facilities located in the Gulf Coast region. Titan's commitment to facilitate lower carbon energy and industrial production will help these crucial manufacturers evolve as leaders in the global energy transition.

The location for this proposed facility is ideally suited to "offtake" captured CO_2 from PALNG as well as other industrial facilities in the vicinity. This site was selected for several reasons such as favorable geology, controlled pore-space storage rights, numerous nearby industrial facilities with sequestration needs, and existing pipeline rights-of-way by which to transport the captured carbon dioxide stream for injection. Proposing to drill and complete two CO_2 sequestration wells in Jefferson County, Titan is applying for a Class VI permit to construct and operate Cronos No. 1 and Rhea No. 1. The wells will be located on surface acreage, with CO_2 injected into and sequestered in subsurface pore space controlled by Titan through underground storage easements.

[1] "Carbon Capture, Utilisation [*sic*] and Storage." IEA. https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage.
[2] Ibid.
[3] 2010 Carbon Atlas of the United States and Canada. National Energy Technology Laboratory, Department of Energy.

The Titan Carbon Sequestration Project (Titan Project), shown in Figure 10-1, will capture and compress low-pressure CO_2 at the PALNG site and then transport it by pipeline to the new Titan compression/dehydration facility to be constructed for this project on land owned by Sempra Infrastructure, or its affiliate. From that facility, the compressed CO_2 will then be transported in supercritical phase via a proposed high-pressure pipeline to the injection wells—where it will be injected into pore space suitable for geological sequestration of CO_2. The project will be sized to permanently store up to [redacted]

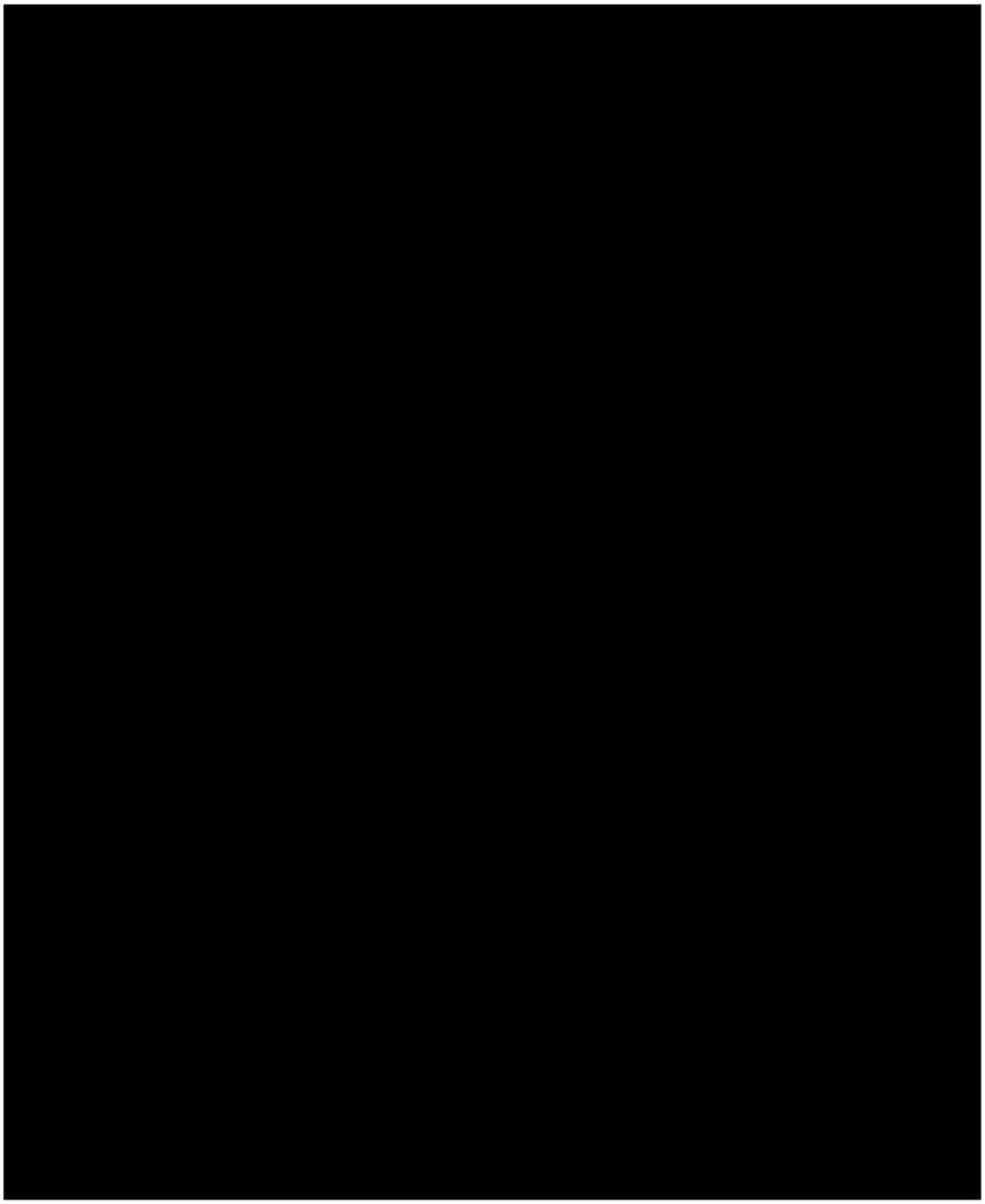


Figure 10-1 – Titan Project Overview Map

10.2 Environmental Justice

Environmental justice (EJ) refers to the "fair treatment and meaningful involvement of all people regardless of race, color, national origin, income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies" (EPA, 2020(a)). "Fair treatment" means that no group of people should bear a disproportionate share of negative environmental consequences because of industrial, governmental, and commercial operations or policies. The EJ communities include populations of color, low-income populations, Native American Tribes, and/or indigenous communities.

To define an analysis area and identify potentially impacted EJ populations, guidance issued by the Council on Environmental Quality (CEQ) in 1997 advises using an "appropriate unit of geographic analysis" that does not "artificially dilute or inflate" the population. The selected area may be a neighborhood census tract or block group, a governing body's jurisdiction, or other similar geographic unit. The census block group (CBG) is the smallest geographic unit for which U.S. Census Bureau demographic data are available and represents the geographic unit of analysis used in this desktop review.

The EJ review followed federal guidance and recommended methodologies outlined by the EPA's Geologic Sequestration of Carbon Dioxide – UIC Quick Reference Guide of June 2011 (Reference Guide), as supplemented by memo dated August 17, 2023, which referenced the use of EJScreen (EJ Guidance Memo). The EJScreen is a tool developed by the EPA to identify if a proposed Class VI project affects communities with potential EJ concerns. Using EJScreen, Titan determined that a 3-mi radius around the two Titan Project injection wells falls within CBG No. 48245011600 (Figure 10-2).

Figure 10-22 – Census Block Group 48245011600 with 3-mile radius from the Titan injection wells[4]

For minority populations, the 50% and the "meaningfully greater" analysis methods were used. If the minority population of the CBG in the area exceeds 50%, or if the minority population in the CBG identified is 10% percent higher than the minority population percent in the county, then an EJ community may be present. To identify low-income populations, the low-income threshold criteria method was used. If the percent of low-income population in the identified CBG is 20% greater than that of the county (not using a "meaningfully greater" factor), then an EJ community may be present.

Data for minority and low-income populations was determined from a review of EJScreen. The demographic indicators for race, ethnicity, and income for the CBG 48245011600, along with other socioeconomic indicators, are shown in Table 10-1. No potential EJ populations were identified for any CBGs as none of the census tracts or CBGs exceed the threshold for minority or low-income populations.

[4] https://ejscreen.epa.gov/mapper/

Table 10-1 – Socioeconomic Indicators for Populations in CBG 4824501160

Area	Minority Population	Low-Income Population	Unemployment Rate	Limited English-Speaking Households	Less Than High School Education
United States of America	39%	31%	6%	5%	12%
State of Texas	58%	34%	5%	8%	16%
Jefferson County, Texas	38%	61%	6%	5%	15%
Block group 4824501160	17%	21%	8%	1%	17%

10.2.1 EJ Indices

Consistent with the Reference Guide and EPA Guidance Memo, Titan used the EPA's EJScreen tool to evaluate the Titan Project area for potential EJ communities. The EJScreen tool employs a framework of 13 Environmental Justice (EJ) indices, yielding a comprehensive overview of the relative environmental burdens faced within a chosen area in comparison to broader geographic scales such as state, EPA region, or nation. These indices are computed by integrating demographic variables, encompassing minority and low-income populations, with corresponding environmental metrics. Unlike a cumulative scoring approach, each EJ index is derived through the multiplication of the percentile rank of an environmental indicator with either the standard demographic index or a supplementary demographic index. The standard demographic index represents the mean of the percentile ranks of minority and low-income populations within the block group. Consequently, block groups with elevated concentrations of minority or low-income residents, coupled with higher environmental indicator values, yield higher calculated EJ indices. In the EPA's EJScreen "How to Interpret EJScreen Data"[5], an initial screening point for EJ indices has been established at the 80th percentile relative to state and national averages.

The EJ index results from EJScreen are provided in Table 10-2.

Table 10-2 – EJ Index Measurements for CBG 48245011600

EJ Index	Percentile in State	Percentile in U.S.
Particulate Matter 2.5	9	42
Ozone	30	53
Diesel Particulate Matter	11	18

[5] https://www.epa.gov/ejscreen/how-interpret-ejscreen-data

EJ Index	Percentile in State	Percentile in U.S.
Air Toxics Cancer Risk	50	61
Air Toxics Respiratory Hazards Index	36	43
Toxic Releases to Air	46	64
Traffic Proximity	8	16
Lead Paint	44	37
Superfund Proximity	26	27
Risk Management Plan (RMP) Facility Proximity	14	32
Hazardous Waste Proximity	32	38
Underground Storage Tanks	16	30
Wastewater Discharge	32	43

None of the thirteen measures reached greater than the EPA guidance for the 80th percentile versus the state and national levels.

Additionally, the EPA computes a supplemental demographic index within the block group context, which combines "data on percent low-income, percent linguistically isolated, percent less than high school education, percent unemployed, and low life expectancy with a single environmental factor", as described on the EJScreen Community Report provided in Appendix I-1. The supplemental EJ index is determined by the multiplication of the environmental indicator with the calculated supplemental demographic index, followed by the identification of its percentile rank. This index serves to offer further insight into the vulnerability of communities at a localized level.

The supplemental EJ index results are presented in Table 10-3.

Table 10-3 – Supplement EJ Index Measurements for CBG 48245011600

EJ Index	Percentile in State	Percentile in U.S.
Particulate Matter 2.5	15	56
Ozone	53	73
Diesel Particulate Matter	18	21
Air Toxics Cancer Risk	65	72
Air Toxics Respiratory Hazards Index	53	53
Toxic Releases to Air	74	83
Traffic Proximity	12	18
Lead Paint	58	47

EJ Index	Percentile in State	Percentile in U.S.
Superfund Proximity	46	37
Risk Management Plan (RMP) Facility Proximity	24	44
Hazardous Waste Proximity	54	52
Underground Storage Tanks	20	33
Wastewater Discharge	55	60

One of the thirteen indices, "Toxic Releases to Air" is identified as being over the 80th percentile nationally. However, in combination with the index percentiles relative to the state plus the lower percentages identified in the socioeconomic indicators, this area is less likely to be identified as an EJCommunity.

10.2.2 EJ Themes

Table 10-3 highlights each of the five themes outlined in the EPA's August 17, 2023 UIC Class VI Permitting guidance memo and how Titan plans to address each theme.

Table 10-4 – EJ Guidance Theme Summary

Theme	Action	Titan Project Plan
Identify Communities with potential EJ concerns	UIC programs should encourage owner/operators to conduct EJScreen assessments during site selection and before submitting a Class VI permit application. UIC programs should conduct and/or verify EJScreen assessments for every Class VI permit application received or sooner if possible. The Area of Review will be used as the boundary to be investigated unless a more relevant EJ boundary is identified. UIC programs should: • Work with appropriate EJ organizations to create structured communication between EJ experts and UIC permitters. • Direct UIC permitters to work with EJ experts to conduct EJScreen for all Class VI projects and develop a community engagement plan for affected communities.	Titan has conducted an EJScreen assessment as part of the preparation of this Class VI application (Section 10.2 and Appendix I-1). The area of review included the complete Census Block Group surrounding the project area of review (maximum plume extent). Titan has developed a community engagement plan as provided in Appendix I-2.
Enhance public involvement	UIC programs should encourage owner/operators to conduct community outreach early for all Class VI permit applications, regardless of if there are apparent EJ concerns. Activities to consider are: • Conduct engagement prior to submittal of the application and throughout the life of the project. • Provide UIC programs a summary of outreach activities in the application. • Conduct outreach while developing plans such as the Emergency and Remedial Response Plans, to better understand community concerns and needs.	Although no EJ communities were identified, Titan has developed a community engagement plan and has begun engaging the local community leaders as discussed in Section 10.7 and Appendix I-2.

Conduct appropriately scoped EJ assessments	For projects that have been identified as having EJ concerns, UIC programs should conduct additional assessments evaluating project impacts on overburdened communities. Assessments will vary according to the specific circumstances of the permit application and may include • Further consideration of how Class VI projects may affect subpopulations identified in the EJScreen analysis. • Further input from stakeholders, including the affected community. • Evaluation of existing environmental data, including water monitoring, identification of wellhead protection areas, ongoing and climate or, as appropriate, other data. • Assessment of compliance record of permit applicant (e.g., may result in additional requirements related to increased monitoring, reporting, etc.). • Evaluation of potential health and environmental effects of the permitting action on the affected community. • Evaluation of the potential health and non-health adverse effects (e.g., noise, odor, and traffic) of the permitting action. • Evaluation of the potential impact of the permit action together with impacts from other regulated and non-regulated sources of pollution and non-pollution stressors in the affected community. • Evaluation of mitigation measures to minimize potential adverse effects of the permitting action on the affected community.	While no EJ Communities have been identified for the Titan Project, Titan has considered the potential adverse effects on the community and is working to minimize the impact of these potential effects as discussed in Sections 10.5 and 10.6

Enhance the transparency throughout the permitting process	UIC programs should post all Class VI applications on an appropriate public website. UIC programs should release EJ information developed from the review of Class VI application, including EJ screening results and any follow-up EJ and community needs assessments on an appropriate public website. UIC programs should make available reporting data (e.g., injection pressures, monitoring data, mechanical integrity test results) on an appropriate public website, in a manner that is user-friendly and understandable to the general public. UIC programs should provide public notification of all Class VI permit violations on an appropriate public website.	Titan supports transparency of the Titan Project to the public with regards to EJ and communities needs and will assist in that transparency throughout the life of the project.
Minimize adverse effects to USDWs and the communities they may serve	Where practicable, UIC programs should encourage owners/operators to consider additional mitigation measures to address concerns raised by the local community. Such actions could include: • Installation of carbon dioxide monitoring and release notification networks. • Installation of enhanced pollution controls. • Adoption of other measures to offset impacts by improving other environmental amenities for the communities near GS projects, and provision of resources for clean-up of previously degraded public areas. • Ensure appropriate community representatives are a part of the development of the Emergency and Remedial Response and Testing and Monitoring plans. • Planning activities could include: o Training for local responders while training facility staff to respond to emergencies at the facility.	As discussed in Section 5 – Testing and Monitoring, Titan plans to install extensive monitoring and notification systems throughout the project site. They have developed an Emergency Response and Remediation Plan, as discussed in Section 8, to address any potential emergency events and ensure local responders and company personnel are sufficiently trained to respond to such events.

	o Working with community to identify the chain of command for notifying the public of an emergency and incorporate these details into their Emergency and Remedial Response Plans. o Developing plans for notification of well related issues and emergencies, including a consideration of local community language needs and the needs of persons with disabilities. o Working with the community to develop a Testing and Monitoring plan that addresses the risks of the project.	

10.3 Sensitive Receptors

The EPA identifies sensitive receptors as areas where the occupants are more susceptible to the adverse effects of exposure to toxic chemicals, pesticides, and other pollutants.[6] These areas include, but are not limited to, hospitals, schools, daycare facilities, elderly housing, and convalescent facilities. Extra care must be taken when dealing with contaminants and pollutants near areas recognized as sensitive receptors. No sensitive receptors were identified within the 3-mi radius of the injection wells.

10.4 Social and Economic Benefits

The purpose of the Titan Project is to provide beneficial environmental impacts by sequestering CO_2 emissions that would otherwise be released to the environment. This environmental benefit, along with the social and economic benefits, outweighs potential adverse impacts associated with construction and operation of the project.

The Titan Project will provide important economic and social benefits to Jefferson County and the State of Texas. Construction of the project will create jobs, additional earnings for households, and rising business activity throughout the Texas economy—as measured by sales and personal earnings. The increase in employment that will be realized because of the Titan Project is estimated to be an average of over 300 workers needed during construction. Additionally, several full-time workers will be employed during ongoing operations.

While the economic benefits and spillovers from the construction of the Titan Project are substantial but temporary, those benefits and spillovers from the ongoing operation of the project facilities will be both substantial and permanent. Economic benefits will accrue to the State of Texas and the Jefferson County region for the duration of facility operations. Titan will be a good corporate citizen involved in employee/community partnerships in Jefferson County and the surrounding communities. Titan also plans to, when possible, buy goods and services locally—and hire locally for the project's construction and implementation. Employment opportunities will be provided to all aspects of the Texas workforce. As a result, the proposed project will result in a net social benefit to the community in the vicinity of the project.

The Titan Project intends to advance CCS infrastructure, recognized as a necessary means to reduce GHG emissions, to support decarbonization efforts of PALNG and nearby industrial facilities. Titan believes that the communal benefits of the project, coupled with the economic benefits that the project will bring to the area, outweigh the adverse environmental impacts from development and operation of the well pads, access roads and compression facility.

[6] U.S. Environmental Protection Agency (2022). What are Sensitive Receptors? Retrieved December 2022, from https://www3.epa.gov/region1/eco/uep/sensitivereceptors.html#:~:text=Sensitive%20receptors%20include%2C%20but%20are,%2C%20pesticides%2C%20and%20other%20pollutants

10.5 Overview of Environmental Impacts of the Project

The Titan Project has opted to utilize electric-powered compressors and dehydration facilities to minimize overall project emissions. The electric-powered equipment to be utilized at the project site will not generate emissions of carbon monoxide, volatile organic compounds, formaldehyde, or nitrogen oxides.

The Titan Project also will not treat or dispose of any hazardous waste or solid waste. Project operations will generate a small quantity of sanitary sewage, but that stream will be treated according to state water-quality regulations on tying into existing utilities. The discharge will have no impact on water quality.

Due to the size of the Titan Project, transportation to and from the project site is not anticipated to be a concern. Construction materials and process equipment will be delivered to the injection site and the compression/dehydration facility via trucks on existing public and rural roadways (Figure 10-1) and site access roads. If local traffic patterns may be potentially impacted by project activities, Titan will coordinate with local officials to mitigate any such disturbance.

10.6 Potential Environmental Effects

Titan selected the site based on the favorable geology for permanent sequestration and designed a monitoring and wellbore construction plan in accordance with regulatory standards to protect Underground Sources of Drinking Water (USDWs). The injection wells are located on private property covered by underground storage easements, and away from existing wellbores to avoid any potential impact to the containment of the injected CO_2. Surface development will not impact state and federal wildlife management areas near the project site; Titan has sited above-ground facilities, underground piping, and its Class VI wells to avoid these areas (Figure 10-1). Titan has also strategically created a robust monitoring program that will ensure the protection of USDWs, the surface environment, and local residents—balancing the program to protect people and the environment while minimizing surface disturbance to the nearby wetland environment.

10.6.1 Air Quality

The potential air emissions from Titan Project construction and operation are minimal and will not cause any adverse impacts to air quality.

Air quality impacts associated with the project construction can be generally classified as temporary impacts from the operation of equipment during construction activities and impacts from dust generation. Impacts associated with the operating equipment during construction of the well pads and access roads plus drilling activities for the Class VI wells may result in minor, temporary increases in emissions. Equipment and movement of material for land clearing, grading, excavation, drilling, and concrete work, along with vehicular traffic on paved and

unpaved roads, could cause dust. The amount of dust will be based on the area of construction, silt and moisture contents of the soil, wind speed, frequency of precipitation, amount of vehicle traffic, vehicle types, and paved or unpaved roads. While "fugitive dust" may occur during all phases of construction, dust will be greater during the drier winter months and in areas of fine-textured soils. During these periods, dust suppression techniques (e.g., watering) will be used to minimize the impacts of fugitive dust.

10.6.2 Water Quality

All stormwater runoff at the well pads will be managed according to Titan's Stormwater Pollution Prevention Plan (SWPPP) currently under development. Titan will install all necessary erosion and sedimentation control structures as required by the State of Texas to minimize potential impacts from stormwater runoff.

10.6.3 Sensitive Soils and Vegetation

Construction of the Titan Project facilities will not generate waste that could leach into soils and affect shallow groundwater. Project operations will not cause the destruction of important vegetation or have any impact on forested lands.

The areas where the project facilities are to be located consist of either existing industrial facilities or undeveloped marsh land. The total land disturbance to accommodate these facility components will be minimized to the extent practicable. Mitigation for unavoidable impacts from construction of the well pads and access roads will be coordinated and approved by the U.S. Army Corps of Engineers, Galveston District office.

10.6.4 Sensitive Wildlife and/or Habitat

Titan will consult with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service to determine the potential for occurrence of federally listed species and their critical habitats that are known or expected to be in the vicinity of the project. Titan will conduct habitat and wetland surveys of the entire proposed project area, to determine the presence or absence of endangered or threatened species or critical habitats in the project area.

10.6.5 Archaeological and Historic Resources

Titan will perform a Phase I Archaeological Survey of the 3-mile radius around the injection wells to identify archaeological and historical resources.

10.7 Community Engagement

Titan's parent company, Sempra Infrastructure Partners (Sempra) has been actively engaged in Jefferson County and the communities of Port Arthur and Sabine Pass since 2004 through the development of its PALNG facility. Community involvement, stakeholder engagement, and

feedback are critical components of both PALNG and the Titan project. Sempra also recognizes that effective communication with its stakeholders may address and reduce community concerns, help build trust and transparency, and contribute to the project's overall success. As part of the Titan Stakeholder Engagement Plan, the project team is committed to the following:

- Conducting a community assessment to help identify and validate concerns and opportunities related to the developmental and operational projects in the area. This assessment will also help to identify not only the project's environmental justice community status, but also opportunities for meaningful social investment.
- Implementing stakeholder engagement activities in which the team actively solicits feedback from the community and property owners about the Titan Project
- Providing regular Titan Project updates to local stakeholders during the calendar year
- Maintaining communication channels for stakeholders, to include a dedicated toll-free phone line, email address, website, and social media channels
- Providing a dedicated outreach team to address community questions and concerns
- Coordinating contributions of the company and employees' time, talent, and funding to support community investment initiatives and events in Jefferson County.

Sempra has established good relationships with stakeholders in the community and intends to continue to build on them. Community engagement specific to CCS is underway through multiple stakeholder-feedback roundtables. Sempra plans to continue to execute its full Stakeholder Engagement Plan (included in *Appendix I – Environmental Justice*) as it progresses in the development of the Titan Project.

10.8 Environmental Justice Summary

Sempra, and its Titan subsidiary, are dedicated to being good partners with the local community of Port Arthur and Sabine Pass. The Titan project is in an area where no identified Environmental Justice communities will be impacted by this project. Titan will take several key actions to minimize any potential impacts to the environment and to the community.

Additionally, the following documents can be found in *Appendix I – Environmental Justice.*

- Appendix I-1 EJ Screen for Census Block Group 48245011600
- Appendix I-2 Titan Stakeholder Engagement Plan

TITAN
CARBON SEQUESTRATION

Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

APPENDICES (PBI)

February 2024

LONQUIST
SEQUESTRATION LLC

APPENDIX A: PROJECT MAPS

Appendix A-1	Project Overview Map
Appendix A-2	Aerial AOR Map
Appendix A-3	Pore Space Ownership Map
Appendix A-4	Pore Space Owner List
Appendix A-5	Topographic Map

APPENDICES A-1 TO A-5 ARE

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX B: SITE CHARACTERIZATION

Appendix B-1	SW-NE Structural Cross-Section
Appendix B-2	NW-SE Structural Cross-Section
Appendix B-3	SW-NE Stratigraphic Cross-Section
Appendix B-4	NW-SE Stratigraphic Cross-Section
Appendix B-5	Cross-Section Reference Map
Appendix B-6	Top Upper Confining Structure
Appendix B-7	Top Injection Zone Structure
Appendix B-8	Top Lower Confining Structure
Appendix B-9	Upper Confining Isochore
Appendix B-10	Injection Zone Isochore
Appendix B-11	Lower Confining Isochore
Appendix B-12	Injection Zone Net Sand
Appendix B-13	Fault Slip Potential Model

APPENDICES B-1 TO B-13 ARE

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX C: AOR AND CORRECTIVE ACTION PLAN

Appendix C-1	Oil and Gas Wells AOR Map
Appendix C-2	Oil and Gas Wells AOR List
Appendix C-3	Freshwater Wells AOR Map
Appendix C-4	Freshwater Wells AOR List
Appendix C-5	Site Review AOR Map

APPENDICES C-1 TO C-5 ARE

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX D: CONSTRUCTION

Appendix D-1	Injection Wellbore Schematics
Appendix D-2	Injection Well Drilling and Completion Prognoses
Appendix D-3	Monitoring Wellbore Schematics
Appendix D-4	Monitoring Well Drilling and Completion Prognoses
Appendix D-5	USDW Monitoring Wellbore Schematics
Appendix D-6	Construction Supporting Programs

APPENDICES D-1 TO A-6 ARE

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX E: METALLURGY

APPENDIX E IS

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX F: TESTING AND MONITORING

Appendix F-1	USDW/AZM Monitoring Well Plan Map
Appendix F-2	TCS WM No. 1 (USDW) Schematic
Appendix F-3	TCS WM No. 2 (USDW) Schematic
Appendix F-4	Atlas No. 1 (AZM) Schematic
Appendix F-5	Andes No. 1 (AZM) Schematic

APPENDICES F-1 TO F-5 ARE

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX G: EMERGENCY OPERATIONS

Appendix G-1	Resources and Infrastructure in AOR Map
Appendix G-2	Complete Risk Assessment Matrix
Appendix G-3	FEMA Flood Zone Hazards Map

APPENDICES G-1 TO G-3 ARE

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX H: PLUGGING AND ABANDONMENT

Appendix H-1	Cronos No. 1 and Rhea No. 1 Zonal Isolation Schematics
Appendix H-2	Cronos No. 1 and Rhea No. 1 Post Injection Schematics
Appendix H-3	Cronos No. 1 Detailed Plugging Procedure
Appendix H-4	Rhea No. 1 Detailed Plugging Procedure
Appendix H-5	Cronos No. 1 and Rhea No. 1 Final P&A Schematics
Appendix H-6	Atlas No. 1 – Final P&A Procedure
Appendix H-7	Atlas No. 1 – Final P&A Schematic
Appendix H-8	Andes No. 1 – Final P&A Procedure
Appendix H-9	Andes No. 1 – Final P&A Schematic
Appendix H-10	TCS WM No. 1 and No. 2 – Final P&A Procedures
Appendix H-11	TCS WM No. 1 and No. 2 – Final P&A Schematics

APPENDICES H-1 TO H-11 ARE

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX I: ENVIRONMENTAL JUSTICE

Appendix I-1 EJ Screen Report – One-mile Buffer

Appendix I-2 Stakeholder Engagement Plan

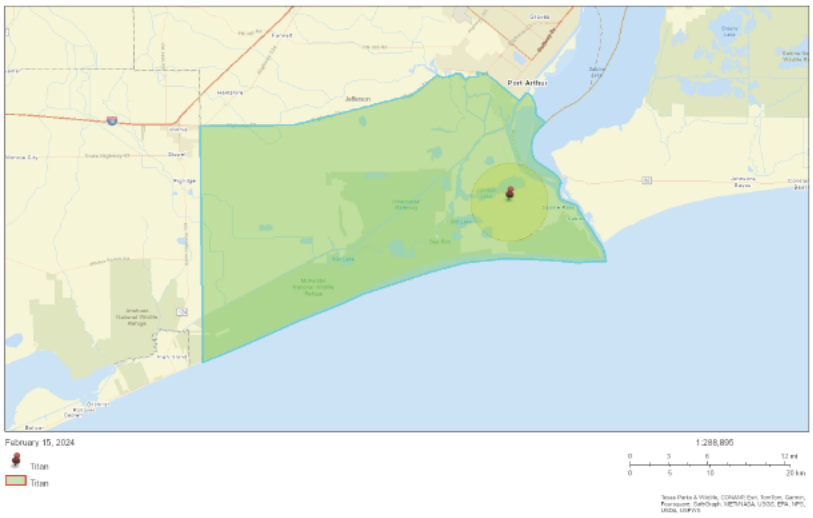
EJScreen Community Report

This report provides environmental and socioeconomic information for user-defined areas, and combines that data into environmental justice and supplemental indexes.

Jefferson County, TX

Blockgroup: 482450116001
Population: 1,437
Area in square miles:413.66

A3 Landscape



LANGUAGES SPOKEN AT HOME

LANGUAGE	PERCENT
English	90%
Spanish	10%
Total Non-English	10%

COMMUNITY INFORMATION

- Low income: 21 percent
- People of color: 17 percent
- Less than high school education: 17 percent
- Limited English households: 1 percent
- Unemployment: 7 percent
- Persons with disabilities: 20 percent
- Male: 52 percent
- Female: 48 percent
- 79 years — Average life expectancy
- $39,407 — Per capita income
- Number of households: 545
- Owner occupied: 93 percent

BREAKDOWN BY RACE

- White: 83%
- Black: 1%
- American Indian: 0%
- Asian: 0%
- Hawaiian/Pacific Islander: 0%
- Other race: 1%
- Two or more races: 2%
- Hispanic: 12%

BREAKDOWN BY AGE

From Ages 1 to 4	8%
From Ages 1 to 18	21%
From Ages 18 and up	79%
From Ages 65 and up	18%

LIMITED ENGLISH SPEAKING BREAKDOWN

Speak Spanish	100%
Speak Other Indo-European Languages	0%
Speak Asian-Pacific Island Languages	0%
Speak Other Languages	0%

Notes Numbers may not sum to totals due to rounding Hispanic population can be of any race
Source U S Census Bureau American Community Survey (ACS) 2017 2021 Life expectancy data comes from the Centers for Disease Control

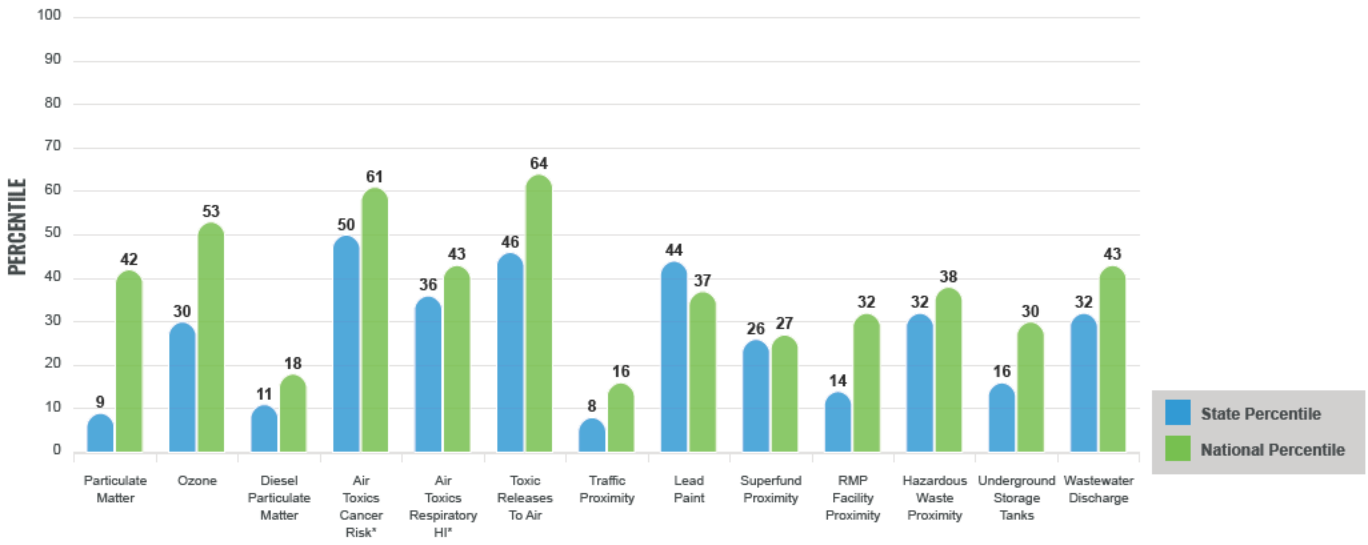
Environmental Justice & Supplemental Indexes

The environmental justice and supplemental indexes are a combination of environmental and socioeconomic information. There are thirteen EJ indexes and supplemental indexes in EJScreen reflecting the 13 environmental indicators. The indexes for a selected area are compared to those for all other locations in the state or nation. For more information and calculation details on the EJ and supplemental indexes, please visit the EJScreen website.

EJ INDEXES

The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.

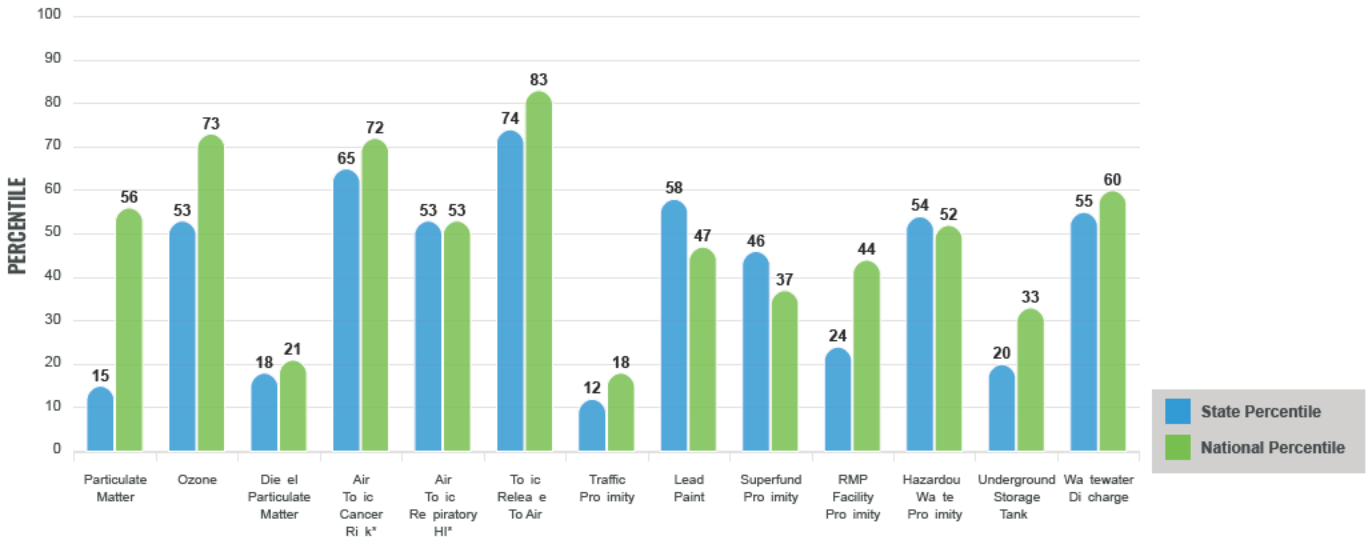
EJ INDEXES FOR THE SELECTED LOCATION



SUPPLEMENTAL INDEXES

The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on percent low-income, percent linguistically isolated, percent less than high school education, percent unemployed, and low life expectancy with a single environmental indicator.

SUPPLEMENTAL INDEXES FOR THE SELECTED LOCATION



These percentiles provide perspective on how the selected block group or buffer area compares to the entire state or nation

Report for Blockgroup 482450116001

EJScreen Environmental and Socioeconomic Indicators Data

SELECTED VARIABLES	VALUE	STATE AVERAGE	PERCENTILE IN STATE	USA AVERAGE	PERCENTILE IN USA
POLLUTION AND SOURCES					
Particulate Matter (µg/m^3)	8.18	9.11	14	8.08	49
Ozone (ppb)	64	64.6	46	61.6	70
Diesel Particulate Matter (µg/m^3)	0.0996	0.218	16	0.261	16
Air Toxics Cancer Risk* (lifetime risk per million)	30	28	44	25	52
Air Toxics Respiratory HI*	0.3	0.3	29	0.31	31
Toxic Releases to Air	21,000	12,000	84	4,600	96
Traffic Proximity (daily traffic count/distance to road)	6.2	150	9	210	13
Lead Paint (% Pre-1960 Housing)	0.14	0.17	64	0.3	41
Superfund Proximity (site count/km distance)	0.03	0.085	40	0.13	28
RMP Facility Proximity (facility count/km distance)	0.11	0.63	18	0.43	34
Hazardous Waste Proximity (facility count/km distance)	0.29	0.75	51	1.9	42
Underground Storage Tanks (count/km^2)	0.027	2.3	15	3.9	23
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.0019	0.91	53	22	53
SOCIOECONOMIC INDICATORS					
Demographic Index	19%	46%	13	35%	29
Supplemental Demographic Index	13%	17%	43	14%	53
People of Color	17%	58%	11	39%	33
Low Income	21%	34%	34	31%	39
Unemployment Rate	8%	5%	74	6%	73
Limited English Speaking Households	1%	8%	43	5%	59
Less Than High School Education	17%	16%	62	12%	76
Under Age 5	8%	6%	65	6%	72
Over Age 64	18%	14%	71	17%	60
Low Life Expectancy	19%	20%	44	20%	50

*Diesel particulate matter air toxics cancer risk and air toxics respiratory hazard index are from the EPA's Air Toxics Data Update which is the Agency's ongoing comprehensive evaluation of air toxics in the United States This effort aims to prioritize air toxics emission sources and locations of interest for further study It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country not definitive risks to specific individuals or locations Cancer risks and hazard indices from the Air Toxics Data Update are reported to one significant figure and any additional significant figures here are due to rounding More information on the Air Toxics Data Update can be found at https //www epa gov/haps/air toxics data update

Sites reporting to EPA within defined area:

Superfund	0
Hazardous Waste, Treatment, Storage, and Disposal Facilities	5
Water Dischargers	58
Air Pollution	23
Brownfields	1
Toxic Release Inventory	16

Other community features within defined area:

Schools	1
Hospitals	0
Places of Worship	0

Other environmental data:

Air Non-attainment	Yes
Impaired Waters	Yes

Selected location contains American Indian Reservation Lands*	No
Selected location contains a "Justice40 (CEJST)" disadvantaged community	No
Selected location contains an EPA IRA disadvantaged community	No

Report for Blockgroup 482450116001

EJScreen Environmental and Socioeconomic Indicators Data

HEALTH INDICATORS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Low Life Expectancy	19%	20%	44	20%	50
Heart Disease	6.7	5.9	65	6.1	64
Asthma	9.3	9.2	56	10	33
Cancer	6.4	5.2	77	6.1	54
Persons with Disabilities	20.6%	12.3%	90	13.4%	87

CLIMATE INDICATORS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Flood Risk	88%	10%	97	12%	98
Wildfire Risk	63%	30%	71	14%	87

CRITICAL SERVICE GAPS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Broadband Internet	16%	15%	61	14%	64
Lack of Health Insurance	15%	18%	44	9%	84
Housing Burden	No	N/A	N/A	N/A	N/A
Transportation Access	Yes	N/A	N/A	N/A	N/A
Food Desert	Yes	N/A	N/A	N/A	N/A

Report for Blockgroup: 482450116001

APPENDIX I-2 IS

CONFIDENTIAL BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX J: REFERENCES

PLEASE SEE SEPARATE .ZIP FOLDER