Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

(Project ID: R06-TX-0025)

Aransas and Refugio County, Texas

Prepared by
ConocoPhillips Texas Gulf Coast CCS LLC
Houston, Texas

In Collaboration With
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Austin, Texas

July 2024

FOREWORD

ConocoPhillips Texas Gulf Coast CCS LLC (Operator), a subsidiary of ConocoPhillips Company, is developing CO_2 sequestration facilities in Aransas and Refugio Counties, Texas. The ConocoPhillips Texas Gulf Coast CCS injection site (Project) is designed to permanently store CO_2 from a hydrogen/ammonia production facility currently under development. This application is for six injection wells.

The Project site is ideally suited for the permanent storage of CO_2. The following application fully details and characterizes the geology of the proposed injection well locations, evaluates the formation to confirm the viability of permanently storing injected CO_2, and describes the engineering design and safety considerations for the wells. Furthermore, the application outlines the Operator's testing and monitoring strategies, designed to safeguard the Underground Source of Drinking Water (USDW) and monitor CO_2 plume migration.

The application was 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. Upon issuance, per the requirements of 40 CFR **§144.36(a)** and 16 TAC **§5.203(d)(1)(A)**, the permit will be updated every 5 years for the wells' active injection life.

CERTIFICATION

CERTIFIED BY:

I, Benjamin Lascaud, certify under penalty of law that this document and all attachments were prepared under my direction or supervision by a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for collecting the data, the information presented is, to the best of my knowledge and belief, true, accurate, and complete. I know there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Benjamin Lascaud
Vice President
ConocoPhillips Texas Gulf Coast CCS LLC
Date Signed: July 12, 2024

CERTIFIED BY:
Lonquist Sequestration, LLC
Texas Registration No. F-22610

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

William H. George, P.E.
Vice President / Principal Engineer
Texas License No. 135476
Date Signed: July 19, 2024

CERTIFIED BY:
Lonquist Sequestration, LLC
Texas Registration No. F-22610

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

Emily Olson, P.G.
Senior Geologist
Texas License No. 15124
Date Signed: July 18, 2024

ACRONYMS AND ABBREVIATIONS

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

40 CFR	Title 40, U.S. Code of Federal Regulations
AAPG	American Association of Petroleum Geologists
AI	acoustic impedance
AOI	area of interest
AOR	area of review
API	American Petroleum Institute
APT	annulus pressure test
AS	aquifer system
AVA	amplitude vs. angles
AVA/AVO	amplitude variation along angle/offset
AZM	above-zone monitoring (wells)
bbl	barrel(s)
BEG	Bureau of Economic Geology
BHA	bottomhole assembly
BHP	bottomhole pressure
BMLS	Beaumont Clay and Lissie Formation
BOP	blowout preventer
bph	barrels per hour
bpm	barrels per minute
BUQW	Base of Usable Quality Water
CBL	cement bond log
CCL	casing collar locator
CCS	carbon capture and storage
CDC	Centers for Disease Control and Prevention
CEQ	Council on Environmental Quality
CFR	U.S. Code of Federal Regulations
CMT	Crisis Management Team

CPLEPC	Coastal Plain Local Emergency Planning Committee
CS	confining system
DAS	distributed acoustic sensing
DEN	density
DF	derrick floor
DT	Delta-Time (or sonic log slowness)
DTC	compressional wave slowness
DTS	shear wave slowness
DTS	distributed temperature sensing
EJ	environmental justice
EOM	end of monitoring
EOS	equation of state
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ERRP	Emergency and Remedial Response Plan
ESD	emergency shutdown (valve)
ESP	electric submersible pump
EVGL	Evangeline Aquifer
FEED	front-end engineering and design
FG	fracture gradient
FM	farm-to-market
FMT	Formation Multi-Tester
FSA	fault slip analysis
FST	Functional Support Team
GAU	Groundwater Advisory Unit
GCA	Gulf Coast Aquifer
GHG	greenhouse gas emissions
GIMAT	Global Incident Management Assist Team
GL	ground level elevation

GMA	Groundwater Management Area
GOM	Gulf of Mexico (e.g., “GOM basin”)
GR	gamma ray
HC	hydrocarbon bearing
HCL	hydrochloric acid
HF	hydrofluoric acid
HSE	Health, Safety, and Environment
ICS	Incident Command System
ID	inner diameter
IpaC	Information for Planning and Consultation
IMT	Incident Management Team
IZM	in-zone monitoring well
JT	Joule-Thomson
KINT	calculated permeability
kppm	thousand parts per million
lbm	pound mass
lb/ft^3	pounds per cubic foot
LCZ	lower confining zone
LDL	Local Deformation Line
LGLD	Lissie Formation and Goliad Sand
LWD	Logging While Drilling (log)
mbbl	thousand barrels
mcf	million cubic feet
MCL	maximum containment level
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
MMcf	million cubic feet
MMI	Modified Mercalli Intensity
MMscf	million standard cubic feet
MMscf/d	million standard cubic feet per day
MTPA	million (metric) tonnes per annum
m.y.	million year
NACE	National Association of Corrosion Engineers
NAD	North American Datum (e.g., “of 1983”—NAD 83)
NEU	neutron
NHPA	National Historic Preservation Act of 1966
NIST	National Institute of Standards and Technology
NMR	nuclear magnetic resonance
NRC	National Response Center
NSDWR	National Secondary Drinking Water Regulations
NSHM	National Seismic Hazard Model
NWS	National Weather Service
OBG	overburden gradient
OD	outer diameter
P&A	plugging and abandonment
PBTD	plugged back total depth
PG	pore pressure gradient
PHIE	calculated effective porosity
PHIT	total porosity
PISC	post-injection site care
PM	preventative maintenance
ppb	parts per billion
ppf	pound per foot
ppg	pounds per gallon

ppk	parts per thousand
ppm	parts per million
ppmv	parts per million by volume
psi	pounds per square inch
psia	pounds per square inch absolute
PSDM	Pre-stack Depth Migration
PSTM	Pre-stack Time Migration
P/T	pressure/temperature
QA/QC	quality assurance/quality control
RCRA	Resource Conservation and Recovery Act
REFPROP	Reference Fluid Thermodynamic and Transport Properties Database
RMP	Risk Management Plan
RTA	rate transient analysis
RTM	reactive transport model
SAU	storage assessment unit
SCADA	Supervisory Control and Data Acquisition
SCF	Southern Composite Fault
scf/D	standard cubic feet per day
SEC	Securities and Exchange Commission
SGR	shale gouge ratio
SMCL	Secondary Maximum Contaminant Level
SOP	standard operating procedure
SOW	slip-on weld
SP	spontaneous potential
SPCC	Spill Prevention, Control, and Countermeasure Plan
SPE	Society of Petroleum Engineers
SRR	seismic review region
SSIV	subsurface injection valve
SWC	sidewall core

SWD	saltwater disposal well
SWPP	Stormwater Pollution Prevention Plan
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TD	total depth
TDEM	Texas Division of Emergency Management
TDR	time-to-depth relationship
TDS	total dissolved solids
TEC	tubing encapsulated conductor
TM	transmissibility modifiers
TPDES	Texas Pollutant Discharge Elimination System
TRRC	Railroad Commission of Texas
TVD	true vertical depth
TVDss	true vertical depth subsea
TWDB	Texas Water Development Board
UCZ	upper confining zone
UIC	Underground Injection Control
UQW	usable quality water
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
VSH	shale volume
VSI	versatile seismic imaging
VSP	vertical seismic profile
WBD	water-based mud
WHP	wellhead pressure
WMA	Waste Management Area
XRD	X-ray diffraction

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REQUIREMENTS MATRIX

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

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	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.	
			Class 6 Geological Documentation / Project Info - Table 7	A detailed location map of all APs of every kind, with surface features and boundaries is required per 40 CFR 146.82(a)(2). It is highly recommended to show this on a topographic map at a minimum scale of 1inch equals 2000 feet. If the data density is too tight, provide a blow-up/in-set of that section. For the review phase, an ESRI equivalent is acceptable, but a PDF or image will be required for the public comment period when/if a draft permit is published. Note that creating the PDF so the wells can be selected to show the required information would be extremely helpful. If the area is outside of Texas, the section, Township, Range lines should be included, for Texas the lease boundaries and names should be included. Note, that the date of the boundaries would be helpful, as BLM updated SW Louisiana recently (2020?) and there were significant changes. All AP/Well locations, major aquifers, USDW base, stratigraphic units, general lithology, confining zones, injection zone and injection interval shown on all maps and cross-sections; (See most recent *R6 Class VI Location Basics draft 20210506..docx*)	§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.	Introduction , 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 E
					§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	3.3.4, Appendix E
					§5.203 (b)(2)(C)	Surface Map Information	other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.	3.3.4
					§5.203 (b)(3)	Surface Map Information	The applicant must identify on the map any known or suspected faults expressed at the surface.	1.1., 1.3, 1.3.2
§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:	1. Project Info - Table 4	Regional Geology (20 to 50 mile radius around AOR); 1.Clearly written and complete summary of the topic. 2.Regional maps and cross-sections constructed with well logs and to scale showing major aquifers, stratigraphic units, general lithology, confining zone(s) and the injection zone. (both figures and full-sized zipped attachments) 3.Regional stratigraphy, including a stratigraphic column. 4.Regional hydrostratigraphy, emphasizing major aquifers and the lowest Underground Source of Drinking Water (USDW); (See also Table 5) 5.Definition and description of Confining Zone(s) with regional structural and isopach maps. (See also Table 8) 6.Definition and description of Injection Zone, including regional structural and isopach maps. (Is there sufficient permeability, porosity, and thickness to contain the fluid safely; Is the trap structural or stratigraphic); (See also Table 9) 7.Regional cross-sections from the surface through the confining strata below the injection zone; or if a major structure exists below the injection zone, to as deep as necessary to define the structure; 8.Discussion of the regional structural geology as it relates to the injection well site. 9.Include fault characteristics and trends as they pertain to the confining and injection zones; (See also Table 11) a.Are faults active? Do they appear to stop at unconformities? Have they reversed offset over time? 10.Discussion of regional groundwater flow in the injection zone. 11.Describe all pressure sources, sinks or other critical activities in the confining or injection zones of the region.	§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;						1.3
§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;	1.3, 1.11

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(a)(3)(iii)	Required class VI permit information	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	1. Project Info - Tables 9-10	1. Detailed description of the confining zones located above and below the injection zone, and any potential secondary confining zone. a. Reference figures, logs, maps, cross-sections, geophysical surveys, publications, etc. as needed. b. Discuss the petrology and mineralogy (lithologic, cementation minerals & dissolution features, mineralogic, petrologic, i.e. hand sample and microscopy) and where the data came from: formation; samples or cores, etc; (See also Table 12) Site Guidance: mineralogy 2 3.4; Facies 3.1 i. Location of the samples on a map; and ii. depths of samples and the names of the formations sampled; iii. Lithologies and descriptions (e.g., color, texture) from cores or hand samples; iv. Mineralogic and petrologic descriptions obtained via microscopy (with approximate percentages of minerals); v. Cementation minerals and dissolution features; and vi. A preliminary discussion of geochemical reactions that may affect the storage, confinement, and/or overall performance of the project (see Section 2.3.9 for additional information on baseline geochemistry). c. Discussion of structure and isopach/isochore maps; supported by available well logs and cores. (see also Table 12) i. Discuss the structural dip and the conservative nature of either a constant or variable dip. (Ties into modeling) ii. Discuss the thickness and whether the values are true stratigraphic depths or vertical measures of thickness. iii. Isopach maps (contour maps showing equal values of true stratigraphic thickness) iv. Isochore maps (contour maps showing equal values of true vertical thickness) 2. Compare the different sources of information and demonstrate the compatibility or areas of uncertainty. Provide a map showing the georeferenced locations of all survey data. 3. Justification of its capability to act as a confining layer. 4. Description of the confining strata beneath injection zone including lithology and rock properties. Table 9: Class VI Application Narrative: Injection Zone Information CFR and Guidance Location & File: GSDT or CBI? INJECTION ZONE(S) 1. Detailed description of the injection zone(s). a. Reference figures, logs, maps, cross-sections, geophysical surveys, publications, etc. as needed. b. Discuss the petrology and mineralogy (lithologic, cementation minerals & dissolution features, mineralogic, petrologic, i.e. hand sample and microscopy) and where the data came from: formation; samples or cores, etc; (See also Table 12) i. Location of the samples on a map; and ii. depths of samples and the names of the formations sampled; iii. Lithologies and descriptions (e.g., color, texture) from cores or hand samples; iv. Mineralogic and petrologic descriptions obtained via microscopy (with approximate percentages of minerals); v. Cementation minerals and dissolution features; and vi. A preliminary discussion of geochemical reactions that may affect the storage, confinement, and/or overall performance of the project (see Section 2.3.9 for additional information on baseline geochemistry). c. Discussion of structure and isopach/isochore maps; supported by available well logs and cores; (See also Table 12) i. Discuss the structural dip and the conservative nature of either a constant or variable dip. (Ties into modeling) ii. Discuss the thickness and whether the values are true stratigraphic depths or vertical measures of thickness. iii. Isopach maps (contour maps showing equal values of true stratigraphic thickness) iv. Isochore maps (contour maps showing equal values of true vertical thickness) 5. Compare the different sources of information (cross-discipline) and demonstrate the compatibility or areas of uncertainty. Provide a map showing the georeferenced locations of all survey data. 6. Justification of its capability to accept and contain waste.	§3.203 (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);			§3.203 (c)(2)(E)	Geologic, geochemical, and hydrologic information	geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;	1.6
§146.82(a)(3)(v)		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			§3.203 (c)(2)(D)	Geologic, geochemical, and hydrologic information	the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;	1.10, 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, 1.8, 3.3.4
				Injection Wells 1. Number of wells (enter all data for each one) 2. Wellbore Direction: a. Vertical (X,Y & model units) or b. Directional (trajectory file) 3. Wellbore Diameter a. Constant: value & unit= vu b. Variable (file) 4. Well Screen Intervals a. Single: vu b. Multiple (file) Injection Parameters 1. Mass rate of injection: vu 2. Total mass injected: vu 3. Inj Temperature: vu (if not = res temp) 4. Modeled Inj Temp: vu (as above) Table 20: Fracture Gradient and Pressure and Other Parameters (Narrative) Information CFR and Guidance Location & File: GSDT or CBI? Fracture Gradient and Pressure 1. Fracture Gradient: vu 2. Max injection pressure: vud 3. How determined (Upload) Additional Parameters 1. Composition: a. Pure CO2 b. Mixture: components & % 2. Injection Period a. Single: start & stop b. Multiple: table				

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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;	AoR Corrective Action Plan - Table 19–22	Table 21: Production/Withdrawal Wells (Narrative) Information CFR and Guidance Location & File: GSDT or CBI? Production/Withdrawal Wells 1. Number of wells (enter all data for each one) 2. Wellbore Direction: a. Vertical (X,Y & model units) or b. Directional (trajectory file) 3. Wellbore Diameter a. Constant: value & unit = vu b. Variable (file) 4. Well Screen Intervals a. Single: vu b. Multiple (file) Production Constraints 1. Pumping/production Rate 2. Constant: vu 3. Variable: file 4. Pressure 5. Fixed: vu 6. Variable: file Operational Information 1. Comments Table 22: AOR Pressure Front Delineation (GSDT) Information CFR and Guidance Location & File: GSDT or CBI? Lowermost USDW 1. Name of lowermost USDW 2. Water Density: vud, location 3. Temperature: vud, location 4. Pressure: vud, location 5. Salinity: vud, location 6. Elevation: vu 7. Name of lowermost USDW Injection Zone 1. Name of injection Zone 2. Water Density: vud, location 3. Temperature: vud, location 4. Pressure: vud, location 5. Salinity: vud, location 6. Elevation: vu Critical Pressure Estimation/Calculations 1. Method of estimation (assumptions or details) a. Static Mass Balance b. Dynamic Modelling c. Other 2. VU Delineated AoR 1. Figure or map, and Shapefile, layer package or KML a. AoR boundary b. Outline of the furthest modeled plume extent Regional request AOR Pressure Front Delineation 1. Comments 2. Figure or map, and Shapefile, layer package or KML Regional request	§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.	3.3.4
§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;	AoR Corrective Action Plan - Table 14	Site Geology & Hydrology: Details in Module 1 1. Incorporation of Local Geology into the model: what and how for each a. Structure b. Thickness c. Porosity and Permeability d. Cross-Flow 2. Faults a. Faults modeled? Y/N b. Coordinates File upload 3. Caprock Modeled a. Caprock modeled? Y/N	§5.203 (c)(2)(A)	Geologic, geochemical, and hydrologic information	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	1.8, Appendices B, C, E
§146.82(a)(6)	Required class VI permit information	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;			§5.203 (c)(2)(G)	Geologic, geochemical, and hydrologic information	Baseline geochemical data on subsurface formations, including all formations containing USDWs in the AOR;	1.8.1
§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:	4.3.4; 4.3.5
§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;	Introduction, 4.2
§146.82(a)(7)(ii)	Required class VI permit information	Average and maximum injection pressure;	Project Info - Table 17	Proposed Stimulation Program When and why it is needed Methods used; with how containment will be maintained an no new fractures will be ensured. Chemicals planned for use in stimulation; potential compatibility issues between chemicals and either the injection or confining zones. How the maximum safe injection pressure was determined. (be explicit)	§5.203 (i)(1)(B)	Operating information	The average and maximum surface injection pressure;	4.3.5
§146.82(a)(7)(iii)	Required class VI permit information	The source(s) of the carbon dioxide stream; and	Project Info - Table 17	Proposed Carbon Dioxide Stream Planned source(s) of the CO2 Physical and chemical characteristics of the stream; method of determination Corrosivity of the stream and behavior under operating conditions downhole; over the lifetime of the project	§5.203 (i)(1)(C)	Operating information	The sources of the carbon dioxide stream and the volume of carbon dioxide from each source; and	Introduction
§146.82(a)(7)(iv)	Required class VI permit information	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	Project Info - Table 17	(?) Proposed Carbon Dioxide Stream Planned source(s) of the CO2 Physical and chemical characteristics of the stream; method of determination Corrosivity of the stream and behavior under operating conditions downhole; over the lifetime of the project	§5.203 (i)(1)(D)	Operating information	An analysis of the chemical and physical characteristics of the carbon dioxide stream prior to injection.	Introduction, 4.2
§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, 4.3.3

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	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;		(7) Proposed Stimulation Program When and why it is needed Methods used; with how containment will be maintained an no new fractures will be ensured. Chemicals planned for use in stimulation; potential compatibility issues between chemicals and either the injection or confining zones. How the maximum safe injection pressure was determined. (be explicit)	§3.203 (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	4.2.3, 4.2.6, 4.2.9, 4.2.12, 4.2.15, 4.2.18
§146.82(a)(10)	Required class VI permit information	Proposed procedure to outline steps necessary to conduct injection operation;	1. Project Info - Table 20	1. Narrative describing updated site characterization information, synthesizing the results of pre-operational logging and testing, and other general project information (compiled into a single file and submitted using the Project Information Tracking module of the GSDT). 2. Final AoR Model Delineation a. short description of the information and files submitted to the GSDT related to the final AoR model and delineation that incorporates the results of pre-operational testing and logging, with references to the rule requirements those submissions satisfy. b. If there is additional information that could not be submitted using the forms in the GSDT, it can be included here. c. How well do site-specific pre-operational testing and logging results compare to the data used in the original permit application? What are the differences between the original and updated site characterization? d. What specific testing and logging results led to updates in the site characterization? e. How well do pre-operational testing and logging results compare to literature and regional geologic and hydrogeologic data? What are the possible reasons for the differences? f. How do the data collected as part of pre-operational testing and logging inform a comprehensive understanding of site-specific conditions? Are any additional testing and monitoring methods required to gain a greater understanding? 3. Any other headings with updated or synthesized information. (per check boxes in GSDT) 1. Final AoR delineation and final corrective action status; In none required include justification in narrative file 2. Results of formation testing and logging (required for all projects) a. AoR and Corrective Action Plan b. Testing and Monitoring Plan c. Well Plugging Plan d. PISC and Site Closure Plan e. Emergency and Remedial Response Plan 1. Financial responsibility demonstration 2. Updated Alternative PISC demonstration 1. Updated injection depth waiver application 2. Updated Aquifer exemption expansion request 5. File names with descriptive headers please	§3.203 (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 §3.206(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;	1. Project Info - Table 17	Injection Well Construction: schematics/graphics of surface & subsurface construction New or existing well (upload details showing compliance) Narrative description of all well schematics Proposed Stimulation Program When and why it is needed Methods used; with how containment will be maintained an no new fractures will be ensured. Chemicals planned for use in stimulation; potential compatibility issues between chemicals and either the injection or confining zones. How the maximum safe injection pressure was determined. (be explicit) **Check R6 Project Information Crosswalk	§3.203 (e)(2)(K)	Injection well construction	Schematic drawings of the surface and subsurface construction details.	4.2.1; 4.2.4, 4.2.7, 4.2.10, 4.2.13, 4.2.16; 4.2.2.9
§146.82(a)(12)	Required class VI permit information	Injection well construction procedures that meet the requirements of § 146.86;	1. Project Info - Table 17	Construction Procedures Specific details supporting chosen method, with respect to mechanical integrity and down-hole stresses Detailed construction materials, and the appropriate standard: API, ASTM ... Compatibility with CO2 and formation fluids, with specific method of determination May be located elsewhere – be specific where Highlight protection of the USDW: prevention of fluid movement Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus Contingency plans for drilling or completion issues that may impact the USDW Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details **Repeated in 146.86(b)-(b)(iv)	§3.203 (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; Appendix F
§146.82(a)(13)	Required class VI permit information	Proposed area of review and corrective action plan that meets the requirements under § 146.84;	AoR Corrective Action Plan - Prologue	40 CFR 146.82(a)(13) and 40 CFR 146.84; Implementation Manual Section 4; Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance; GSDT Guidance for Module. This Crosswalk includes information from the Title 40 Code of Federal Regulations (CFR) and generally follows the layout of the Geologic Sequestration Data Tool (GSDT) and narrative templates, with additional information pulled from the Sequestration Guidance documents available on EPA's national UIC program website. If you have uploaded a file to the GSDT the name will be captured in the system, as will all the filled-in or selected options. They can be downloaded by the permit reviewers as pdfs. What we will need is where within the document that section is located. If the information covers GSDT data fields and you are using the GSDT to enter the data (not a CBI code), then feel free to group the cells and type 'entered' as the location. The list is to also provide you with an idea of where the data is located in the system, some fields are dependent on your initial answer. **Check R6 AoR & Corrective Action Crosswalk	§3.203 (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;			§3.202 (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 §3.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	Section 9
					§3.203 (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 §3.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	Section 9

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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:	Section 5
§146.82(a)(16)	Required class VI permit information	Proposed injection well plugging plan required by § 146.92(b);			§5.206 (j)	Permit Standards	Well plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by §5.203(k) of this title.	Section 6
§146.82(a)(17)	Required class VI permit information	Proposed post-injection site care and site closure plan required by § 146.93(a);			§5.206 (k)(1)	Permit Standards	Post-injection storage facility care and closure plan.	Section 7
§146.82(a)(18)	Required class VI permit information	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);			§5.203 (m)(8)(F)	Post-injection storage facility cares 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;	
§146.82(a)(19)	Required class VI permit information	Proposed emergency and remedial response plan required by § 146.94(a);			§5.206 (h)(1)	Permit Standards	The operator must maintain and comply with the approved emergency and remedial response plan required by §5.203(l) of this title. The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title (relating to Reporting and Record-Keeping). The operator must make copies of the plan available at the storage facility and at the company headquarters.	Section 8
§146.82(a)(20)	Required class VI permit information	A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and						Introduction
§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;	Pre-Operational Testing Doc. - Table 3	Site Characterization Updates: Regional Geology, Hydrogeology and Local Structural Geology Maps and Cross Sections of the AoR Faults and Fractures Injection and Confining Zone Details Geomechanical and Petrophysical Information Seismic History Hydrologic and Hydrogeologic Information Geochemistry Other Information (Including Surface Air and/or Soil Gas Data, If Applicable) Site Suitability 1. Narrative description of updates to geologic structure and hydrologic properties. (align with narrative submitted under Project Information.) a. Compare to literature and regional data. b. Improved comprehensive understanding of site-specific conditions. c. Additional tests and monitoring needed?				
§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;	Project Info - Table 15	1. Discuss any baseline readings and variability of CO2 or parameters planned for tracking the plume front. a. Demonstrate that the locations sampled represent a reasonable grid size and that potential point sources are represented and will serve as a good baseline; b. Demonstrate that seasonal and diurnal variations in carbon dioxide levels have been captured and describe the variability in the data for future reference; c. Site characteristics: soil type, soil organic carbon content, vegetation type and density, topography, surface water hydrology; d. Sampling locations (in map form) and dates; e. Soil temperature and moisture data and atmospheric conditions; f. Sampling and analytical methods, including detection limits; g. Results presented as concentrations and fluxes in tabular and graphic form, including QA samples and analyses; h. Methods and results of regression analyses; and i. Methods and results of any ecological modeling performed, including input data, outputs, and sensitivity analyses.	§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 F, G
					§5.203 (g)(2)	Compatibility determination	fluids in the injection zone; and	1.7.4
					§5.203 (g)(3)	Compatibility determination	minerals in both the injection and the confining zone.	1.7.4

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§146.82(c)(4)	Required class VI permit information	The results of the formation testing program required at paragraph (a)(8) of this section;	Project Info - Table 12, Sec. 2	2. Results of formation testing and logging (required for all projects) a. AoR and Corrective Action Plan b. Testing and Monitoring Plan c. Well Plugging Plan d. PISC and Site Closure Plan e. Emergency and Remedial Response Plan				
§146.82(c)(5)	Required class VI permit information	Final injection well construction procedures that meet the requirements of § 146.86;	Project Info - Table 17	When and why it is needed Methods used; with how containment will be maintained an no new fractures will be ensured. Chemicals planned for use in stimulation; potential compatibility issues between chemicals and either the injection or confining zones. How the maximum safe injection pressure was determined. (be explicit) Construction Procedures Specific details supporting chosen method, with respect to mechanical integrity and down-hole stresses Detailed construction materials, and the appropriate standard: API, ASTM ... Compatibility with CO2 and formation fluids, with specific method of determination May be located elsewhere -- be specific where Highlight protection of the USDW: prevention of fluid movement Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus Contingency plans for drilling or completion issues that may impact the USDW Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details Well Operation Provide text, tables, and/or figures to fulfill the operating data requirements for the permit application; Also include or attach any other information necessary to demonstrate/establish compliance. Operational Procedures Inc. GSDT Narr. Table 3 Describe planned procedures, Inc.: • calculations or methods behind values • relation to critical fracture pressure and specific local geologic or hydrologic concerns • Potential changes throughout the operational life: trigger and result				
§146.82(c)(6)	Required class VI permit information	The status of corrective action on wells in the area of review;	AoR Corrective Action - Table 2-3	1. Each separate bottom hole is considered a different API; i.e pilot hole; deviated legs; each sidetrack 2. Provide a shapefile or equivalent to the Region 3. Wells within the AoR 4. Wells Penetrating the Confining Zone a. Identify any water wells, mines or other penetrations entering the confining zone b. How were the depths of these wells determined? c. What is the type and status of each well (e.g., operating Class II injection well, temporarily abandoned oil well, etc.)? (Attach tables as necessary.) d. What is the condition of each well? e. If corrective action is needed, what activities will be completed and when? 5. Is the well within the critical pressure front or the greatest plume extent Supply a basemap, labeled per document (Inc. surface and bhl locations, if st or deviated) Supporting documents: zip or pdf (mud weight, plugs, cement jobs, casing- materials and depths 1. Level of documentation is dependent on the depth of penetration, i.e. above the confining zone or not 2. legible well logs (annotated preferred) 3. well schematics 4. deviation surveys 5. Scout tickets, log headers, state report forms, drilling history Table 3: Corrective Action (GSDT) Information CFR and Guidance Location & File: GSDT or CBI? Corrective Action 1. Location of All Penetrations within AOR (Excel and shapefile preferred by Region) 2. Location of Wells Potential Corrective Action (Excel and shapefile preferred by Region) 3. Supporting Documentation a. Plugging records b. Cement records c. Associated tests (CBL, MIT, etc)				
§146.82(c)(7)	Required class VI permit information	All available logging and testing program data on the well required by § 146.87;	AoR Corrective Action - Table 3, Sec. 3	1. Supporting Documentation a. Plugging records b. Cement records c. Associated tests (CBL, MIT, etc)				
§146.82(c)(8)	Required class VI permit information	A demonstration of mechanical integrity pursuant to § 146.89;	Project Info - Table 17	Specific details supporting chosen method, with respect to mechanical integrity and down-hole stresses Detailed construction materials, and the appropriate standard: API, ASTM ... Compatibility with CO2 and formation fluids, with specific method of determination May be located elsewhere -- be specific where Highlight protection of the USDW: prevention of fluid movement Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus Contingency plans for drilling or completion issues that may impact the USDW				
§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	AoR Corrective Action - Table 6	AoR Reevaluation (?) 1. AoR Reevaluation Cycle a. What are the specific procedures that will be followed for the AoR reevaluation? (Provide a list of steps or similar description.) b. What monitoring and operational data will be used? What specific thresholds or benchmarks will be used to determine if the testing and monitoring data are consistent with the model predictions? c. How will new data be incorporated into the model? d. How will model reevaluations be compared to the initial AoR modeling and delineation?				

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§146.82(c)(10)	Required class VI permit information	Any other information requested by the Director.	Pre-Operational Testing Doc. - Table 13	1. Describe updates to well operational procedures and/or proposed carbon dioxide stream, if applicable, 2. If no updates are required, it will be assumed that the operational information provided in the 40 CFR 146.82(a) narrative still applies. 3. Changes to well operational procedures or the carbon dioxide stream should be reflected in the final AoR model and delineation described earlier in this narrative. 4. Update tables and/or figures per 40 CFR 146 82(a)(7) and (10). 5. Also include or attach any other information necessary to demonstrate/establish compliance with 40 CFR 146.88.				
§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.	Project Info - Summaries Page	'Nearly all commenters agreed that early and frequent public education and participation would enhance public acceptance of GS projects. ... EPA encourages owners or operators and permitting agencies to involve the public by providing them information about the Class VI permit (and any requests for a waiver of the injection depth requirements or an expansion of the areal extent of an aquifer exemption) as early in the process as possible' (7)	§3.201 (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.	
§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:	Project Info - Table 16	Site Suitability: 40 CFR 146.82(c)(2); 40 CFR 146.83 LAC §3619.A.2; §3615 A 1. Briefly summarize why the geologic setting is suitable for a sequestration project: such as a. The basic geometry (structural or stratigraphic trap), confinement and lack of potential leakage pathways; b. Facies changes in the subsurface and how this feeds the conceptual model. Characterize permeability and capillary pressure to evaluate movement through the confining zone; The implications for connectivity within the injection formation and the suitability of the confining zone; i. Lithofacies distributions mapped in the injection and confining formations, including the distributions of properties such as porosity and permeability for each lithofacies; ii. The potential for preferential flow paths; iii. Diagenetic processes that may affect present-day hydrogeologic properties; and iv. Uncertainties associated with the data and with the resulting facies model. 2. Justification of storage capacity: a. Discuss the capacity versus the planned storage inc. the approach used based on the site-specific information. i. A description of the selected estimation method, including a discussion of its suitability for the type of formation; ii. Tabulation of any input data used, along with estimates of uncertainty in those data; iii. Results in tabular or graphic format; iv. A discussion of the results, relating them to proposed operational parameters and the anticipated total volume of carbon dioxide to be injected and the duration of the project and any identified site-specific vulnerabilities (e.g., faults, fractures, etc.) b. Discuss assumptions and limitations of the method used; c. Discuss uncertainty based on the results of a sensitivity analysis; and d. Discuss how the results are consistent with and/or supported by the AoR delineation modeling	§3.206 (b)(6)	General Criteria	the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include:	
§146.83(a)(1)	Minimum Criteria for siting	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Project Info - Table 10	SUPPORTING DATA FOR CONFINING OR INJECTION ZONES (FULL SCALE) -- 2. Well log data (when it is available), with injection and confining zones highlighted (if well logs are used for this demonstration)., porosity, permeability and both areal extent and lateral continuity of each. a. Provide a sufficient number of well logs to document the structural depths and thicknesses on the structure and isopach maps (may be referenced to an included set) b. Details on the any tests inc. porosity and permeability are discussed in the next section, Geomechanics & Petrophysics. **Check R6 Project Info - Table 10	§3.206 (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	1.11
§146.83(a)(2)	Minimum Criteria for siting	Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Project Info - Table 12	1. Geomechanical: Discuss fractures, stress, pressure, temperature, ductility, rock strength, rock/fluid compressibility and in situ fluid pressures within the confining zone, inc. details from log runs, tests, publications, borehole breakouts etc. 2. Source of the Hydraulic gradients: tests, literature, pressure tests from which wells ... 3. Provide fracture gradient calculations and maximum surface pressure limitation. **Check R6 Project Info - Table 12	§3.206 (b)(6)(B)	General Criteria	a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs;	1.3.1, 1.3.2, 1.3.3, 1.11
§146.83(b)	Minimum Criteria for siting	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.						
§146.84 - Area of Review and Corrective Action								
§146.84	Area of review and corrective action				§3.203 (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

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.84(a)	Area of review and corrective action	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	AoR Corrective Action - Table 2	(?) 4. AoR Delineation 1. Summary of how area was selected. (See model table for details.) a. How was the AoR delineation selected (what model results were used to define the AoR)? Justify how the AoR delineation represents the largest area in which USDWs may be endangered by the injection activity. b. How might the AoR delineation be verified and/or changed during AoR reevaluation, or following pre-operational testing? c. What are the locations of the injection well(s) and any monitoring wells used to track plume and pressure front migration? How will results of testing and monitoring in these wells help verify the extent and location of the delineated AoR? 2. Potential USDW endangerment 3. Demonstrate an adequate search method for all Artificial Penetrations (AP): database sources, status, historic sources 4. Analysis of abandonment to withstand plume or pressure a. Within plume: cement inside and outside casing across Confining and Injection Zones; cement capable of acid environment 5. Phased corrective action to handle deficient APs **Check R6 AoR Corrective Action - Table 2	§5.203 (d)(1)(A)(ii)(IV)	AOR and corrective action	considers the physical and chemical properties of injected and formation fluids; and	2.4, 2.5, 2.6, 3.5
§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:		(?) 4. AoR Delineation 1. Summary of how area was selected. (See model table for details.) a. How was the AoR delineation selected (what model results were used to define the AoR)? Justify how the AoR delineation represents the largest area in which USDWs may be endangered by the injection activity. b. How might the AoR delineation be verified and/or changed during AoR reevaluation, or following pre-operational testing? c. What are the locations of the injection well(s) and any monitoring wells used to track plume and pressure front migration? How will results of testing and monitoring in these wells help verify the extent and location of the delineated AoR? 2. Potential USDW endangerment 3. Demonstrate an adequate search method for all Artificial Penetrations (AP): database sources, status, historic sources 4. Analysis of abandonment to withstand plume or pressure a. Within plume: cement inside and outside casing across Confining and Injection Zones; cement capable of acid environment 5. Phased corrective action to handle deficient APs **Check R6 AoR Corrective Action - Table 2	§5.203 (d)(1)	AOR and corrective action	Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3
§146.84(b)(1)	Area of review and corrective action	The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	AoR Corrective Action - Table 8	1. Upload State primacy information requirements 2. Description of files uploaded **Check R6 AoR Corrective Action - Table 8	§5.203 (d)(2)(A)	AOR and corrective action	The method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	2.2, 2.4, 2.5, 2.6, 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;		1. Minimum fixed frequency of AoR reevaluation: vu 2. AoR reevaluation: y/n (Table 6: Reevaluation Schedule and Criteria (Narrative) Information CFR and Guidance Location & File: GSDT or CBI? AoR Reevaluation 40 CFR 146.84(e); AoR Guidance Section 5 1. AoR Reevaluation Cycle 40 CFR 146.84(e) a. What are the specific procedures that will be followed for the AoR reevaluation? (Provide a list of steps or similar description.) b. What monitoring and operational data will be used? What specific thresholds or benchmarks will be used to determine if the testing and monitoring data are consistent with the model predictions? c. How will new data be incorporated into the model? d. How will model reevaluations be compared to the initial AoR modeling and delineation? 2. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation 40 CFR 146.84(e) ; AoR Guidance Section 5.1 – 5.2 a. Corrective action analysis 40 CFR 146.84(e)(2) b. Perform corrective action (phased) 40 CFR 146 84(e)(3) c. Revise the AoR Corrective Action Plan 40 CFR 146.84(e)(4) Reevaluate the AoR AoR Guidance Section 5 3 1. Adequate Delineation Demonstration 2. Modify existing Delineation) **Check AoR Corrective Action - Table 5-6	§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
§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.	AoR Corrective Action - Table 5-7	(?) Area of Review Reevaluation 40 CFR 146.84(e) 1. Minimum fixed frequency of AoR reevaluation: vu 2. AoR reevaluation: y/n Table 6: Reevaluation Schedule and Criteria (Narrative) Information CFR and Guidance Location & File: GSDT or CBI? AoR Reevaluation 40 CFR 146.84(e); AoR Guidance Section 5 1. AoR Reevaluation Cycle 40 CFR 146.84(e) a. What are the specific procedures that will be followed for the AoR reevaluation? (Provide a list of steps or similar description.) b. What monitoring and operational data will be used? What specific thresholds or benchmarks will be used to determine if the testing and monitoring data are consistent with the model predictions? c. How will new data be incorporated into the model? d. How will model reevaluations be compared to the initial AoR modeling and delineation? 2. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation 40 CFR 146.84(e) ; AoR Guidance Section 5.1 – 5.2 a. Corrective action analysis 40 CFR 146.84(e)(2) b. Perform corrective action (phased) 40 CFR 146 84(e)(3) c. Revise the AoR Corrective Action Plan 40 CFR 146.84(e)(4) Reevaluate the AoR AoR Guidance Section 5 3 1. Adequate Delineation Demonstration 2. Modify existing Delineation Table 7: Additional AoR Delineation Information (GSDT Overview) Additional AOR Delineation Information 40 CFR 146.84(b)(1) 1. Upload State primacy information requirements 2. Description of files uploaded	§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	AoR Corrective Action - Table 6	AoR Reevaluation 1. AoR Reevaluation Cycle a. What are the specific procedures that will be followed for the AoR reevaluation? (Provide a list of steps or similar description.) b. What monitoring and operational data will be used? What specific thresholds or benchmarks will be used to determine if the testing and monitoring data are consistent with the model predictions? c. How will new data be incorporated into the model? d. How will model reevaluations be compared to the initial AoR modeling and delineation?	§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	AoR Corrective Action - Table 4	Corrective Action Schedule 1. What are the phases of corrective action? 2. What are the associated benchmarks/triggers?	§5.203 (d)(2)(C) §5.203 (d)(2)(C)(i) §5.203 (d)(2)(C)(ii)	AOR and corrective action AOR and corrective action AOR and corrective action	a corrective action plan that describes: how the corrective action will be conducted; how corrective action will be adjusted if there are changes in the AOR;	 3.4 3.5

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[illegible]	[illegible]	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	[illegible]	3. Potential changes based on testing, monitoring or reevaluation? **Check AoR Corrective Action - Table 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	
					§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:	AoR Corrective Action - Table 2	4. AoR Delineation 1. Summary of how area was selected. (See model table for details.) a. How was the AoR delineation selected (what model results were used to define the AoR)? Justify how the AoR delineation represents the largest area in which USDWs may be endangered by the injection activity. b. How might the AoR delineation be verified and/or changed during AoR reevaluation, or following pre-operational testing? c. What are the locations of the injection well(s) and any monitoring wells used to track plume and pressure front migration? How will results of testing and monitoring in these wells help verify the extent and location of the delineated AoR? 2. Potential USDW endangerment 3. Demonstrate an adequate search method for all Artificial Penetrations (AP): database sources, status, historic sources 4. Analysis of abandonment to withstand plume or pressure a. Within plume: cement inside and outside casing across Confining and Injection Zones; cement capable of acid environment 5. Phased corrective action to handle deficient APs Tabulation of Wells within the AoR (status, TD, Sidetracks, deviated or not, bottom zone, penetrations, etc.) (Excel document for the Region – listed under GSDT) 1. Each separate bottom hole is considered a different AP; i.e pilot hole; deviated legs; each sidetrack 2. Provide a shapefile or equivalent to the Region 3. Wells within the AoR 4. Wells Penetrating the Confining Zone a. Identify any water wells, mines or other penetrations entering the confining zone b. How were the depths of these wells determined? c. What is the type and status of each well (e.g., operating Class II injection well, temporarily abandoned oil well, etc.)? (Attach tables as necessary.) d. What is the condition of each well? e. If corrective action is needed, what activities will be completed and when? 5. Is the well within the critical pressure front or the greatest plume extent Supply a basemap, labeled per document (inc. surface and bhl locations, if st or deviated) Supporting documents: zip or pdf (mud weight, plugs, cement jobs, casing- materials and depths 1. Level of documentation is dependent on the depth of penetration, i.e. above the confining zone or not 2. legible well logs (annotated preferred) 3. well schematics 4. deviation surveys 5. Scout tickets, log headers, state report forms, drilling history	§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	3.3
					§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.	
					§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;	Project Info - Table 10	SUPPORTING DATA FOR CONFINING OR INJECTION ZONES (FULL SCALE) 1. Uninterpreted copy of the base map, with all wells, etc. aka an AOR map, on the topo base would be helpful 2. Well log data (when it is available), with injection and confining zones highlighted (if well logs are used for this demonstration)., porosity, permeability and both areal extent and lateral continuity of each. a. Provide a sufficient number of well logs to document the structural depths and thicknesses on the structure and isopach maps (may be referenced to an included set) b. Details on the any tests inc. porosity and permeability are discussed in the next section, Geomechanics & Petrophysics. 3. Location/area covered by seismic or other geophysical surveys a. Provide available geophysical characterization (seismic, gravity, magnetic & EM) used to delineate and characterize the local structure: b. The source of the data and whether they are vintage or newly collected; c. The type of survey and other details of the deployment (e.g., date, location/areal extent of the survey, vendor who performed the survey); c. If boreholes were used, the locations of the boreholes; d. Type of data processing, including any reprocessing of vintage data; images, with locations of profiles indicated on a map and salient geologic features identified (including formations below the injection zone where an injection depth waiver is sought); e. Assumptions and limitations associated with the method, data, and their interpretation; f. A narrative discussing the results in the context of the site geologic conceptual model; and g. If the data suggest non-unique interpretations, the owner or operator should address alternative interpretations. Show that the resolution of the data is sufficient for evaluation of the injection and confining zones 4. Cross-Sections per Regional Geological Documentation h. At least minimal coverage: strike & dip intersecting well location(s) i. Log control (legible) j. All required USDW, horizons etc. added and labelled, including fault or fracture zones and salt structures k. Stratigraphic cross-sections include geologic age and datum, on which it is hung. 5. Structural Maps per Regional Geological Documentation l. Key structures covered at effective scales (1" = 2000' or 1: - 500' for dense areas) m. Data sources clearly marked; depths TVD subsea; deviated well depth location identified; existing or planned cavern locations; n. Faults, shear zones, overhangs or any other geological feature, if identified or inferred, should be indicated on the structure map o. All information properly links: cross-sections and maps; faults show offset, seismic lines show same interpretation, etc.	§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	1.3.1, 1.3.2, 1.3.3, 2.4, 2.5
					§5.203 (d)(1)(A)(ii)(II)	AOR and corrective action	is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	Introduction, 2.6, 3.2, 4.2
§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	Project info - Test Analysis, Sec. 4-7	4. Data verification and clean-up 5. Analysis techniques a. Calculations and ramifications thereof b. Outliers and manipulations 6. Compilation of analytical results a. Output parameters and/or projections b. Identification of discontinuities (fractures, faults, barriers, or other changes) 7. Results in tabular and graphical form (semi-log, log-log, etc.) for the formation, confining or injection zones	§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	2.1, 2.2, 2.3, 2.4, 2.5, 3.5
§146.84(c)(1)(iii)	Area of review and corrective action	Consider potential migration through faults, fractures, and artificial penetrations.	Project info - Test Analysis, Sec. 6	6. Compilation of analytical results a. Output parameters and/or projections b. Identification of discontinuities (fractures, faults, barriers, or other changes)	§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.	1.3, 1.11, 2.4, 2.5, 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.	2.4, 2.5, 2.6, 3.2

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§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	Class VI Location Basics - Artificial Penetration Identification	Artificial Penetration Identification See Section 4 of the Guidance document, especially the following sub-sections. 1.Historical Research 2.Site Reconnaissance 3 Aerial and Satellite Imagery Review 4.Geophysical Surveys a.Magnetic Methods b.Electromagnetic Methods c.Ground Penetrating Radar **Check R6 Location Basics Document	§3.203 (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 E
§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.	AoR Corrective Action - Table 2, Sec. 4	1. Analysis of abandonment to withstand plume or pressure 40 CFR 146 84(c)(3); AoR Guidance Section 4.3 a. Within plume: cement inside and outside casing across Confining and Injection Zones; cement capable of acid environment **Check AoR Corrective Action Plan Document	§3.203 (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.	3.4
§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.	AoR Corrective Action - Table 2, Sec. 3	1. Phased corrective action to handle deficient APs 40 CFR 146 84(d) ; AoR Guidance Section 4.4 **Check AoR Corrective Action Plan - Table 2, Sec. 5				3.4
§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:	AoR Corrective Action, Tables 5-6	Area of Review Reevaluation 40 CFR 146 84(e) 1. Minimum fixed frequency of AoR reevaluation: vu AoR Reevaluation 40 CFR 146.84(e); AoR Guidance Section 5 1. AoR Reevaluation Cycle 40 CFR 146.84(e) a. What are the specific procedures that will be followed for the AoR reevaluation? (Provide a list of steps or similar description.) b. What monitoring and operational data will be used? What specific thresholds or benchmarks will be used to determine if the testing and monitoring data are consistent with the model predictions? c. How will new data be incorporated into the model? d. How will model reevaluations be compared to the initial AoR modeling and delineation? 2. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation 40 CFR 146.84(e) ; AoR Guidance Section 5.1 – 5.2	§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:	
§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;	AoR Corrective Action - Table 6	1. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation a. Corrective action analysis	§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	AoR Corrective Action - Table 6	1. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation b. Perform corrective action (phased)	§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.	AoR Corrective Action - Table 6	1. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation c. Revise the AoR Corrective Action Plan	§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.	Project Info - Table 6, Sec. 6	6. Provide a risk assessment of induced seismicity due to injection activities based on a known induced seismicity formula; This will be used to develop the Emergency and Remedial Response Plan. e. Emergency and Remedial Response Plan	§5.205 (b)(3)	Fees, financial responsibility, and financial assurance	The applicant's demonstration of financial responsibility must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.4
§146.84(g)	Area of review and corrective action	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	AoR Corrective Action - Table 6, Sec. 1, Pt. e: Sec.2	a. How will model reevaluations be compared to the initial AoR modeling and delineation? 2. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation	§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.	9.8
					§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 780(d)); and	9.3.1
					§5.205 (b)(2)(B)	Fees, financial responsibility, and financial assurance	the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 780(d)); or	9.3.1
					§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.	9.3.1
					§5.205 (b)(3)	Fees, financial responsibility, and financial assurance	The applicant's demonstration of financial responsibility must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.3.1, 9.4
					§5.205 (c)	Financial assurance	Financial assurance.	
					§5.205 (c)(2)(A)	Fees, financial responsibility, and financial assurance	The applicant must include in an application for a geologic storage facility permit:	

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					§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)(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)(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)(iii)	Financial assurance	The qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	9.3
					§5.205 (c)(2)(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
					§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.	9.8
					§5.205 (c)(2)(F)	Fees, financial responsibility, and financial assurance	The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	9.8
					§5.205 (c)(2)(G)	Fees, financial responsibility, and financial assurance	Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the operator has received written approval from the director.	9.8
					§5.205 (D)(1)	Fees, financial responsibility, and financial assurance	The operator must notify the Commission of adverse financial conditions that may affect the operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An operator must file any notice of bankruptcy in accordance with §3.1(f) of this title (relating to Organization Report; Retention of Records; Notice Requirements). The operator must give such notice by certified mail.	9.3.1
					§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.	TBD
§146.83	Financial Responsibility							
§146.83(a)	Financial Responsibility	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	Financial Responsibility Demo.	**Check Financial Responsibility Document**				

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(1)		The financial responsibility instrument(s) used must be from the following list of qualifying instruments:	Financial Responsibility Demo					
§146.85(a)(1)(i)		Trust Funds.	Financial Responsibility Demo. - Table 2	Trust Fund Details 1. Number of instruments (enter details for each) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company Issuing Rating 2. Credit ratings not used a. Describe proof Trust Fund Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned c. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: includes required conditions coverage: y/n 2. (Upload) Instruments (zip)				
§146.85(a)(1)(ii)		Surety Bonds.	Financial Responsibility Demo. - Table 3	Surety Bond Details 1. Number of bond instruments (fill in for each) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company Issuing Rating 2. Credit ratings not used 3. Describe proof Security Bond Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires Type of Bond 1. Performance Bond 2. Financial Guarantee Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned c. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: includes required conditions coverage: y/n 2. (Upload) Instruments (zip) Standby Trust 1. Not created 2. Created a. Issuing institution b. Value c. Date issued or amended d. Date expires Instruments 1. (Upload) Instruments (zip)				9.3

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(1)(iii)		Letter of Credit.	Financial Responsibility Demo. - Table 4	Letter of Credit Details 1. Number of instruments (fill out for each one) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company issuing Rating 2. Credit ratings not used 3. Describe proof Letter of Credit Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-Injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned c. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: includes required conditions coverage: y/n 2. (Upload) Instruments (zip) Standby Trust 1. Not created 2. Created a. Issuing institution b. Value c. Date issued or amended 3. Date expires Instruments 1. (Upload) Instruments (zip)				
§146.85(a)(1)(iv)		Insurance	Financial Responsibility Demo. - Table 5	Third Party Insurance Details 1. Number of instruments (fill out for each one) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company issuing Rating 2. Credit ratings not used 3. Describe proof Policy Details 1. Date Policy active with description 2. Date policy expires with description Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-Injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned 3. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: includes required conditions coverage: y/n 2. (Upload) Instruments (zip)				
§146.85(a)(1)(v)		Self Insurance (i.e., Financial Test and Corporate Guarantee).	Financial Responsibility Demo. - Table 7	Self-Insurance Details 1. Yes: Corporate guarantee a. Parent Company Name b. Parent owns % Subsidiary Stock c. Years in business 2. Supporting Documentation a. Audited Financial statements; submitted date b. Auditor's special report; submitted date Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-Injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Total Liability 1. Cost covered GS phases 2. Sum Company's financial responsibilities currently met (financial test; Corporate guarantee: Inc. CERCLA and RCRA) Financial Coverage Criteria 1. Passes (A) coverage criteria & either (B) Financial Ratio Test or (C) Bond Rating Test (A) coverage criteria 1. Net working capital 2. Tangible Net Worth 3. Total Assets 4. Domestic Assets (B) Financial Ratio Test 1. Debt-Equity Ratio 2. Asset-Liability Ratio 3. Cash Return on Liabilities Ratio 4. Liquidity				

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
				5. Net Profit (C) Bond Rating Test 1. Name of Company 2. Bond Rating 3. Rating Date 4. Company Issuing Rating Instrument Language (Trust Agreement Template) 1. Used recommended template language? 2. Yes 3. No: Includes required conditions coverage: y/n 4. (Upload) Instruments (zip)				
§146.85(a)(1)(vi)		Escrow Account	Financial Responsibility Demo. - Table 6	Escrow Account Details 1. Number of Instruments (fill out for each one) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of Issuing Institution b. Credit Rating c. Rating Date d. Company Issuing Rating 2. Credit ratings not used 3. Describe proof Escrow Account Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned 3. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: Includes required conditions coverage: y/n Standby Trust 1. Not created 2. Created a. Issuing Institution b. Value c. Date issued or amended 3. Date expires Instruments 1. (Upload) Instruments (zip)				
§146.85(a)(1)(vii)		Any other instrument(s) satisfactory to the Director.	Financial Responsibility Demo. - Table 8	Other Instrument Details 1. Number of Instruments (fill out for each one) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of Issuing Institution b. Credit Rating c. Rating Date d. Company Issuing Rating 2. Credit ratings not used 3. Describe proof Bank Assigned Instrument Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Instrument Language (Trust Agreement Template) 1. Includes required conditions coverage: y/n Standby Trust 1. Not created 2. Created a. Issuing Institution b. Value c. Date issued or amended 3. Date expires Instruments 1. (Upload) Instruments (zip)				
§146.85(a)(2)		The qualifying instrument(s) must be sufficient to cover the cost of:			§3.203 (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
§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).						

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(3)		The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	AoR Corrective Action - Table 2	2. Potential USDW endangerment **Check AoR Corrective Action Doc**				9.2
§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.						9.3
§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.						
§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.						9.3
§146.85(a)(5)(i)		The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).						
§146.85(a)(5)(ii)		The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.						9.8
§146.85(a)(5)(iii)		The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.						
§146.85(a)(6)		The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.						
§146.85(a)(6)(i)		In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.						

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(6)(ii)		When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	Financial Responsibility Demo. - Table 5	(?) Third Party Insurance Details 1. Number of instruments (fill out for each one) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company issuing Rating 2. Credit ratings not used b. Describe proof Policy Details 1. Date Policy active with description 2. Date policy expires with description Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned 3. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: Includes required conditions coverage: y/n				
§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.	Financial Responsibility Demo. - Table 2	Trust Fund Details 1. Number of instruments (enter details for each) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company issuing Rating 2. Credit ratings not used a. Describe proof Trust Fund Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned c. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: Includes required conditions coverage: y/n 2. (Upload) Instruments (zip)				
§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.	Financial Responsibility Demo. - Table 6	Escrow Account Details 1. Number of instruments (fill out for each one) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company issuing Rating 2. Credit ratings not used b. Describe proof Escrow Account Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-injection Site Care and Site Closure 4. Emergency and Remedial Response More than one instrument for a single phase 1. No 2. Yes: value Is a pay-in-period in use 1. No 2. Yes: Number of payments (for each) a. Value b. Date planned 3. Date deposit make Instrument Language (Trust Agreement Template) 1. Used recommended template language? a. Yes b. No: Includes required conditions coverage: y/n				

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
				Statutory Trust 1. Not created 2. Created a. Issuing Institution b. Value c. Date issued or amended d. Date expires Instruments 1. (Upload) Instruments (zip)				
§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.	Financial Responsibility Demo. - Table 7	Self-Insurance Details 1. Yes: Corporate guarantee a. Parent Company Name b. Parent owns % Subsidiary Stock c. Years in business 2. Supporting Documentation a. Audited Financial statements; submitted date b. Auditor's special report; submitted date Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-Injection Site Care and Site Closure 4. Emergency and Remedial Response More than one Instrument for a single phase 1. No 2. Yes: value Total Liability 1. Cost covered GS phases 2. Sum Company's financial responsibilities currently met (financial test; Corporate guarantee: Inc. CERCLA and RCRA) Financial Coverage Criteria 1. Passes (A) coverage criteria & either (B) Financial Ratio Test or (C) Bond Rating Test (A) coverage criteria 1. Net working capital 2. Tangible Net Worth 3. Total Assets 4. Domestic Assets (B) Financial Ratio Test 1. Debt-Equity Ratio 2. Asset-Liability Ratio 3. Cash Return on Liabilities Ratio 4. Liquidity 5. Net Profit (C) Bond Rating Test 1. Name of Company 2. Bond Rating 3. Rating Date 4. Company Issuing Rating Instrument Language (Trust Agreement Template) 1. Used recommended template language? 2. Yes 3. No: Includes required conditions coverage: y/n 4. (Upload) Instruments (zip)				
§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:						9.9
§146.85(b)(1)(i)		The Director receives and approves the completed post-injection site care and site closure plan; and	Injection and Post-Injection Phase - Table 8	Validate Required Fields 1. Required check for blank fields Authorized submission 1. Must have completed an EPA Electronic Signature Agreement 2. Submit means you agree to the certification.				9.9
§146.85(b)(1)(ii)		The Director approves site closure.	Injection and Post-Injection Phase - Table 8	Validate Required Fields 1. Required check for blank fields Authorized submission 1. Must have completed an EPA Electronic Signature Agreement 2. Submit means you agree to the certification.				9.9
§146.85(b)(2)		The owner or operator may be released from a financial instrument in the following circumstances:						
§146.85(b)(2)(i)		The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or						
§146.85(b)(2)(ii)		The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.						

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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.	Financial Responsibility Demo. - Table 1?	(?) Cost Estimates 1. 3rd party company providing estimates a. Cost and Date for the 4 phases. 2. Year of dollars -? Cost Estimate File 1. Cost estimates and all supporting documents (zip) Additional Cost Information 1. Additional documents for primacy state needs Description of information submitted 1. Summary of information in files				9.4, 9.5, 9.6, 9.7
§146.85(c)(1)		The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.	Financial Responsibility Demo. - Table 1?	(?) Cost Estimates 1. 3rd party company providing estimates a. Cost and Date for the 4 phases. 2. Year of dollars -? Cost Estimate File 1. Cost estimates and all supporting documents (zip) Additional Cost Information 1. Additional documents for primacy state needs Description of information submitted 1. Summary of information in files				9.3
§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).	Financial Responsibility Demo. - Table 1?					9.8
§146.85(c)(3)		The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.	Financial Responsibility Demo. - Table 1?	(?) Cost Estimates 1. 3rd party company providing estimates a. Cost and Date for the 4 phases. 2. Year of dollars -? Cost Estimate File 1. Cost estimates and all supporting documents (zip) Additional Cost Information 1. Additional documents for primacy state needs Description of information submitted 1. Summary of information in files				
§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.	Financial Responsibility Demo. - Table 1?					9.8
§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.	Financial Responsibility Demo. - Table 9	Certification 1. Received certified mail copy of notification 2. Electronic notification submitted a. (Upload) file b. Supplemental material c. Comments				9.3.1
§146.85(d)(1)		In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.						
§146.85(d)(2)		A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.						

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(d)(3)		An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.	Financial Responsibility Demo. - Tables 2-7	Trust Fund Details 1. Number of instruments (enter details for each) Proof of Third-Party Financial Strength 1. Credit ratings used a. Name of issuing institution b. Credit Rating c. Rating Date d. Company Issuing Rating 2. Credit ratings not used a. Describe proof Trust Fund Number 1. Enter number 2. Date instrument issued or amended 3. Date instrument expires ...Self-Insurance Details 1. Yes: Corporate guarantee a. Parent Company Name b. Parent owns % Subsidiary Stock c. Years in business 2. Supporting Documentation a. Audited Financial statements; submitted date b. Auditor's special report; submitted date				
§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).	Financial Responsibility Demo. - Table 7	Self-Insurance Details 1. Yes: Corporate guarantee a. Parent Company Name b. Parent owns % Subsidiary Stock c. Years in business 2. Supporting Documentation a. Audited Financial statements; submitted date b. Auditor's special report; submitted date Phases Covered by Instrument 1. Corrective Action on Deficient wells 2. Plugged Injection Well 3. Post-Injection Site Care and Site Closure 4. Emergency and Remedial Response				
§146.85(f)	Financial Responsibility	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	Financial Responsibility Demo. - Table 6	Escrow Account Details 1. Number of instruments (fill out for each one)				
§146.86 - Injection well construction requirements								
§146.86	Injection well construction requirements				§3.203 (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:	Project Info - Table 17	Injection Well Construction: schematics/graphics of surface & subsurface construction New or existing well (upload details showing compliance) Narrative description of all well schematics Proposed Stimulation Program When and why it is needed Methods used; with how containment will be maintained an no new fractures will be ensured. Chemicals planned for use in stimulation; potential compatibility issues between chemicals and either the injection or confining zones. How the maximum safe injection pressure was determined. (be explicit) Construction Procedures Specific details supporting chosen method, with respect to mechanical integrity and down-hole stresses Detailed construction materials, and the appropriate standard: API, ASTM ... Compatibility with CO2 and formation fluids, with specific method of determination May be located elsewhere -- be specific where Highlight protection of the USDW: prevention of fluid movement Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus Contingency plans for drilling or completion issues that may impact the USDW Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details	§3.203 (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.	
					§3.203 (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;	Project Info - Table 17	Highlight protection of the USDW: prevention of fluid movement	§3.203 (e)(1)(A)(i)	Injection well construction	Prevent the movement of injected CO2 or displaced fromation fluids into any unauthorized zones or into any areas where they could endanger USDWs;	4.1
§146.86(a)(2)	Injection well construction requirements	Permit the use of appropriate testing devices and workover tools; and	Project Info - Table 17	Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus	§3.203 (e)(1)(A)(ii)	Injection well construction	Allow the use of appropriate testing devices and workover tools; and	4.2
§146.86(a)(3)	Injection well construction requirements	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	Project Info - Table 17	(*) Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus	§3.203 (e)(1)(A)(iii)	Injection well construction	Allow continuous monitoring of the annulus space between the injection tubing and long string casing.	4.2; 5.5
§146.86(b)	Injection well construction requirements	Casing and cementing of Class VI wells.			§3.203 (e)(1)(B)	Injection well construction	Casing and Cementing of anthropogenic CO2 injection wells	
§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	Project Info - Table 17	Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration	§3.203 (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

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
		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:		Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details Well Operation Provide text, tables, and/or figures to fulfill the operating data requirements for the permit application; Also include or attach any other information necessary to demonstrate/establish compliance.	§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);	4.2.1, 4.2.4. 4.2.7, 4.2.10, 4.2.13, 4.2.16
§146.86(b)(1)(ii)	Injection well construction requirements	Injection pressure, external pressure, internal pressure, and axial loading;	Injection and Post-Injection Phase - Table 3-4	Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure UIC Program Class VI Well Testing and Monitoring Guidance 1. all available results for these parameters 2. Uploaded separately under supplemental or incorporated in the next entry Carbon Dioxide Volume/Mass Injected and Annular Fluid Added UIC Program Class VI Well Testing and Monitoring Guidance 1. CO2 injected stream in one or more tables a. Monthly volume/mass b. Cumulative (over life of project) 2. Monthly Annulus fluid added Table 4: Testing Information CFR and Guidance External Mechanical Integrity Testing 1. Pass or Fail 2. Well repairs Pressure Fall-Off Testing 1. Operating conditions pre-test 2. Need for additional tests; data gap or result driven 3. Compare to earlier results				4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§146.86(b)(1)(iii)	Injection well construction requirements	Hole size;			§5.203 (e)(2)(B)	Injection well construction	Hole size	4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§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);	Project Info - Table 17	Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details Well Operation Provide text, tables, and/or figures to fulfill the operating data requirements for the permit application; Also include or attach any other information necessary to demonstrate/establish compliance.	§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);	4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§146.86(b)(1)(v)	Injection well construction requirements	Corrosiveness of the carbon dioxide stream and formation fluids;	Injection and Post-Injection Phase Reporting - Table 2, Sec. 2	2. any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream compared to the proposed operating data.	§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 G
§146.86(b)(1)(vi)	Injection well construction requirements	Down-hole temperatures;	Project Info - Table 14, Sec. 2, Pt. a-b	a. If the sample was pumped, flow rate, type of pump, and location of the pump, and geochemical modeling results indicating the likely geochemical makeup of the fluids at downhole conditions; b. Data for field measurements (pH, SC, temperature, pressure);	§5.203 (e)(2)(G)	Injection well construction	Down-hole temperatures and pressures	4.2, 4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§146.86(b)(1)(vii)	Injection well construction requirements	Lithology of injection and confining zone(s);	Project Info - Table 8, Sec. 4	4. Description of the confining strata beneath injection zone including lithology and rock properties.	§5.203 (e)(2)(H)	Injection well construction	Lithology of injection and confining zone(s)	1.3.1; 1.3.2; 1.3.3
§146.86(b)(1)(viii)	Injection well construction requirements	Type or grade of cement and cement additives; and	Project Info - Table 17	Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration	§5.203 (e)(2)(I)	Injection well construction	Type or grade of cement and cement additives; and	4.2.2; 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17; Appendix F
§146.86(b)(1)(ix)	Injection well construction requirements	Quantity, chemical composition, and temperature of the carbon dioxide stream.	Injection and Post-Injection Phase Reporting - Table 2, Sec. 2	2. any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream compared to the proposed operating data.	§5.203 (e)(2)(J)	Injection well construction	Quantity, chemical composition, and temperature of the carbon dioxide stream.	4.2
					§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.	4.2.2; 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17; Appendix F
§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.	Project Info - Table 17	Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration	§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	4.2.1, 4.2.4, 4.2.7, 4.2.10, 4.2.13, 4.2.16

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§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.	Project Info - Table 17	(*) Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration	§3.203 (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).	4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§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.	Project Info - Table 17	(*) Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration	§3.203 (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.	Project Info - Table 17	(*) Casing and Cementing Inc. GSDT Narr. Table 1 Casing Details Conditions that will affect performance: such as • avg. down-hole temperature • expected life Discuss structural strength of casing and changes over time; Type of cement, volume estimates and additives, and planned procedure (staged or not, ...) Describe mechanical integrity assurance and demonstration	§3.203 (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.			§3.203 (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.	Project Info - Table 17	Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details				4.2.1, 4.2.4, 4.2.7, 4.2.10, 4.2.13, 4.2.16, Appendix F
§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.	Project Info - Table 17	Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details (Well Operation Provide text, tables, and/or figures to fulfill the operating data requirements for the permit application; Also include or attach any other information necessary to demonstrate/establish compliance.)	§3.203 (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, 4.2.4, 4.2.7, 4.2.10, 4.2.13, 4.2.16, Appendix F
					§3.203 (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
§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, 4.2.4, 4.2.7, 4.2.10, 4.2.14, 4.2.17
§146.86(c)(3)(ii)	Injection well construction requirements	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Project Info - Table 17 / Inc. GSDT Narr. Table 3	Proposed Carbon Dioxide Stream Planned source(s) of the CO2 Physical and chemical characteristics of the stream; method of determination Corrosivity of the stream and behavior under operating conditions downhole; over the lifetime of the project				1.7.2; 4.2, 4.3.3
§146.86(c)(3)(iii)	Injection well construction requirements	Maximum proposed injection pressure;	Project Info - Table 17	Proposed Stimulation Program When and why it is needed Methods used; with how containment will be maintained an no new fractures will be ensured. Chemicals planned for use in stimulation; potential compatibility issues between chemicals and either the injection or confining zones. How the maximum safe injection pressure was determined. (be explicit)				4.3.5
§146.86(c)(3)(iv)	Injection well construction requirements	Maximum proposed annular pressure;	Injection and Post-Injection Phase Reporting - Table 3	Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure 1. all available results for these parameters 2. Uploaded separately under supplemental or incorporated in the next entry				4.3.5
§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;	Injection and Post-Injection Phase Reporting - Table 3	Carbon Dioxide Volume/Mass Injected and Annular Fluid Added 1. CO2 injected stream in one or more tables a. Monthly volume/mass b. Cumulative (over life of project) 2. Monthly Annulus fluid added	§3.203 (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;	4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
					§3.203 (e)(2)(E)	Injection well construction	type of packer and packer setting depth	4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§146.86(c)(3)(vi)	Injection well construction requirements	Size of tubing and casing; and	Project Info - Table 17	(*) Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details (Well Operation Provide text, tables, and/or figures to fulfill the operating data requirements for the permit application; Also include or attach any other information necessary to demonstrate/establish compliance.)				4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17

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§146.86(c)(3)(vii)	Injection well construction requirements	Tubing tensile, burst, and collapse strengths.	Project Info - Table 17	(*) Tubing and Packer Inc. GSDT Narr. Table 2 Tubing and Packer details (Well Operation Provide text, tables, and/or figures to fulfill the operating data requirements for the permit application; Also include or attach any other information necessary to demonstrate/establish compliance.)				4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§146.87 - Logging, sampling, and testing prior to injection well operation								
§146.87		Logging, sampling, and testing prior to injection well operation						
§146.87(a)	Logging, sampling, and testing prior to injection well operation	During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	Pre-Operational Testing - Table(s) 7-9	Logging and Testing 40 CFR 146.82(c)(4),(7) and 146.87: LAC §3619.A.4, 3619.A.7, and 3619.B 1. Narrative of results from required 40 CFR 146.82(a)(8) procedures. a. Synthesize all the above, referencing applicable 40 CFR 146.82(a)(8) requirements. b. (results are submitted in the Pre-Op testing module.) c. Suitability of injection and confining zones. 2. Description of all uploaded files for 40 CFR 146.87. Table 8: Transition from different class well to Class VI Information CFR and Guidance Location & File: GSDT or CBI? Transition from different class well to Class VI 1. Previously collected testing, monitoring and logging data. Table 9: Pre-Operational Logging and Testing Information CFR and Guidance Location & File: GSDT or CBI? Well Logging Core Analyses Characterization of Injection Formation Fluid Properties Fracture Pressure of the Injection and Confining Zones Hydrogeologic Testing Pressure Fall-Off Tests Injectivity and Pump Tests 40 CFR 146.82(c)(4),(7) and 146.87: LAC §3619.A.4, 3619.A.7, and 3619.B 40 CFR 146.87(a)(2) and (3); LAC §3617.B.1.b and 3617.B.1.c §§3617.B.2 and 3617.B.3 40 CFR 146.87(b) 40 CFR 146.87(b) and (c); LAC §3617.B.4.a 40 CFR 146.87(d)(1): LAC §3617.B.5.a through 3617.B.5.c 40 CFR 146.87(e)(1)-(3)	§3.203 (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, 4.3.2, 4.3.3
					§3.203 (f)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The applicant must submit a plan for logging, sampling, and testing of each injection well after permitting but prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.	4.3.1, 4.3.2, 4.3.3
					§3.203 (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, 4.3.2, 4.3.3
§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	Pre-Operational Testing - Table 14	Table 14: Well and Cement Logs Information CFR and Guidance Location & File: GSDT or CBI? Details 1. Number of wells tested (for each well) Location 1. Latitude 2. Longitude 3. Well Name During Drilling 1. Deviation Checks 2. Other: explain	§3.203 (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:	Pre-Operational Testing - Table 14	(*) Pre-Surface Casing Logs (basic list) 1. Resistivity 2. SP 3. Caliper 4. Other: explain				
§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	Pre-Operational Testing - Table 14	Pre-Surface Casing Logs (basic list) 1. Resistivity 2. SP 3. Caliper 4. Other: explain	§3.203 (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.	
§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.	Pre-Operational Testing - Table 14	Post-any Casing Logs 1. Cement Bond 2. Variable Density 3. Other: explain				
§146.87(a)(3)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the long string casing:	Pre-Operational Testing - Table 14	Pre-Long String Casing Logs (+basic list) 1. Gamma Ray 2. Fracture Finder	§3.203 (f)(1)(D)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.	
§146.87(a)(3)(i)	Logging, sampling, and testing prior to injection well operation	Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	Pre-Operational Testing - Table 14	(Pre-Long String Casing Logs (+basic list)) 1. Gamma Ray 2. Fracture Finder				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.	Pre-Operational Testing - Table 14	Post-any Casing Logs 1. Cement Bond 2. Variable Density 3. Other: explain	§3.203 (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.	4.3.2

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	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.	5.4.1
§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:	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Lot 6. Other (approved)	§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:	
§146.87(a)(4)(i)	Logging, sampling, and testing prior to injection well operation	A pressure test with liquid or gas;	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Lot 6. Other (approved)	§5.203 (h)(2)(A)	Mechanical integrity testing	A pressure test with liquid or gas;	5.4.1
§146.87(a)(4)(ii)	Logging, sampling, and testing prior to injection well operation	A tracer survey such as oxygen-activation logging;	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Lot 6. Other (approved)	§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;	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Lot 6. Other (approved)	§5.203 (h)(2)(C)	Mechanical integrity testing	A temperature or noise log;	5.4.2
§146.87(a)(4)(iv)	Logging, sampling, and testing prior to injection well operation	A casing inspection log; and	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Lot 6. Other (approved)	§5.203 (h)(2)(D)	Mechanical integrity testing	A casing inspection log; and	5.4.4
§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.	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Lot 6. Other (approved)	§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.	Pre-Operational Testing - Table 9	Well Logging Core Analyses Characterization of Injection Formation Fluid Properties Fracture Pressure of the Injection and Confining Zones Hydrogeologic Testing Pressure Fall-Off Tests Injectivity and Pump Tests 1. Narrative of formation testing program required by 40 CFR 146.82(a)(8). a. Synthesize comprehensive understanding of site-specific geology and hydrology, and reference Class VI rule requirements at 40 CFR 146.82(a)(8) as applicable. b. (Results submitted directly to the GSDT's Pre-Operational Testing module.) c. Description of the files uploaded for 40 CFR 146.87. d. Match original filing requirements/ recommendations	§5.203 (f)(3)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must submit analyses of whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well.	4.3.1, 4.3.2
§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).	Project Info - Table 14	Injection Zone Details 1. Number of Formations (or distinct units/zones) (for each) Formation/Zone Properties 1. Formation/Zone Name 2. Fluid Temperature 3. pH 4. Conductivity 5. Reservoir Pressure 6. Static Fluid Level 7. List other Physical/Chemical Parameters of the Formation 8. List other Physical/Chemical Parameters of the Formation Fluids	§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

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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):	Project Info - Table 13	Injection Zone Details 1. Number of Formations (or distinct units/zones) (for each) Formation/Zone Properties 1. Formation/Zone Name 2. Fluid Temperature 3. pH 4. Conductivity 5. Reservoir Pressure 6. Static Fluid Level 7. List other Physical/Chemical Parameters of the Formation 8. List other Physical/Chemical Parameters of the Formation Fluids	§3.203 (f)(2)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Testing and determination of hydrogeologic characteristics of injection and confining zone.	
§146.87(d)(1)	Logging, sampling, and testing prior to injection well operation	Fracture pressure;	Pre-Operational - Table 17	Injection Zone Details 1. Number of Formations (or distinct units/zones) (for each) Formation/Zone Properties 1. Formation/Zone Name 2. Fluid Temperature 3. pH 4. Conductivity 5. Reservoir Pressure 6. Static Fluid Level 7. List other Physical/Chemical Parameters of the Formation 8. List other Physical/Chemical Parameters of the Formation Fluids	§3.203 (f)(2)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone	1.6.2.3; 1.6.2.4; 4.3.5
§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	Pre-Operational - Table 17	Injection Zone Details 1. Number of Formations (or distinct units/zones) (for each) Formation/Zone Properties 1. Formation/Zone Name 2. Fluid Temperature 3. pH 4. Conductivity 5. Reservoir Pressure 6. Static Fluid Level 7. List other Physical/Chemical Parameters of the Formation 8. List other Physical/Chemical Parameters of the Formation Fluids				1.3.1, 1.3.2, 1.3.3, 1.7.3, 1.7.4.3; 4.3.1, 4.3.2
§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).	Pre-Operational - Table 17	Injection Zone Details 1. Number of Formations (or distinct units/zones) (for each) Formation/Zone Properties 1. Formation/Zone Name 2. Fluid Temperature 3. pH 4. Conductivity 5. Reservoir Pressure 6. Static Fluid Level 7. List other Physical/Chemical Parameters of the Formation 8. List other Physical/Chemical Parameters of the Formation Fluids				1.7.2, 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):	Pre-Operational - Table 17	Injection Zone Details 1. Number of Formations (or distinct units/zones) (for each) Formation/Zone Properties 1. Formation/Zone Name 2. Fluid Temperature 3. pH 4. Conductivity 5. Reservoir Pressure 6. Static Fluid Level 7. List other Physical/Chemical Parameters of the Formation 8. List other Physical/Chemical Parameters of the Formation Fluids				
§146.87(e)(1)	Logging, sampling, and testing prior to injection well operation	A pressure fall-off test; and,	Project Plan Submissions - Table 8	Pressure Fall-Off Testing 1. Testing location and frequency: inc. timing 2. Testing details: a. Specific procedures b. Gauges or other equipment (range, precision...)	§3.203 (f)(2)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO2.	3.4.3, 3.4.3.1, 3.4.3.2
§146.87(e)(2)		A pump test; or	Pre-Operational - Table 18	Tests Conducted 1. Pressure Fall-Off Test 2. Pump Test 3. Injectivity Test 4. Other: specify				
§146.87(e)(3)		Injectivity tests.	Pre-Operational - Table 18	Tests Conducted 1. Pressure Fall-Off Test 2. Pump Test 3. Injectivity Test 4. Other: specify				4.3.3
§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.	Pre-Operational - Table 7	Logging and Testing 1. Narrative of results from required 40 CFR 146.82(a)(8) procedures. a. Synthesize all the above, referencing applicable 40 CFR 146.82(a)(8) requirements. b. (results are submitted in the Pre-Op testing module.) c. Suitability of injection and confining zones. 2. Description of all uploaded files for 40 CFR 146.87.	§3.206 (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.	4.3
§146.88 - Injection well operating requirements								
§146.88		Injection well operating requirements						
					§3.203 (i)(2)	Operating Information	Maximum injection pressure. The director will approve a maximum injection pressure limit that:	4.3.5

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
					§5.203 (i)(2)(A)	Operating Information	Considers the risks of tensile failure and, where appropriate, geomechanical or other studies that assess the risk of tensile failure and shear failure;	4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
					§5.203 (i)(2)(B)	Operating Information	With a reasonable degree of certainty will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive; and	4.3.5
§146.88(a)	Injection well operating requirements	Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation	Injection and Post-Injection - Table 3	Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure 1. all available results for these parameters 2. Uploaded separately under supplemental or incorporated in the next entry	§5.203 (i)(2)(C)	Operating Information	in no case may cause the movement of injection fluids or formation fluids in a manner that endangers USDWs.	4.1
					§5.203 (f)(2)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone	1.6.2.3, 1.6.2.4, 4.2
§146.88(b)	Injection well construction requirements	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Project Info - Table 17 / Pre-Operational Testing - Table 12	Construction Procedures Specific details supporting chosen method, with respect to mechanical integrity and down-hole stresses Detailed construction materials, and the appropriate standard: API, ASTM ... Compatibility with CO2 and formation fluids, with specific method of determination May be located elsewhere – be specific where Highlight protection of the USDW: prevention of fluid movement Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus Contingency plans for drilling or completion issues that may impact the USDW Plan Updates 1. Results of MIT per 40 CFR 146.82(c)(8). 2. Support 40 CFR 146.89. a. Which approved methods used. b. Evidence of leaks or fluid movement in the wellbore. c. Results cause changes in the testing and monitoring plan? 3. Upload revised plans	§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.	Project Info - Table 17	(*) Construction Procedures Specific details supporting chosen method, with respect to mechanical integrity and down-hole stresses Detailed construction materials, and the appropriate standard: API, ASTM ... Compatibility with CO2 and formation fluids, with specific method of determination May be located elsewhere – be specific where Highlight protection of the USDW: prevention of fluid movement Practicality for testing and monitoring devices that are planned or may be needed; access to the borehole or annulus Contingency plans for drilling or completion issues that may impact the USDW	§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.	4.2.2, 4.2.5, 4.2.8, 4.2.11, 4.2.14, 4.2.17
§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.	Pre-Operational Testing - Table 12	(*) Plan Updates 1. Results of MIT per 40 CFR 146.82(c)(8). 2. Support 40 CFR 146.89. a. Which approved methods used. b. Evidence of leaks or fluid movement in the wellbore. c. Results cause changes in the testing and monitoring plan? 3. Upload revised plans	§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.	Project Plan Submissions - Table 7	External Mechanical Integrity Testing (loosely related...) 1. Testing location and frequency: a. Specific timing of MITs (table: test & location) 2. Testing details (each test) a. specific procedures b. gauges or equipment; range, precision, etc. c. define pass or fail d. additional data for 'no significant leak' e. MITs in monitoring wells (include in table)	§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	Injection and Post-Injection Phase Reporting - Table 3	Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure 1. all available results for these parameters 2. Uploaded separately under supplemental or incorporated in the next entry Carbon Dioxide Volume/Mass Injected and Annular Fluid Added 1. CO2 injected stream in one or more tables a. Monthly volume/mass b. Cumulative (over life of project) 2. Monthly Annulus fluid added	§5.206 (d)(2)(F)(i)	Operating a geologic storage facility	The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	5.5
§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	Region 6 Crosswalk Document	R6 Text / Comments	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	8.6.1, 8.6.2
§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;	8.6.1, 8.6.2
§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	8.6.1, 8.6.2
§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	8.6.1, 8.6.2
§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	8.6.1, 8.6.2
§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	8.6.1, 8.6.2
§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.	5.4.1
§146.89(b)	Mechanical Integrity	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Project Plan Submission - Table 4	Continuous Recording of Operational Parameters 1. Monitoring location and frequency (table): parameter, device, location, min sampling & recording frequencies 2. Monitoring details: for each parameter, refer to table a. Specific location b. equipment/instrumentation c. how often sampled/recorded d. formulas or conversion factors (citations) e. deviation from baseline, predicted, or average values f. support internal mechanical integrity g. changes in injection rate or annular pressure trigger additional sample collection or change the sampling schedule	§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 confirm that the injected fluids are confined to the injection zone.	5.5
§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:	Project Plan Submission - Table 7	External Mechanical Integrity Testing 1. Testing location and frequency: a. Specific timing of MITs (table: test & location) 2. Testing details (each test) a. specific procedures b. gauges or equipment; range, precision, etc. c. define pass or fail d. additional data for 'no significant leak' e. MITs in monitoring wells (include in table)	§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).	5.5
§146.89(c)(1)	Mechanical Integrity	An approved tracer survey such as an oxygen-activation log; or	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Log 6. Other (approved) Reports 1. Number of reports (Uploaded) 2. Description of file (for each) Notes 1. Additional notes				
§146.89(c)(2)	Mechanical Integrity	A temperature or noise log.	Pre-Operational Testing - Table 13	Tests for Internal & External Mechanical Integrity 1. Pressure test (liquid or gas) 2. Tracer Survey: specific name 3. Temperature Log 4. Noise Log 5. Casing Inspection Log 6. Other (approved) Reports 1. Number of reports (Uploaded) 2. Description of file (for each) Notes 1. Additional notes				
§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.	Injection and Post-Injection Phase Reporting - Table 3	Corrosion Monitoring 1. Operational activities that may be related 2. Is accelerated corrosion suggested?				

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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.	Pre-Operational Testing - Table 12	Plan Updates 1. Results of MIT per 40 CFR 146.82(c)(8). 2. Support 40 CFR 146.89. a. Which approved methods used. b. Evidence of leaks or fluid movement in the wellbore. c. Results cause changes in the testing and monitoring plan? 3. Upload revised plans				
§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.	Pre-Operational Testing - Table 12	(*) Plan Updates 1. Results of MIT per 40 CFR 146.82(c)(8). 2. Support 40 CFR 146.89. a. Which approved methods used. b. Evidence of leaks or fluid movement in the wellbore. c. Results cause changes in the testing and monitoring plan? 3. Upload revised plans				
§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.	Pre-Operational Testing - Table 12	a. Which approved methods used. b. Evidence of leaks or fluid movement in the wellbore. c. Results cause changes in the testing and monitoring plan? 1. Upload revised plans	§3.206 (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	Project Plan Submissions - Table 7	1. Testing location and frequency: a. Specific timing of MITs (table: test & location) 2. Testing details (each test) a. specific procedures b. gauges or equipment; range, precision, etc. c. define pass or fail d. additional data for 'no significant leak' e. MITs in monitoring wells (include in table)	§3.203 (j)	Plan for monitoring, sampling, and testing after initiation of operation	Plan for monitoring, sampling, and testing after initiation of operation.	Section 3
					§3.203 (j)(1)	Plan for monitoring, sampling, and testing after initiation of operation	The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.	Section 3
					§3.203 (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;	Project Plan Submissions - Table 3	Carbon Dioxide Stream Analysis 1. Sampling location and frequency a. specific schedule for CO2 stream sampling b. How was this "sufficient frequency" 2. Baseline deviation: predicted, or average values 3. Changes in sampling based on results/deviations a. shut-in for X time, the CO2 stream analyzed X (days, weeks) after ops resume. b. Define alternative CO2 stream sampling schedule based on injected amount, not time, triggered if permit modified or if injection activities deviate significantly (define) from expected rates (e.g., if injection volume is less than X over X period). c. A significant (define) change in chemical or physical characteristics of the CO2 stream will trigger additional sampling at a frequency of X to collect sufficient data to characterize the CO2 stream 4. Details of any tracer plan 5. Analytical parameters: table with method 6. Sampling methods a. Where collected b. What materials/equipment used? c. What sample collection procedures for representative sample? (Refer to the QASP as appropriate.) 7. Laboratory to be used/chain of custody and analysis procedures a. Where analyzed b. What chain of custody procedures (Refer to QASP) c. What detection limits for analytical methods (Refer to QASP)	§3.203 (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;	3.3.3
§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;	Project Plan Submissions - Table 4	Continuous Recording of Operational Parameters 1. Monitoring location and frequency (table): parameter, device, location, min sampling & recording frequencies 2. Monitoring details: for each parameter, refer to table a. Specific location b. equipment/instrumentation c. how often sampled/recorded d. formulas or conversion factors (citations) e. deviation from baseline, predicted, or average values f. support internal mechanical integrity g. changes in injection rate or annular pressure trigger additional sample collection or change the sampling schedule	§3.203 (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	3.3

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§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:	Project Plan Submissions - Table 5	Corrosion Monitoring 1. Monitoring location and frequency a. Specific schedule b. Additional monitoring if deviation 2. Sample description: (table: component & construction material): a. Which materials monitored b. Baseline assessment 3. Monitoring details c. Design for representative conditions d. Techniques to assess & quantify (citations) e. deviation from baseline, predicted, or average values f. supplemental tests or logging	§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:	3.5.4
§146.90(c)(1)	Testing and monitoring requirements	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	Project Plan Submissions - Table 5	2. Sample description: (table: component & construction material): a. Which materials monitored b. Baseline assessment	§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	3.5.4.1
§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	Project Plan Submissions - Table 5	1. Monitoring location and frequency a. Specific schedule b. Additional monitoring if deviation	§5.203 (j)(2)(C)(ii)	Plan for monitoring, sampling, and testing after initiation of operation	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	
§146.90(c)(3)	Testing and monitoring requirements	Using an alternative method approved by the Director;			§5.203 (j)(2)(C)(iii)	Plan for monitoring, sampling, and testing after initiation of operation	using an alternative method, materials, or time period approved by the director;	
§146.90(d)	Testing and monitoring requirements	Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	Project Plan Submissions - Table 6	Above Confining Zone Monitoring 1. Monitoring location and frequency: table (Formation, activity, location, spatial coverage, frequency) a. Specific sampling schedule b. Depth/elevaton of each interval c. deviation from baseline, predicted, or average values d. sufficiency of monitoring wells for site e. triggers by geochemical changes f. sufficiently identify leaks/characterize ground water quality above the confining zone g. accompanying indirect monitoring for comprehensive leak detection/ground water monitoring strategy h. phased monitoring planned based on predicted plume migration 2. Analytical parameters: table (Each Formation: parameter & analytical method) a. Why site-specific set of parameters b. Trigger criteria for tracer detection 3. Sampling methods: material used, collection procedures (QASP) 4. Laboratory to be used/chain of custody procedures: detection limits (QASP)	§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;	3.5.5
					§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	3.5
§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).	Project Plan Submissions - Table 6-7	Above Confining Zone Monitoring 1. Monitoring location and frequency: table (Formation, activity, location, spatial coverage, frequency) a. Specific sampling schedule /External Mechanical Integrity Testing 1. Testing location and frequency: a. Specific timing of MITs (table: test & location)	§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;	3.5
§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;	Project Plan Submissions - Table 7	External Mechanical Integrity Testing 1. Testing location and frequency: a. Specific timing of MITs (table: test & location) 2. Testing details (each test) a. specific procedures b. gauges or equipment: range, precision, etc. c. define pass or fail d. additional data for 'no significant leak' e. MITs in monitoring wells (include in table)	§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;	3.4.2
§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;	Project Plan Submission - Table 8	Pressure Fall-Off Testing 1. Testing location and frequency: inc. timing 2. Testing details: a. Specific procedures b. Gauges or other equipment (range, precision...)	§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	3.4.3

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§146.90(g)	Testing and monitoring requirements	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Project Plan Submission - Table 9	Carbon Dioxide Plume and Pressure Front Tracking 1. QASP 2. Plume monitoring location and frequency: (Table: Direct & Indirect: Fm; activity; location; special coverage; freq) 3. Specific schedule 4. Continuous monitoring: how sampled & recorded 5. Mixed location/frequency or adaptive: 6. Triggers & timeframes 7. Maps for locations 8. Depth/elevation of each interval 9. Plume monitoring details (each method): Table (by Fm: parameter, analytical method) a. Output data b. Gauges or other eq. (range, precision, ...) c. QASP: fluid sample collection: materials used, procedures, analysis, COC, detection limits d. Processing methods for geophysical methods e. Deviation form baseline f. proposed combination of direct and indirect monitoring 2. Pressure-front monitoring location and frequency: (Table: Direct & Indirect: Fm; activity; location; special coverage; freq) a. QASP b. Specific schedule c. Continuous monitoring: sampling & recording d. Fixed or adaptive locations e. Depth/elevation of interval f. Output data g. Gauges or other eq. (range, precision, ...) h. QASP: fluid sample collection: materials used, procedures, analysis, COC, detection limits i. Combination direct & indirect 2. Pressure-front monitoring details	§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,	Project Plan Submission - Table 9	Carbon Dioxide Plume and Pressure Front Tracking 1. QASP 2. Plume monitoring location and frequency: (Table: Direct & Indirect: Fm; activity; location; special coverage; freq) 3. Specific schedule 4. Continuous monitoring: how sampled & recorded 5. Mixed location/frequency or adaptive: 6. Triggers & timeframes 7. Maps for locations 8. Depth/elevation of each interval 9. Plume monitoring details (each method): Table (by Fm: parameter, analytical method) a. Output data b. Gauges or other eq. (range, precision, ...) c. QASP: fluid sample collection: materials used, procedures, analysis, COC, detection limits d. Processing methods for geophysical methods e. Deviation form baseline f. proposed combination of direct and indirect monitoring 2. Pressure-front monitoring location and frequency: (Table: Direct & Indirect: Fm; activity; location; special coverage; freq) a. QASP b. Specific schedule c. Continuous monitoring: sampling & recording d. Fixed or adaptive locations e. Depth/elevation of interval f. Output data g. Gauges or other eq. (range, precision, ...) h. QASP: fluid sample collection: materials used, procedures, analysis, COC, detection limits i. Combination direct & indirect 2. Pressure-front monitoring details				3.3.7

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	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;	Project Plan Submission - Table 9	Carbon Dioxide Plume and Pressure Front Tracking 1. QASP 2. Plume monitoring location and frequency: (Table: Direct & Indirect: Fm; activity; location; special coverage; freq) 3. Specific schedule 4. Continuous monitoring: how sampled & recorded 5. Mixed location/frequency or adaptive: 6. Triggers & timeframes 7. Maps for locations 8. Depth/elevation of each interval 9. Plume monitoring details (each method): Table (by Fm: parameter, analytical method) a. Output data b. Gauges or other eq. (range, precision, ...) c. QASP: fluid sample collection: materials used, procedures, analysis, COC, detection limits d. Processing methods for geophysical methods e. Deviation form baseline f. proposed combination of direct and indirect monitoring 2. Pressure-front monitoring location and frequency: (Table: Direct & Indirect: Fm; activity; location; special coverage; freq) a. QASP b. Specific schedule c. Continuous monitoring: sampling & recording d. Fixed or adaptive locations e. Depth/elevation of interval f. Output data g. Gauges or other eq. (range, precision, ...) h. QASP: fluid sample collection: materials used, procedures, analysis, COC, detection limits **i. Combination direct & indirect** 2. Pressure-front monitoring details	§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;	5.5.7
§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.	Project Plan Submission - Table 10	Surface Monitoring: Air or Soil Gas 1. Design based on risk 2. Freq, spatial distr, etc, per 144.12 3. Qualifications under Clean Air Act (cited) and 146.91(c)(3) a. Additional modeling				
§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;	Project Plan Submissions - Table 10	Surface Monitoring: Air or Soil Gas 1. Design based on risk 2. Freq, spatial distr, etc, per 144.12 3. Qualifications under Clean Air Act (cited) and 146.91(c)(3) a. Additional modeling				
§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;	Project Plan Submissions - Table 10	Surface Monitoring: Air or Soil Gas 1. Design based on risk 2. Freq, spatial distr, etc, per 144.12 3. Qualifications under Clean Air Act (cited) and 146.91(c)(3) a. Additional modeling				
§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)(3), 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;	Project Plan Submissions - Table 10	Surface Monitoring: Air or Soil Gas 1. Design based on risk 2. Freq, spatial distr, etc, per 144.12 3. Qualifications under Clean Air Act (cited) and 146.91(c)(3) a. Additional modeling				
§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;	Project Plan Submissions - Table 10	Additional modeling 1. To improve review evaluation	§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	
§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:	Project Plan Submissions - Table 11	Periodic Review of Plan 1. Min every 5 years; with AoR review 2. Amend or demonstrate none needed a. within 1 yr of AoR review b. after significant changes (+monitor or inj well) c. When required by Director				5.3

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§146.90(j)(1)		Within one year of an area of review reevaluation;	Project Plan Submissions - Table 11	Periodic Review of Plan 1. Min every 5 years; with AoR review 2. Amend or demonstrate none needed a. within 1 yr of AoR review b. after significant changes (+monitor or inj well) c. When required by Director				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.	Project Plan Submissions - Table 11	Quality Assurance and Surveillance Plan 1. Appendix	§5.203 (a)(4)	General	Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.	5.4.3.3, 5.5.3.5, 5.5.6.8
§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:	Project Plan Submissions - Table 2	Overall Strategy and Approach for Testing and Monitoring 1. Narrative: the proposed testing and monitoring activities support USDW non-endangerment, and collect sufficient data on site-specific system behavior a. spatial distribution (depth and areal extent) of the proposed monitoring network b. data collection schedule c. collection locations & frequency d. Fit to regional/site & risk profile; inc. seismicity e. How are areas of concern it site char/AoR modeling addressed. f. how will collected data be compared to baseline data, etc. 2. Quality assurance procedures 3. Reporting procedures	§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);	5.2
					§5.207 (a)(2)(D)(iii)	Reporting and Record-Keeping	re-calculated AOR unless the operator submits a statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR on file with the Commission;	5.2
					§5.207 (a)(2)(D)(iv)	Reporting and Record-Keeping	the updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;	5.2
					§5.207 (a)(2)(D)(v)	Reporting and Record-Keeping	tons of CO2 injected; and	5.2
§146.91(e)	Reporting requirements	Semi-annual reports containing:	Injection and Post-Injection Phase Reproting - Table 2	Carbon Dioxide Stream Analysis (include 146.91(e)) 1. Detailed overall results 2. any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream compared to the proposed operating data.	§5.207 (a)(2)(C)	Reporting and Record-Keeping	Semi-annual reports containing:	
§146.91(e)(1)	Reporting requirements	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	Injection and Post-Injection Phase Reproting - Table 2-3	Carbon Dioxide Stream Analysis (include 146.91(e)) 1. Detailed overall results 2. any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream compared to the proposed operating data. /Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure 1. all available results for these parameters 2. Uploaded separately under supplemental or incorporated in the next entry Carbon Dioxide Volume/Mass Injected and Annular Fluid Added 1. CO2 injected stream in one or more tables a. Monthly volume/mass b. Cumulative (over life of project) 2. Monthly Annulus fluid added	§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(e)(2)	Reporting requirements	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	Injection and Post-Injection Phase Reporting - Table 3	Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure 1. all available results for these parameters	§5.207 (a)(2)(C)(i)	Reporting and Record-Keeping	a summary of well head pressure monitoring;	
					§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(e)(3)	Reporting requirements	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	Injection and Post-Injection Phase Reporting - Table 1	1. Summarize the testing and monitoring results over report period with interpretations: 2. For each topic cover appropriate generic information (above), plus a. Exceedances or Shut-offs b. Project milestones c. Unexpected results, trends or fluctuations 3. Compare compatible results 4. QA/QC concerns and how addressed	§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

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§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;			§3.207 (a)(2)(C)(vi)	Reporting and Record-Keeping	a description of any event that triggers a shutdown device and the response taken; and	3.2
§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;	Injection and Post-Injection Phase Reporting - Table 3	Carbon Dioxide Volume/Mass Injected and Annular Fluid Added 1. CO2 injected stream in one or more tables a. Monthly volume/mass b. Cumulative (over life of project) 2. Monthly Annulus fluid added	§3.207 (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;	3.2
§146.91(a)(6)	Reporting requirements	Monthly annulus fluid volume added; and	Injection and Post-Injection Phase Reporting - Table 3	Carbon Dioxide Volume/Mass Injected and Annular Fluid Added 1. CO2 injected stream in one or more tables a. Monthly volume/mass b. Cumulative (over life of project) 2. Monthly Annulus fluid added	§3.207 (a)(2)(C)(iv)	Reporting and Record-Keeping	monthly annulus fluid volume added;	3.2
§146.91(a)(7)	Reporting requirements	The results of monitoring prescribed under § 146.90.	Injection and Post-Injection Phase Reporting - Table 3	Carbon Dioxide Volume/Mass Injected and Annular Fluid Added 1. CO2 injected stream in one or more tables a. Monthly volume/mass b. Cumulative (over life of project) 2. Monthly Annulus fluid added	§3.207 (a)(2)(C)(vii)	Reporting and Record-Keeping	the results of monitoring prescribed under §3.206€ (§3.206(d)) of this title (relating to Permit Standards).	3.2
§146.91(b)	Reporting requirements	Report, within 30 days, the results of:	Injection and Post-Injection Phase Reporting - Table 4	External Mechanical Integrity Testing 1. Pass or Fail 2. Well repairs	§3.207 (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;	Injection and Post-Injection Phase Reporting - Table 4	External Mechanical Integrity Testing 1. Pass or Fail 2. Well repairs	§3.207 (a)(2)(B)(i)	Reporting and Record-Keeping	the results of periodic tests for mechanical integrity;	3.2
§146.91(b)(2)	Reporting requirements	Any well workover; and,	Injection and Post-Injection Phase Reporting - Table 4	External Mechanical Integrity Testing 1. Pass or Fail 2. Well repairs	§3.207 (a)(2)(B)(iii)	Reporting and Record-Keeping	a description of any well workover.	3.2
§146.91(b)(3)	Reporting requirements	Any other test of the injection well conducted by the permittee if required by the Director.	Injection and Post-Injection Phase Reporting - Table 4	External Mechanical Integrity Testing 1. Pass or Fail 2. Well repairs Pressure Fall-Off Testing 1. Operating conditions pre-test 2. Need for additional tests; data gap or result driven 3. Compare to earlier results	§3.207 (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	3.2
§146.91(c)	Reporting requirements	Report, within 24 hours:	Injection and Post-Injection Phase Reporting - Table 6	Emergency and Remedial Response 1. Evidence of USDW Endangerment 2. Noncompliance with a permit condition 3. Triggering of a shut-off system 4. Failure to maintain mechanical integrity 5. Release of CO2 to the atmosphere or biosphere a. Include soil gas or air monitoring 6. Other	§3.207 (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.	
					§3.207 (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.	
					§3.207 (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;	3.2
§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;	Injection and Post-Injection Phase Reporting - Table 6	Emergency and Remedial Response 1. Evidence of USDW Endangerment 2. Noncompliance with a permit condition 3. Triggering of a shut-off system 4. Failure to maintain mechanical integrity 5. Release of CO2 to the atmosphere or biosphere a. Include soil gas or air monitoring 6. Other	§3.207 (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;	3.2
§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;	Injection and Post-Injection Phase Reporting - Table 6	Emergency and Remedial Response 1. Evidence of USDW Endangerment 2. Noncompliance with a permit condition 3. Triggering of a shut-off system 4. Failure to maintain mechanical integrity 5. Release of CO2 to the atmosphere or biosphere a. Include soil gas or air monitoring 6. Other	§3.207 (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;	3.2
§146.91(c)(3)	Reporting requirements	Any triggering of a shut-off system (i.e., down-hole or at the surface);	Injection and Post-Injection Phase Reporting - Table 6	Emergency and Remedial Response 1. Evidence of USDW Endangerment 2. Noncompliance with a permit condition 3. Triggering of a shut-off system 4. Failure to maintain mechanical integrity 5. Release of CO2 to the atmosphere or biosphere a. Include soil gas or air monitoring 6. Other	§3.207 (a)(2)(A)(iv)	Reporting and Record-Keeping	any triggering of a shut-off system (i.e., down-hole or at the surface); and	3.2
§146.91(c)(4)	Reporting requirements	Any failure to maintain mechanical integrity; or.	Injection and Post-Injection Phase Reporting - Table 6	Emergency and Remedial Response 1. Evidence of USDW Endangerment 2. Noncompliance with a permit condition 3. Triggering of a shut-off system 4. Failure to maintain mechanical integrity 5. Release of CO2 to the atmosphere or biosphere a. Include soil gas or air monitoring 6. Other	§3.207 (a)(2)(A)(v)	Reporting and Record-Keeping	any failure to maintain mechanical integrity.	3.2

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.91(c)(3)	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.	Injection and Post-injection Phase Reporting - Table 6/ Project Plan Submissions - Table 10	Emergency and Remedial Response 1. Evidence of USDW Endangerment 2. Noncompliance with a permit condition 3. Triggering of a shut-off system 4. Failure to maintain mechanical integrity 5. Release of CO2 to the atmosphere or biosphere a. Include soil gas or air monitoring 6. Other Surface Monitoring: Air or Soil Gas 1. Design based on risk 2. Freq, spatial distr, etc, per 144.12 3. Qualifications under Clean Air Act (cited) and 146.91(c)(3) a. Additional modeling				
§146.91(d)	Reporting requirements	Owners or operators must notify the Director in writing 30 days in advance of			§3.206 (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
					§3.207 (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.	Project Plan Submissions - Table 21	1. Summary of Existing Monitoring Data a. All previous data b. Compared to baseline	§3.207 (b)(2)	Reporting and Record-Keeping	The operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by director.	5.2
§146.91(f)	Reporting requirements				§3.207 (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.	CO2 Sequestration Walkthrough - GSDT and State Primacy Options	Under the Class VI Rule at 40 CFR 146.91(e), owners or operators must submit Class VI data (i.e., data generated, collected, and submitted during the lifetime of a Class VI project), including required reports, submittals, and notifications, directly to the EPA in an electronic format approved by the EPA. This requirement applies regardless of whether the project is located in a state with primary enforcement responsibility (primacy) for Class VI wells The state may elect to use an alternative electronic reporting format, possibly as part of the primacy agreement. Our understanding is an alternative will require EPA approval.	§3.207 (e)(1)	Reporting and Record-Keeping	The operator must retain all data collected under §3.203 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.	CO2 Sequestration Walkthrough - GSDT and State Primacy Options	Under the Class VI Rule at 40 CFR 146.91(e), owners or operators must submit Class VI data (i.e., data generated, collected, and submitted during the lifetime of a Class VI project), including required reports, submittals, and notifications, directly to the EPA in an electronic format approved by the EPA. This requirement applies regardless of whether the project is located in a state with primary enforcement responsibility (primacy) for Class VI wells The state may elect to use an alternative electronic reporting format, possibly as part of the primacy agreement. Our understanding is an alternative will require EPA approval.	§3.207 (e)(2)	Reporting and Record-Keeping	The operator must retain data on the nature and composition of all injected fluids collected pursuant to §3.203(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
					§3.207 (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.	CO2 Sequestration Walkthrough - GSDT and State Primacy Options	Under the Class VI Rule at 40 CFR 146.91(e), owners or operators must submit Class VI data (i.e., data generated, collected, and submitted during the lifetime of a Class VI project), including required reports, submittals, and notifications, directly to the EPA in an electronic format approved by the EPA. This requirement applies regardless of whether the project is located in a state with primary enforcement responsibility (primacy) for Class VI wells The state may elect to use an alternative electronic reporting format, possibly as part of the primacy agreement. Our understanding is an alternative will require EPA approval.	§3.207 (e)(3)	Reporting and Record-Keeping	The operator must retain all testing and monitoring data collected pursuant to the plans required under §3.203(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.	CO2 Sequestration Walkthrough - GSDT and State Primacy Options	Under the Class VI Rule at 40 CFR 146.91(e), owners or operators must submit Class VI data (i.e., data generated, collected, and submitted during the lifetime of a Class VI project), including required reports, submittals, and notifications, directly to the EPA in an electronic format approved by the EPA. This requirement applies regardless of whether the project is located in a state with primary enforcement responsibility (primacy) for Class VI wells The state may elect to use an alternative electronic reporting format, possibly as part of the primacy agreement. Our understanding is an alternative will require EPA approval.	§3.207 (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 §3.206(k)(6) and (m) of this title for 10 years following storage facility closure.	5.2
					§3.207 (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 §3.206(k)(7) of this title.	5.2

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.91(f)(5)	Reporting requirements	The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	CO2 Sequestration Walkthrough - GSDT and State Primacy Options	Under the Class VI Rule at 40 CFR 146.91(e), owners or operators must submit Class VI data (i.e., data generated, collected, and submitted during the lifetime of a Class VI project), including required reports, submittals, and notifications, directly to the EPA in an electronic format approved by the EPA. This requirement applies regardless of whether the project is located in a state with primary enforcement responsibility (primacy) for Class VI wells The state may elect to use an alternative electronic reporting format, possibly as part of the primacy agreement. Our understanding is an alternative will require EPA approval.	§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	
§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.	Project Plan Submissions - Table 12	(*) Facility Information 1. Facility name 2. Well Number	§5.203 (k)(2)(A)	Well Plugging Plan	flush each injection well with a buffer fluid;	6.2.2
					§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.2.2
					§5.203 (k)(2)(C)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.2.2
§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:	Project Plan Submissions - Table 12	Facility Information 1. Facility name 2. Well Number 3. Facility contact & details 4. Facility address 5. Well location: city, co. state; lat/long	§5.203 (k)	Well Plugging Plan	Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that penetrate the base of usable quality water that includes the following:	
					§5.203 (k)(1)	Well Plugging Plan	A proposal for plugging all monitoring wells that penetrate the base of usable quality water and all injection wells upon abandonment in accordance with §3.14 of this title (relating to Plugging), in addition to the requirements of this section. The proposal must include:	6.2.1, 6.2.2, 6.3.2, 6.3.3, 6.3.4; Appendix J
§146.92(b)(1)	Injection Well Plugging	Appropriate tests or measures for determining bottomhole reservoir pressure;	Project Plan Submissions - Table 12	Bottom-Hole Reservoir Pressure (BHP) 1. Detailed steps or methods to determine BHP	§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.3.1
§146.92(b)(2)	Injection Well Plugging	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	Project Plan Submissions - Table 13	External Mechanical Integrity Test(s) 1. specific procedures for each type of test? (Provide a list of steps or similar description.) 2. gauges or other equipment: range, precision, etc. 3. What will constitute a "pass" or "fail" for each test? 4. Table: planned tests: description; location	§5.203 (k)(2)(C)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.3.1
§146.92(b)(3)	Injection Well Plugging	The type and number of plugs to be used;	Project Plan Submissions - Table 14	Information on Plugs 1. Table: materials & methods; all parameters (see template) 2. Method for cement volume calculations 3. Discussion of materials and potential interactions	§5.203 (k)(1)(A)	Well Plugging Plan	The type and number of plugs to be used;	6.2.2.1, 6.3.2, 6.3.3, 6.3.4; Appendix J
§146.92(b)(4)	Injection Well Plugging	The placement of each plug, including the elevation of the top and bottom of each plug;	Project Plan Submissions - Table 14	Information on Plugs 1. Table: materials & methods; all parameters (see template) 2. Method for cement volume calculations 3. Discussion of materials and potential interactions	§5.203 (k)(1)(B)	Well Plugging Plan	The placement of each plug, including the elevation of the top and bottom of each plug;	6.2.2.1, 6.3.2, 6.3.3, 6.3.4; Appendix J
§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	Project Plan Submissions - Table 14	Information on Plugs 1. Table: materials & methods; all parameters (see template) 2. Method for cement volume calculations 3. Discussion of materials and potential interactions	§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	6.2.2.1, 6.3.2, 6.3.3, 6.3.4; Appendix J
					§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;	6.2.2.1, 6.3.2, 6.3.3, 6.3.4; Appendix J
§146.92(b)(6)	Injection Well Plugging	The method of placement of the plugs.	Project Plan Submissions - Table 14	Information on Plugs 1. Table: materials & methods; all parameters (see template) 2. Method for cement volume calculations 3. Discussion of materials and potential interactions	§5.203 (k)(1)(D)	Well Plugging Plan	The method of placement of the plugs.	6.2.2.1, 6.3.2, 6.3.3, 6.3.4; Appendix J
§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.	Project Plan Submissions - Table 15	Narrative Description of Plugging Procedures 1. Notifications, Permits, and Inspections a. Agencies to be notified or involved with i. Additional permits ii. Inspections 2. Plugging Procedures a. Specific procedures (detailed list) b. Contingency plans	§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	6.2.1, 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;	6.2.1, 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;	6.3.4
§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.	Project Plan Submissions - Table 22	Site Closure Plan 1. Plugging Monitoring Wells a. Same criteria as plugging plan. b. Well tests pre-plugging 2. Other infrastructure removal 3. Site restoration (state & local regulations) 4. Site Closure Report a. Plugging any and all wells b. Plat survey of sealed injection well (submitted to which authority) c. Records: CO2 volume, composition, nature; post-monitoring d. Notation on property deed: sequestration site, plat (see above); volume fluid				
§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	Region 6 Crosswalk Document	R6 Text / Comments	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:		[illegible] injected; formation used; period of injection. 5. Record retention				
§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);	Project Plan Submissions - Table 17	Pre- and Post-Injection Pressure Differential 1. Modeled time after closure to reach baseline pressure at the injection site. 2. Expected decline rate: at well and monitor wells 3. Largest differential in pressure over life of project; when	§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);	Project Plan Submissions - Table 18 / 20	Predicted Position of the CO2 Plume and Associated Pressure Front at Site Closure 1. Figure: maximum extent of the plume and pressure front at end of timeframe above (per final model results) 1. Predicted Rate of Plume Migration a. Predicted/Actual rate or spread during and after injection b. Discuss decline/rate and effective end of motion or return to background pressure at well c. available monitoring data d. Sensitivity analysis (here or below) e. Supporting documentation	§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;	Project Plan Submissions - Table 19	Post-Injection Monitoring Plan 1. Planned monitoring methods (details below) a. Types by wells or sites; location; subsurface zone 1. Carbon Dioxide Plume and Pressure Front Tracking a. Post-Inj Plume Monitoring: by Direct & Indirect methods Table b. Summary of Sampling & Analytics Table c. Pressure Front Monitoring Table: by direct & indirect, then formation d. QASP for Fluid Sampling e. Details for all sampling and monitoring	§5.203 (m)(4)	Post-injection storage facility care and closure plan	A description of post-injection monitoring location, methods, and proposed frequency;	5.5, 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,	Project Plan Submissions - Table 19	1. Schedule for Submitting Post-Injection Monitoring Results a. When b. Frequency	§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,	7.6
§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.	Project Plan Submissions - Table 21	(*) Non-Endangerment Demonstration Criteria 1. Introduction and Overview a. Summarize operational history, date of demonstration relative to post-injection PISC and Site Closure Plan. b. Overview of monitoring and modeling as support	§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;	7.7
§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.	Project Plan Submissions - Table 22	(*) Site Closure Plan 1. Plugging Monitoring Wells a. Same criteria as plugging plan. b. Well tests pre-plugging 2. Other infrastructure removal 3. Site restoration (state & local regulations) 4. Site Closure Report a. Plugging any and all wells b. Plat survey of sealed injection well (submitted to which authority) c. Records: CO2 volume, composition, nature (*): post-monitoring d. Notation on property deed: sequestration site, plat (per above); volume fluid injected; formation used; period of injection. 5. Record retention				7.5
§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.	Project Plan Submissions - Table 22	(*) Site Closure Plan 1. Plugging Monitoring Wells a. Same criteria as plugging plan. b. Well tests pre-plugging 2. Other infrastructure removal 3. Site restoration (state & local regulations) 4. Site Closure Report a. Plugging any and all wells b. Plat survey of sealed injection well (submitted to which authority) c. Records: CO2 volume, composition, nature (*): post-monitoring d. Notation on property deed: sequestration site, plat (per above); volume fluid injected; formation used; period of injection. 5. Record retention	§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.	
§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.	Project Plan Submissions - Table 19	1. Monitoring Above the Confining Zone (by formation) a. Monitoring Table: Ground water quality & geochemical changes b. Parameters & analytical methods Table	§5.206 (k)(2)	Post-injection storage facility care and closure	Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	7.5
§146.93(b)(1)		Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.						7.5

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§146.93(b)(2)		If the owner or operator can demonstrate to the satisfaction of the Director before 30 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.						7.5
§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:	7.7
§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.	Project Plan Submissions - Table 20	Alternative Post-Injection Site Care Timeframe 1. Summary of how each supports plan (data & calculations) a. Modeled time after closure to reach baseline pressure at the injection site.				
					§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
§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:	Project Plan Submissions - Table 20	Alternative Post-Injection Site Care Timeframe 1. Summary of how each supports plan (data & calculations) a. Modeled time after closure to reach baseline pressure at the injection site.	§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;	Project Plan Submissions - Table 20	1. Computational Modeling Results (with figures: extents through time; cross-section; sensitivity runs) a. Evolution of plume and pressure front with time b. Sensitivity analysis from AoR model; uncertain parameters; extent addressed in Testing & Monitoring c. How proposed operation conditions support this timeframe.	§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;	Project Plan Submissions - Table 20	1. Predicted Timeframe for Pressure Decline a. Same questions as next so could be combined so long as both pressure and plume are covered. b. decline: hetero or homogenous	§5.203 (m)(7)(B)	Post-injection storage facility care and closure plan	the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre-injection pressures;	
§146.93(c)(1)(iii)	Post-injection and site closure	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	Project Plan Submissions - Table 20	1. Predicted Rate of Plume Migration a. Predicted/Actual rate or spread during and after injection b. Discuss decline/rate and effective end of motion or return to background pressure at well c. available monitoring data d. Sensitivity analysis (here or below) e. Supporting documentation	§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;	Project Plan Submissions - Table 20	1. Site-Specific Trapping Processes a. match methods used in AoR delineation b. Discuss physical and chemical trapping processes c. Trapping rates: i. Formulas (source) ii. Estimates iii. Parameters iv. Results changing over time d. Mineralization potential of CO2	§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;	Project Plan Submissions - Table 20	1. Site-Specific Trapping Processes a. match methods used in AoR delineation b. Discuss physical and chemical trapping processes c. Trapping rates: i. Formulas (source) ii. Estimates iii. Parameters iv. Results changing over time d. Mineralization potential of CO2	§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;	Project Plan Submissions - Table 20	1. Site-Specific Trapping Processes a. match methods used in AoR delineation b. Discuss physical and chemical trapping processes c. Trapping rates: i. Formulas (source) ii. Estimates iii. Parameters iv. Results changing over time d. Mineralization potential of CO2	§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;	

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§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;	Project Plan Submissions - Table 20	1. Confining Zone Characterization a. Site specific support for alternative PISC b. Discuss modeling of this zone for trapping c. Amendments needed for changes in different reporting modules.	§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;	Project Plan Submissions - Table 20	1. Assessment of Fluid Movement Potential a. Aps as potential conduits; corrective action plan and modeled arrival b. USDW protection after cessation	§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;	Project Plan Submissions - Table 20	1. Assessment of Fluid Movement Potential a. Aps as potential conduits; corrective action plan and modeled arrival b. USDW protection after cessation	§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	Project Plan Submissions - Table 20	1. Location of USDWs 2. Compare the USDW (vertical and lateral) injection zone to i. Closest point ii. maximum plume extent b. summary of how USDW determined c. Other factors in analysis d. Discuss relative to PISC timeframe	§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:	Project Plan Submissions - Table 20	Alternative Post-injection Site Care Timeframe 1. Summary of how each supports plan (data & calculations) a. Modeled time after closure to reach baseline pressure at the injection site.	§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;	Project Plan Submissions - Table 20	Alternative Post-injection Site Care Timeframe 1. Summary of how each supports plan (data & calculations) a. Modeled time after closure to reach baseline pressure at the injection site. 2. Computational Modeling Results (with figures: extents through time; cross-section; sensitivity runs) a. Evolution of plume and pressure front with time b. Sensitivity analysis from AoR model; uncertain parameters; extent addressed in Testing & Monitoring c. How proposed operation conditions support this timeframe. 3. Predicted Timeframe for Pressure Decline a. Same questions as next so could be combined so long as both pressure and plume are covered. b. decline: hetero or homogenous 4. Predicted Rate of Plume Migration a. Predicted/Actual rate or spread during and after injection b. Discuss decline/rate and effective end of motion or return to background pressure at well c. available monitoring data d. Sensitivity analysis (here or below) e. Supporting documentation 5. Site-Specific Trapping Processes a. match methods used in AoR delineation b. Discuss physical and chemical trapping processes c. Trapping rates: i. Formulas (source) ii. Estimates iii. Parameters iv. Results changing over time d. Mineralization potential of CO2 2. Confining Zone Characterization a. Site specific support for alternative PISC b. Discuss modeling of this zone for trapping c. Amendments needed for changes in different reporting modules. 3. Assessment of Fluid Movement Potential a. Aps as potential conduits; corrective action plan and modeled arrival b. USDW protection after cessation 4. Location of USDWs	§5.203 (m)(8)(A)	Post-injection storage facility care and closure plan	all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	
§146.93(c)(2)(ii)	Post-injection and site closure	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;			§5.203 (m)(8)(B)	Post-injection storage facility care and closure plan	estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	
§146.93(c)(2)(iii)	Post-injection and site closure	Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;			§5.203 (m)(8)(C)	Post-injection storage facility care and closure plan	predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project;	
§146.93(c)(2)(iv)	Post-injection and site closure	Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;			§5.203 (m)(8)(D)	Post-injection storage facility care and closure plan	predictive models must be calibrated using existing information where sufficient data are available;	
§146.93(c)(2)(v)	Post-injection and site closure	Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;			§5.203 (m)(8)(E)	Post-injection storage facility care and closure plan	reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	
§146.93(c)(2)(vi)	Post-injection and site closure	An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.			§5.203 (m)(8)(F)	Post-injection storage facility care and closure plan	an analysis must be performed to identify and assess aspects of the alternative PISC timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;	
§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	

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§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.	7.8.1
§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.	Project Plan Submissions - Table 22	Site Closure Plan 1. Plugging Monitoring Wells a. Same criteria as plugging plan. b. Well tests pre-plugging 2. Other infrastructure removal 3. Site restoration (state & local regulations)	§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.	7.8.2
§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:	Project Plan Submissions - Table 22	Site Closure Plan 1. Plugging Monitoring Wells a. Same criteria as plugging plan. b. Well tests pre-plugging 2. Other infrastructure removal 3. Site restoration (state & local regulations) 4. Site Closure Report a. Plugging any and all wells b. Plat survey of sealed injection well (submitted to which authority) c. Records: CO2 volume, composition, nature (*); post-monitoring	§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:	7.8.4
§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;	Project Plan Submissions - Table 22	Site Closure Plan 1. Plugging Monitoring Wells a. Same criteria as plugging plan. b. Well tests pre-plugging	§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.	7.8.4
§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, locsl, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	Project Plan Submissions - Table 22	2. Other infrastructure removal	§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	7.8.4
§146.93(f)(3)	Post-injection and site closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	Project Plan Submissions - Table 22	3. Site restoration (state & local regulations)	§5.206 (k)(6)(C)	Post-injection storage facility care and closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	7.8.4
§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:	Project Plan Submissions - Table 22	1. Site Closure Report a. Plugging any and all wells b. Plat survey of sealed injection well (submitted to which authority) c. Records: CO2 volume, composition, nature (*); post-monitoring d. Notation on property deed: sequestration site, plat (per above); volume fluid injected; formation used; period of injection.	§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:	7.8.4
					§5.206 (l)(1)	Permit Standards	a complete legal description of the affected property;	7.8.4
§146.93(g)(1)	Post-injection and site closure	The fact that land has been used to sequester carbon dioxide;			§5.206 (l)(2)	Deed notation	The fact that land has been used to sequester carbon dioxide;	7.8.4
§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;	7.8.4
					§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	7.8.4
§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.	Project Plan Submissions - Table 22	1. Site Closure Report a. Plugging any and all wells b. Plat survey of sealed injection well (submitted to which authority) c. Records: CO2 volume, composition, nature (*); post-monitoring d. Notation on property deed: sequestration site, plat (per above); volume fluid injected; formation used; period of injection.	§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.	7.8.4
					§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
					§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
					§5.206 (m)(2)(B)		Data on the nature and composition of all injected fluids collected pursuant to §5.203(j)(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
					§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
					§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

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					§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.	5.2; 6.3.4
					§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:	7.8.4
					§5.206 (m)(4)(A)		documentation of appropriate injection and monitoring well plugging as specified in §5.203(k) of this title. The operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; and	7.8.4
					§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	7.8.4
					§5.206 (m)(5)		Records reflecting the nature, composition, and volume of the CO2 plume shall be retained for 10 years following site closure.	7.8.4
§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.	Project Plan Submissions - Table 22	1. Record retention 40 CFR 146.93(h)	§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.	7.8.4
§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.	Project Plan Submissions - Table 26-27	Potential Risk Scenarios 1. Well Integrity Failure 2. Injection Well Monitoring Equipment Failure 3. Potential Brine or CO2 Leakage to USDW 4. Natural Disaster 5. Induced Seismic Event 6. Table: Defining level, i.e. Major, Serious, Minor Emergency Identification and Response Actions 1. Steps to take to identify & characterize the severity (for each of the above) a. See template 2. RESPONSE ACTIONS 3. Notify UIC Director within 24 hours of event 4. Other actions based on severity (for each of the above); see generic response	§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;	3.4, 8.3
					§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;	8.6.1
					§5.203 (l)(3)	Emergency and remedial response plan	includes a safety plan that includes:	Section 8
					§5.203 (l)(3)(A)	Emergency and remedial response plan	emergency response procedures;	8.6.1
					§5.203 (l)(3)(B)	Emergency and remedial response plan	provisions to provide security against unauthorized activity;	8.4
					§5.203 (l)(3)(C)	Emergency and remedial response plan	CO2 release detection and prevention measures;	8.6.2
					§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;	8.3
					§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;	8.3
					§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,	8.11
					§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	8.11
					§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	8.6.1, 8.6.2
§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;	8.6.1
§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;	8.6.1
§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	8.6.1
§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.	8.6.1
§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.	

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§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:						8.2
§146.94(d)(1)	Emergency and remedial response	Within one year of an area of review reevaluation;						8.2
§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.	
§146.94(d)(3)	Emergency and remedial response	When required by the Director.						
Additional TAC 5 Regulations								
					§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
					§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.	Introduction
					§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;	Introduction
					§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.	4.3.3
					§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.	8.8
					§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);	TBD
					§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)(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, 4.2

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
					§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)(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, 5.5.2.2
					§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
					§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
					§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
					§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 (f)(1)	Permit Standards	The operator must maintain and comply with the approved mechanical integrity testing plan submitted in accordance with §5.203(i) of this title.	5.4.1; 5.4.2
					§5.206 (h)(2)(A)	Permit Standards	The operator must prepare and implement a plan to train and test each employee at the storage facility on occupational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must make copies of the plan available at the geological storage facility. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility.	8.8
					§5.206 (h)(2)(B)	Permit Standards	The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. The operator must explain emergency measures specific to the contractor's work in the contractor safety meeting.	8.8
					§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.	8.8
					§5.206 (k)(1)(A)	Permit Standards	The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan.	Section 7
					§5.206 (k)(1)(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.	7.5
					§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);	7.7
					§5.206 (k)(3)(B)	Permit Standards	that there is no leakage of either CO2 or displaced formation fluids that will endanger USDWs;	7.7
					§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;	7.7
					§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	6.2
					§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.	6.3

EPA 40 CFR	CFR Category	CFR Text	Region 6 Crosswalk Document	R6 Text / Comments	16 TAC Chapter 5	TAC Category	Description	Permit Application
					§5.206 (o)(2)(M)(vi)	Permit Standards	Twenty-four hour reporting. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The permittee shall report any noncompliance which may endanger health or the environment including:	5.2
					§5.206 (o)(2)(M)(vi)(I)	Permit Standards	any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and	5.2
					§5.206 (o)(2)(M)(vi)(II)	Permit Standards	any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.	5.2
					§5.206 (o)(2)(O)	Permit Standards	Other noncompliance. The permittee shall report all instances of noncompliance not reported under subsection (e) of this section, subparagraphs (J) and (M) of this paragraph, and §5.207(a)(2)(A) of this title at the time monitoring reports are submitted. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The reports required by this subparagraph shall contain the following information:	5.2
					§5.206 (o)(2)(O)(i)	Permit Standards	any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and	5.2
					§5.206 (o)(2)(O)(ii)	Permit Standards	any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.	5.2

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 0 – INTRODUCTION

July 2024

SECTION 0 – INTRODUCTION

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Overview

As the first U.S.-based oil and gas company to adopt a Paris-aligned framework and set an ambition to achieve net-zero operational emissions by 2050, ConocoPhillips Company is committed to achieving sustainable success throughout the energy transition. We are applying our strategic capabilities and resources to meet this challenge in an economically viable and responsible way that balances the interests of our stakeholders.

In early 2021, the company established a multi-disciplinary Low Carbon Technologies organization. The organization supports the net-zero ambition of Scope 1 and 2 emissions (Figure 0-1), understands the lower-carbon energy landscape, and prioritizes opportunities for future competitive investment. ConocoPhillips Company is approaching this effort with the same discipline followed in our traditional business investment and capital allocation processes. The Low Carbon Technologies organization has prioritized opportunities in carbon capture and storage (CCS) and hydrogen technologies, as these support the aim of reducing greenhouse gasses (GHGs) while aligning closely with our technical competencies, global reach, and company business objectives.

Figure 0-1 – Overview of GHG protocol scopes and emissions across the value chain[1].

[1] [redacted]

[redacted] To produce blue hydrogen/ammonia, CO_2 from the process must be captured, treated, compressed, and transported from the hydrogen/ammonia facility, and then injected into underground geologic formations for safe and permanent storage.

The overall development consists of multiple components: a hydrogen/ammonia production facility, a CO_2 pipeline, and a CCS injection site. To facilitate the development of the CCS injection site (Project), ConocoPhillips Company established a subsidiary, ConocoPhillips Texas Gulf Coast CCS LLC (Operator).

[redacted]

Key Project Attributes

Operator is submitting a Class VI injection well permit application (Application) for the Project, which will be located in Refugio and Aransas Counties, Texas. This Application is for drilling, completing, operating, and monitoring six Class VI CCS injection wells, which are designed to meet the requirements of American Petroleum Institute (API) 1171, along with the regulatory requirements outlined in 16 Texas Administrative Code (TAC) **§5.206(c)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**].

To identify suitable sites for CCS, Operator's subsurface team evaluated saline aquifers along the Texas Gulf Coast, adopting conventional exploration workflows. Prospective CO_2 storage sites must meet three primary technical conditions: capacity, injectivity, and containment. Operator evaluated key screening parameters including injection zone quality (porosity, permeability, and thickness), presence of seals to demonstrate containment, rural areas with low well density, and data availability (2D/3D seismic coverage). The subsurface geology of the Texas Gulf Coast provides an ideal CO_2 storage environment due to the stacked sand-shale sequences of the Oligocene- and Miocene-age formations being high in porosity, permeability, and thickness. This type of geologic environment creates the storage-and-trapping mechanism needed for permanent sequestration of CO_2.

[redacted]

[redacted]

A Project overview map is provided in Figure 0-2 (*Appendix A-1*). [redacted] Injection well location plats are included in *Appendix A-3*.

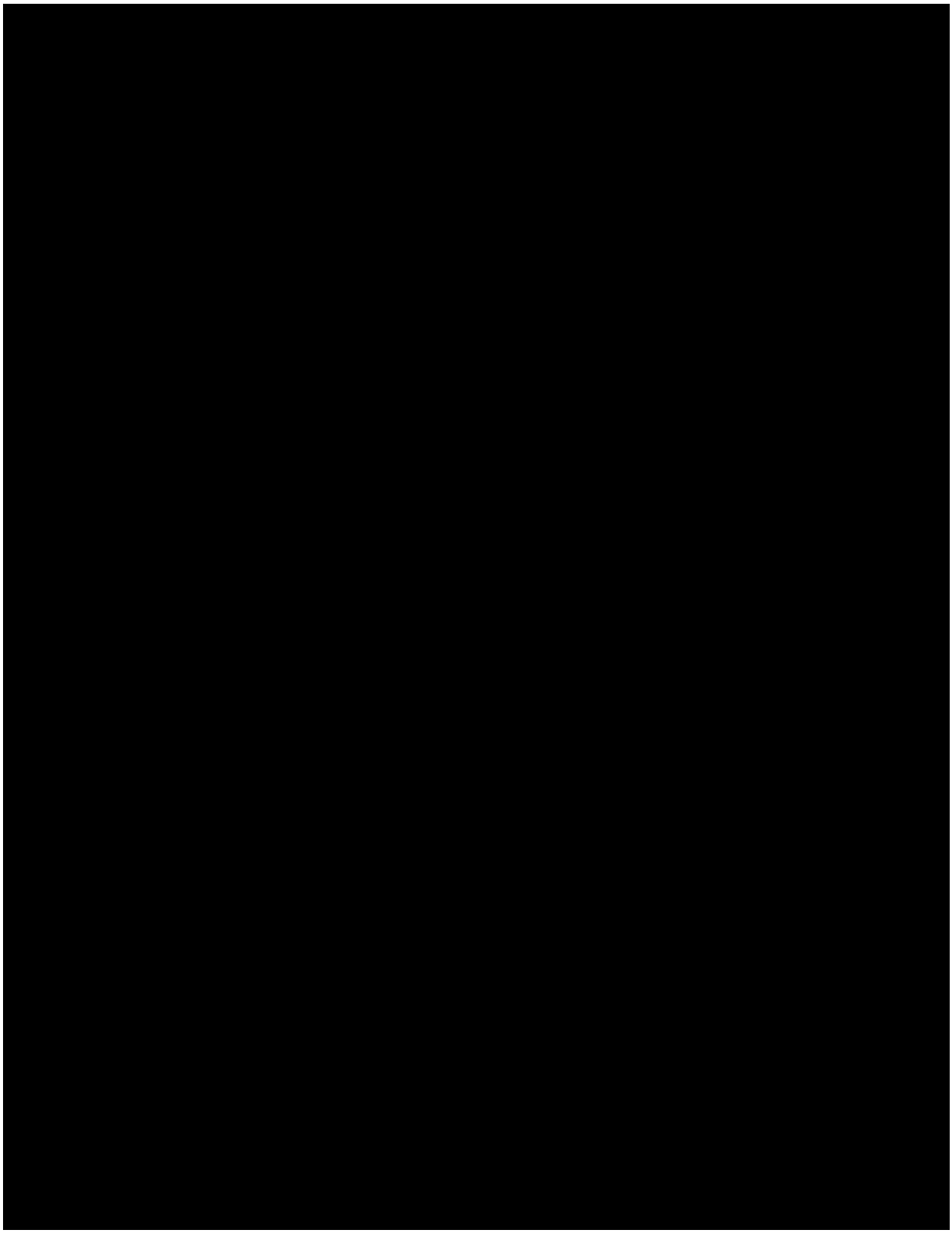

Figure 0-2 – Project area map.

Pore Space Discussion

The underground storage easement grants Operator access to sufficient saline aquifer capacity to store the expected CO_2 volumes [redacted]

[redacted]

Appraisal Program

Operator is currently executing a geologic site characterization (appraisal) program. The intent of this program is to verify capacity and containment assumptions by gathering additional site-specific subsurface data. [redacted] After data acquisition and evaluation, Operator is committed to collaboration with EPA Region 6 and the Railroad Commission of Texas (TRRC), as permit evaluations progress to incorporate the results in Operator's Project plans thoughtfully and efficiently.

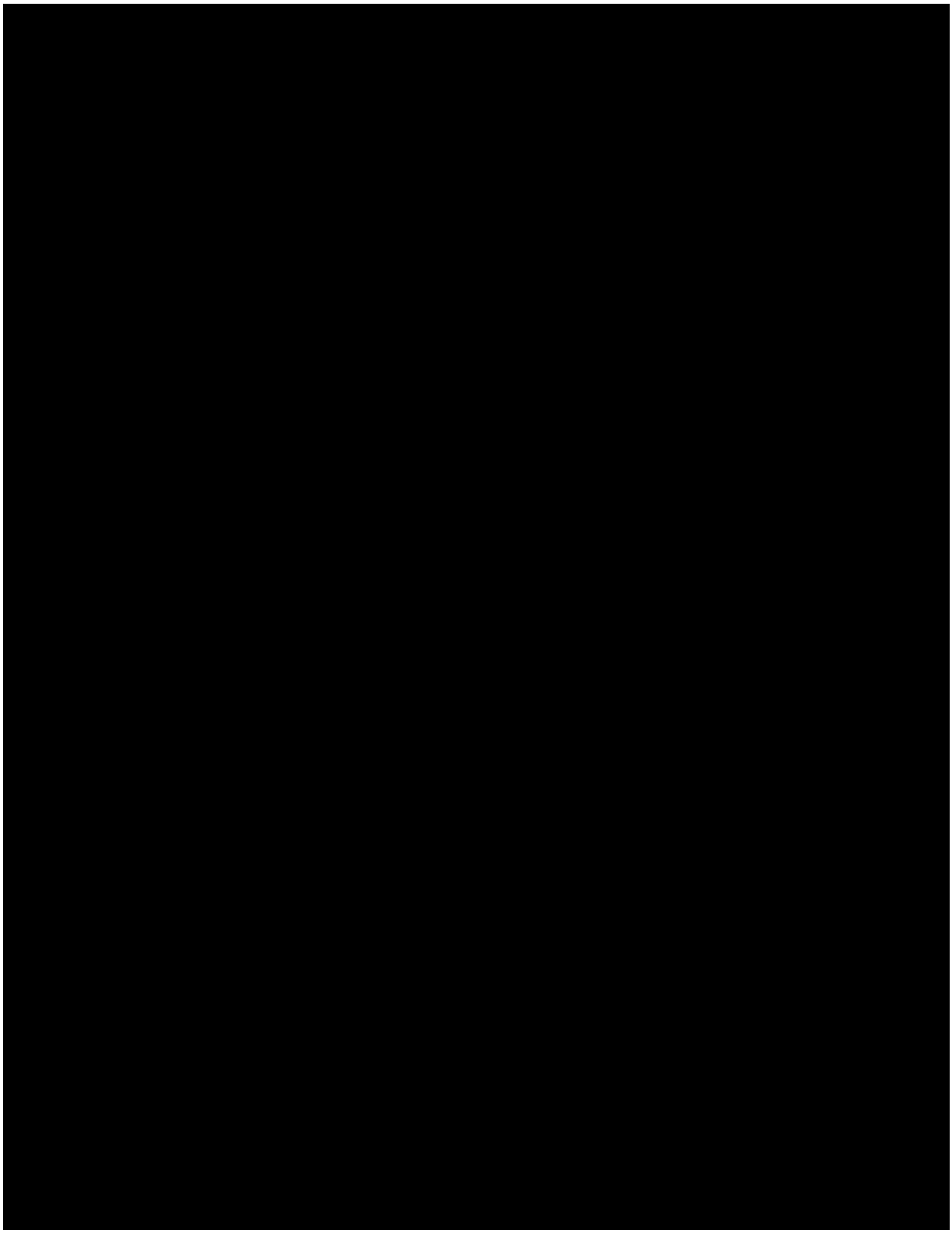

Figure 0-3 – Stratigraphic test well locations map.

Proposed CO_2 Storage System Discussion

The anticipated primary source of CO_2 for the Project is the hydrogen/ammonia facility. [redacted]

Injectate Information

[redacted] The expected composition of the CO_2 injection stream is presented in Table 0-1 and will be confirmed prior to construction of the injection wells if the CO_2 stream composition changes.

Table 0-1 – CO_2 injection stream composition.

Component	Value
[redacted]	

*ppm – parts per million

Injection Well Surface Facility Details

[redacted]

Site Suitability

Operator's evaluation of the Project location considered the following factors:

- Geologic faults or fractures in the Project area based on seismic analysis or geophysical well-log characterization
- Pore space capacity
- Containment
- Injectivity potential
- Underground Source of Drinking Water (USDW) location
- Artificial penetrations in the Project area
- Nearby communities
- Consideration of the Project area relative to federal sites, buildings, and facilities
- Location of the proposed Project site relative to existing emission sources
- Threatened and endangered species surveys
- Flood zones and wetlands
- Existing infrastructure
- Existing surface and subsurface mines or quarries
- Proximity to state or federal cleanup sites

These site-specific qualifications are addressed more specifically in the Application.

The Project's area of review (AOR) totals [redacted] square miles (sq mi) and encompasses portions of southern Refugio County and northwestern Aransas County. The AOR is located within the coastal zone boundary, as defined by the Texas Coastal Management Plan. [redacted] Nearby communities include Holiday Beach [redacted] and the town of Refugio [redacted] The town of Refugio is the closest community to the Project from a road access perspective. [redacted] Corpus Christi is approximately [redacted] southwest of the Project AOR.

The AOR does not overlap with any federal sites, buildings, facilities, or federal cleanup sites. There are no permanent residents within the AOR, and buildings within the AOR are limited to structures such as barns or cattle enclosures, owned solely by the private landowners. As scattered wetland features are present within the AOR, Operator will conduct thorough wetland delineation, threatened and endangered species surveys, and cultural resources surveys prior to Project construction.

The Project's anticipated CO_2 plume is contained within a rural property owned by private landowners who utilize the property primarily for hunting and cattle operations.

Summary

Six injection wells are planned for the Project (Snapper North INJ 1, Snapper North INJ 2, Snapper North INJ 3, Snapper South INJ 1, Snapper South INJ 2, and Snapper South INJ 3). These injection wells will support [redacted] of permanent CO_2 storage, and Operator plans to inject for [redacted] years. This Application includes details of the geologic investigation, reservoir model, design of the Class VI wells, and all the associated components required as part of 16 TAC **§5** [40 CFR **§146(h)**].

This Application is comprised of 10 sections that will address the regulatory requirements of this Project.

Appendix A: Project Overview Maps and Plats:

- Appendix A-1: Project Area Map
- Appendix A-2: Stratigraphic Test Well Locations Map
- Appendix A-3: Injection Well Location Plats

Required Administrative Information

General Application Information

Project Name: ConocoPhillips Texas Gulf Coast CCS

EPA Project ID: R06-TX-0025

Injection Well Information:

Well Name	County	Latitude (NAD 83)	Longitude (NAD 83)
Snapper North INJ 1	[redacted]		
Snapper North INJ 2			
Snapper North INJ 3			
Snapper South INJ 1			
Snapper South INJ 2			
Snapper South INJ 3			

*NAD 83 – North American Datu

Applicant:

Name: ConocoPhillips Texas Gulf Coast CCS LLC
Address: 925 North Eldridge Parkway
Houston, Texas 77079

This project is not located on federal or Indian lands.

Project Contact: [redacted]

Ownership Status: As of July 1, 2024, ConocoPhillips Texas Gulf Coast CCS LLC is a 100% fully owned subsidiary of ConocoPhillips Company.

Entity Type: Texas Foreign Limited Liability Company (LLC); formed in Delaware.

Entity Status: Active

Additional Permits

Table 0-2 – Additional required permits.

Agency	Permit and Authorization	Timing	Status
[redacted]			

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 1 – SITE CHARACTERIZATION

July 2024

SECTION 1 – SITE CHARACTERIZATION

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1.1 Overview

This site characterization for the ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) project (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 Project site. 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 Project site is in south-central Texas, within the Gulf of Mexico (GOM) basin. The onshore portion of the basin spans from northern Mexico to western Florida (Roberts-Ashby et al., 2012). Figure 1-1 depicts the Project location within the GOM basin, on the northeastern side of the Rio Grande Embayment.

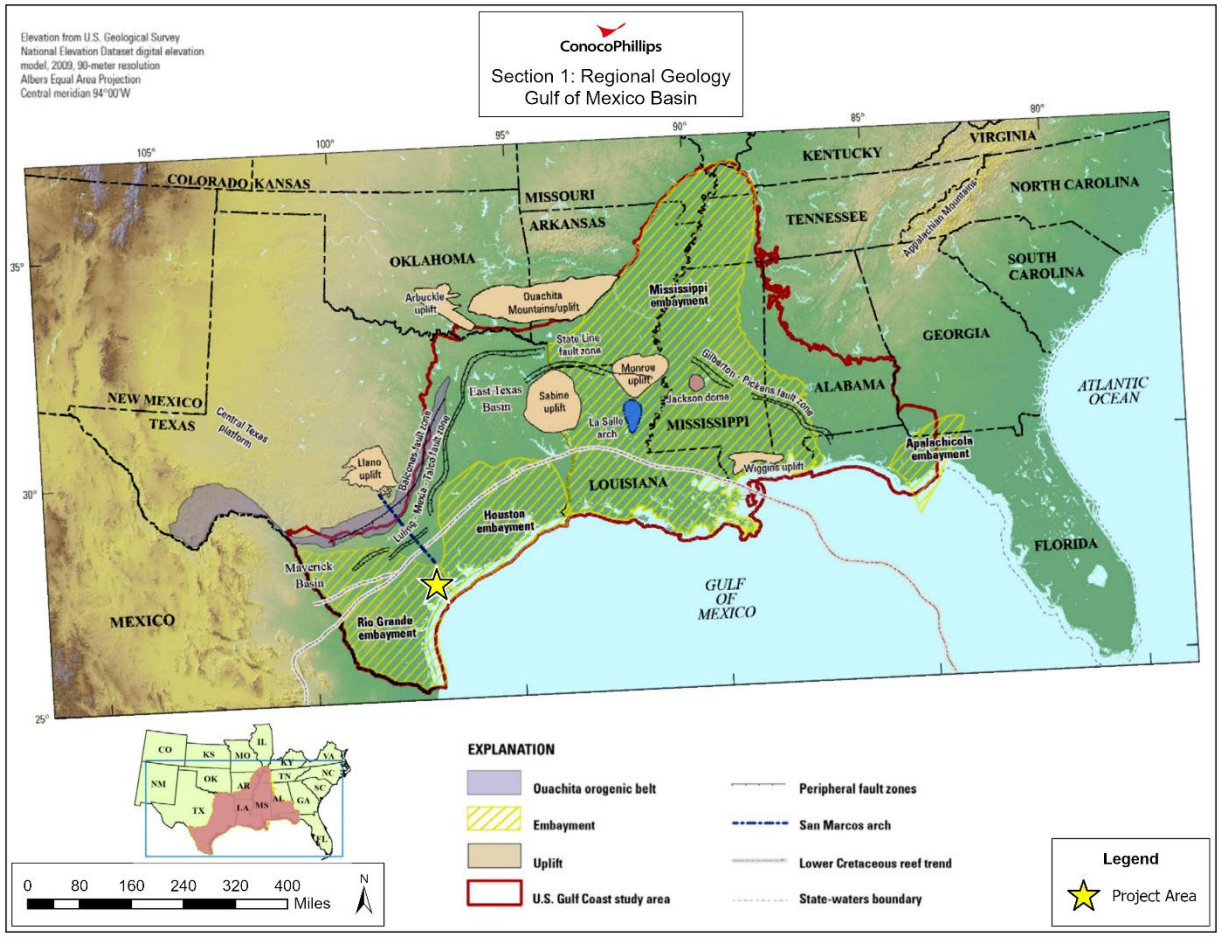


Figure 1-1 – Gulf of Mexico Basin, with the Project's approximate location marked with a star (modified from Roberts-Ashby et al., 2012).

The GOM basin was formed by crustal spreading and rifting events responsible for the separation of the North American plate and the Yucatan block during the Mesozoic breakup of Pangea, 200 million years ago (Skarke, 2018). Repeated cycles of rifting and expansion, which lasted approximately 25 million years, resulted in basin subsidence and thinning of continental crust (Treviño and Rhatigan, 2017).

Initial sedimentation in the GOM basin occurred between the Late Triassic to Early Jurassic, with deposits filling the accommodation space within graben structures created by seafloor spreading; these deposits consisted of terrestrial red beds and volcanics of the Eagle Mills Formation (Galloway, 2008). During the Middle to Late Jurassic, the basin developed a narrow connection to the Atlantic Ocean (Treviño and Rhatigan, 2017). This connection resulted in large-scale deposition of a continuous evaporitic sequence along the margins of the basin, up to 4 kilometers (km) thick, known as the Louann Salt—the deposition of which was influenced by structural features in the GOM, as shown in Figure 1-1 (Galloway, 2008). Those features include the Llano Uplift, Ouachita Mountain Range, Luling-Mexia-Talco fault zone, and San Marcos Arch (Galloway, 2008). The Louann Salt, which provided a foundation across the basin, plays a critical role in later structural development of the basin (Galloway, 2008). After the precipitation of the Louann Salt, low clastic sediment supply led to carbonate-dominated deposition during the Late Jurassic to Early Cretaceous (Treviño and Rhatigan, 2017). The carbonate platforms and subsidence during this period created the outline of the present-day GOM basin (Galloway, 2008).

The basin increased in depth until the beginning of the Eocene epoch, filling with fluvial-deltaic or shallow-marine depositional episodes during the Cenozoic along the western basin margin (Galloway, 2008). These deposits reflect changes in eustasy and sediment supply from mainland North America. Occasionally interbedded in the Eocene- to Miocene-age sands is tuffaceous ash, derived from volcanic sources in the Davis Mountains and Trans-Pecos Texas (Sellards et al., 1932). A generalized stratigraphic column of the northern GOM basin is provided in Figure 1-2.

The GOM structural setting is dominated by gravity tectonics—initiated by rapid sediment loading on top of the thick Louann Salt substrate and basin subsidence. The structures resulting from the gravity tectonics produced features including salt welds, salt diapirs, shale diapirs, allochthonous salt bodies, salt-based detachment faults, growth faults, and basin-floor compressional fold belts (Galloway, 2008). Examples of these features are shown in Figure 1-3, a basin-scale, dip-oriented cross section from northwest to southeast adjacent to the Project site—with generalized stratigraphic, structural, crustal, and salt features. An approximate location along strike of the Project is also indicated on Figure 1-3.

As outlined above, structures associated with gravity tectonics are common in the GOM basin. The rapid deposition of unconsolidated material upon a mobile substrate can produce diapirs and listric faulting (Galloway, 2008). Diapirs present along the northern and western margins of the GOM basin are generally composed of salt; however, mud or shale may produce similar structures (shale diapirs). Northeast of the Project area, a subsurface investigation was led by Ogiesoba and Hernandez (2015) to study the origins of local shale diapirs and growth faults. Based on integrated seismic survey data and well logs, two activities are believed to have

produced the shale diapirs present in the region: rapid sediment loading and localized compression against the San Marcos Arch from the southwest (Ogiesoba and Hernandez, 2015). The geologic history of the area proposed by these authors suggests the formation of a salt-withdrawal minibasin, followed by rapid influx and burial of siliciclastic sediments saturated with fluid into the minibasin. As deposition continued, increased overburden produced overpressurization of the fluid-rich beds—particularly the muds and shales—exacerbated by additional confinement due to lateral compression against the existing San Marcos Arch. Release of pressure along fractures or fault conduits initiated in this environment propelled underlying sediments and fluids to flow upward, creating shale diapirs. The upward movement of these diapirs stabilized once the underlying pore pressure reduced. The faults also accommodated lateral expansion, as synthetic listric faults coalesced and slid along the fault plane toward the coast (Ogiesoba and Hernandez, 2015).

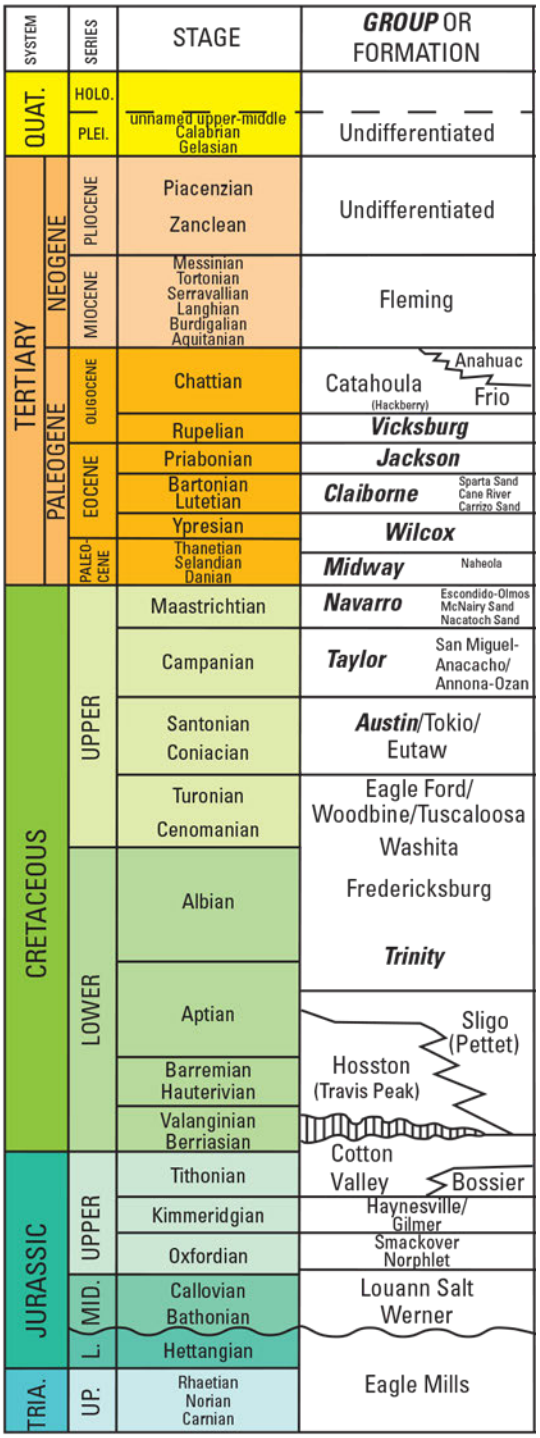


Figure 1-2 – Stratigraphic column of the northern Gulf of Mexico Basin (modified from Warwick, 2022; group names in bold italics). [redacted]

Figure 1-3 – Basin-scale schematic cross section across the central Texas coastal plain (modified from Swanson, Karlsen, and Valentine, 2013).

1.2.1 Major Stratigraphic Units

The primary stratigraphic intervals of interest in the Project area consist of the late Oligocene-age Frio Formation and the early Miocene-age Oakville Formation as shown in Figure 1-4. [redacted]

Figure 1-4 – Eocene and younger stratigraphic section
(modified from Young, et al., 2010; Olariu, et al., 2019; Loucks, et al., 2011).

1.2.2 Upper Confining Zone – [redacted]

1.2.3 Injection Zone – Miocene "Oakville" and Oligocene "Greta" and "Frio" Sands

In the Project area, the sands of the Lower Miocene 1 are collectively known as "Oakville Sandstone." These progradational sands overlie the shale-rich Anahuac transgression (Swanson, Karlsen, and Valentine, 2013). The shoreline strata within the Oakville Sandstone are well-developed and indicate extensive reworking by wave action (Galloway, 1989).

The Frio Formation is a major progradational wedge into the GOM basin, composed of a series of sandstones and shales deposited in deltaic and marine settings during the Oligocene (Swanson, Karlsen, and Valentine, 2013). The uppermost section of the Frio Formation along much of the Gulf Coast is a massive sand that is 100 feet (ft) or more, with a blocky spontaneous potential (SP) signature, which is an informal lithostratigraphic unit known as the Greta (Galloway and Cheng, 1985). The Texas coastal plain experienced a massive influx of sediment from Mexico and the southwestern United States during the Oligocene time, due to an increase in volcanism, regional uplift, and westward erosion associated with the Laramide orogeny. This sediment was transported to the GOM basin via the Rio Grande, Gueydan, and Chita/Corrigan fluvial systems—and accumulated along four primary deltas: the Norma, Norias, Houston, and Mississippi (Swanson, Karlsen, and Valentine, 2013; Hovorka et al., 2003). Once the sediment reached the basin via the deltas, it was reworked by wave action and transported to interdeltaic embayments, where it formed sand-rich progradational shore-zone systems (Galloway et al., 2000).

The Project site lies along a wave-dominated, barrier-strand, plain-system paleo-coastline, flanked to the north by the Houston delta and to the south by the Norias delta, near the present-day U.S.-Mexico border.

The Frio Formation is considered one of the largest hydrocarbon producers from the Paleogene within the GOM basin (Swanson, Karlsen, and Valentine, 2013). The same reservoir properties that brand the Frio Formation as a prolific hydrocarbon pool have attracted attention from institutions interested in carbon storage (Hovorka et al., 2003; Sakurai et al., 2006; McGuire, 2009; Roberts-Ashby et al., 2012).

1.2.4 Regional Shale Bed – Anahuac Shale

The Frio Formation is conformably overlain by the Anahuac Shale, a thick marine shale unit that can be up to 800 ft in the Project area and that includes a maximum flooding surface (Galloway et al., 2000). The Anahuac Shale regionally caps the Oligocene sequence and serves as an excellent top seal for nearby hydrocarbon accumulations. This shale-rich interval is identified by the U.S. Geological Survey (USGS) Frio and Vicksburg Formations Storage Assessment Unit (SAU) as a "robust top-seal for prospective CO_2 storage" (Roberts-Ashby et al., 2012).

1.2.5 Lower Confining Zone – [redacted]

[redacted]

[redacted]

1.3 Site Geology

The Project's area of review (AOR) totals [redacted] and encompasses portions of southern Refugio County and northwestern Aransas County, Texas. [redacted]

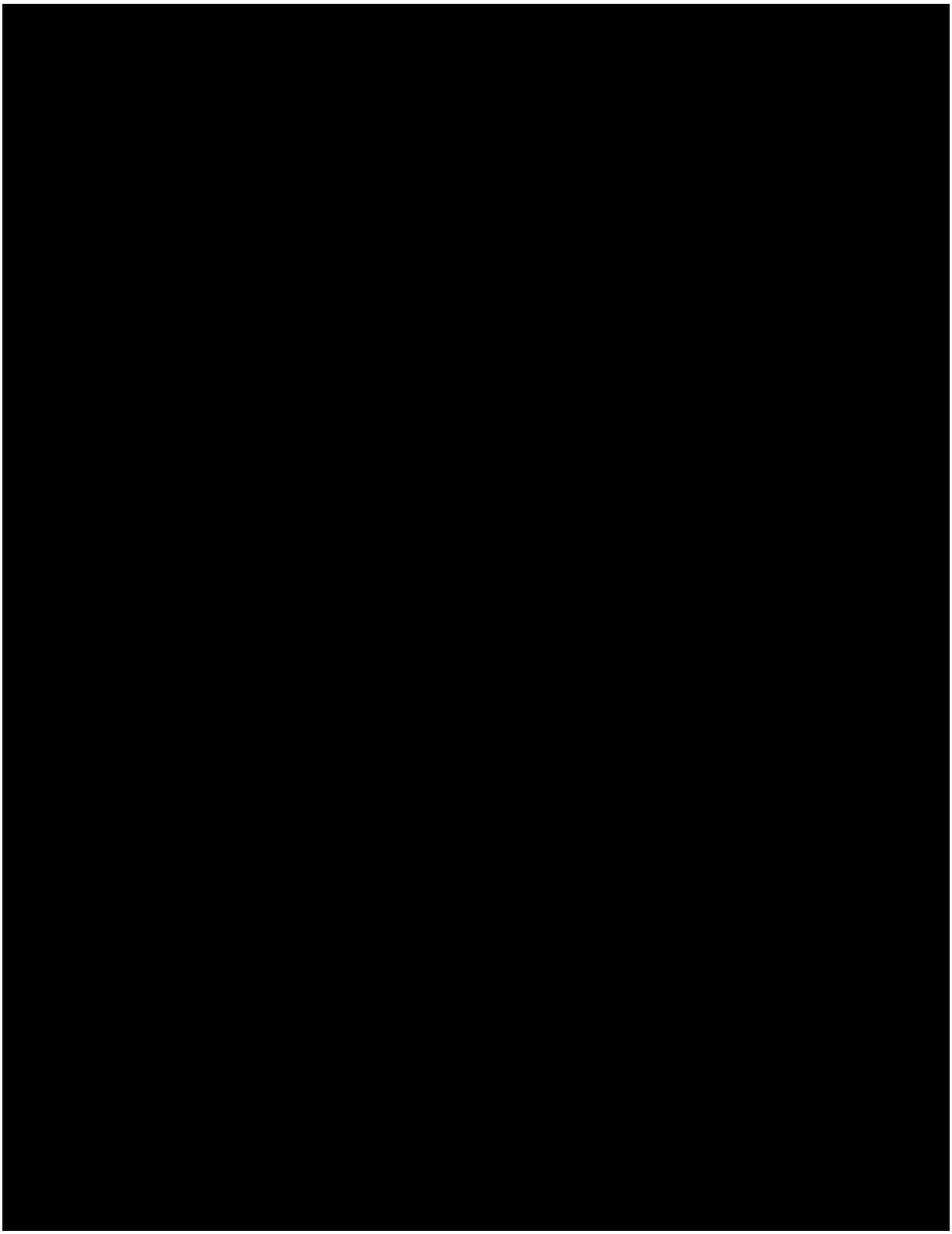


Figure 1-5 – Map of proposed injection locations
in relation to stratigraphic test wells with CO_2 plume and AOR indicated.

Regional studies were employed to delineate broad mineralogical compositions and reservoir attributes. Wherever possible, offset core samples and cuttings data were incorporated alongside analyses of offset wellbore information, to portray the anticipated well-site characteristics. In addition, wireline logs, petrophysical assessments, and production data from neighboring wellbores were scrutinized to estimate the expected conditions at the site.

Two stratigraphic test wells are included in the Project plan. [redacted] the nearest planned injection well (Figure 1-6). Information obtained from openhole well logging and coring activities will be collected during the drilling process of the stratigraphic test wells—and used to supplement the research data with site-specific information.

The static geocellular model for the Project area was constructed using available digital wells inside the area of interest (AOI) shown in *Appendix B-1*. Note that the term "AOI" is used to describe the broad area reviewed for the site characterization, the boundary of which is defined in Figure 1-6. The modeling process involved identifying stratigraphic tops and establishing log ties to core and seismic interpretations. A total of [redacted] wells contributed to the structural model, while [redacted] wells were employed for delineating porosity/permeability distributions. Details of the development of the geocellular model, including structural framework and rock property distribution, are located in *Section 2.4*.

The [redacted] well (API No. [redacted]), approximately [redacted] from the closest planned injection well, was logged via openhole on [redacted] The map shown in Figure 1-6 delineates the AOI and shows the relative location of the [redacted], the Project wells, and another well referenced later in this section, the [redacted] The stratigraphic column in Figure 1-7 corresponds to the measured depths in the [redacted] Table 1-1 displays the formation tops and depths to the upper confining zone, injection zone, and lower confining zone as logged in the [redacted]

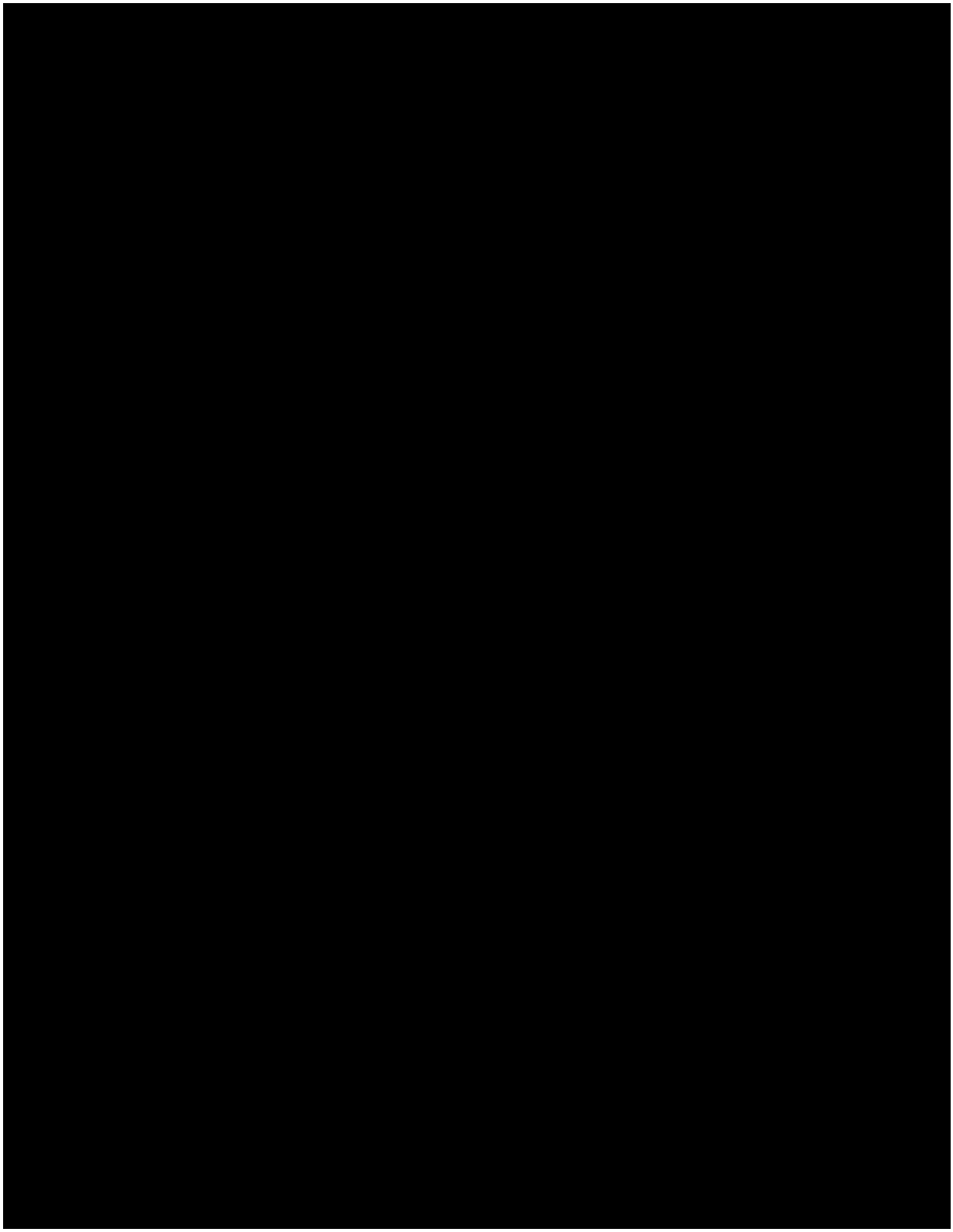


Figure 1-6 – Location map of nearby wells
used for geologic reference, underground storage easement, planned stratigraphic test and injection wells, and the geomodel outline used for the AOI.

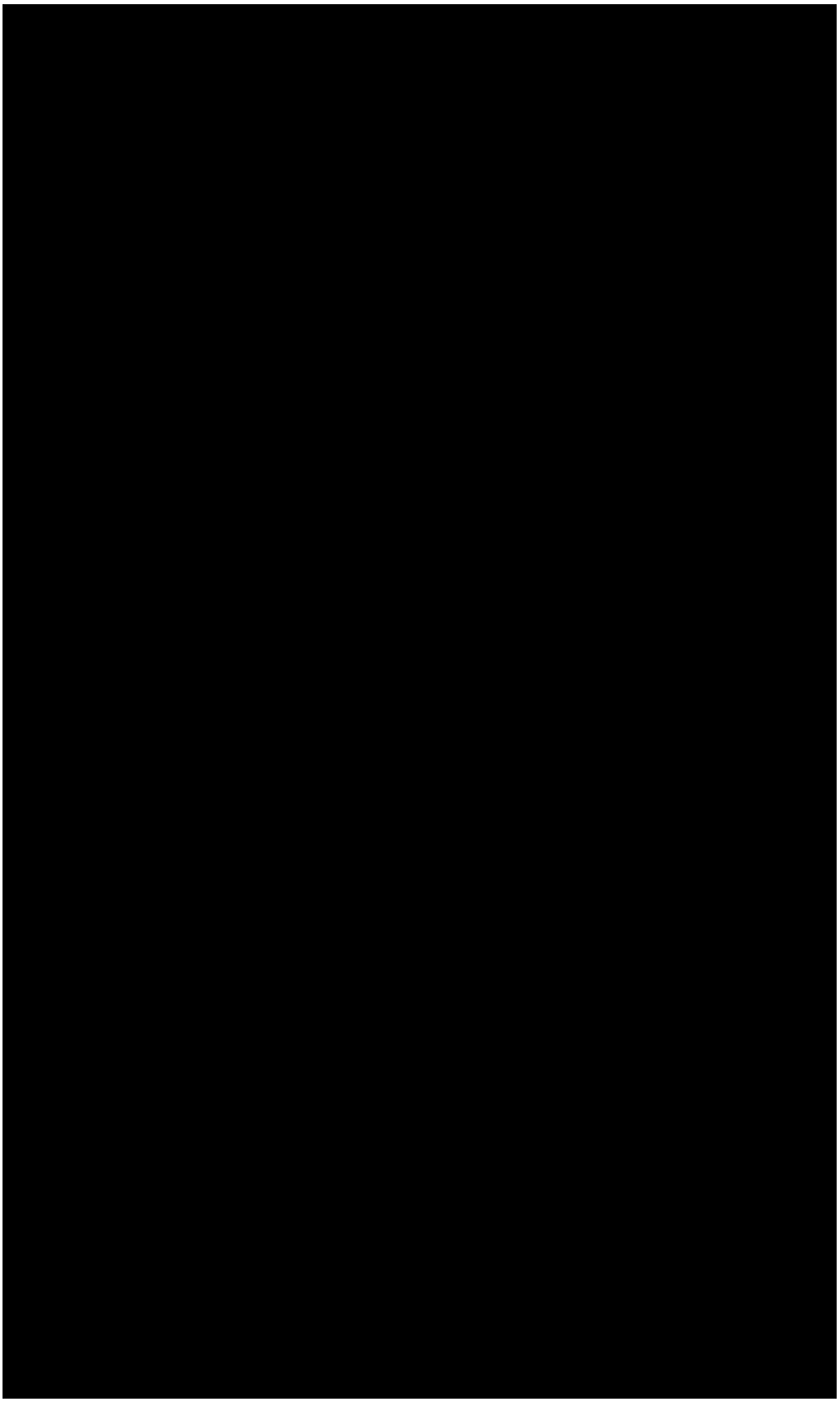


Figure 1-7 – Stratigraphic Column [redacted]

Table 1-1 – Injection and confining zones identified in [redacted]

System	Group / Formation Name	Injection / Confining Zone	Formation Top – Formation Bottom (ft TVD)	Thickness (ft)
[redacted]	[redacted]	Upper confining	[redacted]	[redacted]
Lower Miocene	Oakville	Injection formation	[redacted]	[redacted]
Oligocene	Greta and Frio Sands	Injection formations	[redacted]	[redacted]
[redacted]	[redacted]	Lower confining	[redacted]	[redacted]

*TVD – true vertical depth

While drilling the stratigraphic test wells, an extensive coring program will be executed. The outcomes of this testing program will be utilized to enhance the accuracy of both static and dynamic reservoir models at the planned intervals outlined in Table 1-2. The exact core intervals may change during drilling operations as data is collected.

Table 1-2 – Planned Core Intervals

Zone	[redacted] (ft TVD)	[redacted] (ft TVD)
Upper Confining Zone – [redacted]	[redacted]	[redacted]
Injection Zone – Oakville Formation		
Regional Shale Bed – Anahuac Shale		
Injection Zone – Greta and Frio Sands		
Lower Confining Zone – [redacted]		

1.3.1 Injection Zone

The injection zone consists of the Oakville Formation, Greta, and Frio sands, which include interbedded layers of sands and shales. The Anahuac Shale is a major transgressive marine-wedge sequence that separates the Frio and Oakville formations. It is characterized as a mix of shelf and prodeltaic mudstone—and most likely a product of open-shelf, suspension sedimentation on the Middle Texas Coast Plain (Galloway, Hobday, and Magara, 1982). As illustrated in the stratigraphic column in Figure 1-7, the Oakville Formation lies within the Lower Miocene, while the Greta and Frio Sands are of the Oligocene epoch.

At the Project site, the Frio Formation falls within the Greta Barrier Strandplain depositional system. This barrier system is sourced from the Houston delta to the north and the Norias delta to the south. The deltas provided ample sand to the barrier-strandplain, with the maximum sand thickness exceeding 5,000 ft in the shore zone system (Snedden and Galloway, 2019). Figure 1-8 is a depiction of the late Oligocene, indicating the Project's site location within the Greta Barrier Strandplain depositional system. Facies within the proposed Frio Formation resemble that of "massive, blocky, stacked barrier and strandplain sandstones" with shaly interbeds (Galloway, Hobday, and Magara, 1982).

Net sand count within the Upper and Middle Frio at the proposed location indicates higher sandstone composition, while the Lower Frio grades toward marine mudstone. This count is featured in Figures 1-9 to 1-11, which display Lower, Middle, and Upper Frio sandstone percentages, respectively, at the proposed Project site. The sand percentage maps indicate that, during Upper and Middle Frio deposition, the Project's site was located near the Greta Barrier shoreline axis, while Lower Frio (which occurs closer to the shelf margin) deposits are primarily shallow marine mudstones (Snedden and Galloway, 2019). As mentioned in *Section 1.2.3,* the uppermost section of the Frio along the Gulf Coast is an informal lithostratigraphic unit known as the Greta. In the Project area, this massive, blocky sand ranges from [redacted] ft to [redacted] ft thick and is the result of high sediment input being matched with relative sea-level rise (Kincade, 2018).

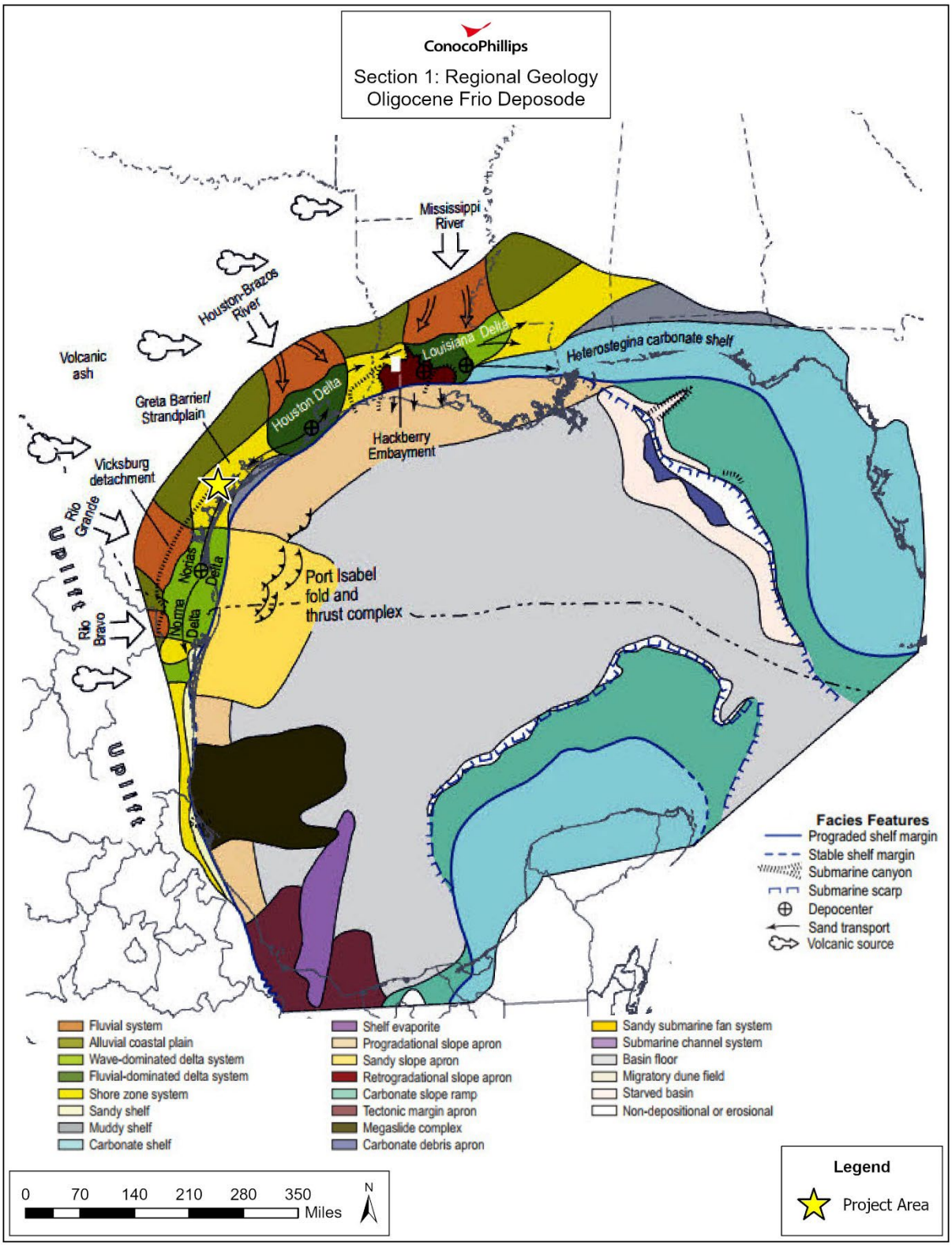


Figure 1-8 – Late Oligocene depositional systems map,
with the yellow star indicating the location of the Project area (Snedden and Galloway, 2019).

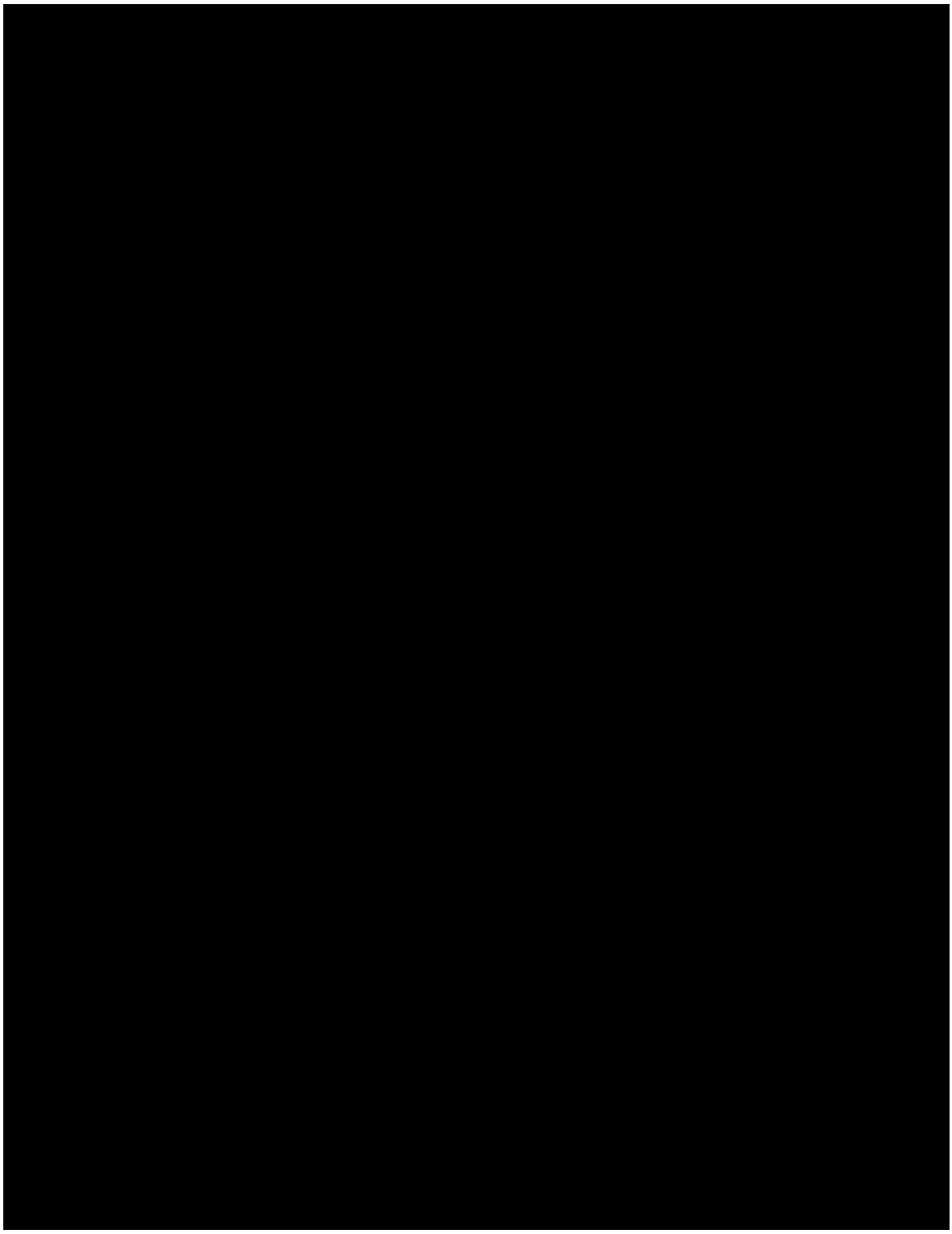


Figure 1-9 – Sand percentage map of the Lower Frio formation (Galloway, Hobday, and Magara, 1982), with the location of the underground storage easement indicated.

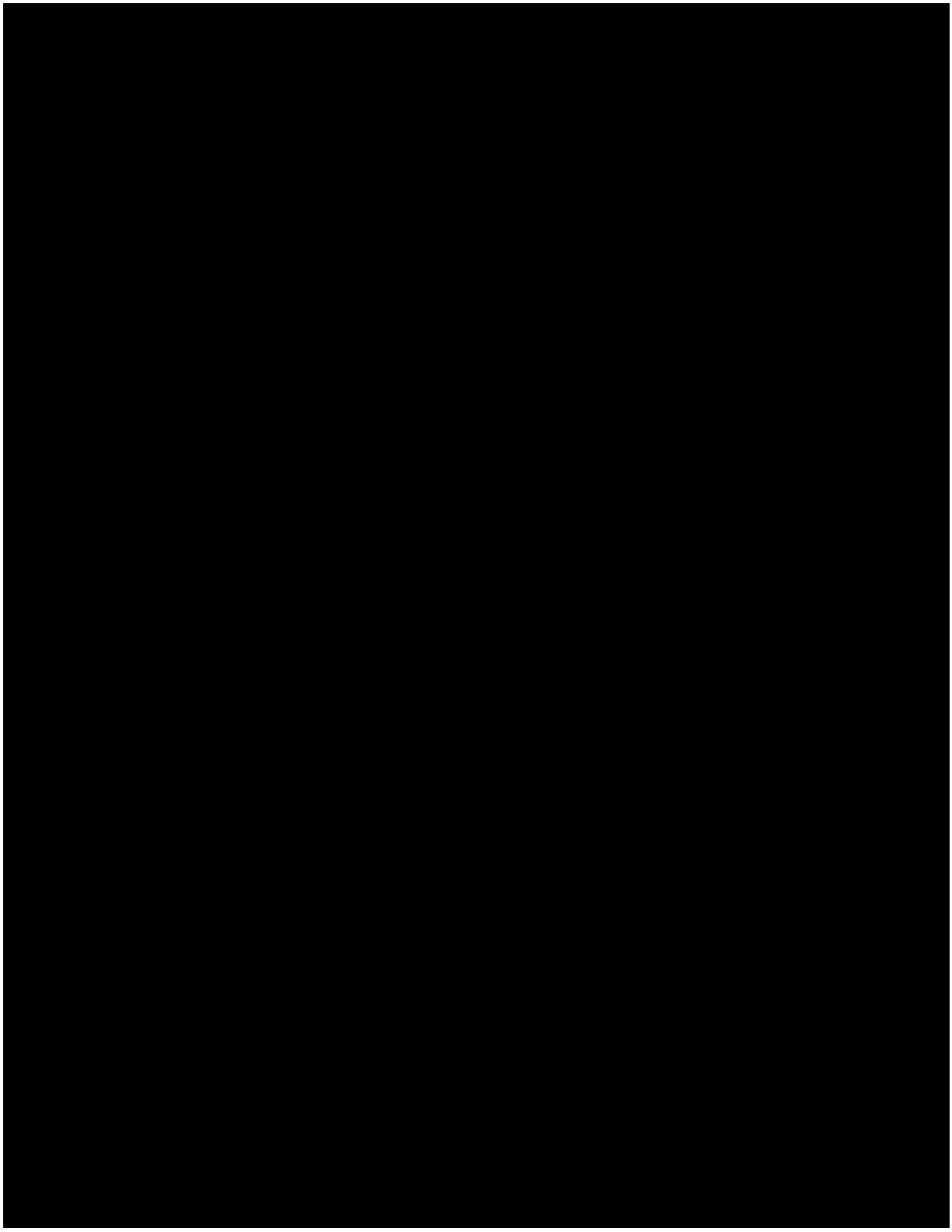


Figure 1-10 – Sand percentage map of the Middle Frio formation (Galloway, Hobday, and Magara, 1982), with the location of the underground storage easement indicated.

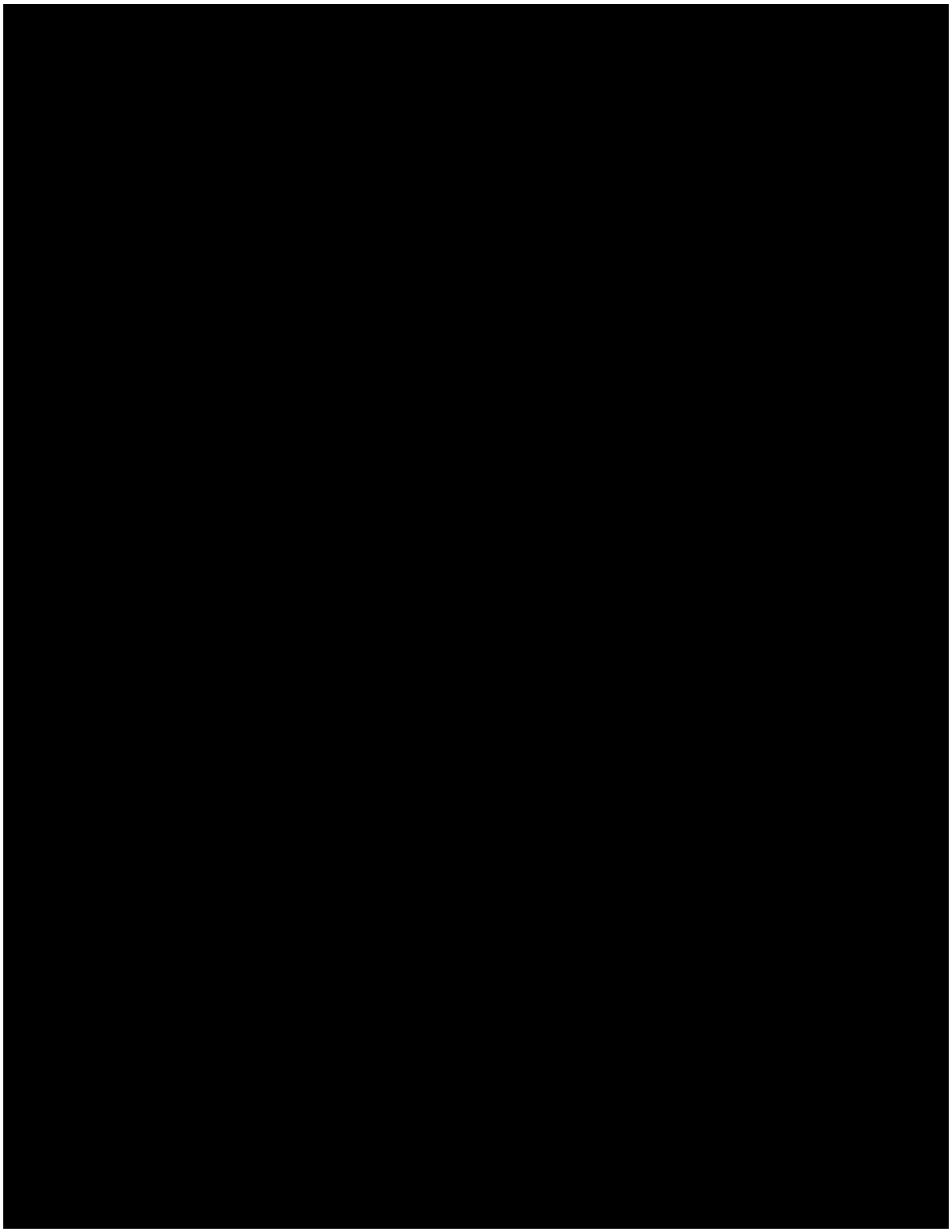


Figure 1-11 – Sand percentage map of the Upper Frio formation (Galloway, Hobday, and Magara, 1982), with the location of the underground storage easement indicated.

Volcanic sediments are present within the Frio Formation from volcanic uplands found in Mexico and in the southwestern United States (Snedden and Galloway, 2019). Higher concentrations of these volcanic sediments are found closer to the Rio Grande system, with the presence of volcanic sediments decreasing to the east toward Louisiana (Snedden and Galloway, 2019). Mineralogy within the Frio is diverse and affected by these volcanic sediments, indicated by the presence of smectite within the clays and plagioclase feldspar within the sands (Snedden and Galloway, 2019). [redacted]

Above the Frio injection interval is the Anahuac Shale, representing a 2-million-year (m.y.) retrogradational period that culminated in a regional maximum flooding surface. Within the Middle Texas Coast, it is easily identifiable due to the thick shale that is likely the product of open-shelf suspension sedimentation (Galloway, Hobday, and Magara, 1982). This continuous, laterally extensive shale exhibits high clay concentrations. Regional thickness varies from [redacted] within the Project site and is approximately [redacted] thick in the [redacted] This unit will regionally seal and prohibit any transmissibility between the Oakville and Frio injection intervals.

The Catahoula, alternatively referred to as the Catahoula Tuff, lies above the Anahuac and below the sequence boundary at the base of the Oakville Formation. This formation is the upper portion of the Catahoula Confining System, which acts as a hydrogeologic confining layer between the overlaying Oakville and lower-lying Frio (Baker, 1979). Amounts of clay tend to increase downdip until the Anahuac formation is approached, which can be seen via the higher clay content (Baker, 1979). Offset field data indicates increased volcanic ash concentrations within the Catahoula, likely decreasing reservoir quality (Stamey, Montgomery, and Easton, 1935).

Similar to the depositional environment of the Frio Formation at the Project site, the Oakville Formation is within the "Oakville Barrier," which occurs between the North Padre and Calcasieu deltas, acting as a barrier system producing "thick, strike-aligned, amalgamated sand bodies separating landward lagoonal and coastal plain facies from downdip fossiliferous, muddy facies deposited on the narrow shelf" (Snedden and Galloway, 2019). Figure 1-12 depicts the depositional environment of the GOM basin during the Lower Miocene (Galloway, et al., 2000) and shows the proposed location within the Oakville Barrier depositional system. The depositional environment associated with the Oakville Barrier allowed for extensive wave reworking of sediments and longshore transport. In addition to barrier island and strandplain environments, the Oakville strata includes deltaic, lagoonal, and fluvial-related deposits.

The Oakville Formation consists predominantly of terrigenous clastic sediments, forming alternating layers of sand and clay. The clay concentration progressively rises toward the upper limit of the formation (Baker, 1979). More prominent transgressive episodes within the Lower Miocene will act as regional seals within these interbedded reservoirs.

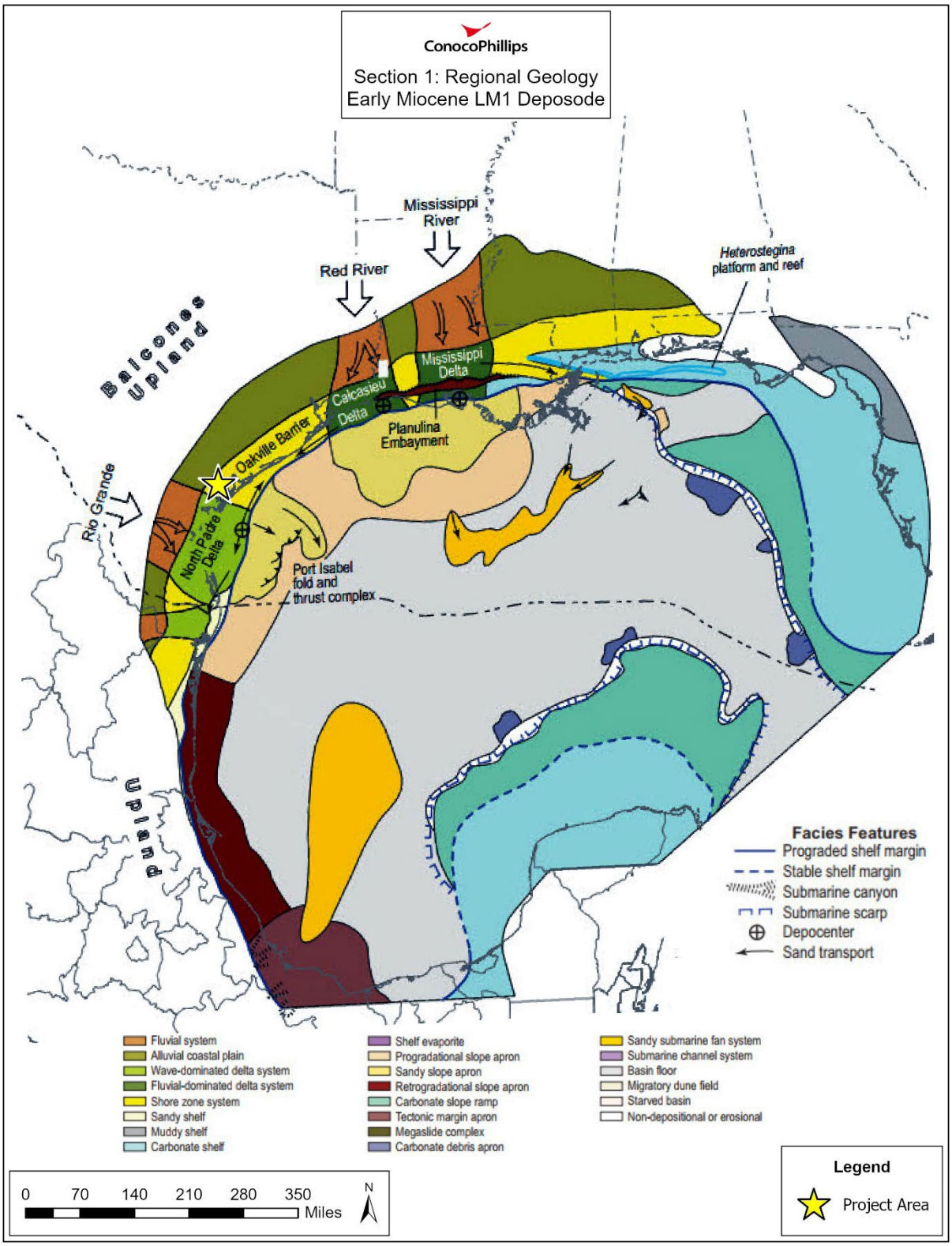


Figure 1-12 – Lower Miocene depositional systems map,
with the yellow star indicating the location of the Project area (Snedden and Galloway, 2019).

In support of the trend discussed by Snedden and Galloway (2019), a petrographic study on the Frio conducted by the Bureau of Economic Geology (BEG) has identified a rock compositional trend indicating poorer reservoir quality towards southern Texas along the Gulf Coast (Loucks, Dodge, and Galloway, 1979). However, the likelihood of diminished reservoir quality in the Upper Frio due to increased amounts of volcanic and carbonate grains appears to be lower at the Project site, since it is situated in the shore zone east of the Rio Grande System, and sediment supply was derived from local uplands and the reworking of nearby deltas. Additionally, petrographic data indicates that quartzose feldspathic litharenite and lithic arkose are the most common sand types at that location.[1]

Furthermore, the Lower Miocene sands exhibit a higher lithic content in southern Texas compared to Louisiana, featuring a composition ranging from litharenite to feldspathic litharenite at the Project site.[2] Figures 1-13 and 1-14 represent maps depicting the petrographic facies distributions of the Oligocene Frio formation and the Lower Miocene 1 unit, respectively, along the Texas coast in relation to the proposed Project site. Both the Oligocene and Miocene targets are expected to have sufficient reservoir quality despite the variable lithic content.

[1] https://ig.utexas.edu/energy/gbds/
[2] Ibid.

Figure 1-13 – Ternary plot of Oligocene Frio in relation to the underground storage easement [redacted] (https://ig.utexas.edu/energy/gbds/).

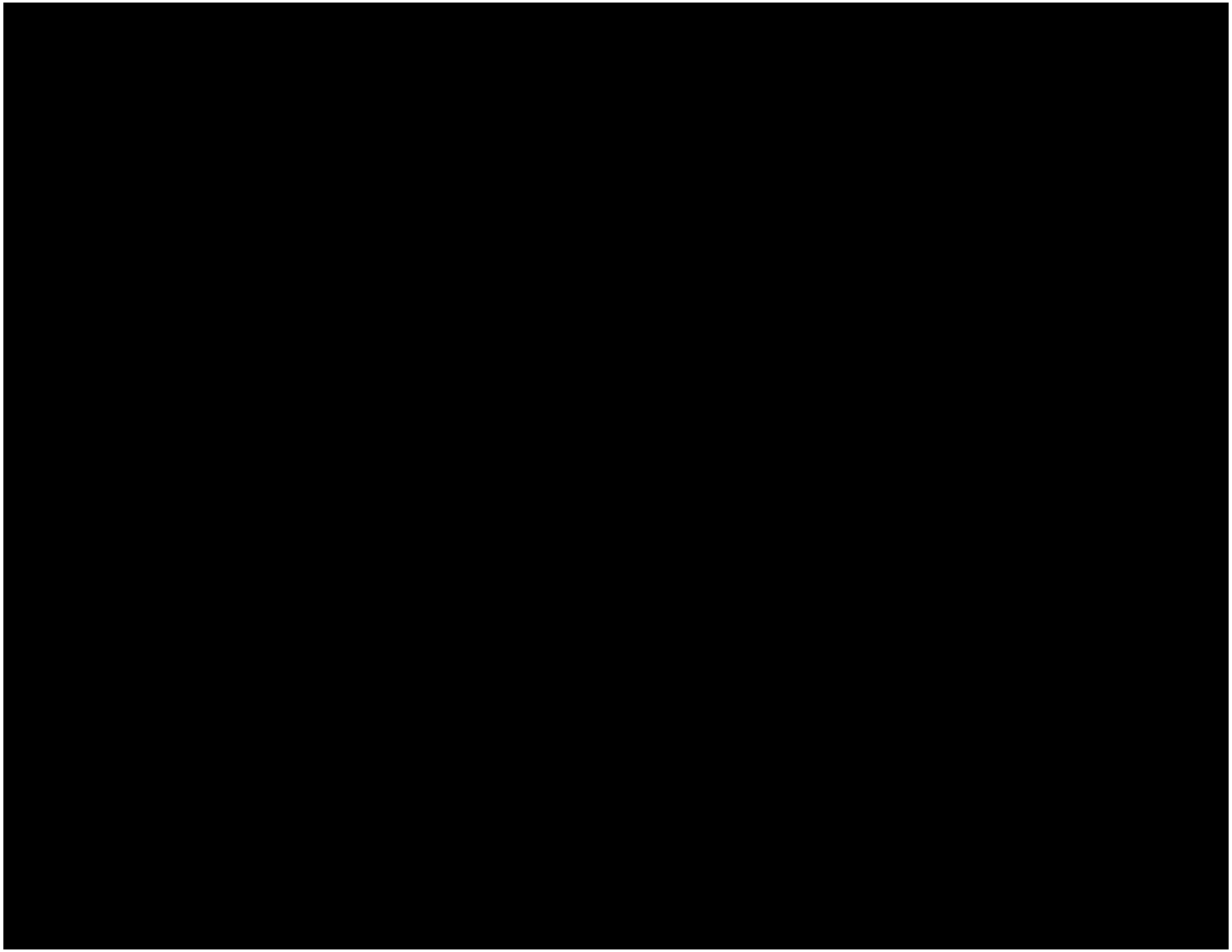


Figure 1-14 – Ternary plot of LM1 in relation to underground storage easement [redacted] (https://ig.utexas.edu/energy/gbds/).

Examinations of the lateral extents of sand and shale packages within the injection interval were carried out through the analysis of 3D seismic surveys and subsurface well control up to 20 mi outside the AOI. The findings from these analyses were employed to construct a geocellular model, subsequently integrated into the plume model to enhance the identification of sands capable of potential communication. [redacted] More details regarding the geocellular model are elaborated in *Section 1.4*.

Figure 1-15 presents an openhole log from the [redacted], illustrating local stratigraphy. The shale volume (VSH) log, derived from the SP curve, is displayed in Track 1, featuring shading to the right of the curve to represent varying shale content (darker brown indicates higher shale content). Track 2 showcases shallow and deep resistivity curves. The injection interval, starting from the top of the Oakville Basal sand marker and extending to the Lower Frio marker, encompasses all intervening strata. The gross thickness of the injection zone in Figure 1-15 measures [redacted] Within this gross interval [redacted], an estimated [redacted] of net sand is present. Gross thickness of the injection zone within the proposed injection area ranges from [redacted], as shown in *Appendixes B-16* and *B-18*. A net sand map of the injection zone is displayed in Appendix B-21.

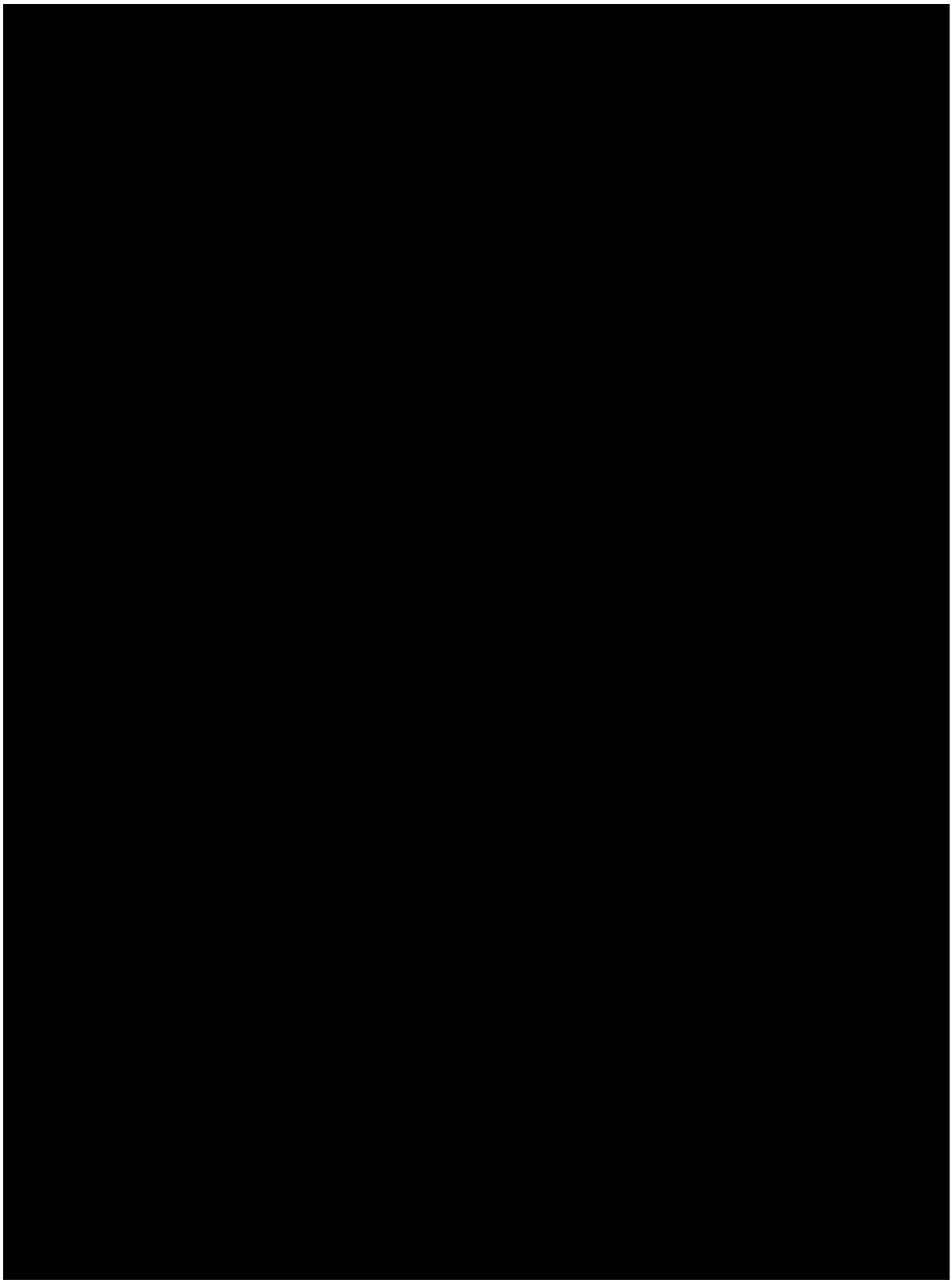


Figure 1-15 – Openhole log of [redacted] displaying the injection interval. [redacted]

1.3.2 Upper Confining Zone

[redacted]

[redacted]

[redacted]

An openhole log of the [redacted] is displayed in Figure 1-17 with the VSH curve found in Track 1, while both shallow and deep resistivity curves are found in Track 2. [redacted] The gross thickness of the UCZ within this well is [redacted] with a net shale footage of [redacted] when a [redacted] VSH cutoff was applied. This relationship results in a [redacted] net shale ratio within the UCZ, supporting the interpretation that the transgressive marine shale sequence was established through this section.

Given the importance of this zone, a more detailed correlation was done prior to modeling to ensure the lateral continuity of both shale layers at the top and base of the zone. [redacted]

[redacted]

The gross thickness of the [redacted] ranges from [redacted] across the Project AOI (*Appendix B-15*). Net thickness of the shales within the [redacted] range from [redacted] across the Project AOI (*Appendix B-20*). [redacted]

The modeled distribution ultimately confirmed the sealing nature of the UCZ.

[redacted]

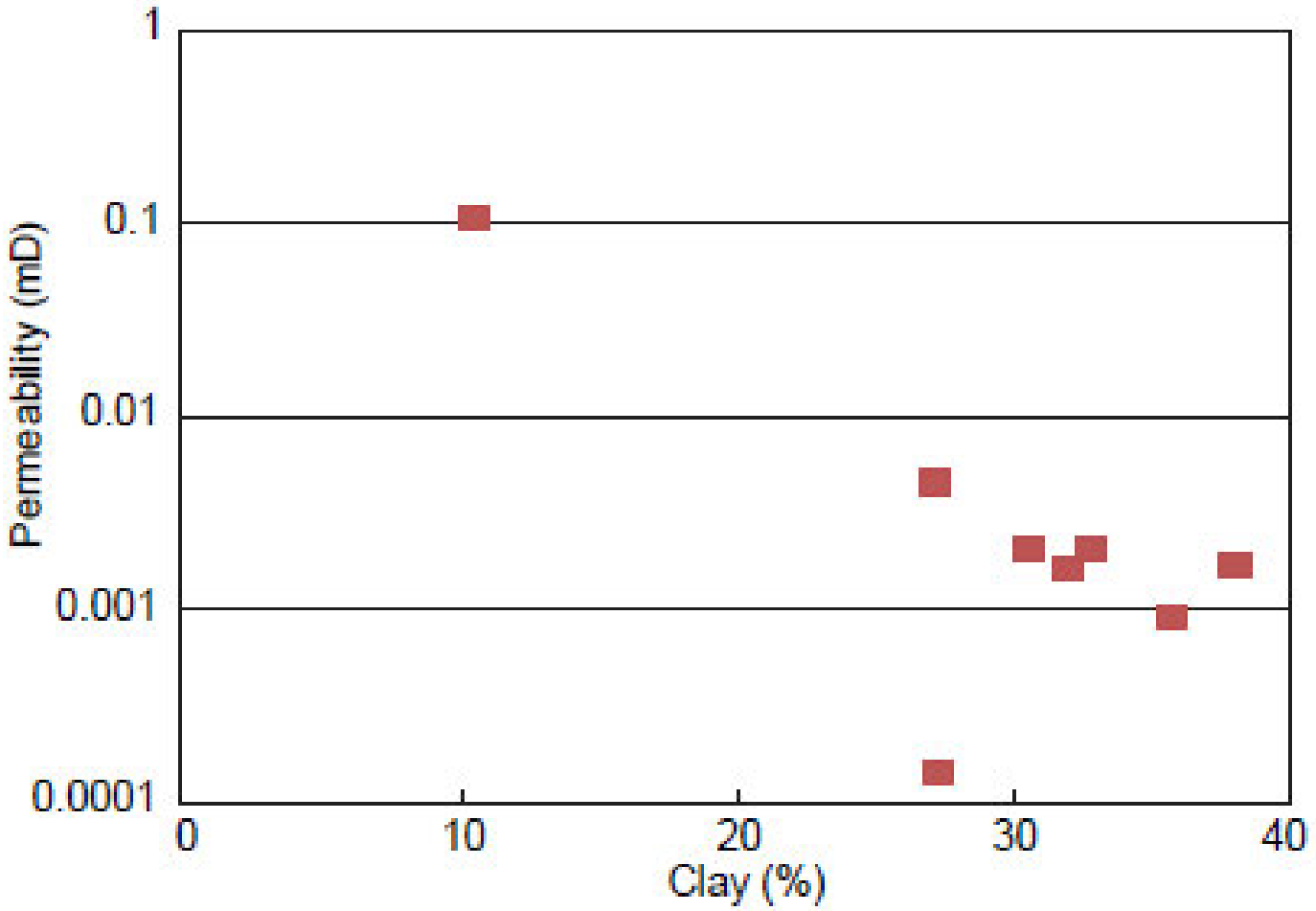


Figure 1-16 – Permeability vs. clay abundance showing decreasing permeability with higher clay abundance. Samples are from the well OCS-G-4708 #1 (API No. 42-703-40126) from a 40-ft interval (Lu et al., 2017).

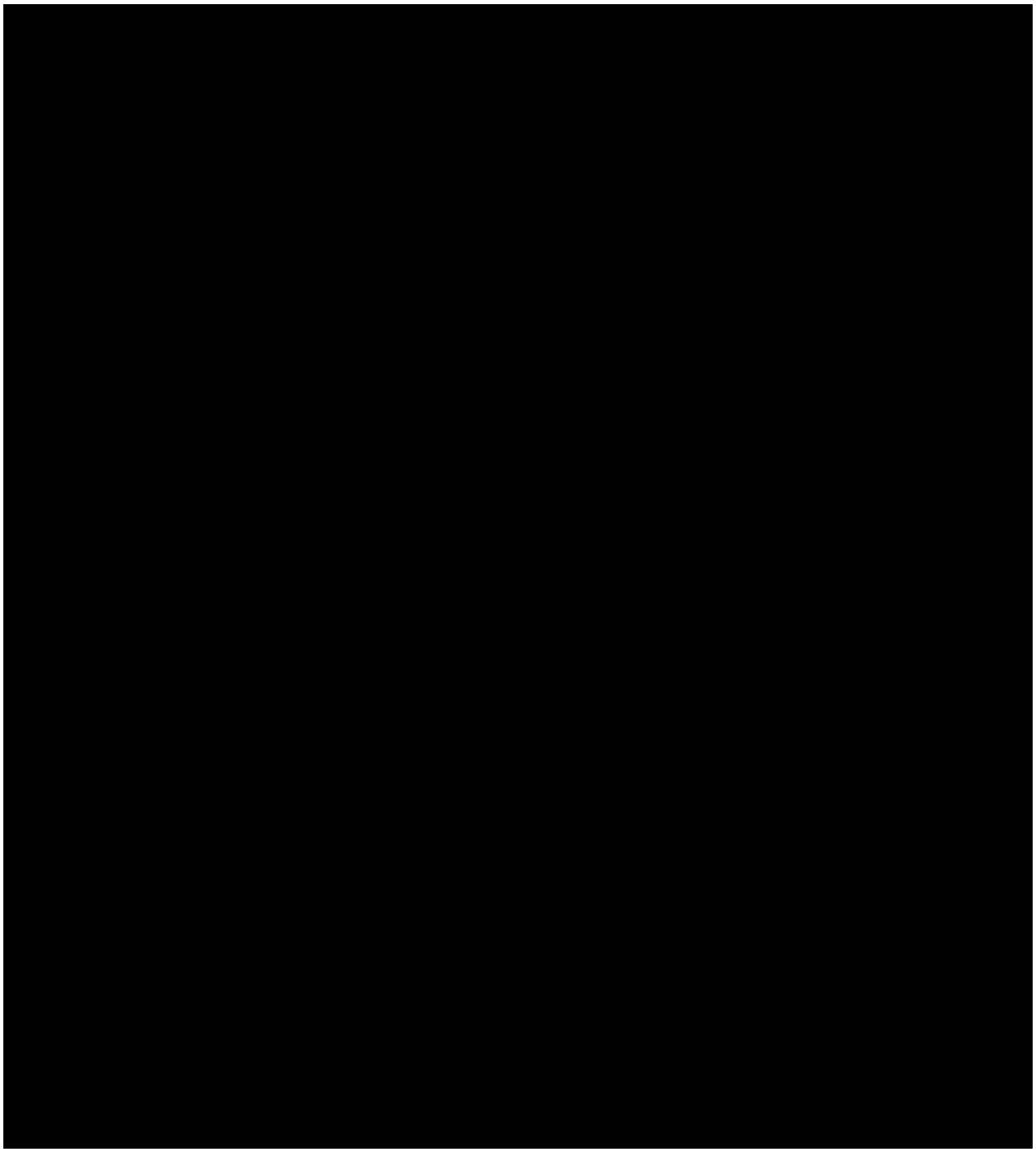


Figure 1-17 – Openhole log of offset log depicting the UCZ.

1.3.2.1 Section from UCZ to USDW

Above the [redacted] is the topmost section of the Oakville, which contains the sands that will be used for above-zone monitoring (AZM) wells, ranging in thickness from [redacted] across the Project AOI, with an average of [redacted] These sands have a net-to-gross sand ratio of [redacted] This sand package is the last significant package before a thick section of mostly shale, with a few interbedded sands.

Above these Oakville sands lies the transgressive maximum flooding surface associated with the Amph B. This substantial marine transgression is the sequence separating the Middle and Lower Miocene (Snedden and Galloway, 2019). Locally, the marine transgression is referred to as the Burkeville Confining Unit (Baker, 1979). This confining unit lies between the AZM sands and the base of the Underground Source of Drinking Water (USDW), providing ample additional separation between the proposed injection interval and the base of the USDW. The stratigraphic column in Figure 1-4 showed the Burkeville Confining Unit in relation to the Amph B, Marg A, and Siph Dav biostratigraphic markers.

Similar to the Siph Dav, the Amph B consists of high concentrations of thick clay mudstone. The earlier referenced study by Lu et al. (2017) specifically referenced the Amph B as a "proven seal," which will "provide good confinement solution for injected CO_2" (Lu et al., 2017).

Figure 1-18 shows this section in the [redacted] Track 1 plots a VSH curve, and Track 2 depicts both shallow and deep resistivity curves. The log indicates that the Burkeville Confining Unit has considerable thickness, primarily comprised of tight clays with occasional interbedded sands. The thickness of the Burkeville Confining Unit is approximately [redacted], with a shale net thickness of [redacted] These characteristics suggest that it provides additional geologic protection, ensuring CO_2 injectate will not migrate to shallower fresh water-bearing aquifers. The total thickness of this section from the top of the UCZ to the presumed USDW is [redacted] with an average of [redacted]

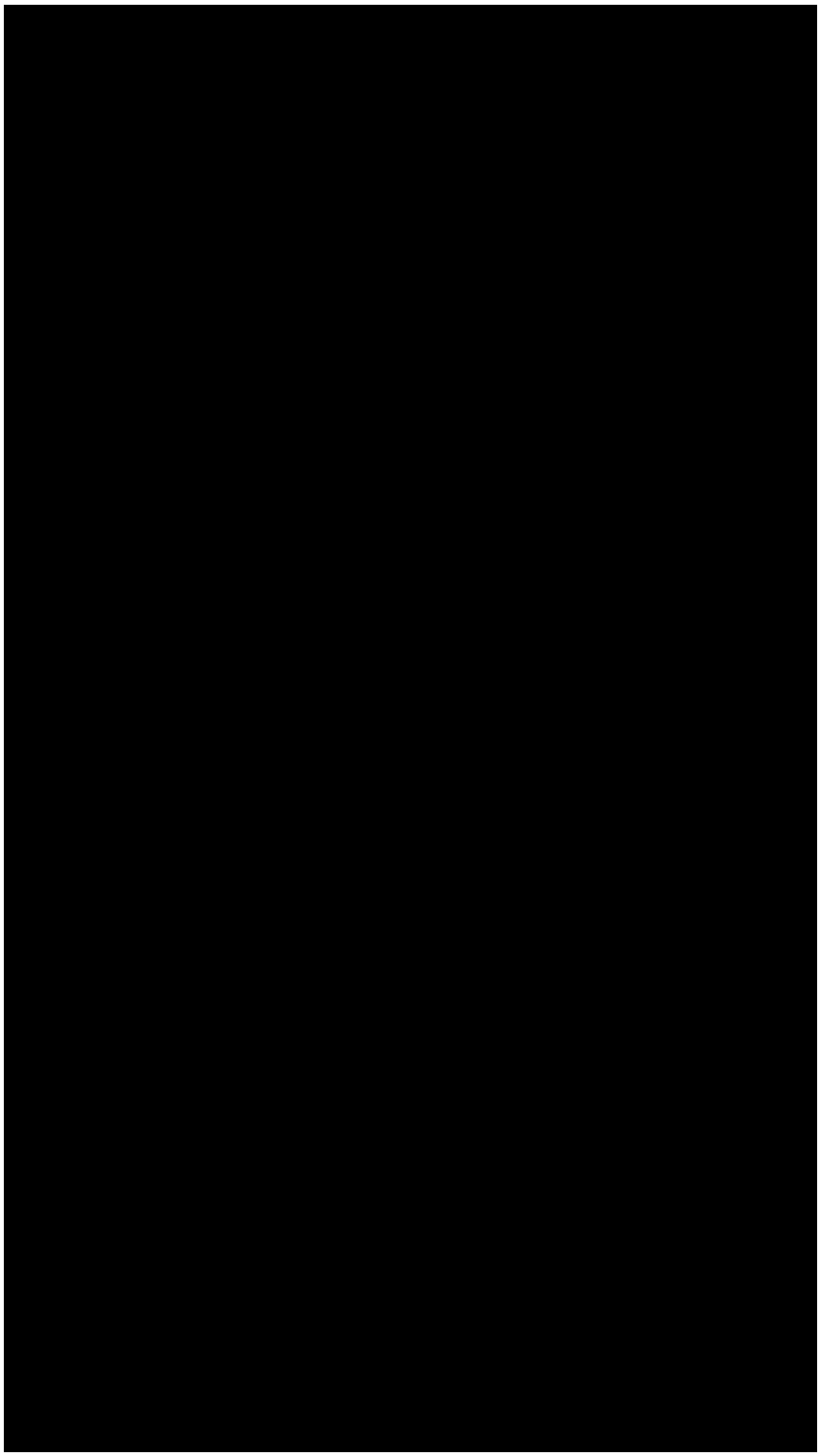


Figure 1-18 – Openhole log of offset well depicting the section above the UCZ,

1.3.3 Lower Confining Zone

[redacted]

Figure 1-19 is an openhole log display of the LCZ represented in the nearby [redacted] The gross thickness of the LCZ is [redacted], with [redacted] of net shale. [redacted] In addition to the lithologic makeup of the LCZ, downward migration of the proposed injectate will be unlikely due to two factors: (1) overpressure in the deeper portion of the LCZ helping to contain injected fluid to the injection zone; and (2) the injectate's lower density in contrast to the connate fluid within the injection zone. This buoyancy effect will work in favor of the compartmentalization of the CO_2 and restrict downward movement. The gross thickness of the LCZ across the Project AOI ranges from [redacted] (*Appendix B-19*). Net thickness of the shale facies within the LCZ AOI ranges from [redacted] across the Project (*Appendix B-22*).

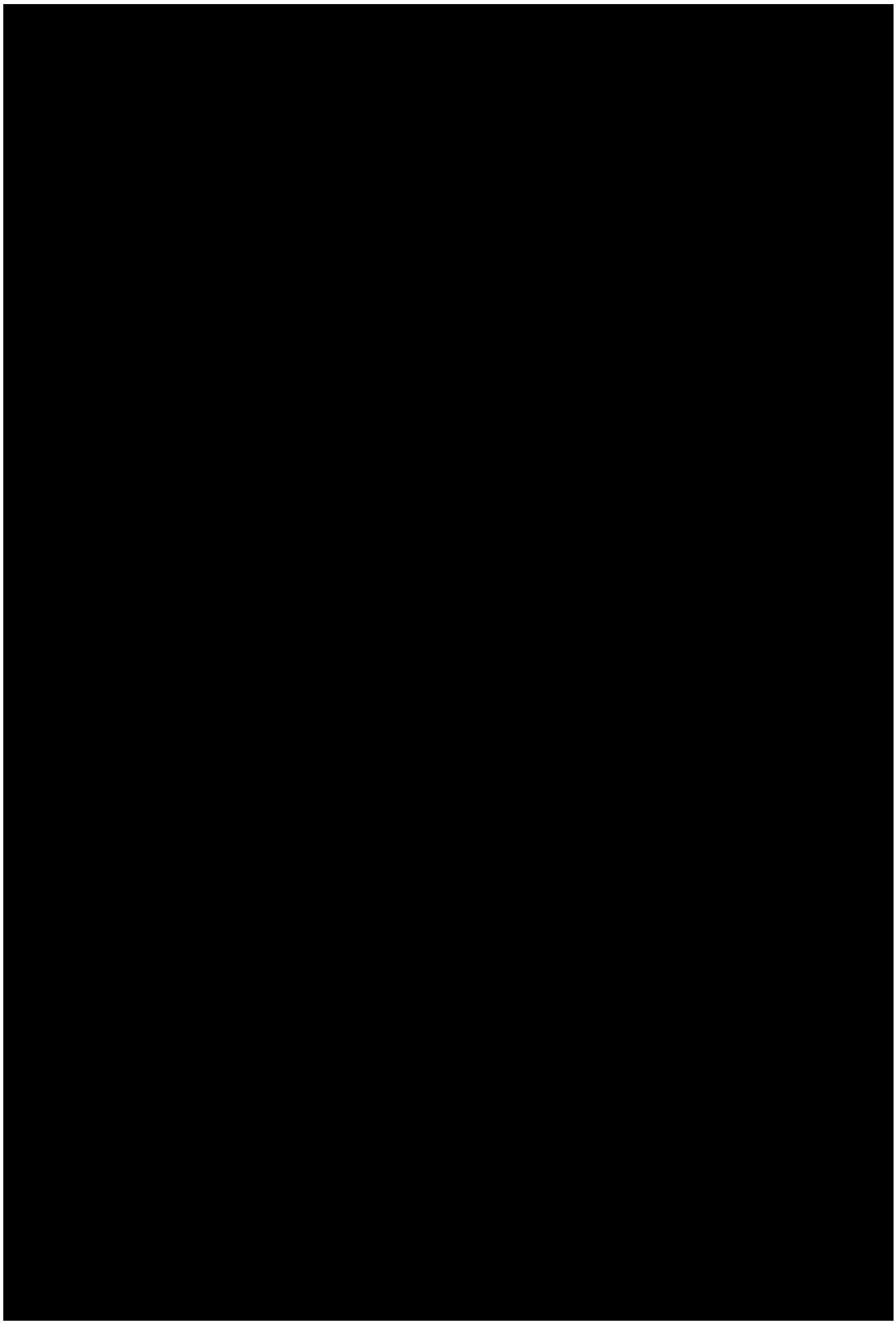


Figure 1-19 – Openhole log of offset well depicting the LCZ.

1.4 Rock Properties and Petrophysical Evaluation

1.4.1 Rock Properties

The distribution of porosity and permeability of Cenozoic sandstones along the GOM basin is shaped by depositional and diagenetic processes. As discussed in *Section 1.3.1*, reservoir development in the Miocene and Oligocene sandstones that constitute the proposed injection zone in the Project AOI occurs within strandplain and barrier bar depositional systems. These reservoir-quality sandstones are interbedded with local silts and shales and delimited vertically by upper- and lower-confining regional shale intervals. [redacted]

Burial and compaction processes generally result in porosity diminution. Compaction is a mechanical process due to increasing overburden that causes grains to reorient and expel water as they pack more densely (Ulmer-Scholle et al., 2014). Porosity data from available core is plotted against depth in Figure 1-20. Though the graph demonstrates a general decline in porosity over increasing depths, the effect is subtle—and the data did not support the application of a compaction depth trend.

Cement precipitation, typically composed of carbonate (e.g., calcite) or quartz, is a common post-burial diagenetic process within Cenozoic sandstones along the Texas coast. [redacted]

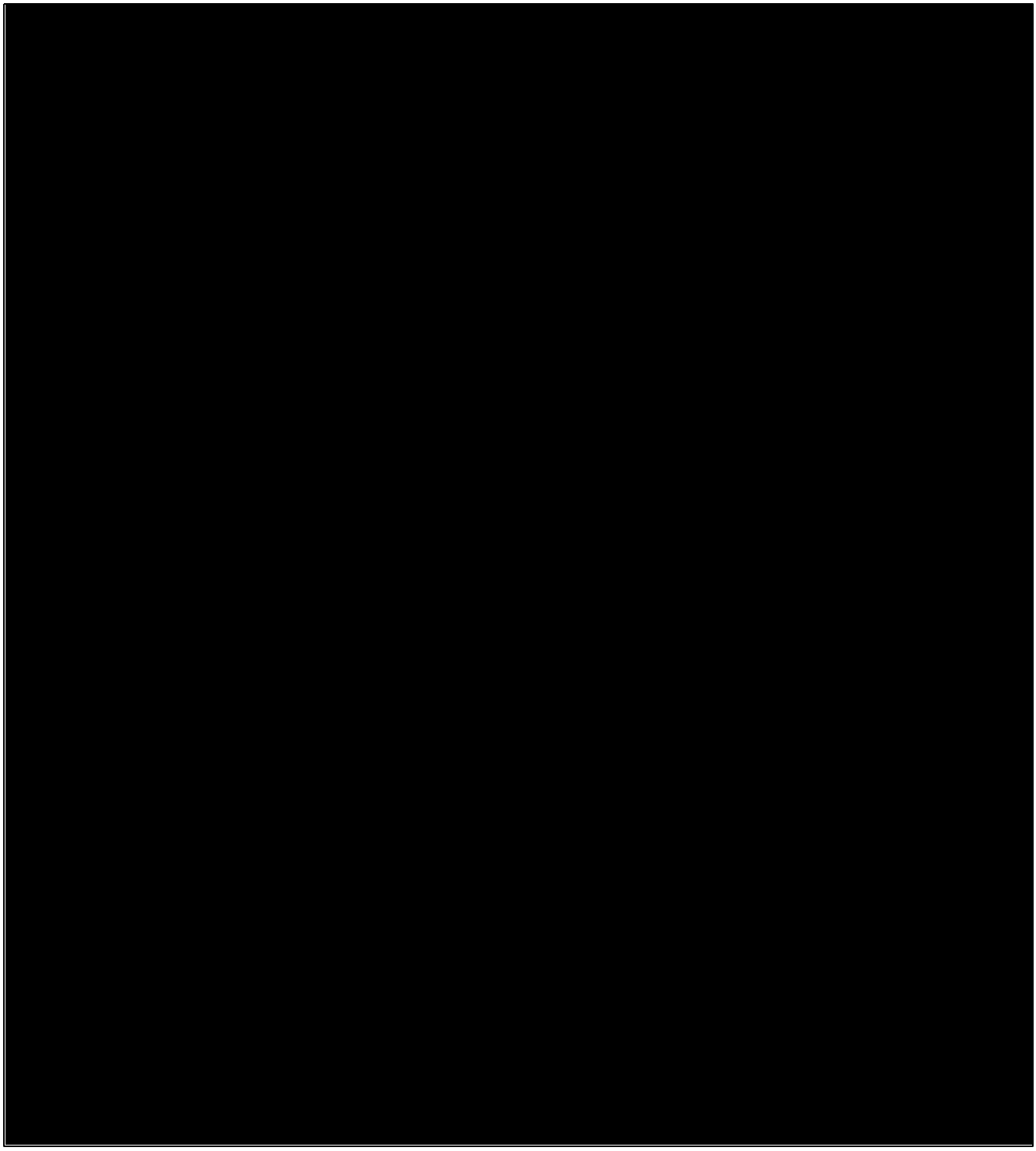


Figure 1-20 – Core porosity and depth plot.

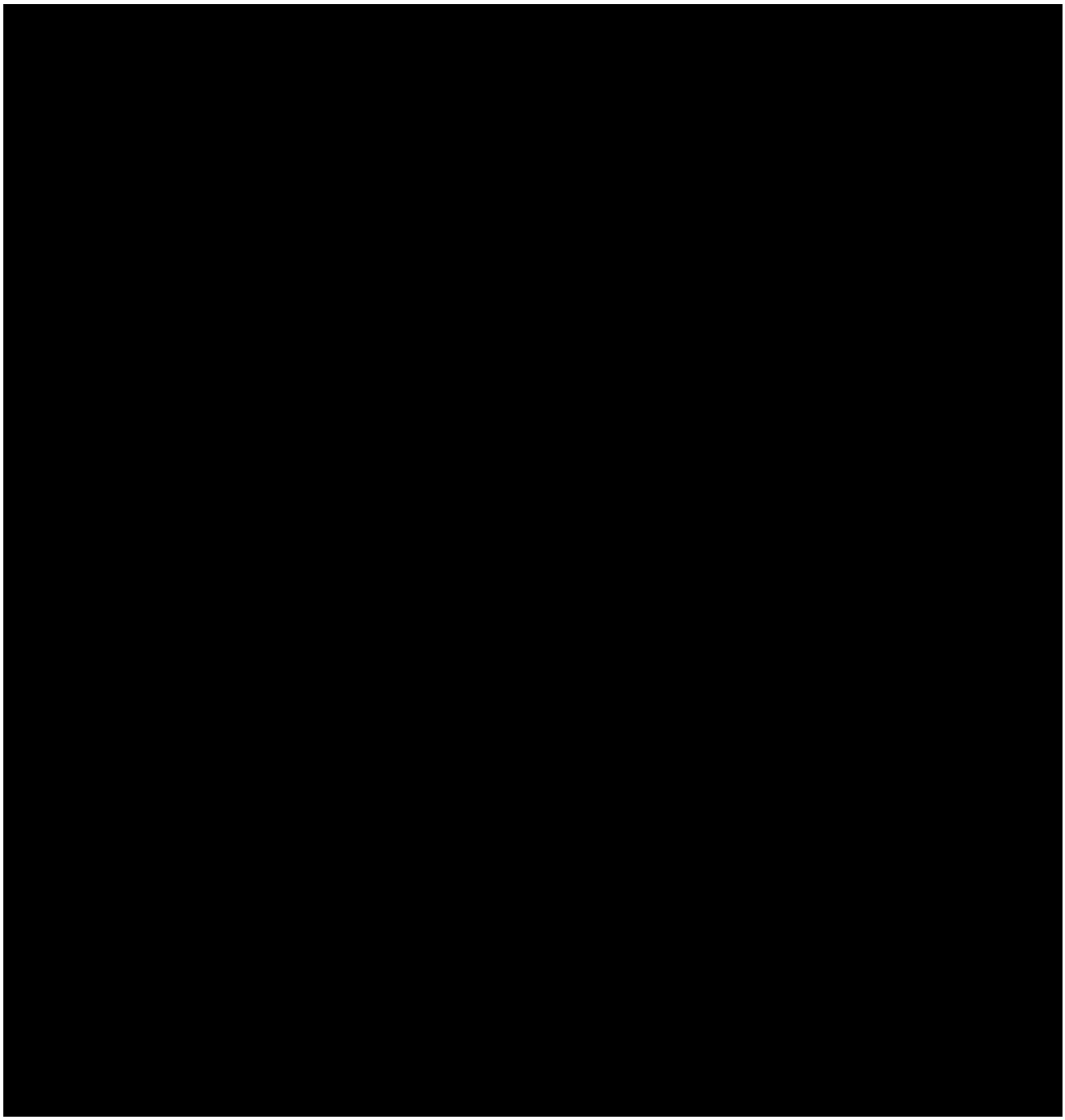


Figure 1-21 – [redacted] well log example of carbonate cemented zone.

Figure 1-22 – [redacted] VSH-porosity crossplot.

1.4.2 Petrophysical Evaluation

Petrophysical analysis was performed on [redacted] offset wells with lithologic indicator logs (SP or gamma ray (GR)), and a total porosity curve was generated for [redacted] of those wells. Core data was analyzed from [redacted] wells, indicated in Figure 1-23 [redacted]

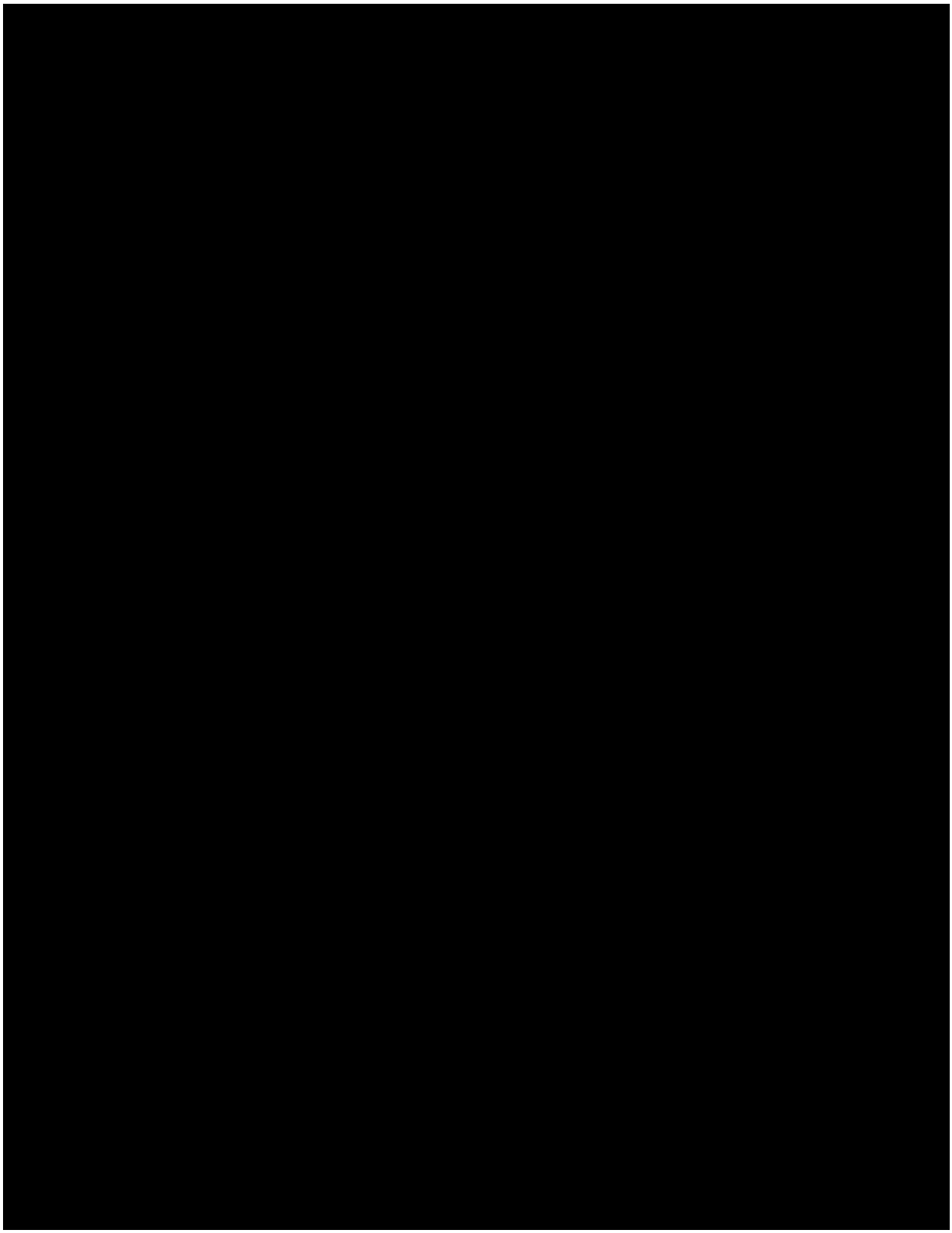


Figure 1-23 – Location of core data.

1.4.2.1 Data Quality Control

Many of the legacy wells along the Gulf Coast were drilled and logged with water-based mud.

[redacted]

The following workflow is applied to all log data:

[redacted]

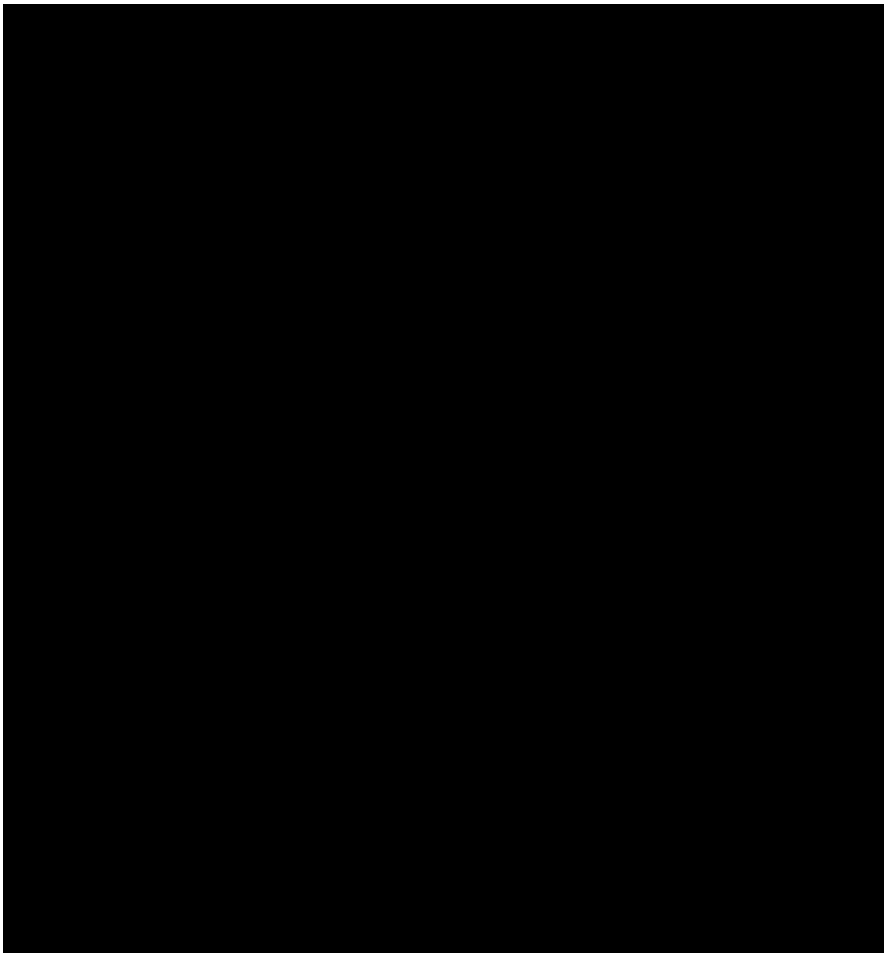


Figure 1-24 – Example of QC process [redacted]

1.4.2.2 Shale Volume

In conventional clastic formations, such as the Oakville and Frio Sands along the Gulf Coast, VSH can be calculated from GR logs, density/neutron (DEN/NEU), or SP. In the Gulf Coast area, SP logs are the most commonly available, followed by GR, and then DEN/NEU. To keep the calculation consistent, VSH is calculated using SP by default, resulting in VSH_{SP}.

The equations for VSH calculation are listed as follows:

Eq. 1:

$VSH_{SP} = (SP_{Shale}-SP)/(SP_{Shale}-SP_{Sand})$

Where:

VSH_{SP} = shale volume, in percentage

SP = value of SP curve

SP_{Sand} = baseline sandstone SP curve value

SP_{Shale} = baseline shale SP curve value

Eq. 2:

$VSH_{GR} = (GR_{Shale}-GR)/(GR_{Shale}-GR_{Sand})$

Where:

VSH_{GR} = shale volume, in percentage

GR = value of GR curve

GR_{Sand} = baseline sandstone GR curve value

GR_{Shale} = baseline shale GR curve value

If the baselines are relatively consistent along the interval of calculation, fixed values (static) of baseline can be used for the calculation. If the baselines change along the interval, the baseline values can be variable (dynamic). Figure 1-25 shows an example of how VSH is calculated dynamically using variable baselines. At each depth of calculation, the SP/GR values in the processing window [redacted] are collected. The baselines for sand and shale at each depth are selected based on the histogram of the collected values in the processing window [redacted] The VSH is calculated using SP or GR, depending on log curve availability, with the corresponding baselines.

Facies are defined by VSH cutoffs: [redacted]

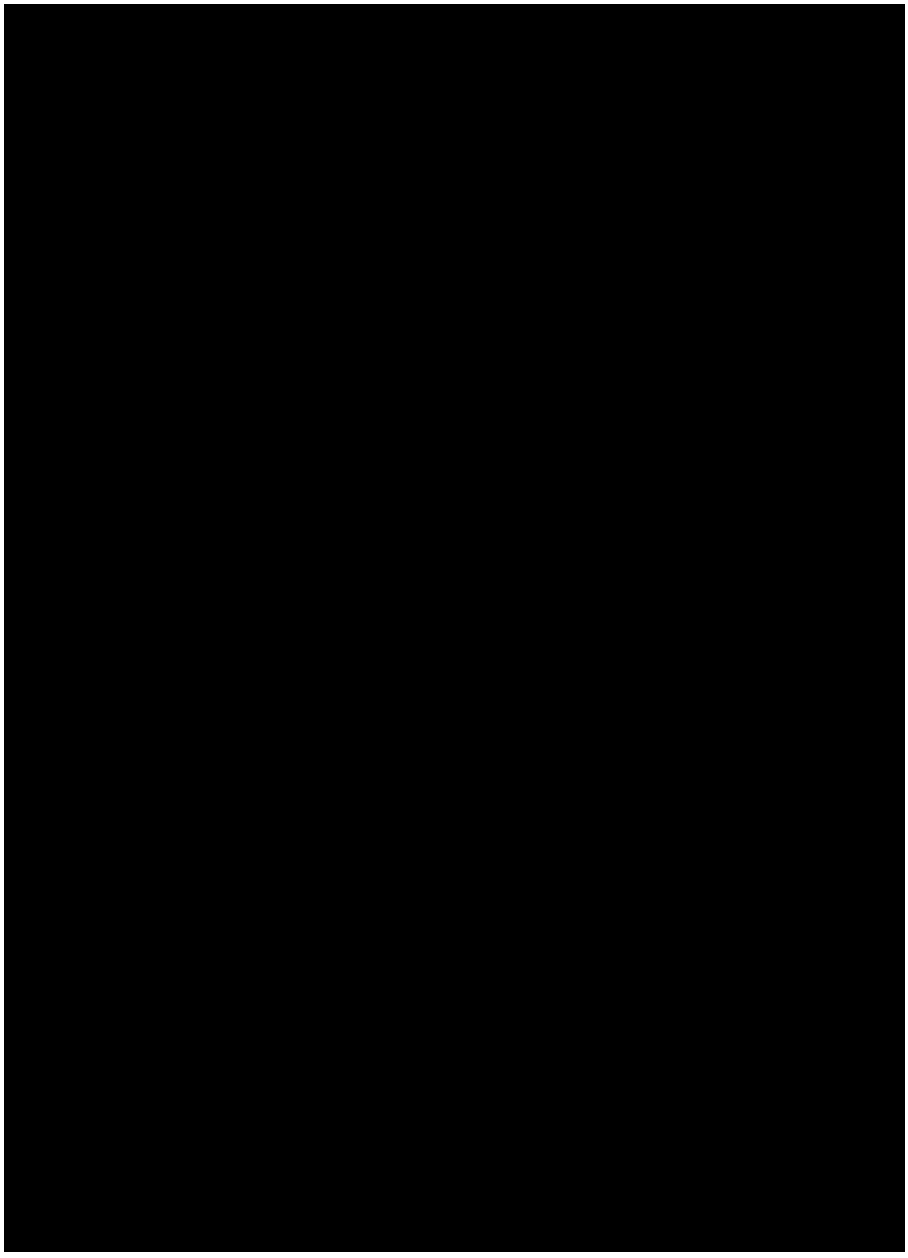


Figure 1-25 – VSH dynamic calculation using variable baselines

1.4.2.3 Total Porosity

Total porosity (PHIT) of the formation was calculated using DEN/NEU, with GR for clay effect correction. Figure 1-26 shows the workflow for the calculation of total porosity. There are two models for porosity calculation: a wet model and a hydrocarbon-bearing (HC) model. In a wet model, it is assumed that the water saturation (S_w) of the formation is 100%, with water as the only formation fluid. In an HC model, both water and hydrocarbon are assumed to coexist in the formation. The analogous core data in the area lacks the formation electrical properties needed to accurately determine formation fluid saturation.

[redacted]

Figure 1-26 – Total porosity calculation workflow.

Wet Model

In the wet model, logs of GR, DEN, and NEU are used as inputs of log interpretation and PHIT calculation. The wet model is implemented where the formation is shale or an obviously water-saturated sand, such as those found in the proposed injection interval. Calculated VSH is used to identify the shale zones [redacted] To identify water-saturated clean sand zones, deep resistivity and VSH are used (e.g., relatively low deep resistivity and VSH), assuming the sand is 100% water-saturated (i.e., wet). Mudlogs with recorded gas measurements are also used as a reference, if available.

The equation for PHIT calculation is as follows:

Eq. 3:

$GR = GR_{clay} \times V_{clay} + GR_{quartz} \times (1\text{-}PHIT\text{-}V_{clay})$

$RHOB = RHO_{clay} \times V_{clay} + RHO_{quartz} \times (1\text{-}PHIT\text{-}V_{clay}) + RHO_{water} \times PHIT$

$NPHI = NPHI_{clay} \times V_{clay} + NPHI_{quartz} \times (1\text{-}PHIT\text{-}V_{clay}) + NPHI_{water} \times PHIT$

Where:

V_{clay} = clay volume, in percentage

GR = value of GR curve

GR_{clay} = GR value for clay

GR_{quartz} = GR value for quartz

RHOB = value of bulk density curve

RHO_{clay} = density value of clay

RHO_{quarz} = density value of quartz

RHO_{water} = density value of formation water

$NPHI_{clay}$ = neutron porosity value of clay

$NPHI_{quarz}$ = neutron porosity value of quartz

$NPHI_{water}$ = neutron porosity value of formation water

[redacted]

[redacted]

Total Porosity

Figure 1-26 showed the workflow of porosity calculation. [redacted]

[redacted]

[redacted]

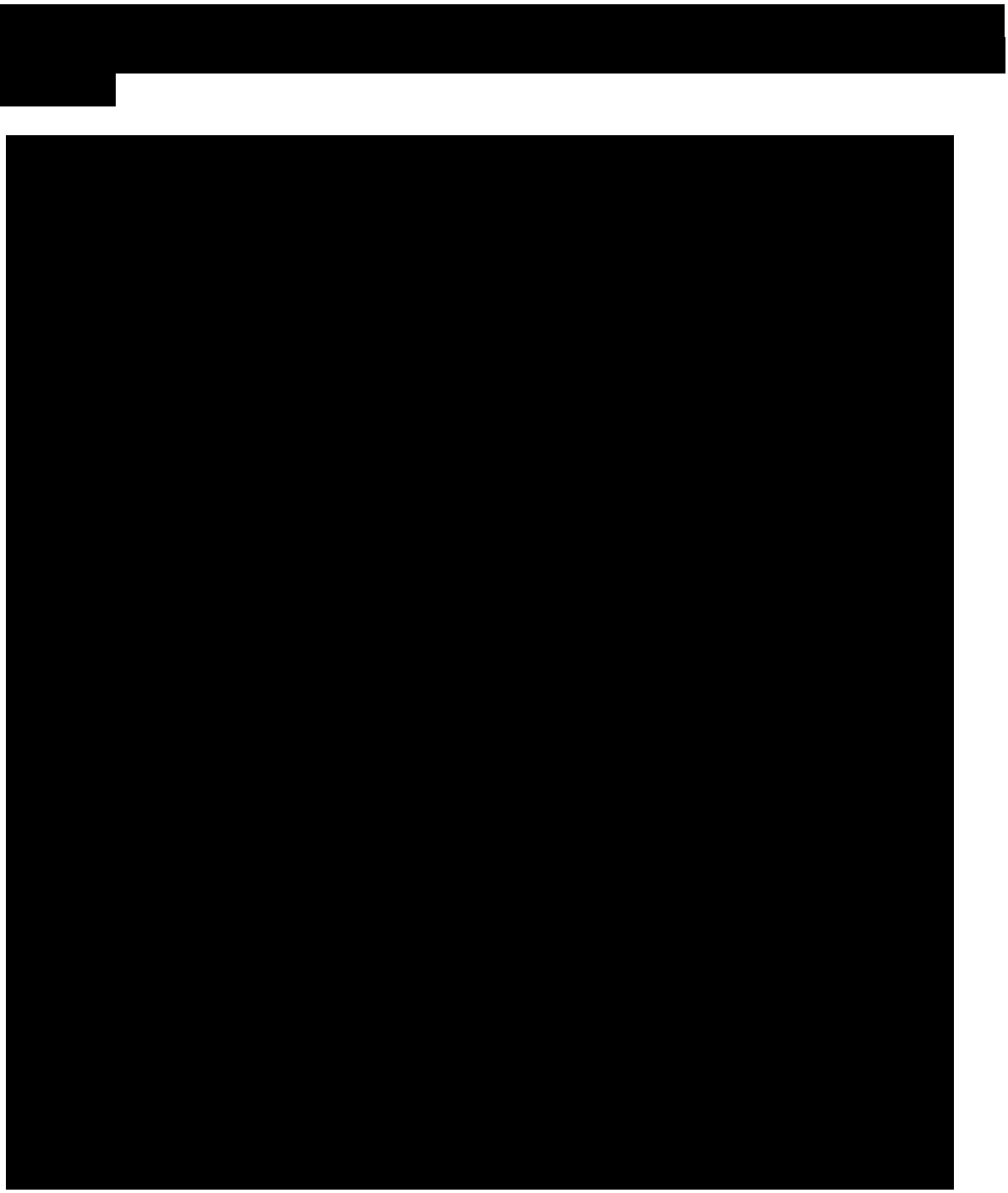


Figure 1-27 – Example of porosity and volume calculations

1.4.2.4 Effective Porosity

The effective porosity, or percent volume of interconnected pore space, is calculated using PHIT and shale volume VSH, with shale porosity Φ_{SH} as an input parameter. The equation for the calculation is listed below.

Eq. 4:

$PHIE = PHIT - (VSH \times \Phi_{SH})$

Where:

PHIE = effective porosity, in decimal percent

PHIT = total porosity, in decimal percent

VSH = shale volume, in decimal percent

Φ_{SH} = shale porosity, in decimal

1.4.2.5 Permeability

The porosity-permeability correlation is obtained by performing data fitting on a crossplot of core porosity and permeability data in log-log scale. Figure 1-28 shows an example of the porosity-permeability correlation from a crossplot of core data from the three closest wells [redacted] to the proposed injection locations. The same correlation is used to calculate log-derived permeability using PHIT calculated from logs. The equation of the correlation line is as follows:

Eq. 5:

$\log_{10}(\text{Permeability}) = 9.5 \times \log_{10}(\text{PHIT}) - 11.6$

Where:

PHIT = total porosity, in percent

Figure 1-28 – Log-log crossplot of core porosity (%) and core permeability (mD).

While the permeability equation above provides a good approximation of permeability from porosity, the permeability model was further refined to consider mineralogy. In this model, total porosity and volume fractions of minerals are used as inputs to consider the contributions of both porosity and mineralogy.

A comparison of log-derived permeability and core permeability using the two methods above is displayed in Figure 1-29.

Figure 1-29 – Crossplots of log-derived permeability and core permeability:
(a) using the porosity-permeability correlation and (b) using the mineralogy/porosity based-model.

1.4.2.6 Water Salinity

Water salinities in clean sand zones are calculated using Archie's equation, with deep resistivity and total porosity as inputs. The method is outlined as follows:

1. Identify water-saturated clean sand zones using deep resistivity and calculated total porosity and clay volume (e.g., good porosity rock with relatively low deep resistivity and clay volume), assuming the sand is 100% water-saturated. Mudlogs are also used as a reference, if available.
2. Calculate formation water resistivity using Archie's equation, with deep resistivity and total porosity as inputs.

   Eq. 6:

   $R_w = R_t \times PHIT^m$

   Where:

   R_w = formation water resistivity

   R_t = formation resistivity

   PHIT = total porosity, in decimal percent

   m = cementation exponent, default value of 2

3. Convert formation water resistivity to water salinity at each depth (SLB Chartbook 2013, Gen-6).
4. Plot a histogram of the water salinity of each identified wet sand zone. The values of P10/P50/P90 are from the histogram for each wet sand zone (Table 1-3).

Table 1-3 – Salinity values by zone.
The P10, P50, and P90 values of log-calculated salinity
are shown for each clean, wet sand zone of interest in the vicinity of the Project site.

Well	Depths (ft)	Zone	Salinity P10-P50-P90 (kppm)
[redacted]			

*kppm – thousand parts per million

1.4.2.7 Water Saturation

The Waxman-Smits equation, detailed below, is used to calculate water saturation (S_w), with deep resistivity and PHIT as inputs. Since the core data lacks formation electrical properties, default saturation parameters are used. Formation water salinity is derived from the adjacent 100% water-saturated sand intervals. [redacted]

Eq. 7 – Waxman Smits Equation:

$$R_t = \frac{R_w}{S_w^{m*} \emptyset^{n*} (1 + B \frac{Q_v}{S_w})}$$

Where:

R_w = formation water resistivity

R_t = formation resistivity

S_w = water saturation

Φ = total porosity

Qv = cation exchange capacity per unit pore volume of illite

B = equivalent cationic conductance of a sodium ion (SLB: 1978 Waxman B chart)

m* = cementation exponent, default value of 2

n* = saturation exponent, default value of 2

[redacted]

[redacted]

Figure 1-30 – Statistics of the calculated water saturation over the injection target

Figure 1-31 – Calculated water saturation by depth
with the thickness of potential pay zones labeled.

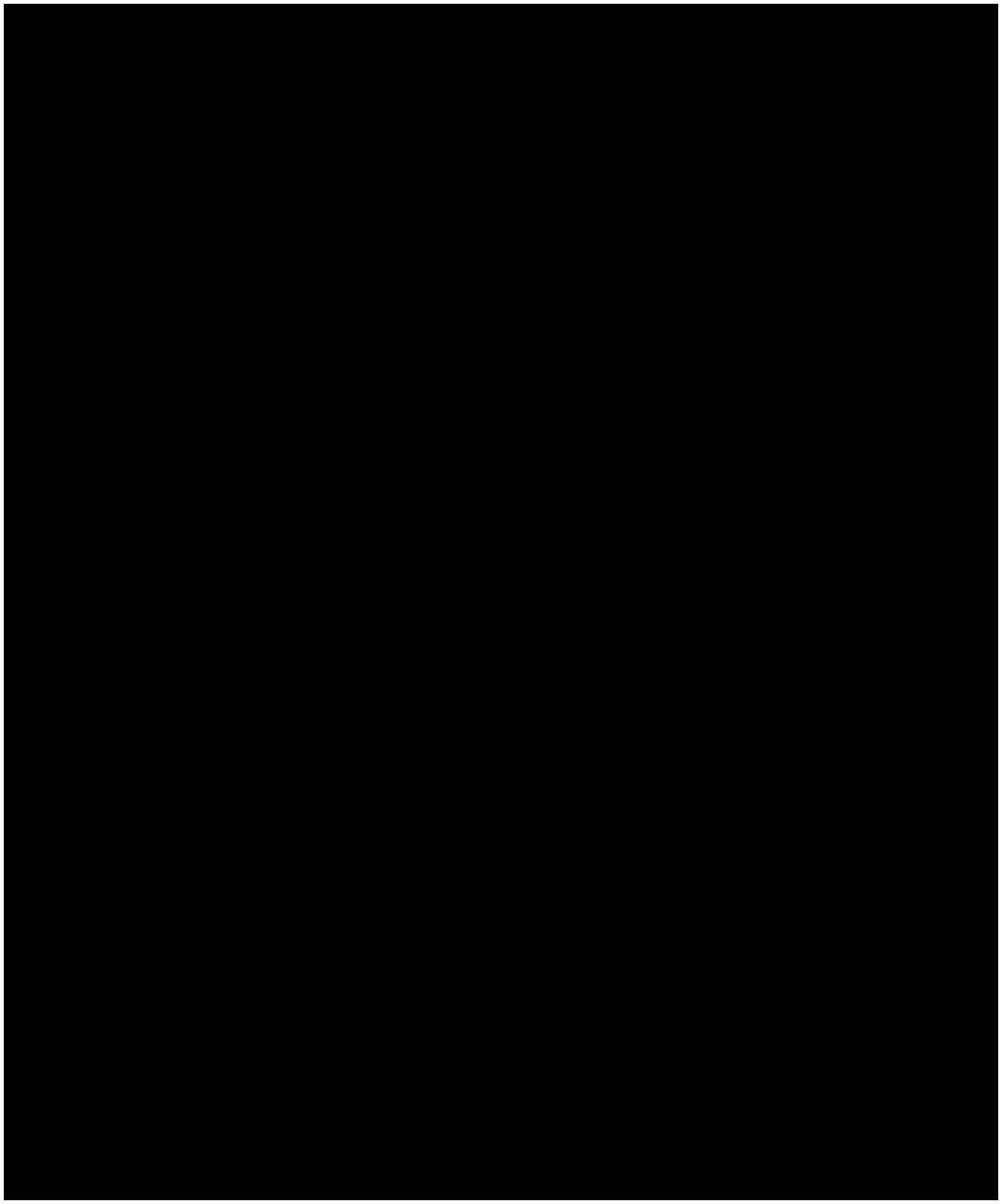


Figure 1-32 – [redacted] well log display and core data.

Figure 1-33 – [redacted] well log display and formation test results.

Figure 1-34 – Water saturation in the UCZ.

1.4.2.8 Uncertainties

[redacted] Whole core will be collected in the UCZ, injection intervals, and LCZ from the planned stratigraphic test wells in the Project area as outlined in Table 1-2.

1.4.3 Upper Confining Zone Porosity and Permeability

Figure 1-35 is an openhole log of the offset [redacted], displaying from left to right: calculated VSH, depth track in measured depth, calculated effective porosity (PHIE), and calculated permeability (KINT). Effective porosity is scaled from 0 to 60%, in decimal form. Permeability is in logarithmic scale from 0.01 to 10,000 millidarcy (mD).

A histogram displaying facies volumes within the gross UCZ is displayed in Figure 1-36. [redacted]

Figure 1-35 – Offset well log of calculated shale volume and effective porosity and permeability across the UCZ.

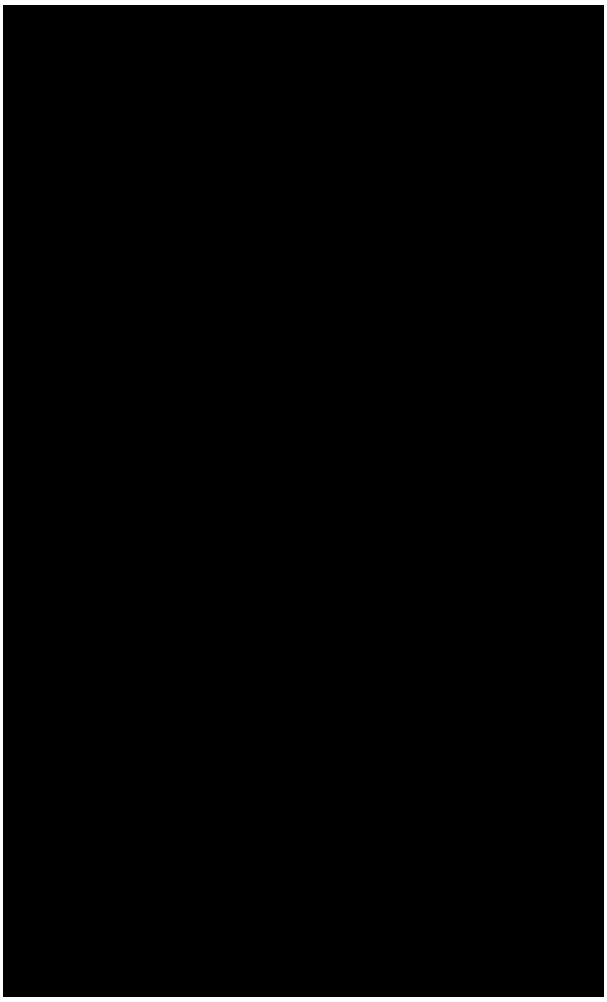


Figure 1-36 – Volume of facies, in percentage, within the UCZ and across the AOI.

1.4.3.1 Upper Confining Zone Porosity

Histograms of total porosity and effective porosity in the UCZ are presented in Figures 1-37 and 1-38, respectively. Each porosity type is further delineated by facies—to illustrate the distribution of values

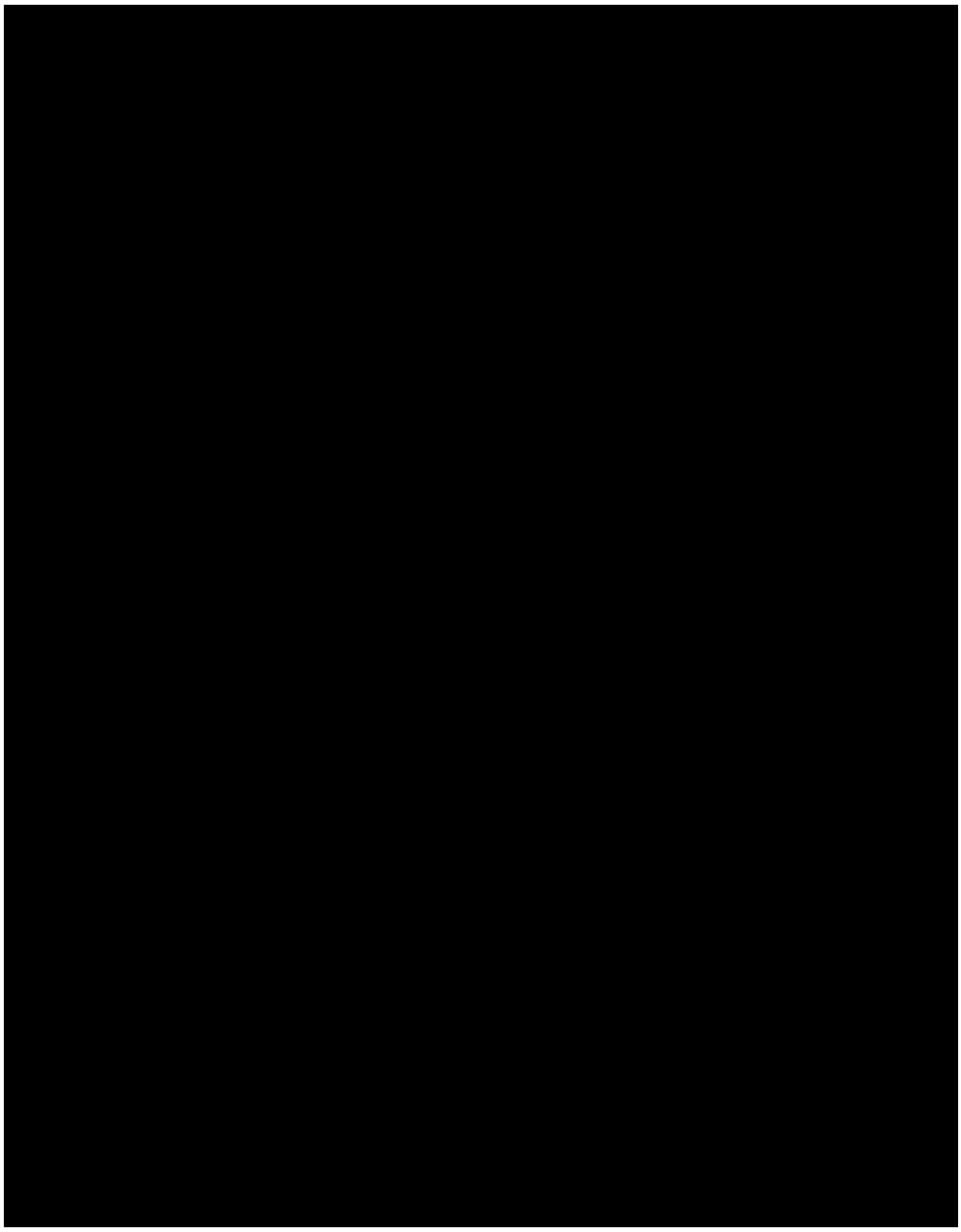


Figure 1-37 – Distribution of porosity by facies across the UCZ

Figure 1-38 – Histogram of UCZ effective porosity

1.4.3.2 Upper Confining Zone Permeability

Based on published data, the permeability of shale beds in the area—such as those in the UCZ—is minimal (Lu et al., 2017). During drilling of the stratigraphic test wells, coring operations are planned within the UCZ to validate modeled permeability. Once core data is received, this permit application will be updated with the results of the analysis.

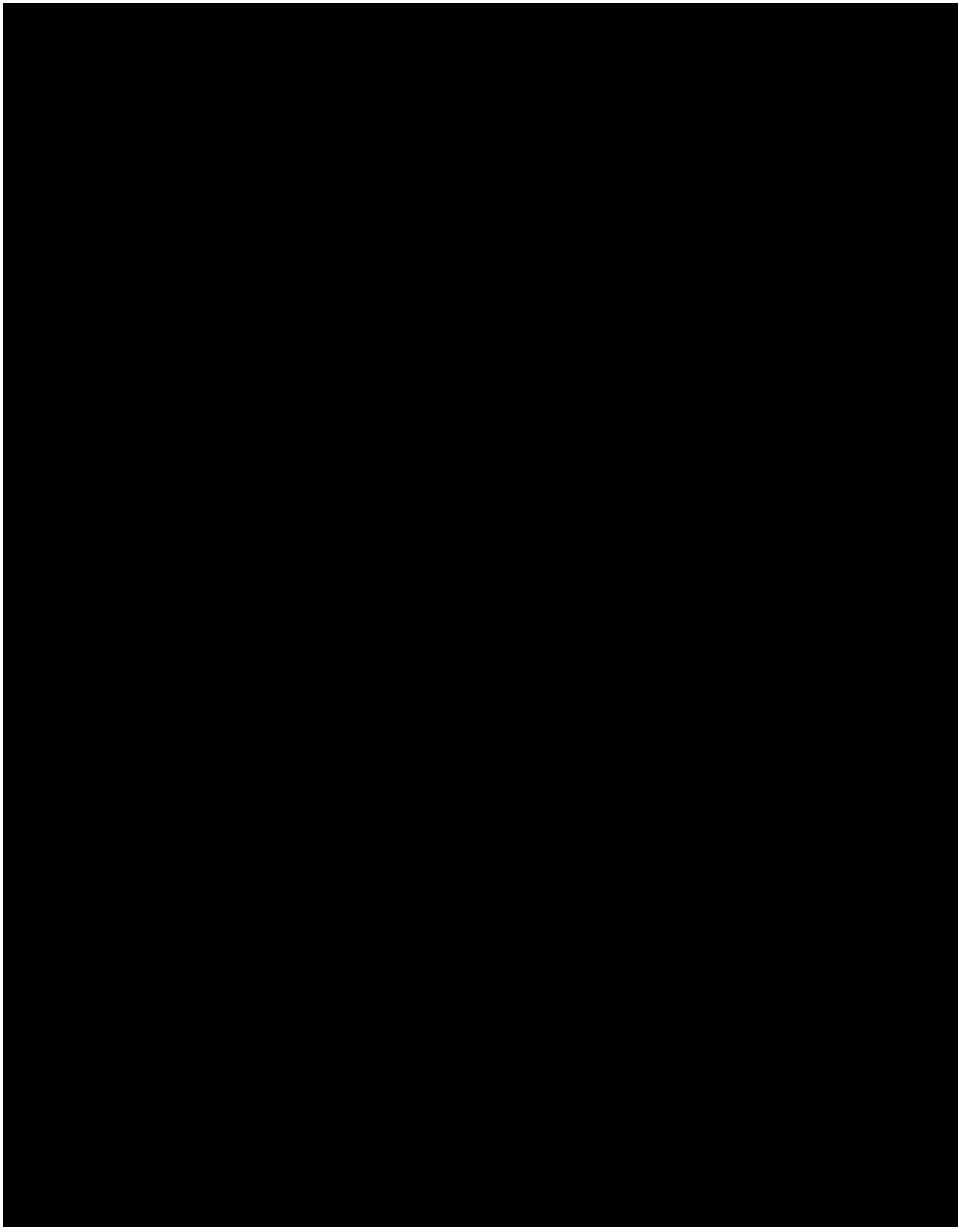


Figure 1-39 – Distribution of permeability by facies across the UCZ

1.4.4 Injection Zone Porosity and Permeability

Figure 1-40 is an openhole log of the offset [redacted] Displaying from left to right are the calculated VSH, depth track in measured depth, calculated PHIE, and calculated KINT. Effective porosity is scaled from 0–60%, in decimal form. Permeability is in logarithmic scale from 0.01–10,000 mD.

A histogram displaying facies volumes within the gross injection zone is displayed in Figure 1-41. [redacted]

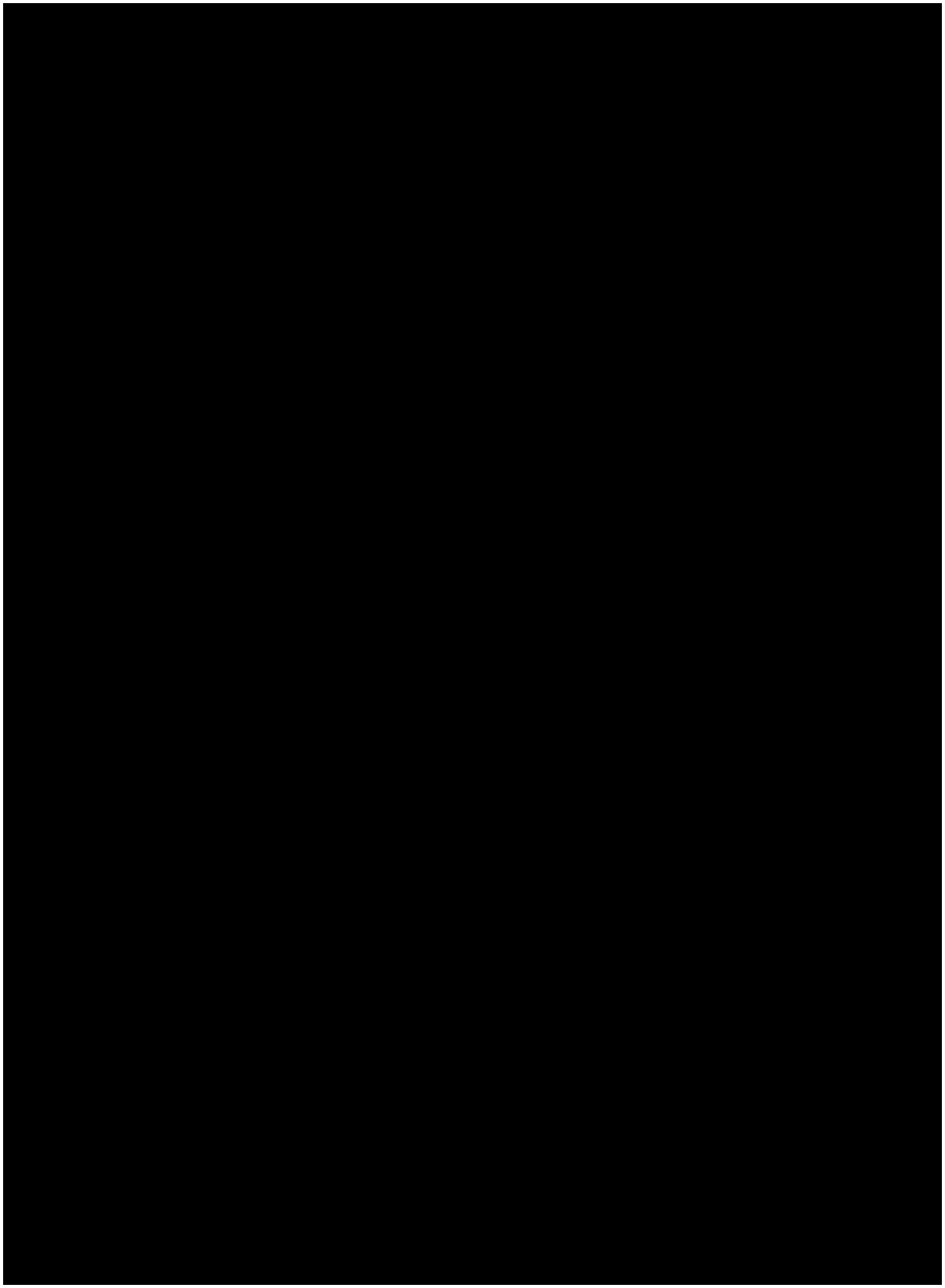


Figure 1-40 – Offset well log of calculated shale volume
and effective porosity and permeability across the injection zone.

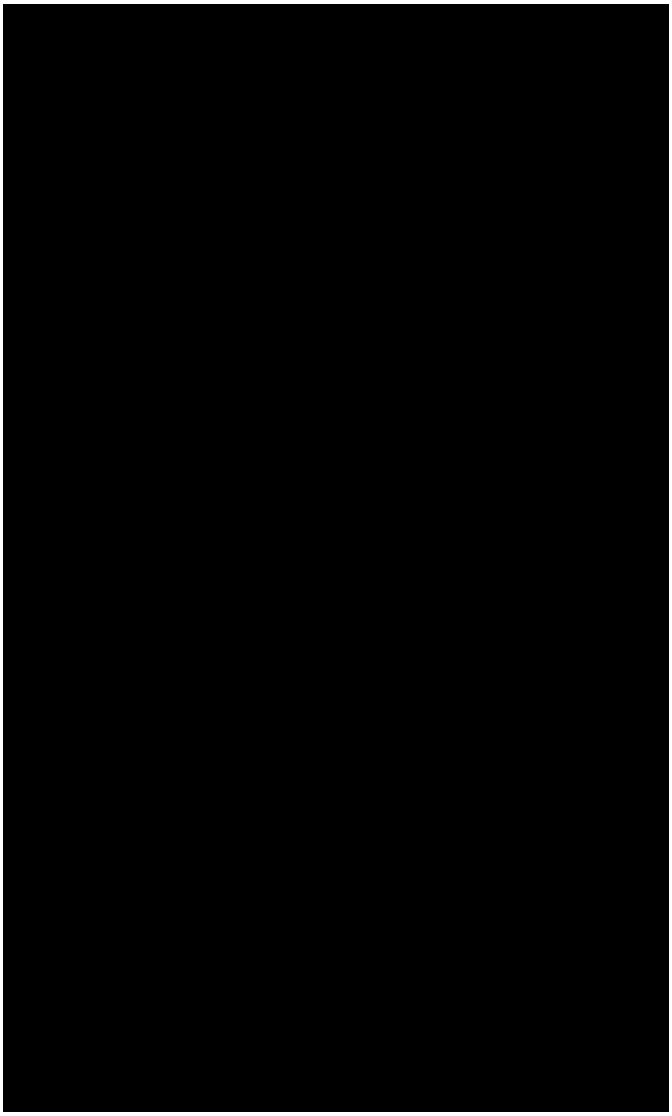


Figure 1-41 – Volume of facies, in percentage, within the injection zone across the AOI.

1.4.4.1 Injection Zone Porosity

Histograms of total porosity and effective porosity in the injection zone are presented in Figures 1-42 and 1-43, respectively. Each porosity type is further delineated by facies to illustrate the distribution of values within the injection zone. The total porosity of the sand facies ranges from , with an average of Silt and shale facies contribute to the volume of total porosity; however, due to shale content, their contribution to effective porosity is much lower. The porosity of the sand facies drives the high effective porosity values shown in Figure 1-43. This high effective porosity supports the use of the sand facies as injection targets within the injection zone.

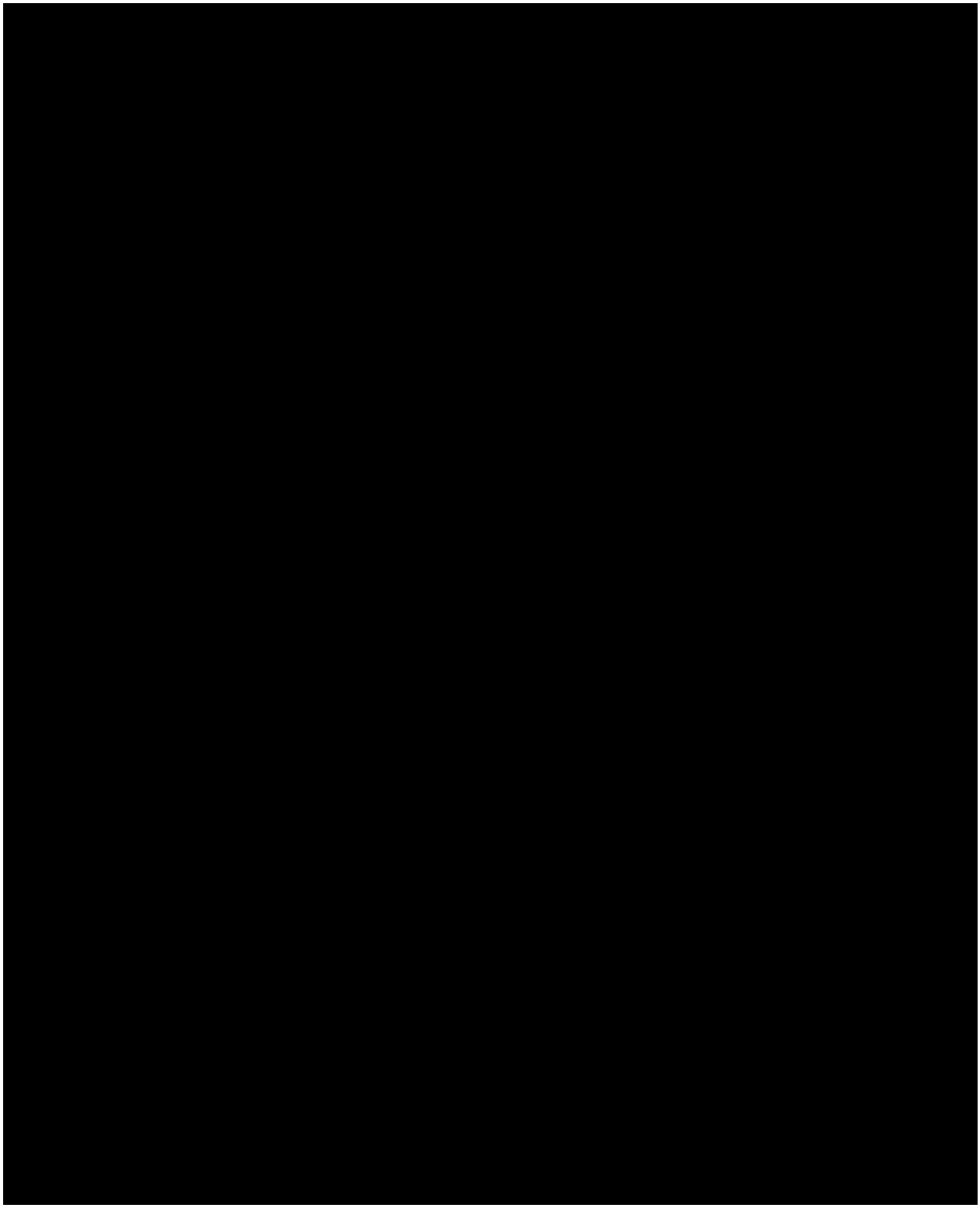


Figure 1-42 – Distribution of porosity by facies across the injection zone

Figure 1-43 – Histogram of injection zone effective porosity

1.4.4.2 Injection Zone Permeability

The permeability values across the injection zone are supported by core results from nearby wells, delineated in *Section 1.3.1*. The histograms displayed in Figure 1-44 confirm that the sands of the injection zone possess ideal characteristics for CO_2 injection and storage. Sand facies within the injection zone range from , with an average of . Permeability values in silt facies range from , with an average of Low permeability is contributed by shales, which serve to separate the targeted injection zone sands. During drilling of the stratigraphic test wells, multiple coring operations are planned within the injection zone to validate modeled permeability.

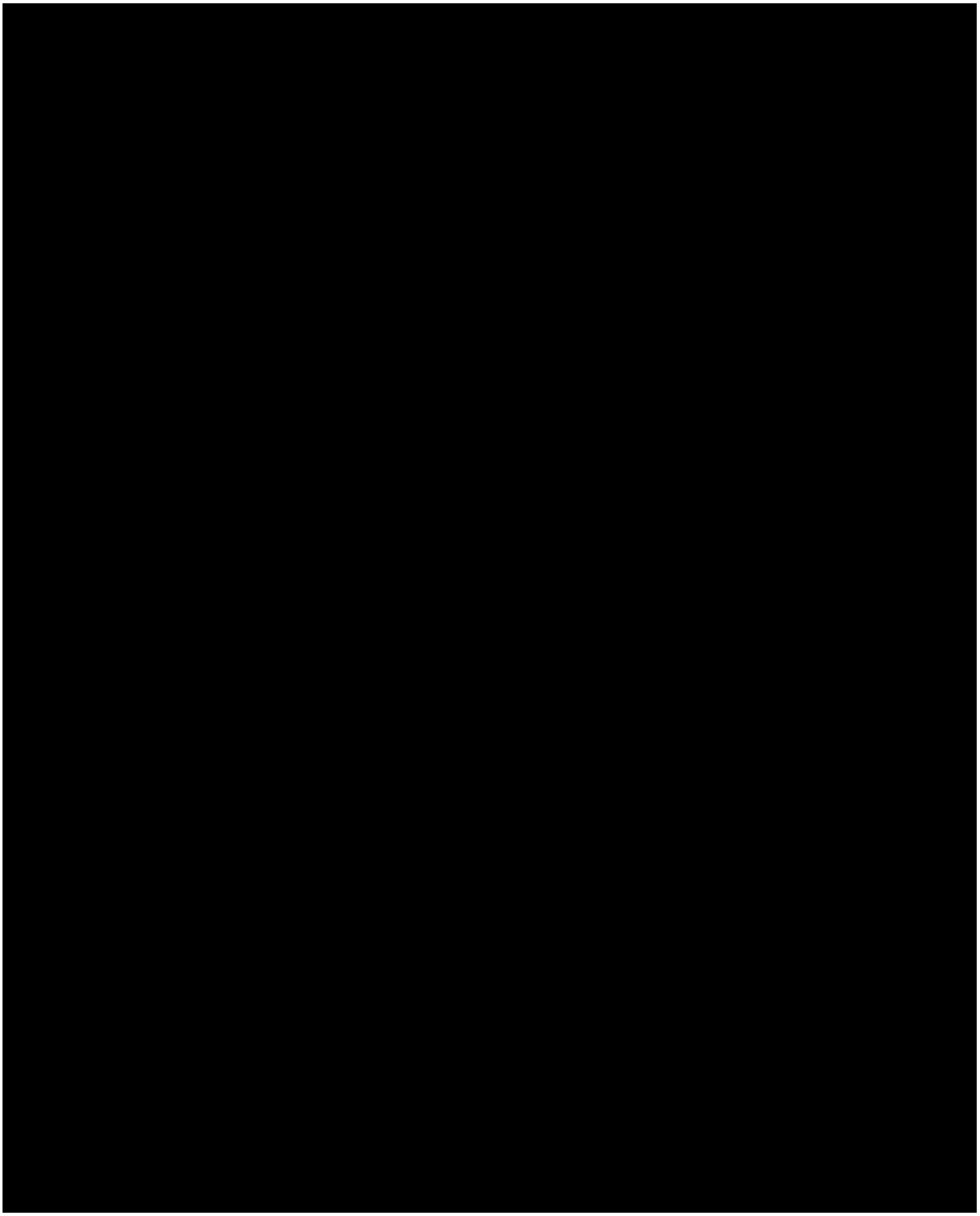


Figure 1-44 – Distribution of permeability by facies across the injection zone

1.4.5 Lower Confining Zone Porosity and Permeability

Figure 1-45 is an openhole log of the offset [redacted]—displaying from left to right: calculated VSH, depth track in measured depth, calculated PHIE, and calculated KINT. Effective porosity is scaled from 0–60%, in decimal form. Permeability is in logarithmic scale from 0.01–10,000 mD.

A histogram displaying facies volumes within the gross LCZ is displayed in Figure 1-46. [redacted]

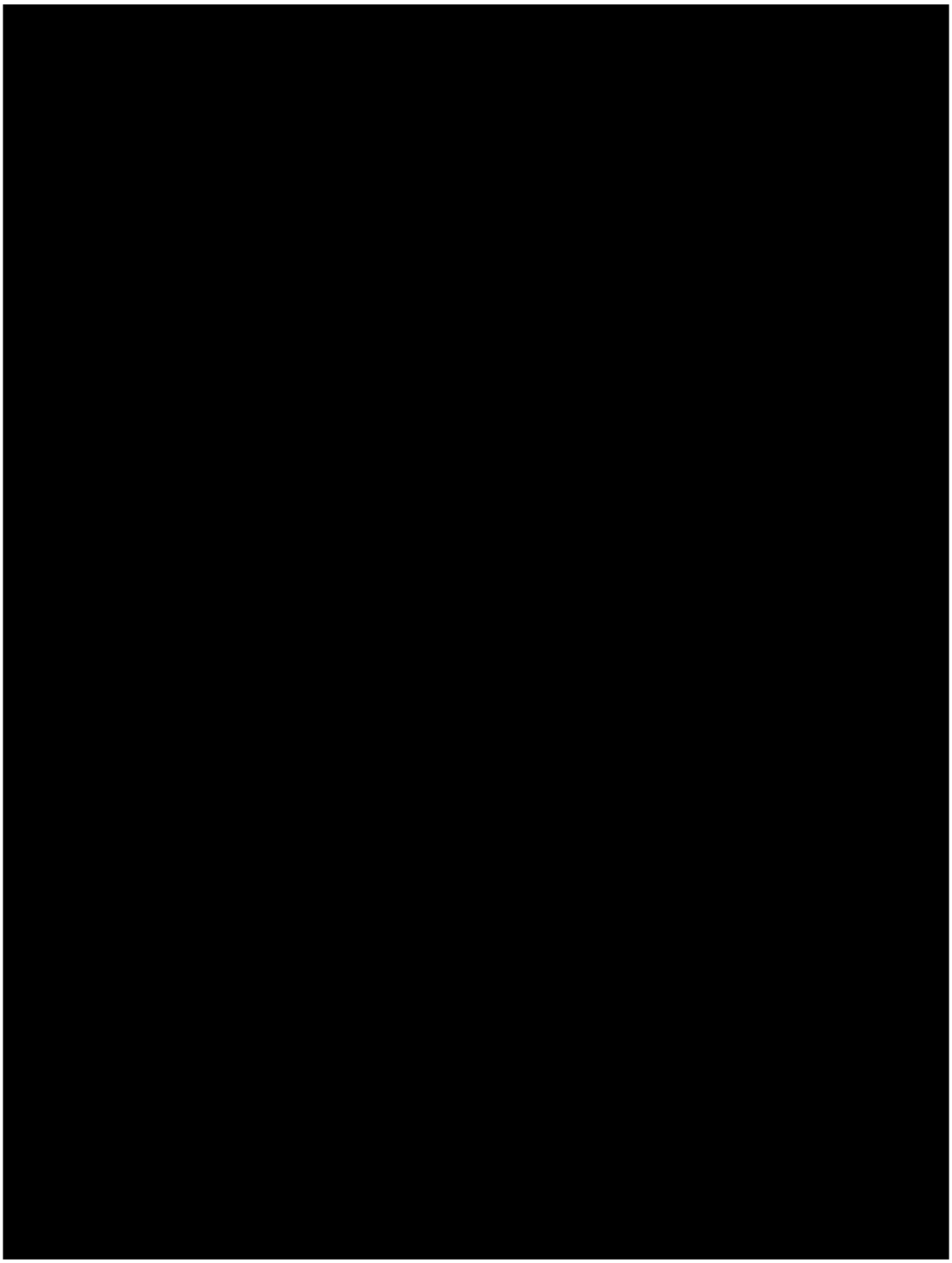


Figure 1-45 – Offset well log of calculated shale volume, effective porosity, and permeability across the LCZ.

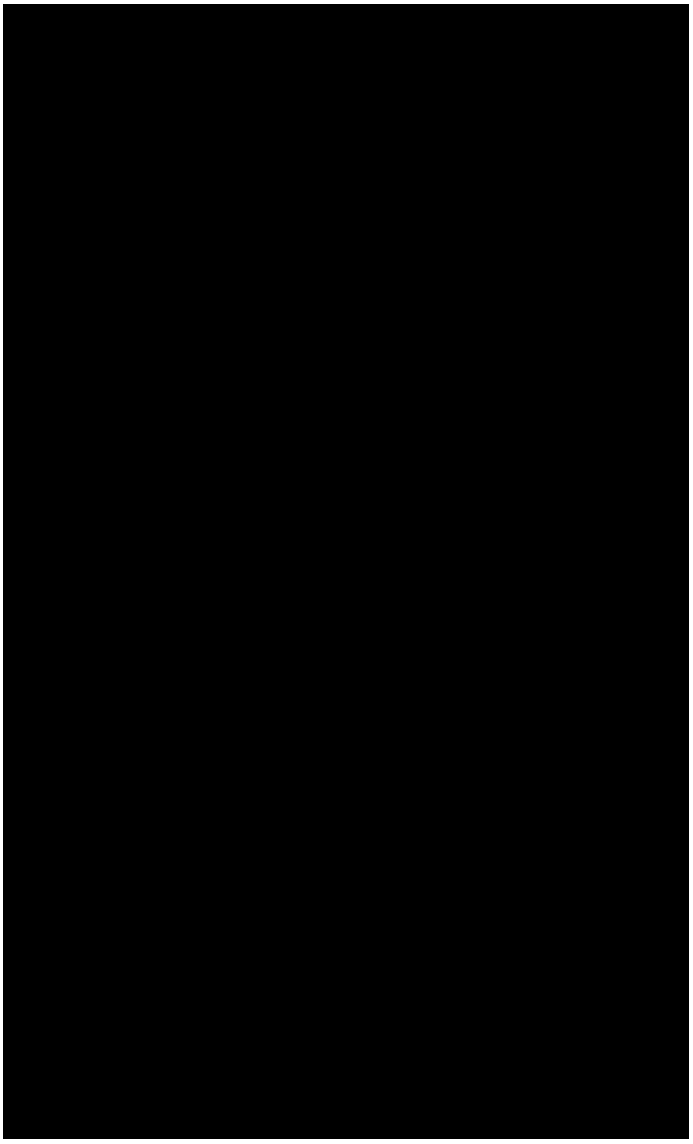


Figure 1-46 – Volume of facies, in percentage, within the LCZ across the AOI.

1.4.5.1 Lower Confining Zone Porosity

Histograms of total porosity and effective porosity in the LCZ are presented in Figures 1-47 and 1-48, respectively. Each porosity type is further delineated by facies to illustrate the distribution of values

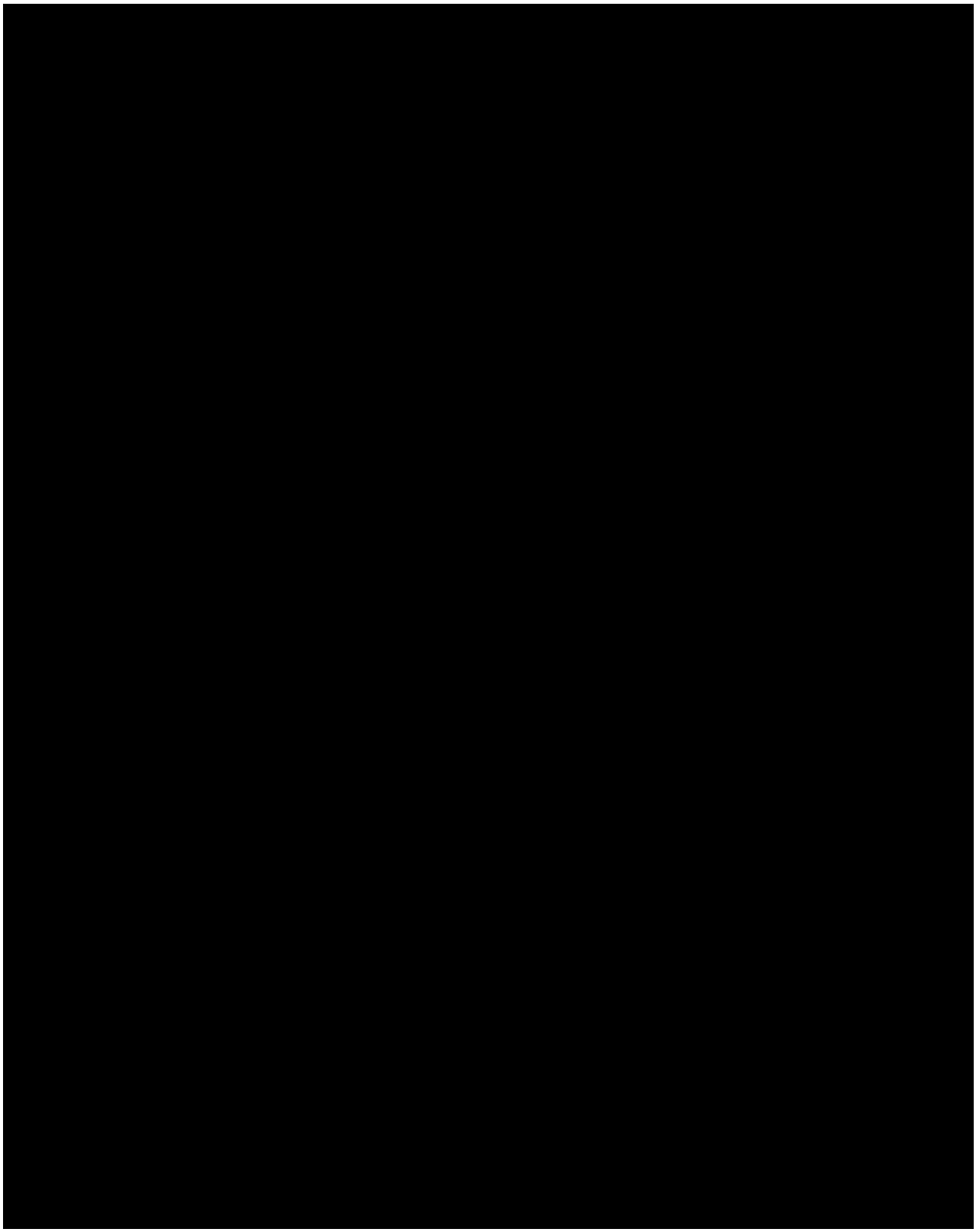


Figure 1-47 – Distribution of porosity by facies across the LCZ

Figure 1-48 – Histogram of LCZ effective porosity

1.4.5.2 Lower Confining Zone Permeability

The exceptionally thick lower confining zone is composed of multiple stacks of impermeable shale beds. This environment creates ideal lower confinement for the proposed injection operations. During drilling of the stratigraphic test wells, coring operations are planned within the LCZ to validate modeled permeability. Once core data is received, this permit application will be updated with the results of the analysis.

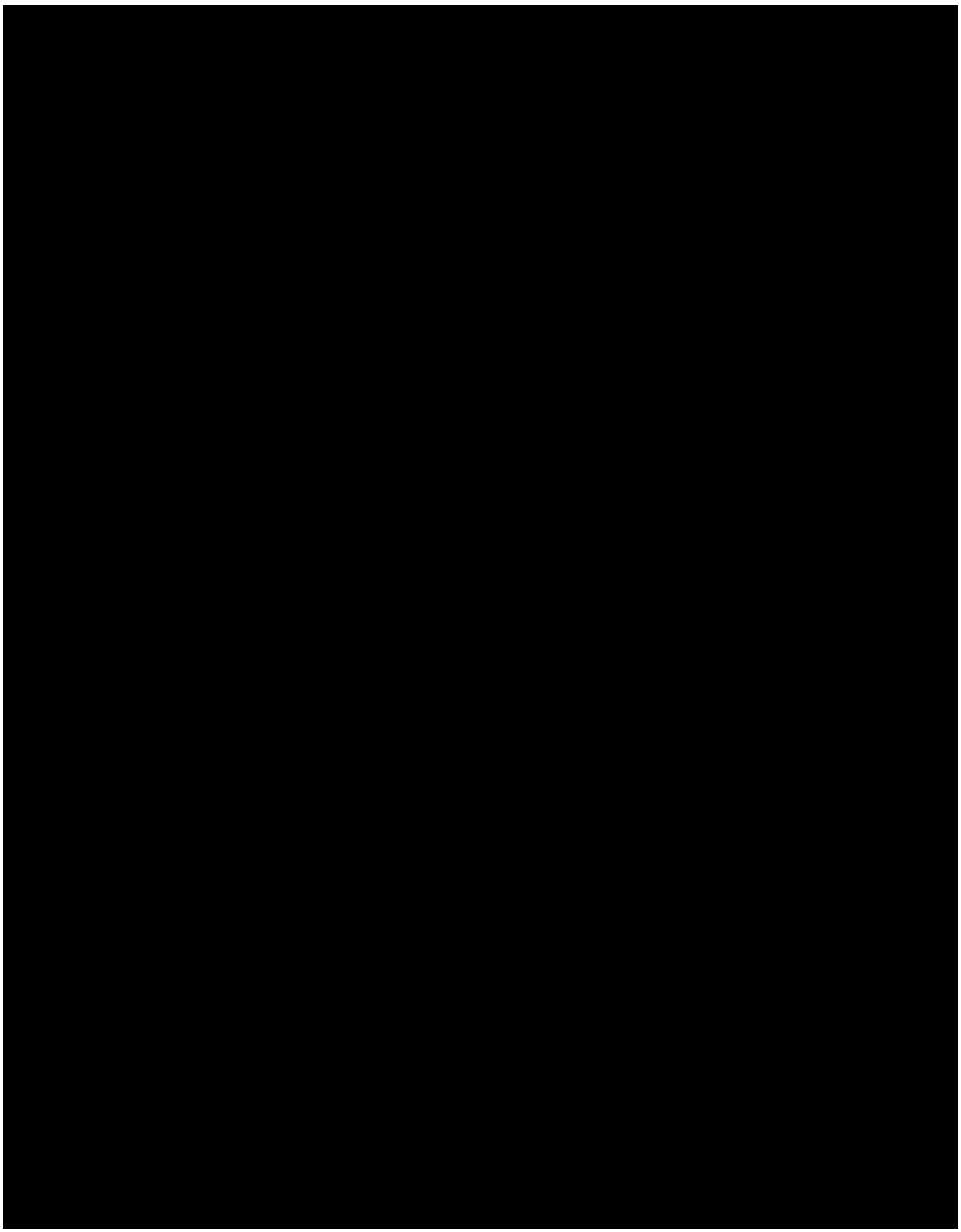


Figure 1-49 – Distribution of permeability by facies across the LCZ

1.5 Structural Geology

1.5.1 Site Geologic Structure

Well control and 3D seismic data were utilized to map structural dips of sedimentary strata within the injection interval (Figure 1-50). The resulting structure maps, isochore maps, and cross sections from these mapping efforts are included in *Appendix B-2 through B-18*.

Figure 1-50 – Map of the Project area showing the seismic outline and well data control inside the AOI used to generate structural maps, isochore maps, and cross sections.

1.5.1.1 Reflection Seismic Profiles

Approximately [redacted] of 3D surface seismic data was licensed by ConocoPhillips Company for this interpretation. [redacted] 3D seismic surveys comprise this data set; the boundaries of each are shown in Figure 1-51. The acquisition parameters of each survey are detailed in Table 1-4.

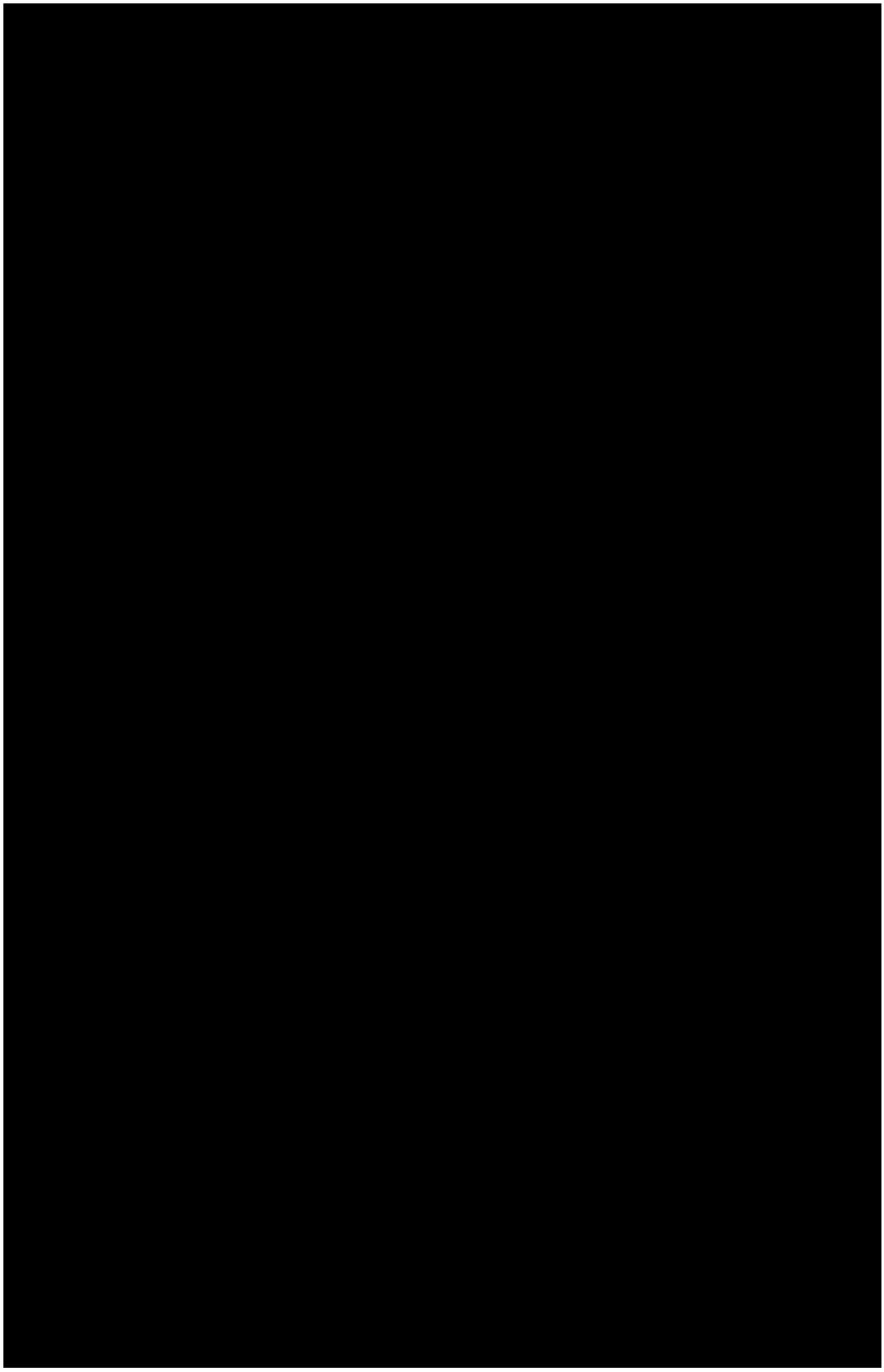


Figure 1-51– Outline of 3D seismic surveys.

Table 1-4 – 3D survey acquisition parameters
within underground storage easement.

The seismic surveys image the subsurface based on density and velocity contrasts. The resulting 3D reflection profiles, when combined with subsurface well control (geologic formation tops), are used to map the proposed injection and confining intervals. Subsurface well control is derived from [redacted] wells within [redacted] of the proposed injection sites, from multiple data sources including TGS, IHS, Enverus, and the Railroad Commission of Texas (TRRC). These data sets are compared to each other to ensure accuracy in well placement and identification. Directional surveys were used to correctly position deviated wellbores. Formation tops based on well log responses were correlated across the AOI, establishing subsurface structural control of the UCZ, LCZ, and injection zones. Integrating the interpretation from the seismic and geologic well data resulted in *Appendices B-9* through *B-14*—structure maps representing formation depths and any discontinuities (e.g., faulting). An example of these integrated maps is the top Frio structure map, shown in Figure 1-52. Seismic sections representative of the AOI (Figures 1-53 through 1-55) are also plotted on Figure 1-52.

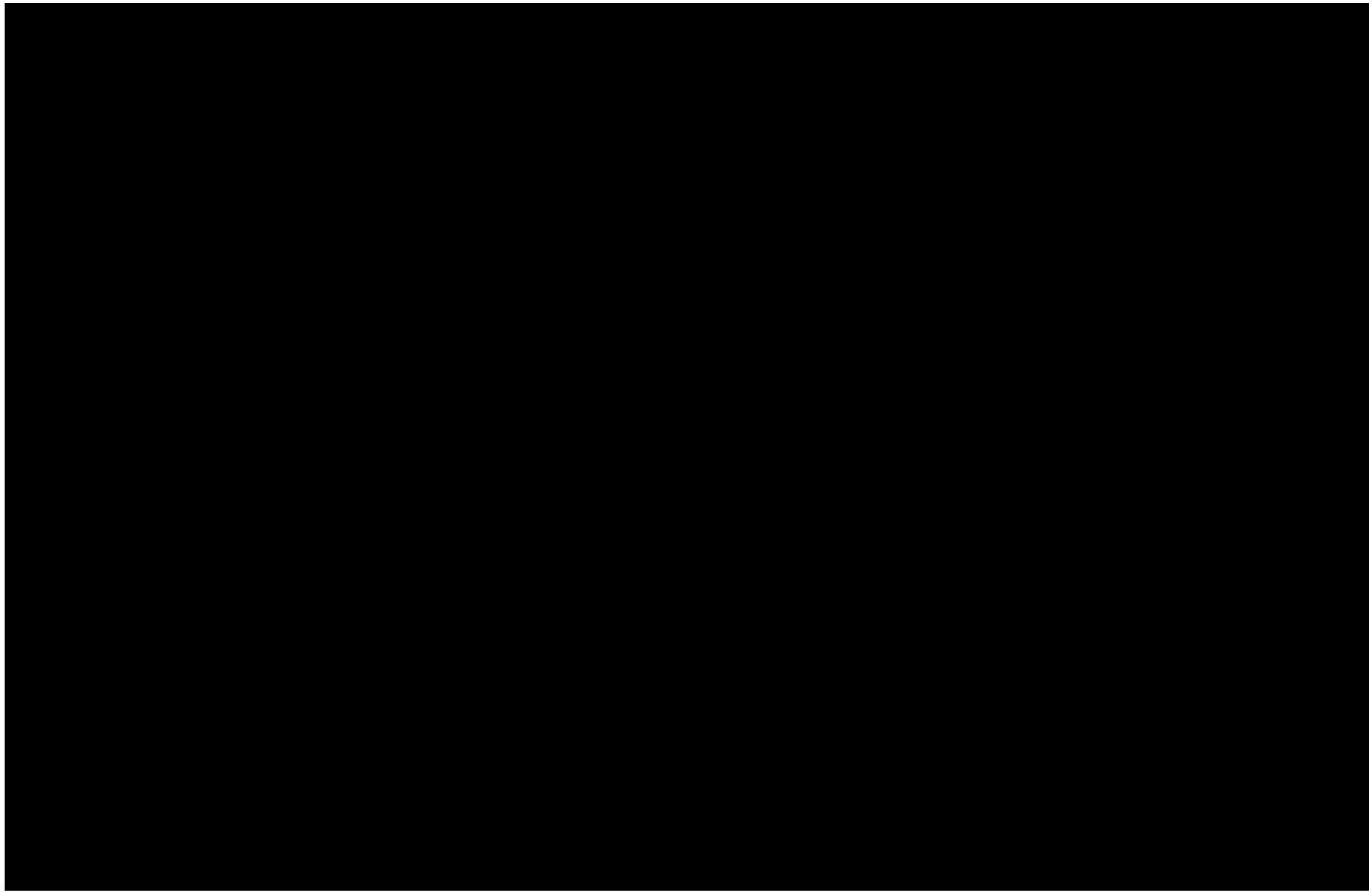


Figure 1-52 – Structure map on Frio horizon
featuring lines of seismic section along strike and dip.

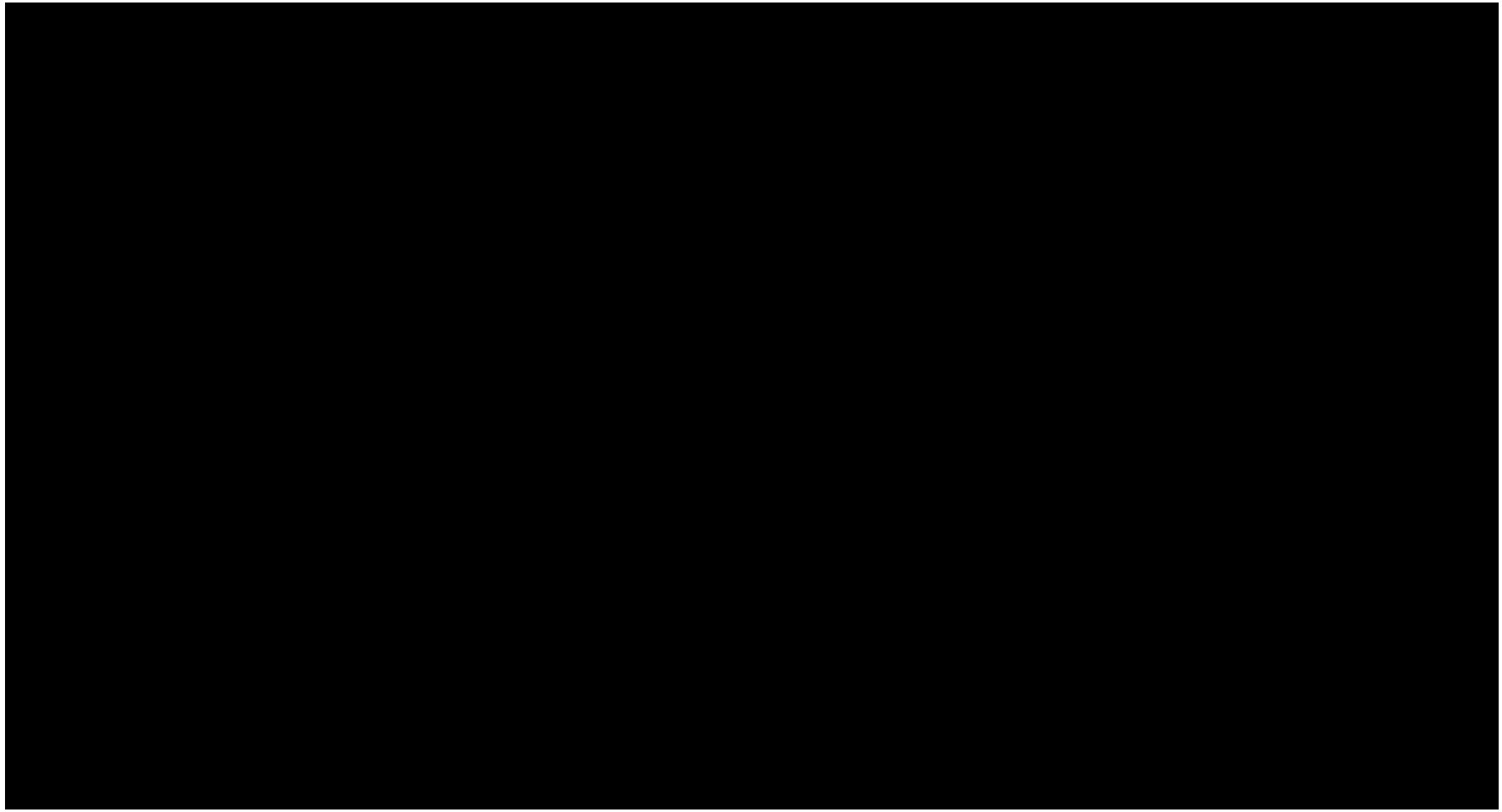


Figure 1-53 – Typical structural dip seismic line (“Dip Line”)
crossing the proposed CO_2 storage area.

Figure 1-54 – Typical structural strike seismic line
(“Strike Line [redacted]”) intersecting proposed [redacted] injection wells.

Figure 1-55 – Typical structural strike seismic line
("Strike Line [redacted]") through [redacted] injection wells.

The seismic data is of sufficient quality for qualitative interpretation of faults and horizons. The subsurface interpretation performed for the site characterization places emphasis on "hard" geologic control points based on well control. [redacted]

The overall structure across the AOI is a gentle dip to the southeast, with the injection wells located away from the faults in the AOI. The subsurface interpretation does not indicate significant changes in the thickness of the injection or confining zones. [redacted]

1.5.1.2 Velocity Control and Synthetic Seismogram

[redacted] velocity surveys were available in and around the 3D seismic data used for the seismic interpretation, shown in Figure 1-56. The velocity information, combined with a synthetic seismogram were used to confirm the time-to-depth relationship (TDR) between geologic well tops [redacted] The location of wells used to generate synthetic seismograms is also shown in Figure 1-56. [redacted] Regional checkshot data was used to calibrate the sonic log for synthetic generation. Figure 1-57 shows the TDR from checkshot data. An example of synthetic seismogram in [redacted] is displayed in Figure 1-58.

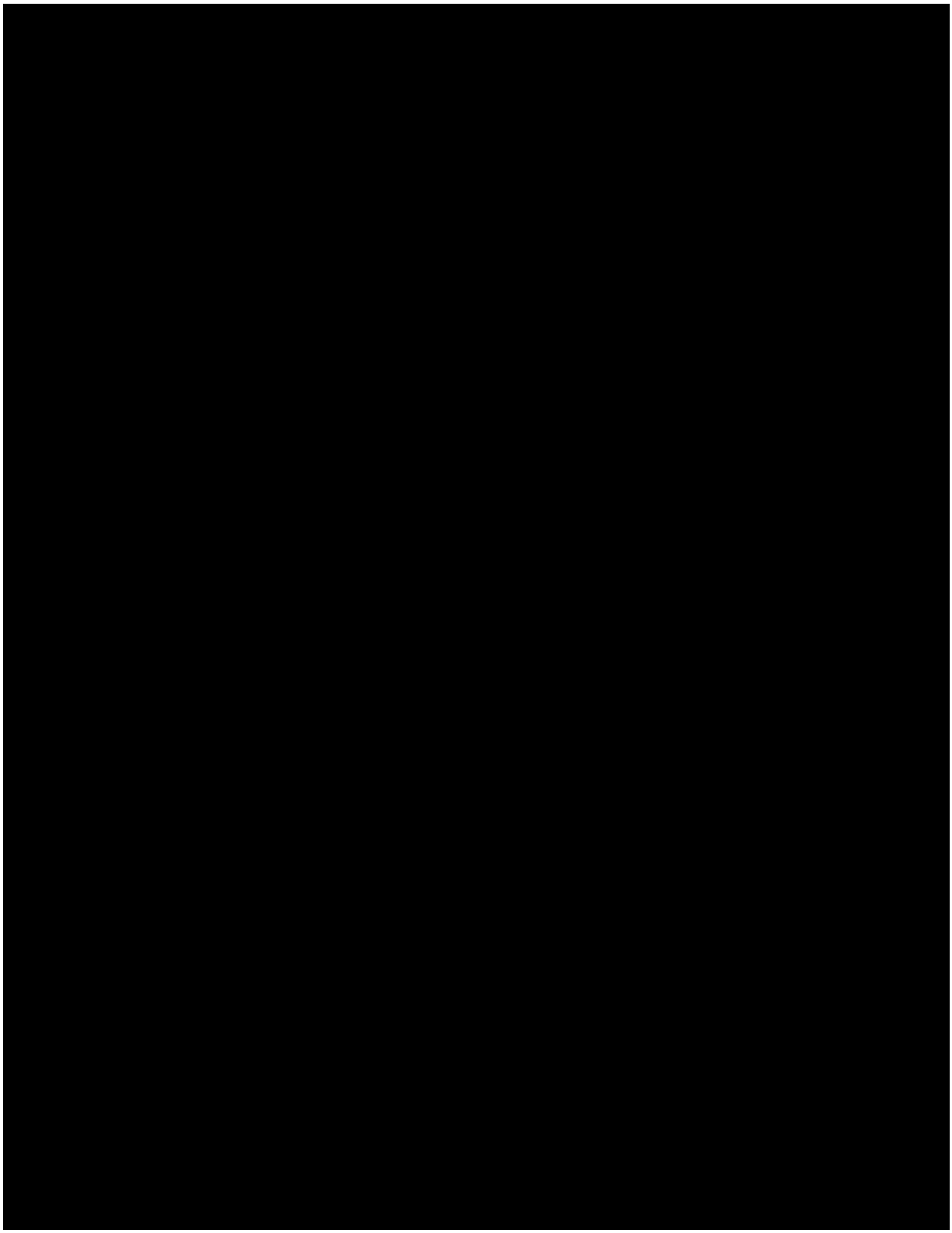


Figure 1-56 – Location of wells with checkshot data near the AOI,
used to constrain the velocity model.

Figure 1-57 – Regional time-to-depth relationship from checkshot data.

Figure 1-58 – Synthetic seismogram example

1.5.1.3 Depth Maps

A multi-well velocity model was built utilizing TDRs, synthetic ties, picked seismic horizons, and high-confidence geologic formation tops from wells. The model was vertically constrained using interval velocity from seismic well ties and TDRs. Laterally, the model was constrained using seismic horizons and well tops. [redacted] The velocity model was used to convert seismic horizons and faults to depth. Figure 1-52 showed a sample of the resulting depth maps.

1.5.2 Fault Seal Analysis

Subsurface faults can act as both barriers to flow, or they can act as cross-fault or along-fault flow conduits. [redacted] ressure increase can also cause faults to fail mechanically or reactivate, and cause along-fault flow, or induced seismicity. Along-fault flow is examined as part of a broader study on fault stability presented in *Appendix K*. The results of this analysis indicate that predicted injection-zone pore pressure increases will not be high enough to reactivate faults.

Fault locations are important in understanding seal integrity within the confining zones. [redacted] As demonstrated in Figure 1-62 (a) and (b), the CO_2 plume does not intersect any fault planes within the injection zone.

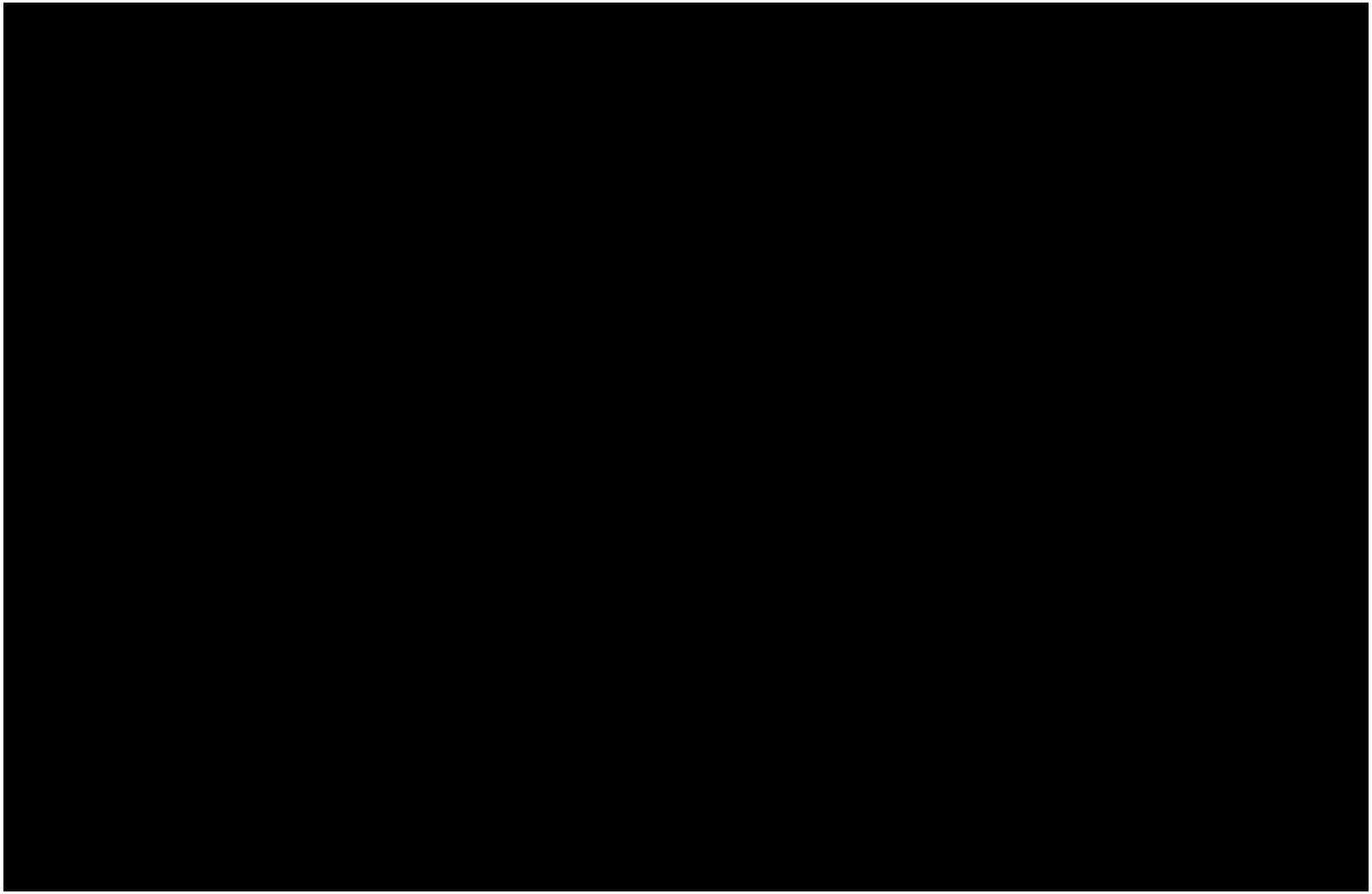


Figure 1-59 – UCZ structure map;

Figure 1-60 – Anahuac Shale structure map

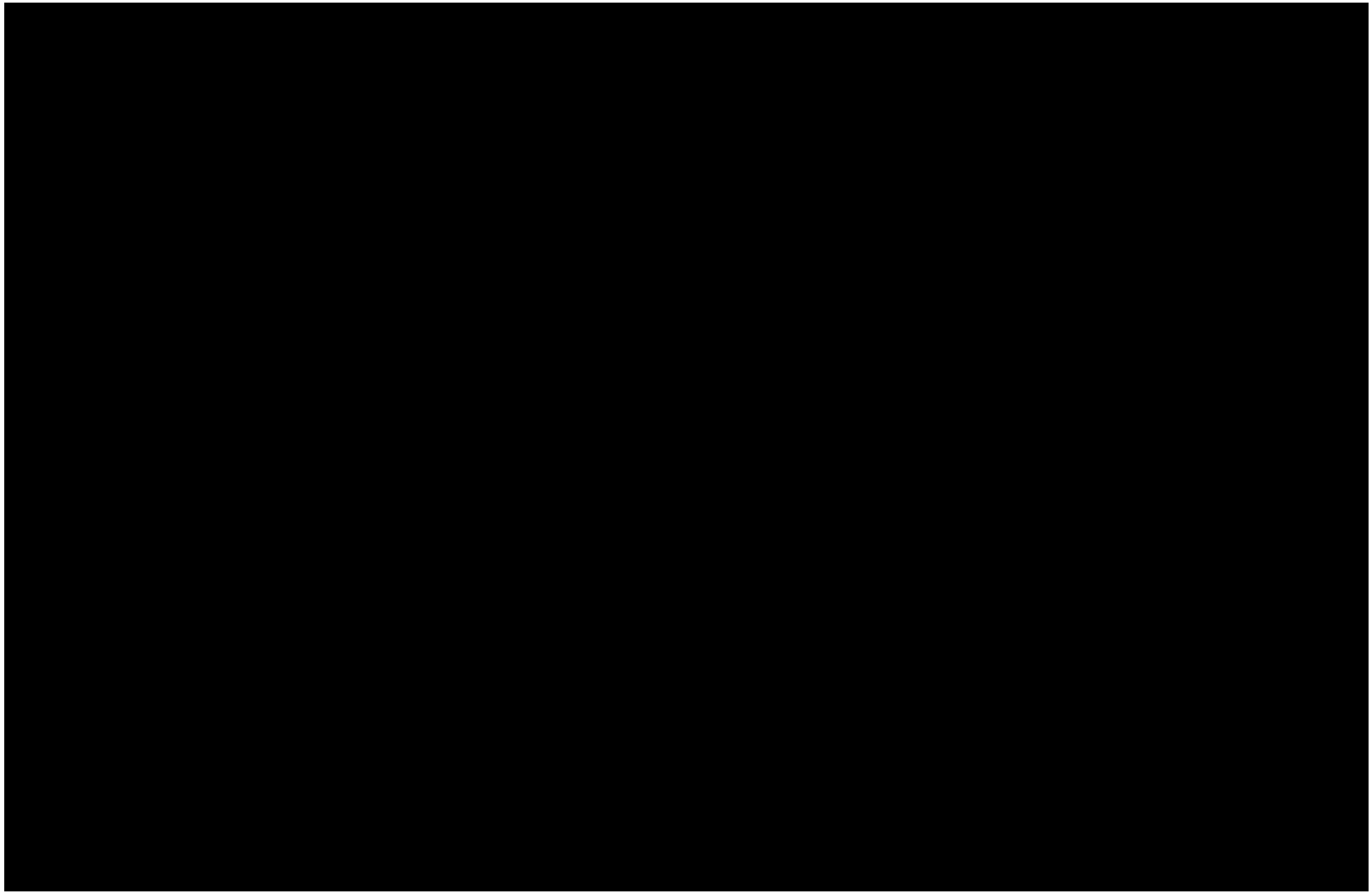


Figure 1-61 – LCZ structure map;

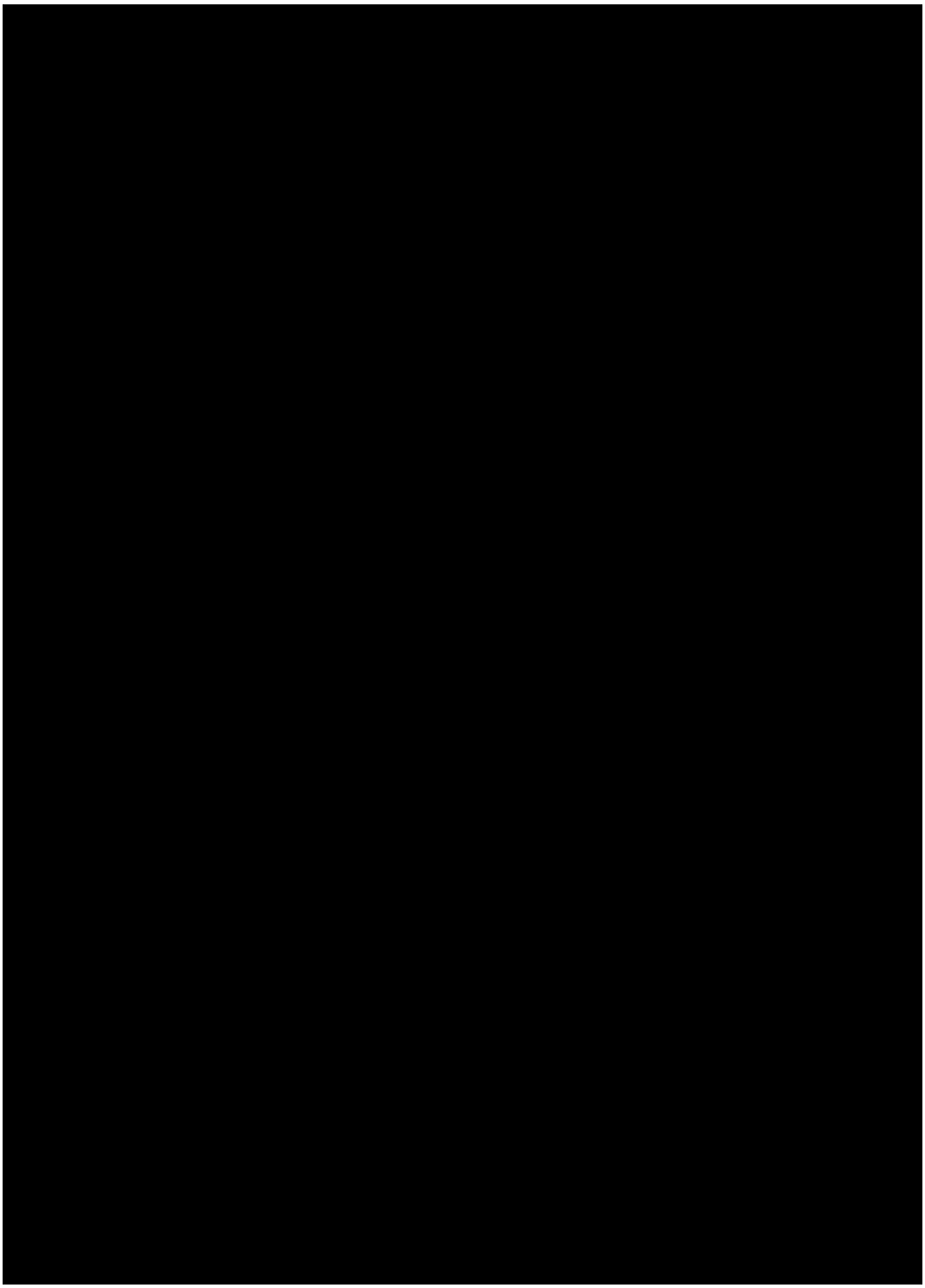


Figure 1-62 (a) and (b) – Views of [redacted] injection locations [redacted]

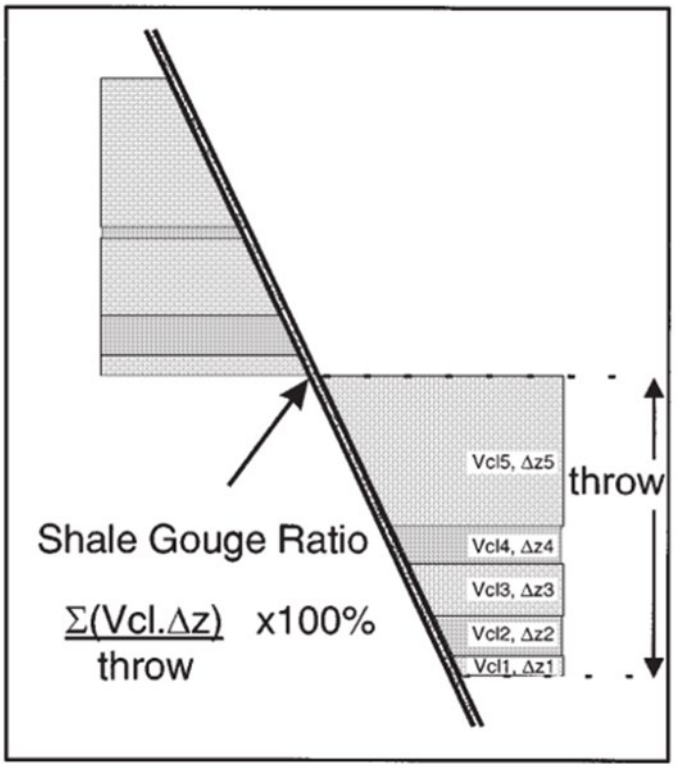
[redacted]

1.5.2.1 Method

The workflow used to calculate fault rock properties and sealing characteristics can be summarized as follows:

[redacted]

Fault rock porosity and permeability properties are determined by the host rock lithologies that get entrained or mixed into the fault (such as sand or shale), the processes of fault evolution (e.g., cataclasis – permeability reduction due to crushing of grains), and diagenesis. Fault shale content has been shown, both empirically and experimentally, to be a primary control on fault rock permeability (Yielding, Freeman, and Needham, 1997; Sperrevik et al., 2002; Manzocchi, Childs, and Walsh, 2010). Fault-rock clay content can be estimated using SGR, which is a measure of the total thickness of shale that has moved past any specific point on a fault (Figure 1-63, Yielding, Freeman, and Needham, 1997). Analysis of known hydrocarbon accumulations against faults indicates that SGR values over 0.15–0.2 tend to be sealing (e.g., Bretan, Yielding, and Jones, 2003; Meckel and Trevino, 2014).



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

Figure 1-63 – Shale gouge ratio conceptual diagram and equation (Yielding, Freeman, and Needham, 1997).

Fault rock permeability is determined from the 3D modeled shale content of the fault (SGR) and follows the "Local Deformation Line" (LDL) method presented by Grant (2020). Following this method, the SGR to fault permeability transform is calibrated by local permeability data from core samples and spans from pure sandstone permeability (SGR = 0) to shale permeability (SGR > 0.5). The sandstone permeability trend is defined by permeability/porosity measurements of core samples retrieved from the [redacted] The porosity/permeability trends for shale are modeled using the method presented by Yang and Aplin (2007, 2010). Sand and shale permeability were upscaled using facies cutoffs within the [redacted] well (Figure 1-65) and are illustrated in Figure 1-66.

Figure 1-64 – Porosity and permeability measurements

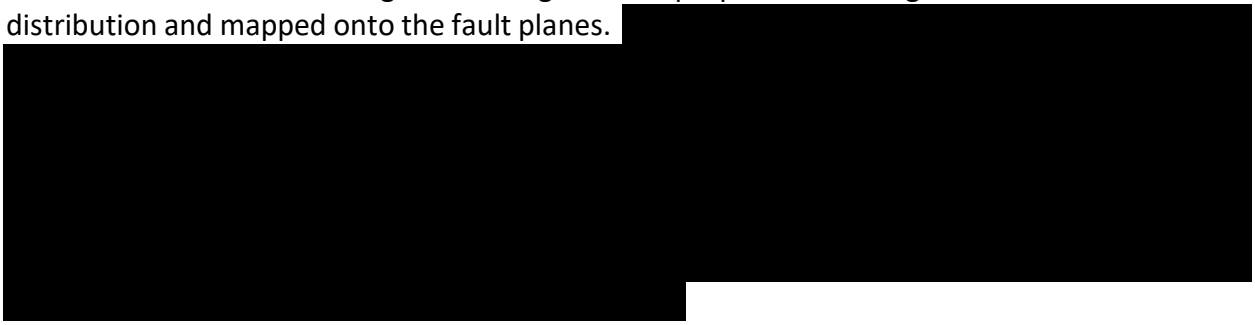
Figure 1-65 – A representative log section [redacted]

Figure 1-66 – Porosity/permeability of all upscaled layers

The fault rock permeability LDL (Grant, 2020) reflects fault rock mixing (SGR or fault VSH). Lower VSH points define a high permeability sand trend (Figure 1-67). Higher VSH values (> 50%) define the lower permeability shale trend line. It is assumed that fault rock permeabilities will vary between these two trends depending on VSH content. At low VSH, fault rock permeability is a function of grain crushing and cataclasis and can reduce permeability up to four orders of magnitude (Fisher and Knipe, 2001). From 20–50% VSH, fault permeability is controlled by a complex mixing of host rock lithologies into the fault, creating shale smears and gouge (phyllosilicate fault framework gouge). Above 50% VSH, the fault rock effectively acts as a shale with low permeability. For comparison to our locally derived LDL transform, Figure 1-67 also shows the fault rock permeability transform following the method outlined by Sperrevik et al. (2002) for faulting at approximately 2,500 meters (m) in depth. Note that the VSH/log permeability trends are comparable, with the LDL showing lower permeability at the 20% VSH range. However, while the Sperrevik transform continues to lower permeabilities above VSH of 50%, the LDL model tracks the calculated shale permeability trend.

Figure 1-67 – Fault permeability
as a function of fault rock Vshale (VSH) and definition of the LDL model.

The SGR was calculated along faults using the VSH properties of the geocellular modeled facies distribution and mapped onto the fault planes.



Fault permeabilities, derived from the LDL SGR/fault permeability transform, are illustrated on [redacted]—on Figures 1-70 and 1-73, respectively.

Figure 1-68 – [redacted] facies juxtaposition map.

[redacted]

Figure 1-69 – [redacted] shale gouge ratio.

[redacted]

Figure 1-70 – [redacted] permeability.

[redacted]

Figure 1-71 – [redacted] facies juxtaposition map.

[redacted]

Figure 1-72 – [redacted] shale gouge ratio.

[redacted]

Figure 1-73 – [redacted] fault permeability.

[redacted]

1.5.3 Results

Cross-fault sealing characteristics and fault properties were derived from an estimate of shale content of the fault rock—or the SGR (Yielding, Freeman, and Needham, 1997). This approach also includes the juxtaposition of permeable-impermeable rocks captured in the geostatic model and accounted for in the dynamic modeling stage. Two parameters provided by the fault seal analysis at the present/static conditions are fault SGR and fault permeability. [redacted]

[redacted]

Table 1-5 – Sealing characteristics of faults within the AOI by zone: SGR and permeability.

Zone	Fault SGR (% > 0.20)	Fault Permeability (% < 0.001 mD)
[redacted]		

These calculated parameters define the fault behavior under present conditions and also set thresholds for the fault behavior under changing dynamic conditions.

[redacted]

[redacted]

In addition, the dynamic simulation model suggests that pore pressures will not exceed the Mohr-Coulomb critical pressure required for fault reactivation and dilation to allow for along-fault flow (analysis in *Appendix K)*.

1.6 Geomechanics

1.6.1 Local Stress Conditions

The Project will assess the local formation stress within the AOI. The stress will be defined for the UCZ, the injection zones, and the LCZ by using core test results, X-dipole openhole logs, and "mini-frac" measurements. Figure 1-74 plots the regional data points used for the example calculations provided in this section. The maximum horizontal stress (SH_{max}) orientation along the Texas Gulf Coast is indicated as parallel to the coast, specifically in the northeast direction (52–65°) (Heidbach et al., 2016; McKeighan et al., 2022).

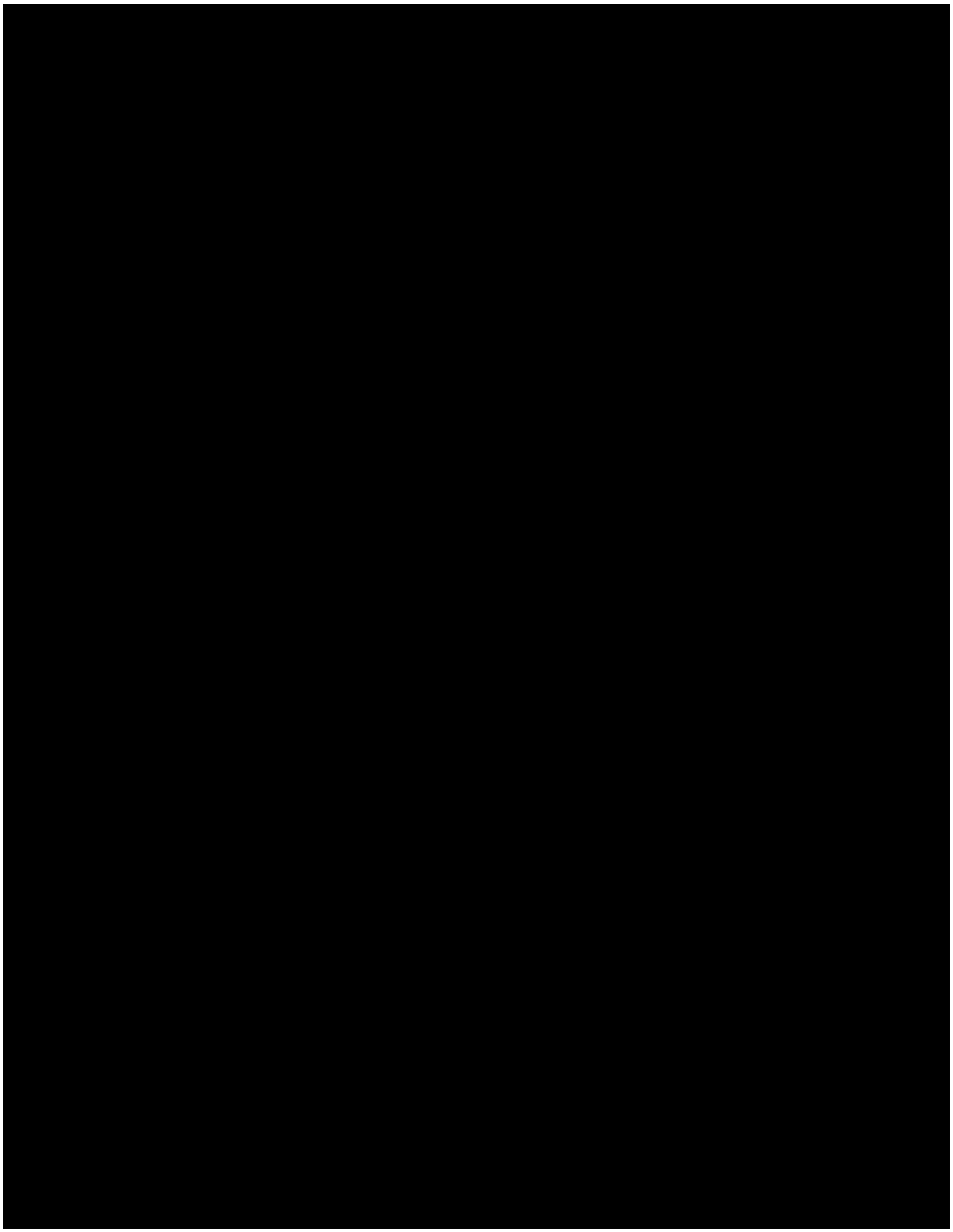


Figure 1-74 – Horizontal stress orientations reported by the World Stress Map (Heidbach et al., 2016).

There are no direct measurements of SH_{max} orientation available within the AOI (e.g., borehole breakout orientation). [redacted] The SH_{max} orientation in the Project area will be better defined through the acquisition of image logs and the characterization of borehole breakout patterns and drilling-induced tensile fractures within the stratigraphic test wells.

1.6.2 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress (S_v) can be characterized as the weight of the overlying formation for a given depth, due to the overburden pressure, which is a result of the densities of the rocks and fluids above that depth (Aird, 2019). The average bulk density for the "Oakville" and "Greta and Frio" injection zone was determined by the bulk density log of the [redacted] and is assumed to be [redacted] and [redacted] grams per cubic centimeter (g/cm^3), respectively. The average bulk density of the upper confining and lower confining zones was assumed from the log of the offset well, [redacted], estimated at [redacted] g/cm^3 and [redacted] g/cm^3, respectively. The overburden pressure gradient was calculated from density logs of offset wells, specifically the [redacted] and [redacted] and determined to be [redacted] pounds per square inch per ft (psi/ft) from surface.

An example of the vertical stress calculations performed for each well is displayed in Table 1-6. This table lists the depths of each interval in [redacted], along with the estimated average density, overburden gradient, and vertical stress.

Table 1-6 – Example of calculated vertical stresses in [redacted]

Formation	Depth (TVD ft)	Avg Density (g/cm^3)	Avg Density (lb/ft^3)	Vertical Stress (psi)	Gradient (psi/ft)
[redacted]					

1.6.2.1 Elastic Moduli and Fracture Gradient

During the drilling of the stratigraphic test wells, core samples will be collected and tested, and correlated with log data to determine the static elastic moduli. The core samples will undergo testing, including triaxial compressive strength, to provide the geomechanical properties listed in Table 1-7. The Poisson's ratio for each of the intervals is currently estimated by the offset well logs of [redacted] and approximated at [redacted] or [redacted] for the injection intervals, [redacted] for the UCZ, and [redacted] for the LCZ.

Table 1-7 – Triaxial compressive strength test properties to be collected.

[redacted]

1.6.2.2 Injection Zone Fracture Gradient

The fracture pressure was determined through an investigation of available offset well log data and validation of published literature pertaining to the Gulf Coast region, and by applying industry standard values. The fracture pressure of the injection zone was approximated by using Eaton's equation (Eaton, 1969). The equation was implemented as a reliable method to calculate the fracture pressure of a rock in the Gulf Coast sands and is an accepted standard practice for estimation of fracture gradients. The calculation incorporates Poisson's ratio (ν), overburden gradient (OBG), and pore pressure gradient (PG) to calculate the required pressure to fracture a zone of interest. However, it is recognized that the calculated values are a simplification, and calibration is necessary (e.g., Whitehead et al., 1986). During the drilling of the stratigraphic test wells, core samples will be collected and tested, and correlated with log data to estimate the fracture gradient more accurately.

The overburden pressure gradient was calculated from the density logs of offset wells, specifically the [redacted], and determined to be [redacted] psi/ft from surface.

The pore pressure gradient was determined from measurements taken from the nearby offset wells [redacted] Data from Modular Formation Dynamics Tester or Formation Multi-Tester (MDT/FMT) tests in those wells is shown in Figure 1-75. The red circle highlights the stabilized pretest and brine sample pressure used to establish the [redacted] psi/ft gradient. [redacted]

[redacted]

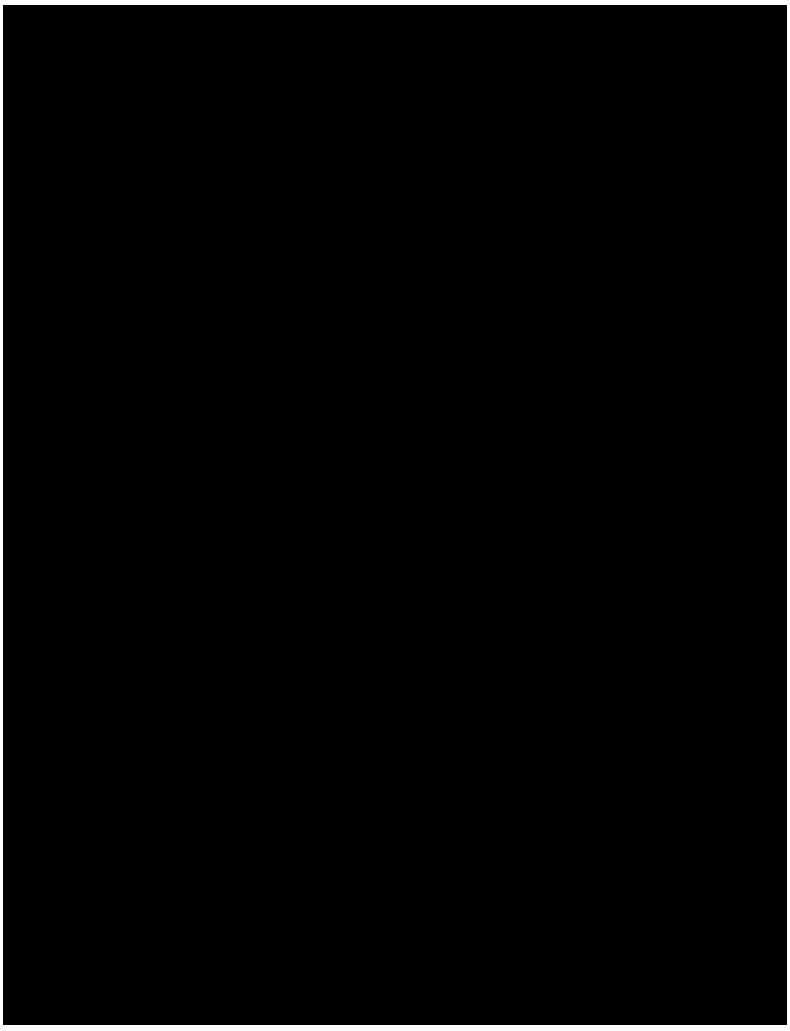


Figure 1-75 – Pressure data [redacted]

[redacted] Pressures throughout the storage interval will be updated with the collection of formation pressure data from the two planned stratigraphic test wells.

Poisson's ratio was informed through a literature review and calculated using a petrophysical relationship between compressional and shear sonic. Commonly, Poisson's ratio for lithologic units is obtained from compressional (Vp) and shear velocities (Vs) (Eq. 8, Mavko, Mukerji, and Dvorkin, 2009), [redacted] Poisson's ratio was calculated using compressional and shear sonic logs at the [redacted]

Eq. 8: $$\text{Poisson's Ratio } (\nu) = \frac{Vp^2 - 2Vs^2}{2(Vp^2 - Vs^2)}$$

The values determined for each unit are provided in Table 1-8. Given their geomechanical similarity, the Oakville and Greta sands are quantified using the same Poisson's ratio—using the more conservative value calculated in the Greta sand.

Inputting these values in the equation below, a fracture gradient of [redacted] psi/ft was calculated for the Oakville Formation and Greta sands. The same calculation was performed for the Frio sands, calculating a fracture gradient of [redacted] psi/ft. Per 16 TAC **§5.203(i)(2)(C)** [40 CFR **§146.88(a)**], the well may not exceed 90% of the FG during injection operations. Maximum bottomhole pressure was determined by taking 90% of the determined fracture pressure, resulting in a maximum bottomhole pressure gradient of [redacted] psi/ft and [redacted] psi/ft, respectively.

Eq. 9 – Eaton's Equation:

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

[redacted]

Table 1-8 – Injection zone fracture gradient calculation inputs and results using Eaton's equation (Eaton, 1969).

Zone	Formation	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)	FG with SF (psi/ft)
[redacted]						

*SF – Safety Factor, 90% of the Fracture Gradient

[redacted]

1.6.2.3 Confining Zone Fracture Gradient

The fracture gradients of the UCZ, Anahuac Shale, and LCZ, over the Project AOI, were approximated using Eaton's equation. The pore pressure gradient and overburden gradient are assumed at [redacted] psi/ft and [redacted] psi/ft, respectively, as above, and are commonly accepted

industry values for a normally pressured interval within the Gulf Coast region. Poisson's ratio values of [redacted] were determined from log data of the offset well, [redacted]—and are assumed to be a safe approximation [redacted] (Table 1-9). These values were used in Equation 9 to arrive at a fracture gradient of [redacted] psi/ft for the UCZ, [redacted] psi/ft for the Anahuac Shale, and [redacted] psi/ft for the LCZ.

Table 1-9 – Confining zones' fracture gradient calculated using Eaton's equation (Eaton, 1969).

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

1.7 Baseline Geochemistry

1.7.1 Methods

To understand the mineral-brine-CO_2 reactions likely to occur from the injection of CO_2 in the subject area, an analysis of water and rock sample data from analogous systems was combined with log analysis to create numerical models simulating the subsurface system. The estimated brine salinity is calculated using resistivity logs across the formations of interest using Archie's Equation. The results are supported by data from the USGS National Produced Waters Geochemical Database (Workbook: USGSPWDBv3.0)[3]. The mineralogy is estimated using proprietary sample data from a BEG study, the interpretation of which is further supported by a BEG study (Trevino and Meckel, 2017). The reaction modeling was completed using TOUGHREACT-Pitzer (Zhang et al., 2006), a reactive transport-modeling software applicable to high salinity systems such as subsurface brines. Brine and formation rock will be sampled as part of the data acquisition in the stratigraphic test wells, and models will be updated accordingly.

[3]https://tableau.usgs.gov/views/USGSPWDBv3_0/USGSPWDBv3_0Dashboard?%3Aembed=y&%3AisGuestRedirectFromVizportal=y

1.7.2 Brine Geochemistry

The salinity of the brine in the injection zone was derived from water chemistry data collected in [redacted]—and from calculated salinity ranges from [redacted], using the resistivity logs from [redacted] nearby wells (data points shown in Figure 1-76) as discussed in detail in *Section 1.3.1*).

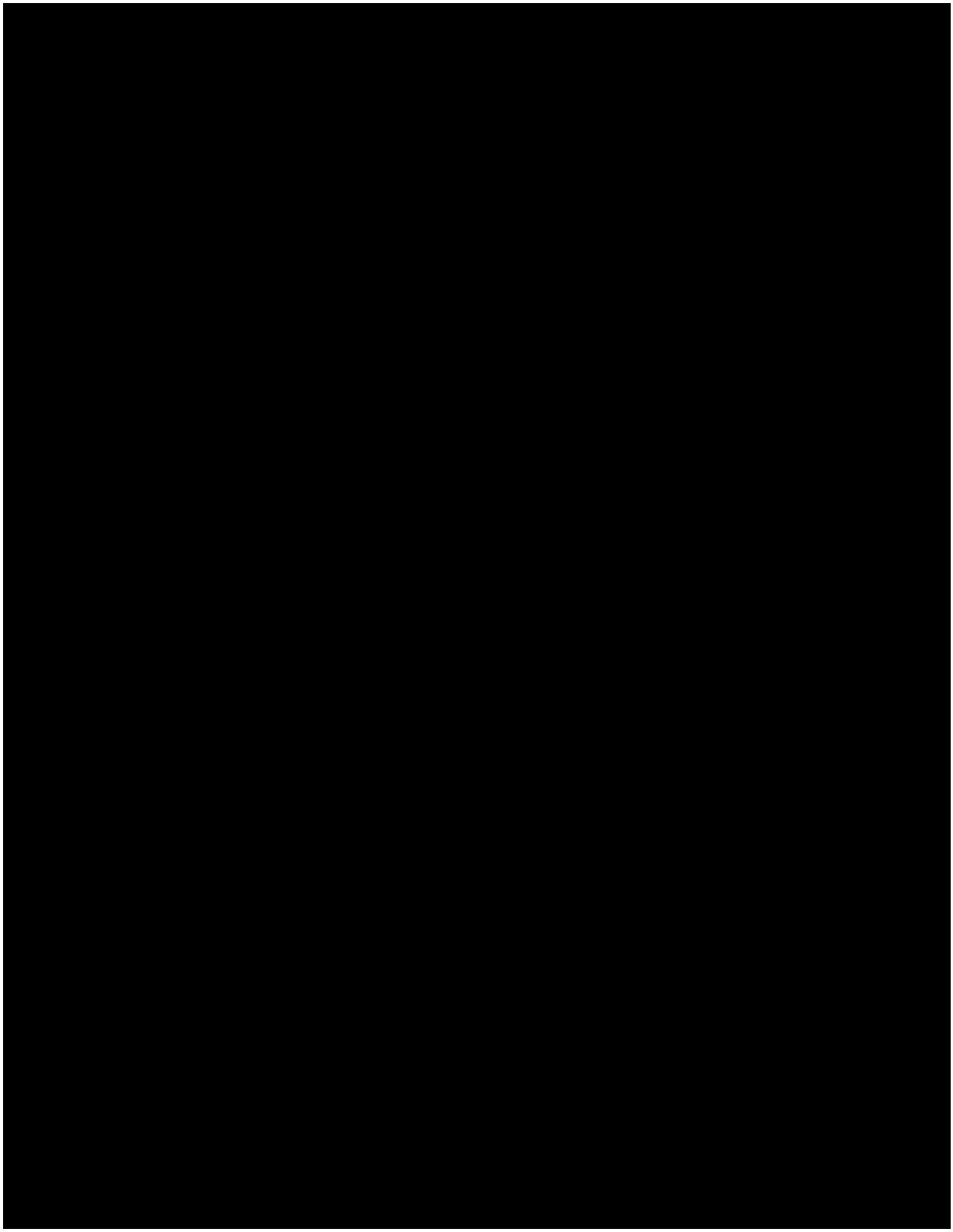


Figure 1-76 – Wells with measured formation water salinity and/or with calculated salinities from resistivity logs.

The P10, P50, and P90 values were calculated from these computed salinity values and shown in Table 1-10. The results indicate that the median salinity across the zones of interest is [redacted] parts per million (ppm). This value is used as a baseline for geochemical modeling.

Table 1-10 – P10, P50, and P90 values from log-calculated salinity and measured formation water salinity values in the vicinity of the Project site.

Zone	Averaged Salinity (kppm)		
	P10	P50	P90
[redacted]			

The initial concentration of ions used in the modeling is derived by averaging five water samples from four wells [redacted] in the [redacted], available in the USGS National Produced Waters Geochemical Database (Figure 1-77). The values used are shown in Table 1-11. This average concentration is then reacted with the formation mineralogy under reservoir conditions for 1 m.y. of model time, until a steady state is achieved. This model-derived steady state is used as the brine concentration at the start of CO_2 injection modeling.

Table 1-11 – Initial brine composition.

Species	Concentration	Units
TDS	[redacted]	mg/l
Ba		mg/l
HCO3		mg/l
Ca		mg/l
Cl		mg/l
FeTot		mg/l
Na		mg/l
Mg		mg/l
SO4		mg/l
Si		mg/l

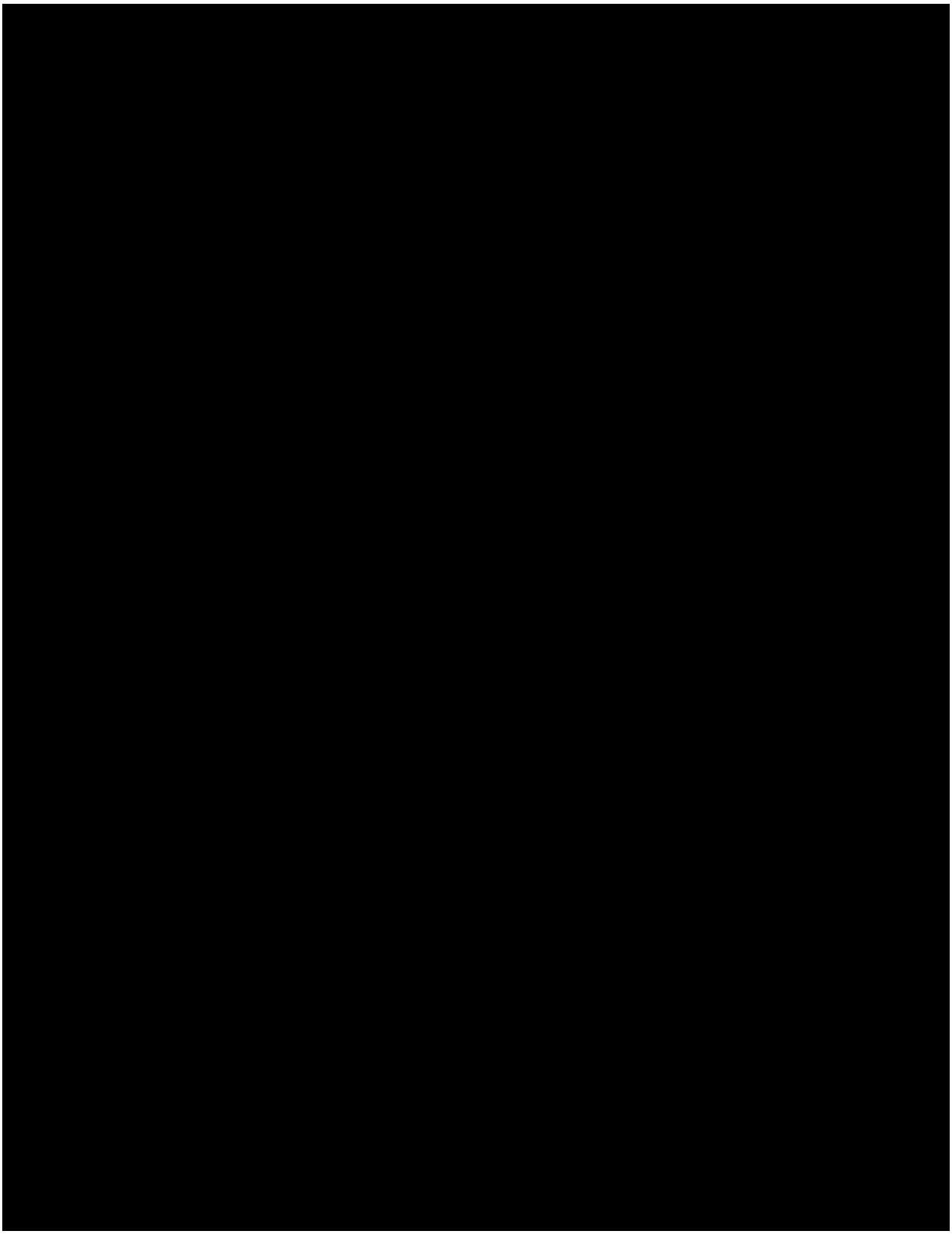


Figure 1-77 – Wells with available ion data for the [redacted]
(USGS National Produced Waters Geochemical Database).

1.7.3 Mineral Geochemistry

Despite the well-understood nature of the stratigraphy in the vicinity of the Project site, published x-ray diffraction (XRD) data across the target formations is relatively scarce. The available data consists of the following: [redacted] from 7 offset wells analyzed as part of a BEG study (Gulf of Mexico Basin Depositional Synthesis Project (utexas.edu), Figure 1-78); 11 published XRD samples from the Anahuac Shale section of a cored interval in an oil field near Lavaca Bay, Texas (Lu, Larson, and Smyth, 2014); 26 published XRD samples from offshore oil fields near Port Aransas, Texas (Trevino and Meckel, 2017); and generalized lithologic data from Holtz et al. (2005). Additional XRD and petrographic data will be collected in the planned stratigraphic test wells to inform mineral geochemistry.

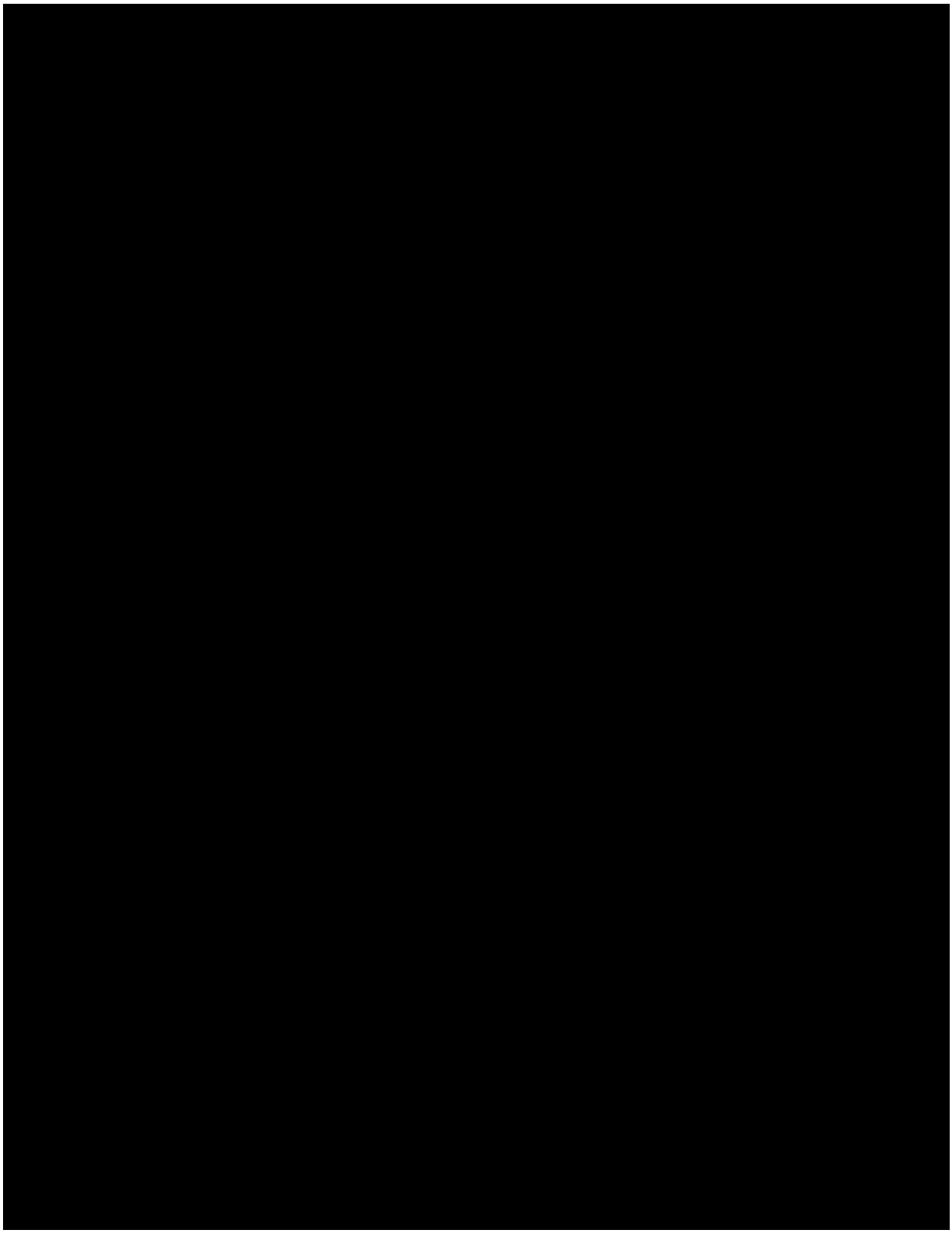


Figure 1-78 – Map showing locations of wells
included in the Frio petrography study as part of the Gulf of Mexico Basin Depositional Synthesis Project.

The injection zone mineralogy used in the reactive transport modeling was calculated from [redacted] The total quartz fraction is composed of quartz grains, quartz cement, and silicified rock fragments. The total plagioclase fraction is composed of albite grains and plagioclase cement. The total K-feldspar fraction is made up of both potassium feldspar grains (orthoclase) and potassium feldspar cement. The total carbonate fraction is comprised of calcite cement, calcite replacement, and fragments of carbonate rock. Similarly, the total kaolinite fraction consists of both kaolinite cement and kaolinite replacement. The total Sm/illite fraction is composed of pore-filling smectite and illite, clay-replaced volcanic rock fragments, and mud clasts. The computed average bulk volume of these fractions is shown in the last column of Table 1-12. [redacted]

[redacted] Furthermore, lithologic descriptions and generalized XRD data from Hovorka et al. (2003); Bebout, Loucks, and Gregory (1979); and McGuire (2009) support the values used.

The mineral compositions used in the simulations for the confining units were likewise estimated from XRD data and are supported by lithologic descriptions from Hovorka et al. (2003) and Meckel and Trevino (2019), as well as from XRD analyses of silicate rocks from similar depositional environments published by Weaver (1977). The values used in the simulation experiments are shown in Table 1-12.

Table 1-12 – Estimated mineral compositions used to model the stratigraphic units.

Facies Name	Confining Zones	Injection Zone	Injection Zone
Stratigraphic Unit	[redacted]		
Quartz			
Calcite			
Plagioclase (albite)			
K-Feldspar			
Smectite/Illite			
Kaolinite			
Other (e.g., Pyrite)			

1.7.4 Reactive Transport Models

1.7.4.1 Introduction

The mineral-brine-CO_2 interactions that occur during CO_2 sequestration leads to the alteration of host rock, and eventual equilibrium in the mineral-brine-CO_2 system. Chemical modeling and laboratory experiments from literature show that these reactions and eventual equilibria are driven by the specific mineralogy of the target formation, the composition of the brine, the acidity of the CO_2-brine mixture, and the 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.

1.7.4.2 Methods

Reactive transport models (RTMs) were created for the facies assemblages present at the subject location. In general, RTMs simulate single or multiphase flow, heat transfer, and geochemical reactions under isothermal or non-isothermal conditions. The RTMs in this section use the TOUGHREACT-Pitzer application, a high-salinity specific version of TOUGHREACT (Xu et al., 2006; Xu et al., 2011; Zhang et al., 2006). This version simulates water and CO_2 flow, heat transfer, solute transport (using advection and diffusion), and a variety of geochemical reactions including aqueous speciation, mineral dissolution and precipitation, gas dissolution and precipitation, and surface complexation under a wide range of salinities.

The RTMs are created to understand the impact of mineral-brine-CO_2 interaction under a certain range of thermal and hydraulic condition variations—both during and after the injection—based on the data available for the time being. It is not intended to provide predictions of the actual CO_2 plume. Detailed modeling of the CO_2 plume distribution in the complex subsurface is discussed in *Section 2 – Plume Model*.

The RTMs in this section are modeled as 2D radial RTMs. The system models a well located at the center of a radial domain with a radius of [redacted] In the model of the Miocene (Oakville), the vertical system is modeled as [redacted] thick in the injection zone and [redacted] thick in the confining zone. In the model of the Frio, the vertical system is modeled as [redacted] thick in the injection zone and [redacted] thick in the confining zone. [redacted]

[redacted]

1.7.4.3 Models

A total of two RTMs models were conducted, one each for the upper and lower confining zones and their associated injection zones. [redacted] The models assume an initial pressure gradient of [redacted] psi/ft and an initial thermal gradient of [redacted] /100 ft for the shallow zone [redacted], and [redacted] /100 ft for deep zone [redacted] —with a mean annual surface temperature of 70°F. A constant injection rate at [redacted] is applied in each model (formation), and the injection lasts [redacted] years. The models run a period of 10,000 years after the injection period to evaluate the long-term plume development and CO_2 being trapped by capillarity and minerals. [redacted] The RTMs are subjected to further calibration with the data to be collected from the test well.

1.7.4.4 Results

Frio Formation

[redacted]

The results for the Frio formation show that the temperature around the injection wellbore decreases within a [redacted] radius by the end of the [redacted] injection period. [redacted] The results are displayed in Figure 1-79, where mineralogy changes are represented in volume fraction—with negative numbers representing dissolution and positive numbers representing precipitation.

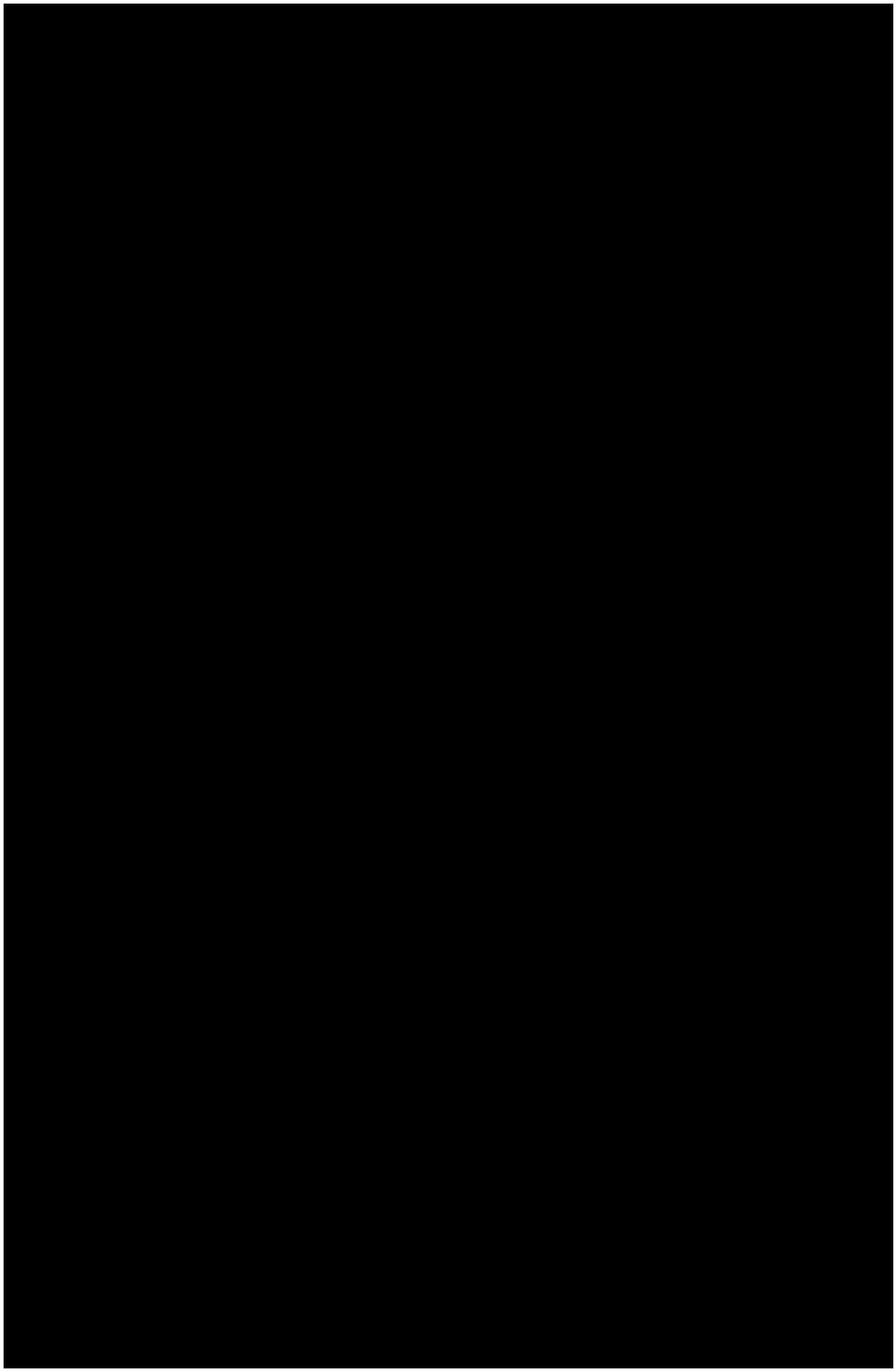


Figure 1-79 – Modeled carbonate concentration (in mol), pH, and mineralogy (in volume fraction, positive for precipitation and negative for dissolution)

Miocene (Oakville) Interval

Similar to the Frio model, the results for the Miocene show that temperature around the injection wellbore decreases within a [redacted] radius at the end of the well's planned [redacted] injection period. [redacted] The results are displayed in Figure 1-80, where mineralogy changes are represented in volume fraction, with negative numbers representing dissolution and positive numbers representing precipitation.

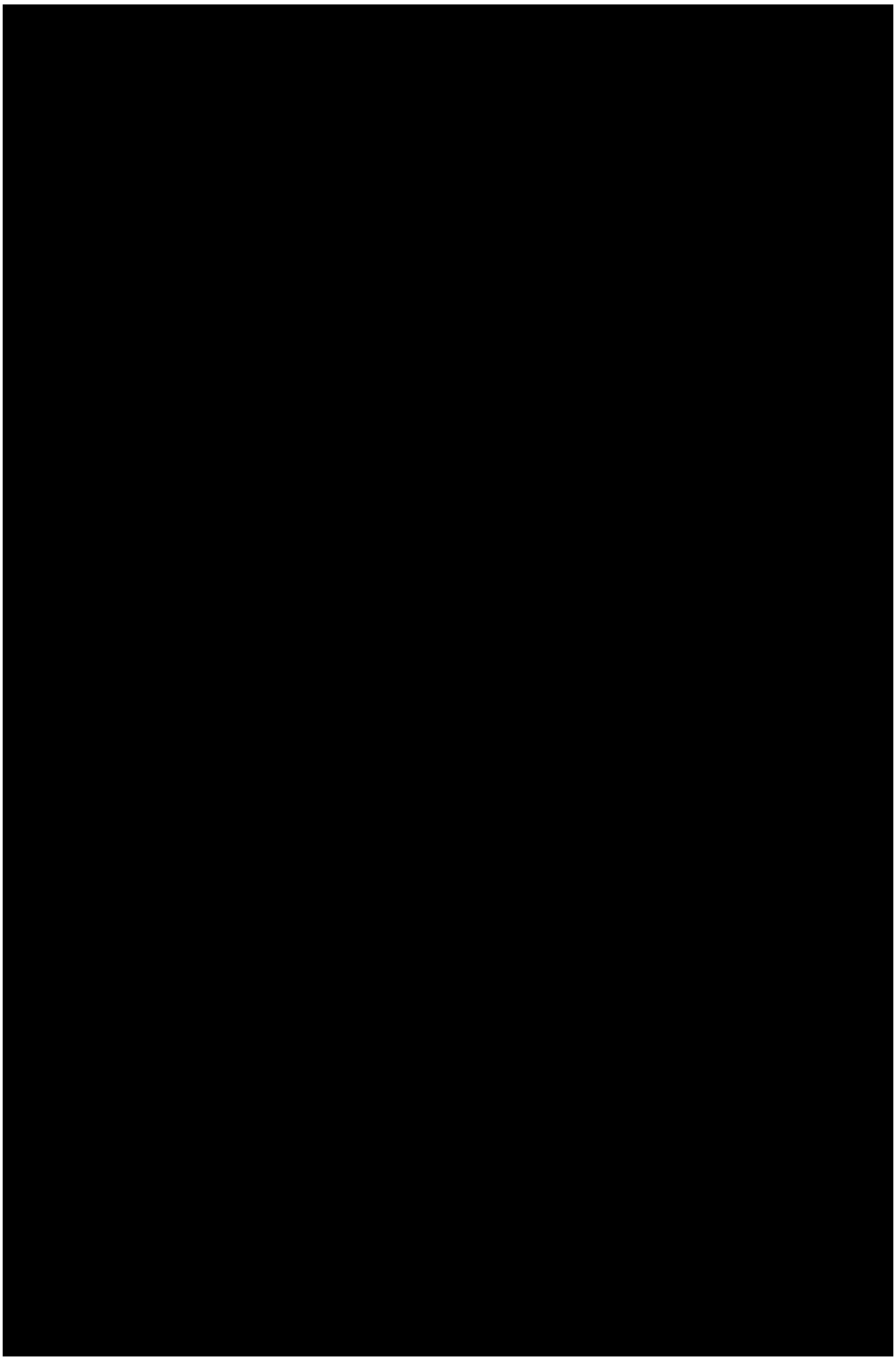


Figure 1-80 – Modeled carbonate concentration (in mol), pH, and mineralogy (volume fraction, positive for precipitation and negative for dissolution)

The RTMs run to 10,000 years to evaluate the long-term effects of the CO_2 residing in the reservoir. Model results indicated that the CO_2 is continuously dissolving into the brine and precipitating into minerals—meaning the CO_2 is mineralogically trapped in the reservoir [redacted] The primary trapping mechanisms are discussed in detail in *Section 2 – Plume Model.*

[redacted]

Figure 1-81 – [redacted]

1.8 Hydrology

The hydrology in Texas is composed of multiple aquifers, including 9 major aquifers and 21 minor aquifers. The Gulf Coast Aquifer (GCA) is a major aquifer, dating from the Oligocene to the Holocene, and is shaped like a broad belt along the Gulf of Mexico—and composed of sedimentary rocks (sand or gravel) with high permeability and porosity that are confined or separated by clay and silt layers. The following hydrostratigraphic units are included in the GCA, from deepest to shallowest: Catahoula Confining Unit, Jasper aquifer, Burkeville Confining Unit, Evangeline aquifer, and the Chicot aquifers. These aquifers have the potential to serve as regional USDWs, depending on location (George, Mace, and Petrossian, 2011). Since no other major or minor aquifers underlie Refugio County, Texas, this study concentrates on the GCA.

Figure 1-82 illustrates the major Texas aquifer extents and the Project location. A regional stratigraphic column of the hydrogeologic units is provided in Figure 1-83, highlighting the GCA paleontological markers, aquifer boundaries, geologic age, and epoch. Publicly available data from the Texas Water Development Board (TWDB), USGS, EPA, and peer-reviewed journals were utilized to provide each aquifer's groundwater information, water well data, and relevant figures for this section.

Water withdrawal and usage are reported by the TWDB. The GCA covers 41,970 sq mi, extending to 56 counties, with the Greater Houston metropolitan area using the largest municipal groundwater—models for which are divided into three sections: northern, central, and southern (Mace et al., 2006). The central part of the Gulf Coast Aquifer Model covers Refugio County, Texas, which falls within the Groundwater Management Area (GMA) 15 section. Groundwater is considered a primary source of water in Refugio County, roughly accounting for 79% of the total water used (Mace et al., 2006). Refugio County utilized 2,776 acre-ft/yr in 2020 (2022 State Water Plan for Refugio County, accessed in 2024). The water usage is mainly industrial or public supply, with some irrigation and domestic usage as well. Groundwater resources in Refugio County predominantly rely on the Chicot Aquifer System (AS) and the Evangeline AS (Mason, 1963).

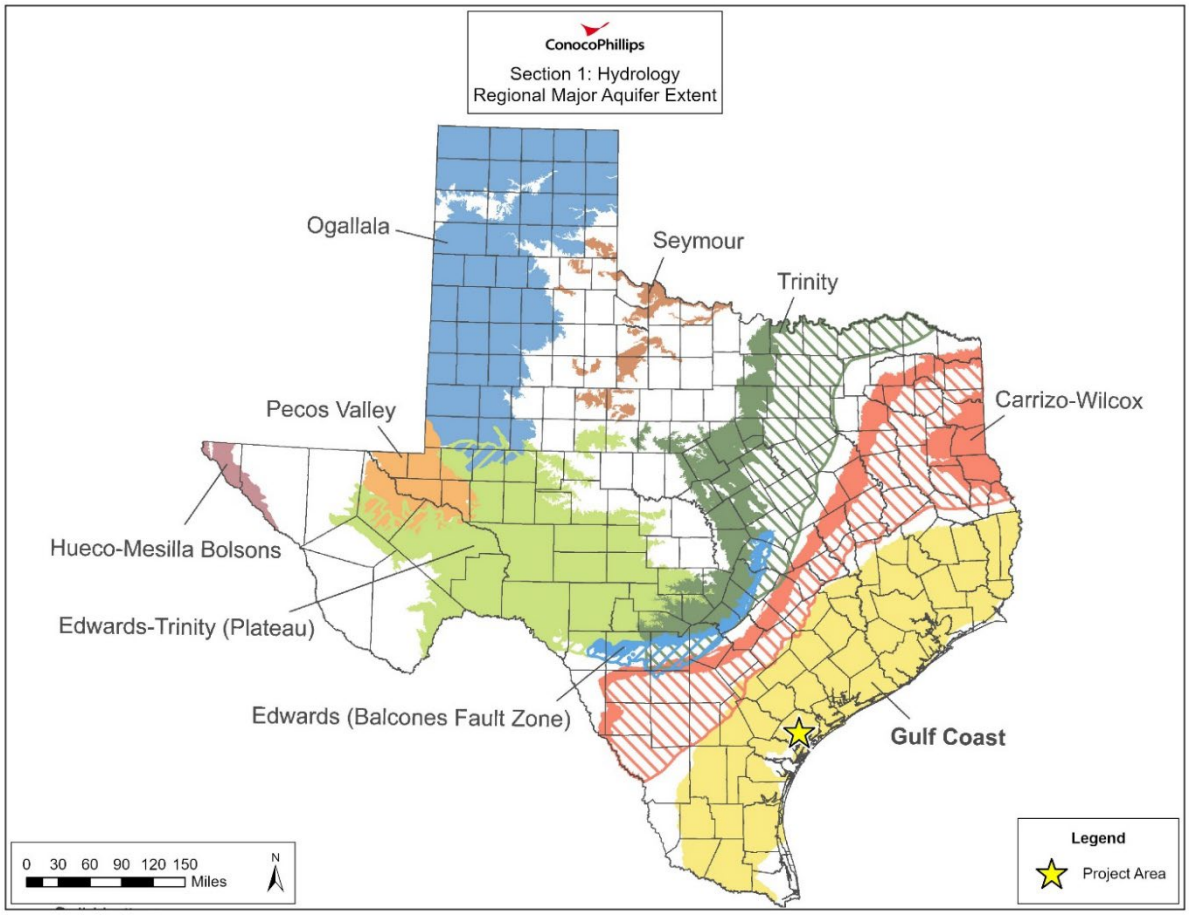


Figure 1-82 – Regional major aquifer extent and the Project area (modified from George, Mace, and Petrossian, 2011).

Figure 1-83 – General hydrological units
(modified from Young et al., 2010; Olariu et al., 2019; Loucks et al., 2011), color coded to match Figure 1-84.

1.8.1 Base of USDW Determination

The base of the USDW at the Project site is in the Goliad Formation of the Evangeline aquifer, which correlates to Layers 4 and 5 in Figure 1-84. A structure map of the base of the USDW is shown in Figure 1-85; this map and associated USDW cross sections at the Project site are included in *Appendix C-1 through C-8.* The base of the USDW at the Project AOI was established using a variety of publicly available data including Groundwater Advisory Unit (GAU) letters provided by the Texas Commission on Environmental Quality (TCEQ), the USDW as defined by the Underground Injection Control (UIC) program, and well logs from which values of total dissolved solids were calculated. The GAU letters provided either Base of Usable Quality Water (BUQW) or USDW values. Additionally, proprietary data from shallow wellbore samples collected [redacted] provided site-specific values to determine the base of the USDW for the Project AOI.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The USDW base in the AOI [redacted] ranges from [redacted] This intrusion is corroborated by Mace et al. (2006) and Solis (1981). [redacted] The mapping and analysis of the following aquifers below is supported by the regional west-east and north-south schematic cross sections presented in Figures 1-88 and 1-89, respectively, which show the associated aquifers, different salinity boundaries including freshwater (or BUQW), and stratigraphy over multi-parish distances. Baseline samples are planned during stratigraphic test well operations for the following formations, as they may contain USDWs: Beaumont, Lissie, Willis, and Goliad. The groundwater

and above-zone monitoring plan provided in *Section 5 – Testing and Monitoring Plan* is designed to secure the protection of all USDWs.

Figure 1-84 – General cross sections No. 16 along dip for the Gulf Coast aquifer including Refugio County, relative aquifer, depths, and thicknesses (modified from Young et al., 2010).

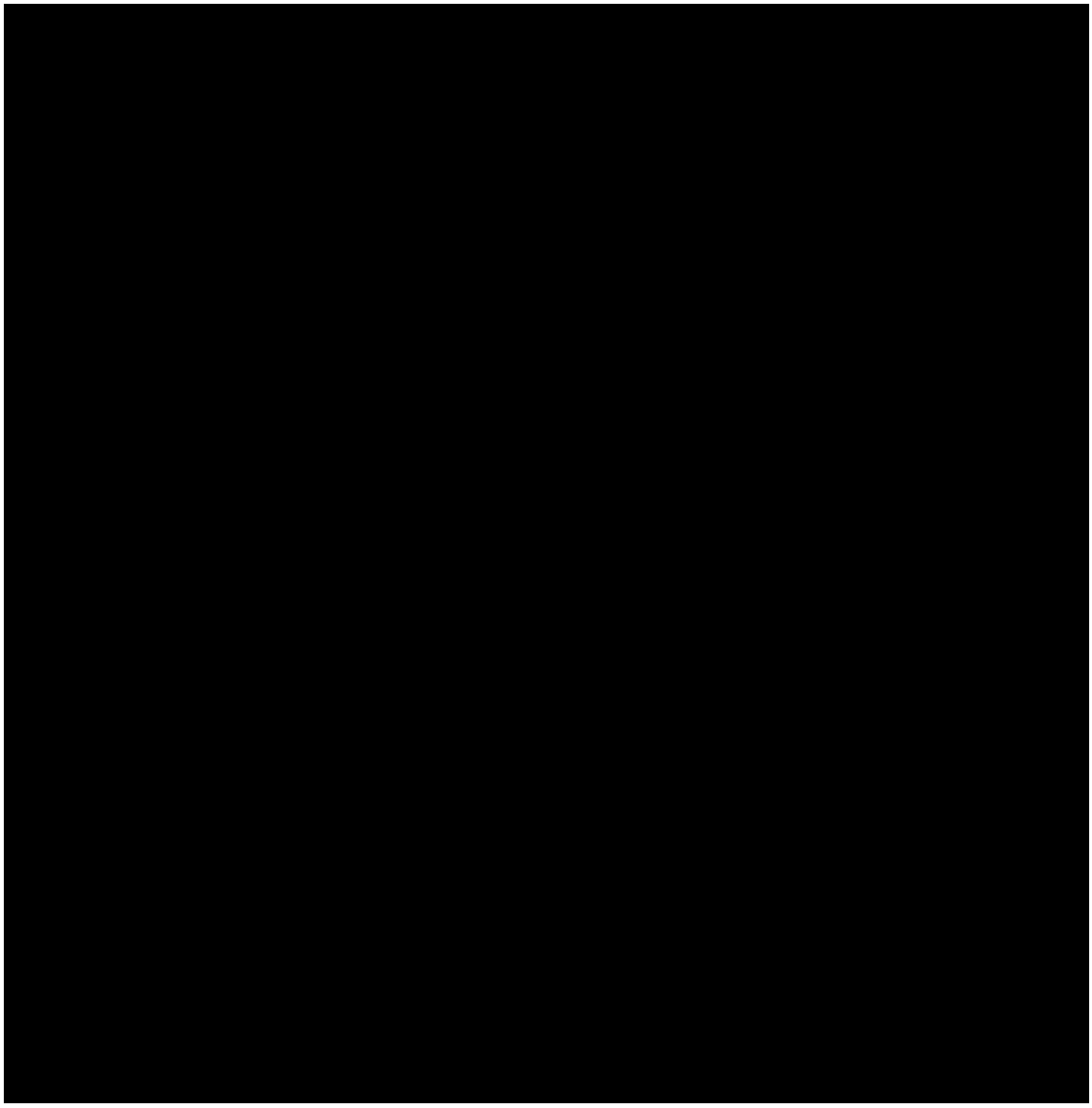


Figure 1-85 – Base of USDW within AOI

Figure 1-86 – Surface-hole wireline well logs and petrophysical interpretation for [redacted]

Figure 1-87 – Calculated salinity profiles from [redacted] logs and water samples [redacted]

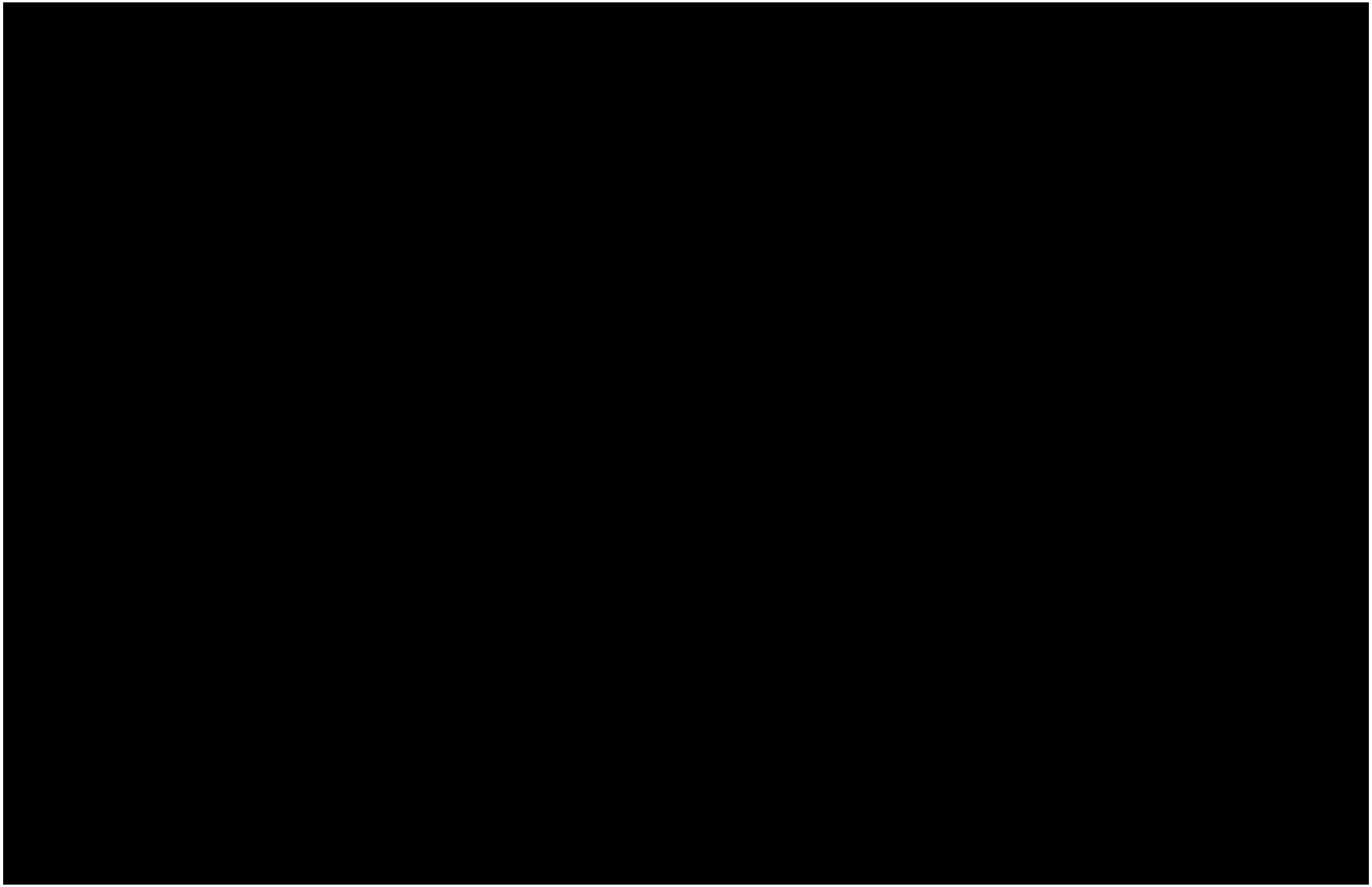


Figure 1-88 – NW-SE cross section along dip (Young et al., 2016)

Figure 1-89 – Gulf Coast general cross section

1.8.2 Major Aquifer: Gulf Coast Aquifer

The Gulf Coast Aquifer is a major aquifer in Texas that supplies groundwater to multiple municipalities along the Gulf Coast region and is part of the Gulf of Mexico basin (Mace et al., 2006). It contains complex sedimentary facies, produced by the cyclical deposition of fluvial-deltaic to shallow-marine sediments over the Miocene to Pleistocene periods. Sea-level changes, basin subsidence, and multiple growth faults (parallel to the Gulf Coast) regulated the patterns of sediment accumulation and dispersion, producing irregular layers of sand, clay, silt, and gravel (Mace et al., 2006). It includes the following hydrostratigraphic units, from deepest to shallowest: the Catahoula Confining Unit, Jasper aquifer, Burkeville Confining Unit, Evangeline aquifer, Chicot aquifer, and Alluvium aquifer. Regional elevation ranges from 900 ft in the southwest to sea level on the coast (Mace et al., 2006). Passing through the Gulf Coast region with a southeasterly flow are 11 of Texas's principal rivers, including the San Antonio River (Mace et al., 2006). Yearly precipitation in the southwest and northeast averages, respectively, from 28 to 58 inches (in.) (Mace et al., 2006). The quality of the water varies as salt domes, heavy pumping, and manufacturing may locally lead to depression cones, saltwater intrusions, and increased levels of chloride and arsenic (Mace et al., 2006).

According to the 2020 Census, nearly 25% of Texans live in the Gulf Coast region. The Project is located in Refugio and Aransas Counties, which are primarily rural within the AOI. The population and water demand are expected to remain constant until 2070, per the data from the 2022 State Water Plan for Refugio County (accessed in 2024). However, effective water management remains essential, as it is surrounded by large cities like Houston, San Antonio, and Corpus Christi, which have high water demand and potential scarcity due to population growth (Moorthy, 2005; Mason, 1963).

1.8.2.1 Summary of the Catahoula Confining System

The Catahoula Confining System (CS) is the lowest hydrostratigraphic unit in the Gulf Coast aquifer. It is composed of Oligocene-age sediments, including the Catahoula and the Frio Formations. These fluvial sediments are interbedded with non-marine sands, clays, and volcaniclastic deposits. The Frio Formation is predominantly located in the northern portion of the Gulf Coast aquifer. In Central Texas, the thickness of this formation is between 150 and 200 ft. The base of the Catahoula CS is the Frio Clay or Vicksburg Group equivalent (Mace et al., 2006). In the Project AOI, this formation is expected to only include brine. Regionally, groundwater is expected to flow northwest (Young et al., 2010). [redacted]

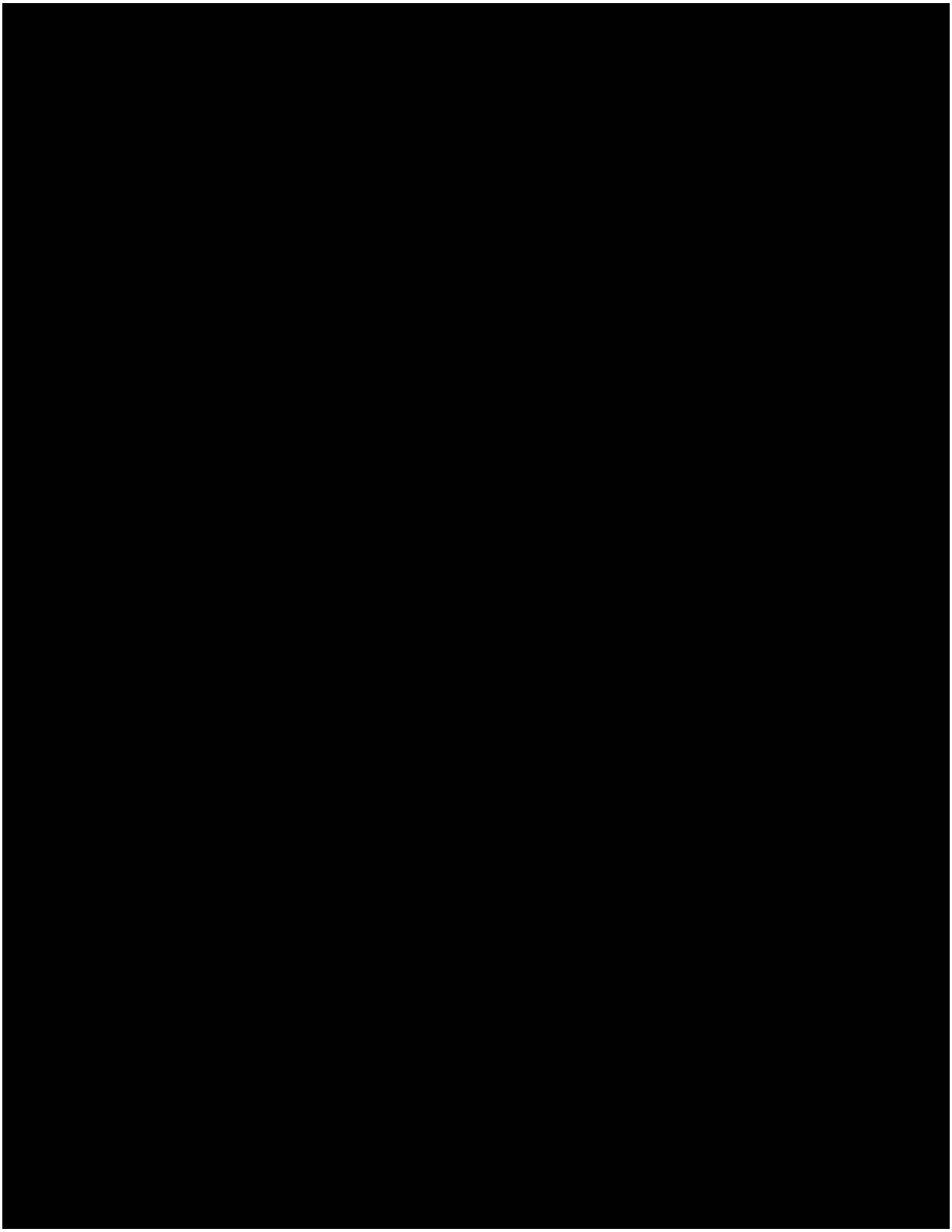


Figure 1-90 – Frio regional potentiometric surface map
(modified from Kreitler and Akhter, 1987).

1.8.2.2 Summary of the Jasper Aquifer System

The Jasper AS consists of a series of Miocene-age sediments. This aquifer system is located between the Burkeville Confining Unit and the underlying Catahoula Confining Unit. The Jasper AS in Texas includes the Oakville sands. The aquifer dips and thickens towards the Gulf of Mexico. The regional elevation for the aquifer base is around -8,000 ft TVDss along the Gulf Coast, with a thickness of about 3,200 ft. The Jasper AS recharges via precipitation at locations where the system outcrops and groundwater is expected to flow southeast (Mace et al., 2006). Discharge is primarily by water withdrawals from pumping in counties along the western boundary of the Gulf Coast Aquifer. Though the Jasper AS covers half of Refugio County, no freshwater is expected in the Project AOI. Water salinities in the Jasper AS are expected to be above the fresh groundwater threshold of < 10,000 milligrams per liter (mg/L) of total dissolved solids (TDS). This is supported by offset wells' resistivity log measurements, temperature, and TDS calculations. Figure 1-91 illustrates the Jasper AS potentiometric surface maps, the expected freshwater, and Refugio County.

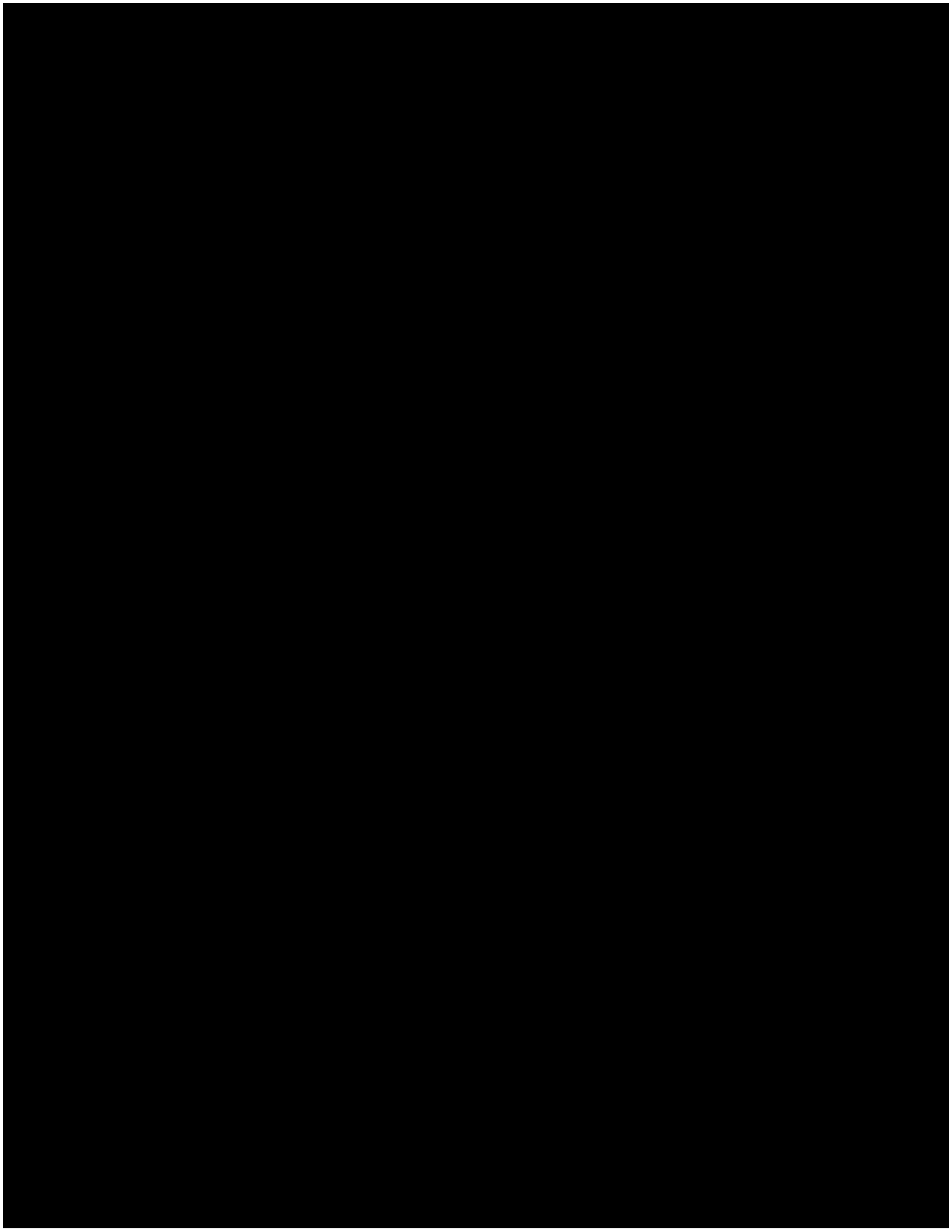


Figure 1-91 – Potentiometric surface maps including Refugio County for the Jasper AS in Texas (modified Mace et al., 2006).

1.8.2.3 Summary of the Burkeville Confining Unit

The Burkeville Confining Unit in Texas also extends along the Gulf Coast Plain, as it is part of the Gulf Coast aquifer—situated below the Evangeline AS and above the Jasper AS. This unit includes the Miocene-age Fleming Formation, which generally corresponds to the Lagarto Clay. Generally, this unit dips and thickens towards the Gulf, with an estimated elevation of -5,000 ft near the southern part of the Texas coastline and a thickness of up to 1,600 ft. The Burkeville Confining Unit is mainly composed of silt and clay and acts as a confining unit for the Evangeline AS (Mace et al., 2006). In Refugio County, this unit ranges from 400–800 ft thick according to Young et al. (2010) structural maps, and in the AOI it is estimated to be around [redacted] thick.

1.8.2.4 Stratigraphy of the Evangeline Aquifer System

The Evangeline AS in Texas, as part of the Gulf Coast aquifer, also extends along the Gulf Coast Plain. The Evangeline aquifer is situated below the Chicot AS and overlies the Burkeville confining unit. Most reports classify the Goliad Formation as Pliocene-Miocene in age, which are included in the Evangeline AS. Generally, the aquifer contains freshwater, but as it descends the encroachment of saltwater makes it more saline. The aquifer dips and thickens towards the Gulf of Mexico, with an estimated elevation of -2,600 ft near the southern part of the Texas coast and a thickness of up to 2,800 ft (Mace et al., 2006). The Evangeline aquifer in Refugio County is formed by the Goliad Formation and the lower Lissie Formation.

Goliad formation

The Goliad Formation, according to Mason (1963), is composed of sand or sandstone interbedded with gravel and clay. It outcrops in Bee and Goliad Counties. The shallowest top in the aquifer is estimated to be 600 ft above sea level, with a thickness of 300–600 ft. In Refugio County, the Evangeline AS's base ranges from 2,500 ft in the north to 3,000 ft in the south (TVDss) (Young et al., 2010). Fresh to slightly saline water is prevalent throughout most of Refugio County. According to the TWDB Groundwater data set (accessed in 2024), 126 wells have been screened in the Lissie Formation and Goliad Sand (LGLD) and the Evangeline Aquifer (EVGL). [redacted]

1.8.2.5 Characteristics of the Evangeline Aquifer System

Recharge and discharge

Recharge to the Evangeline AS occurs via precipitation in areas where the system outcrops; discharge is primarily by water withdrawals from wells used for domestic, public, irrigational, stock, and industrial purposes (Mace et al., 2006). [redacted]

Potentiometric surface and groundwater flow direction

The Evangeline AS fresh to slightly saline water underlies all of Refugio County (Mason, 1963). Regional groundwater movement is southeast (Figure 1-92); locally it flows from west to east (Mace et al., 2006). It is estimated that the base of the fresh to slightly saline water is between 500 ft below sea level in the south and 1,700 ft below sea level in the northeast, with a water level ranging from -20 to -30 ft (Mason, 1963).

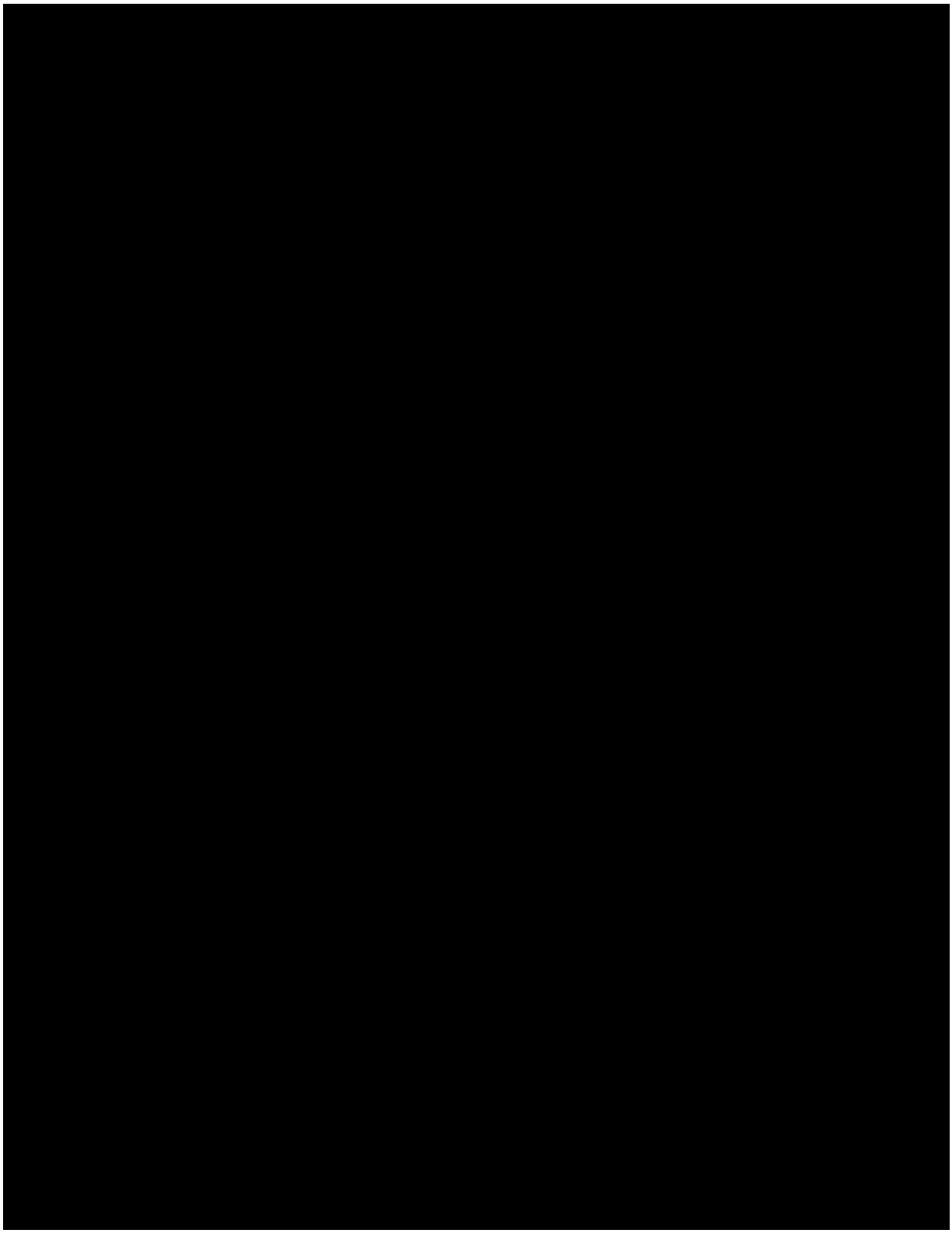


Figure 1-92 – Potentiometric surface map of the Chicot AS
(modified from Mace et al., 2006).

Water quality

The freshwater-quality characteristics in Refugio County generally describe the water as soft to moderately hard, with some wells exceeding the EPA maximum contaminant levels (MCLs) for drinking water. The Evangeline water quality in the Project AOI is expected to exceed the EPA MCLs of 250 µg/L for chloride (Moorthy, 2005). [redacted]

Table 1-13 – Evangeline AS water-quality characteristics in the AOI.

ID	Well Depth (ft)	Temp (°C)	pH, (SU)	Alkalinity (mg/L as $CaC0_3$)	Chloride, Filtered (mg/L as Cl)	Iron, Filtered (µg/L as Fe)	Sulfate Dissolved (mg/L as SO4)	Total Dissolved Solids (mg/L)
[redacted]								

1.8.2.6 Stratigraphy of the Chicot Aquifer System

The Chicot AS in southeastern Texas covers more than 37 counties. Generally, it consists of the Willis, Lissie, Bentley, Montgomery, and Beaumont Formations. These Pleistocene-age sediments are composed of interbedded and cross-bedded layers of sands, clay, gravel, conglomerates, and silt (Mace et al., 2006). These heterogeneous sediment beds dip toward the Gulf of Mexico and thicken to the east to a maximum of 1,200 ft, along the Gulf Coast (Mace et al., 2006). The base of the Chicot aquifer is estimated to be 1,200 ft below the surface at its deepest point, in the southern portion of the Texas Gulf Coast (Mace et al., 2006). The Beaumont Clay and Lissie Formations are present in Refugio County and are considered the main subgroups of the Pleistocene system (Mason, 1963; Mace et al., 2006). According to the TWDB Groundwater data set in Refugio County, more than 220 registered water wells were screened in the Beaumont Clay and Lissie Formation (BMLS), CHCTL Chicot Aquifer Lower, and CHCT Chicot Aquifer as of 2024. The average water well in Refugio County has a depth of less than 500 ft below the surface and a mode of 200 ft. The Chicot AS stratigraphic column provided in Figure 1-93 assists in identifying Refugio County nomenclature.

Beaumont Clay

The Beaumont Clay lies below the Alluvium aquifer and above the Lissie Formation. It consists of interbedded layers of medium- to fine-grained sand that are layered over a mostly clay substrate. The formation thickens and dips to the southeast, towards the Gulf of Mexico. In Refugio County, the Beaumont Clay is estimated to be zero to no more than 600 ft in thickness (Mason, 1963).

Lissie Formations

Below the Beaumont Clay lies the Lissie Formation, typically composed of varying thicknesses of deltaic beds primarily made of sand with small gravel layers and interbedded silt and clay sections. The base of the aquifer is often determined by the base of the caliche beds, according to Mace et al. (2006). The formation thickens to the southeast, reaching a depth of 400–600 ft (Mason, 1963). These beds can produce large quantities of fresh to moderately saline groundwater in Refugio County.

As the Chicot aquifer is an unconfined aquifer, the TWDB Groundwater data set has included the Lissie Formation as part of the BMLS or the LGLD, splitting the formation into an "upper Lissie" and "lower Lissie," with a boundary not clearly defined (Mason, 1963). According to Mason (1963), this boundary is at a depth of 500–700 ft, but Moorthy (2005) places it at around 300–700 ft below ground surface. Based on this classification, the lower Lissie sands fall within the boundary of the Evangeline aquifer (Moorthy, 2005). [redacted]

The Chicot AS base in the Project AOI ranges from 250 ft TVDss in the north and 750 ft TVDss in the south (Mace et al., 2006; Young et al., 2010). [redacted]

<table>
<tr><th>System</th><th>Series</th><th>Formation</th><th>Hydrologic Unit</th><th>Aquifer</th></tr>
<tr><td rowspan="3">Quaternary</td><td rowspan="2">Holocene</td><td>Alluvium</td><td rowspan="3">Beaumont/ Upper Lissie</td><td rowspan="3">Chicot</td></tr>
<tr><td rowspan="2">Beaumont Formation</td></tr>
<tr><td rowspan="2">Pleistocene</td></tr>
<tr><td rowspan="2">Tertiary</td><td>Lissie Formation</td><td rowspan="2">Lower Lissie/ Goliad Sand</td><td rowspan="2">Evangeline</td></tr>
<tr><td>Pliocene</td><td>Goliad Sand</td></tr>
<tr><td></td><td>Miocene</td><td>Fleming Formation</td><td>Burkeville Aquiclude</td><td>Burkeville</td></tr>
</table>

Figure 1-93 – Stratigraphic column
displaying Chicot AS nomenclatures in Refugio County (Moorthy, 2005).

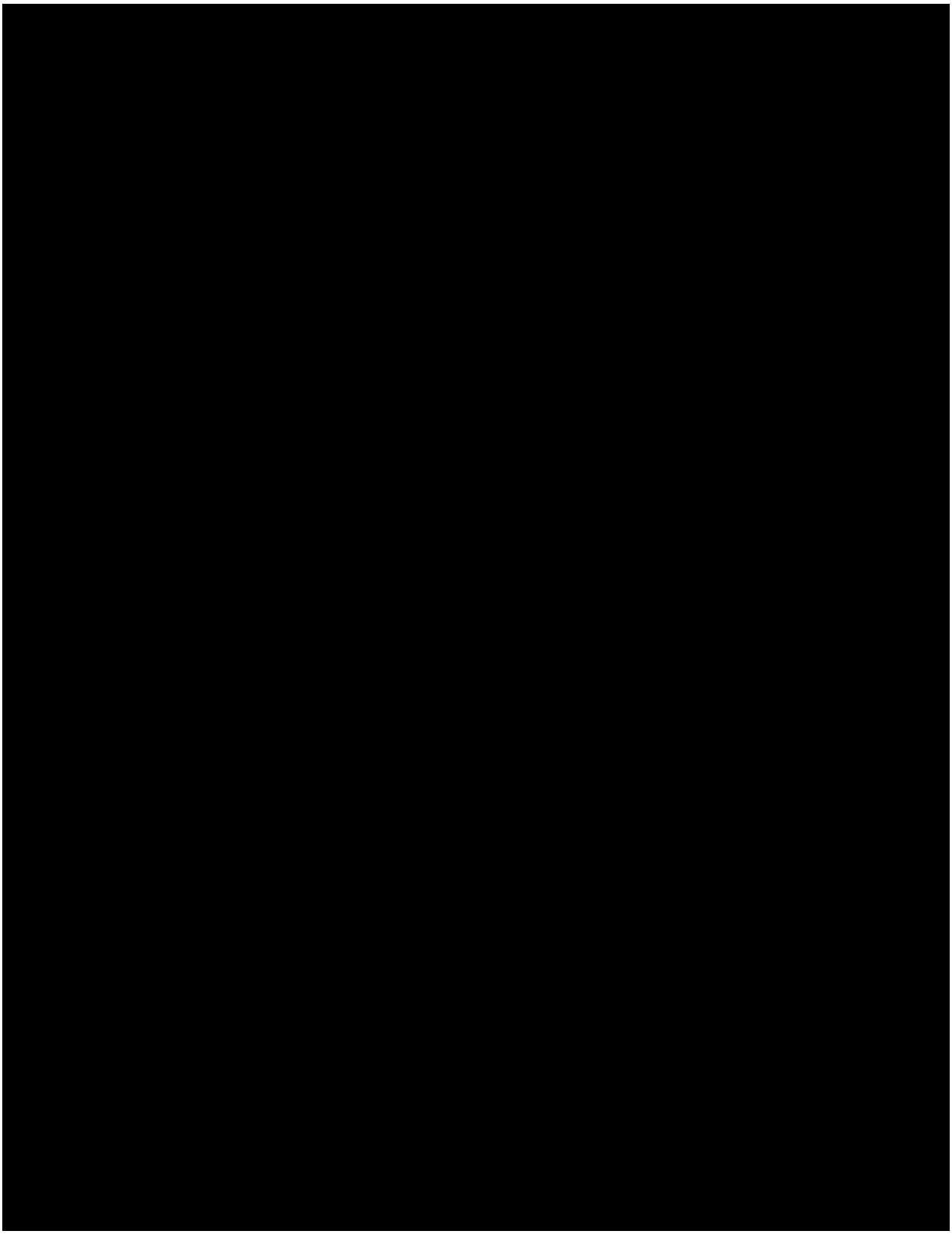


Figure 1-94 – Water wells in the Chicot aquifers within the Project AOI.

1.8.2.7 Characteristics of the Chicot Aquifer System

Recharge and discharge

The primary recharge source for this Chicot AS is precipitation in the outcrop zones, as water percolates vertically through the unconfined beds. Discharge is by pumping river runoff as water seeps into sandy soil, evapotranspiration, and vertical seepage to the underlying Evangeline aquifer (Mason, 1963). Spring discharges are connected to the San Antonio River in the north, the Aransas River in the south, and the Mission River in the middle (Mace et al., 2006).

Potentiometric surface and groundwater flow direction

Groundwater flow in an aquifer relies on the aquifer slope, as the flow goes from higher hydraulic head areas to lower hydraulic head areas, running perpendicular to potentiometric surface contours. In Texas, the Chicot AS water flow has changed as excessive water withdrawals have caused depression cones in Harris and Kleberg counties and affected water levels (Mace et al., 2006). In Refugio County, the water levels can vary from 0–92 ft throughout the county. [redacted] The array of groundwater monitoring wells displayed in *Appendix H-2* is designed to protect USDWs.

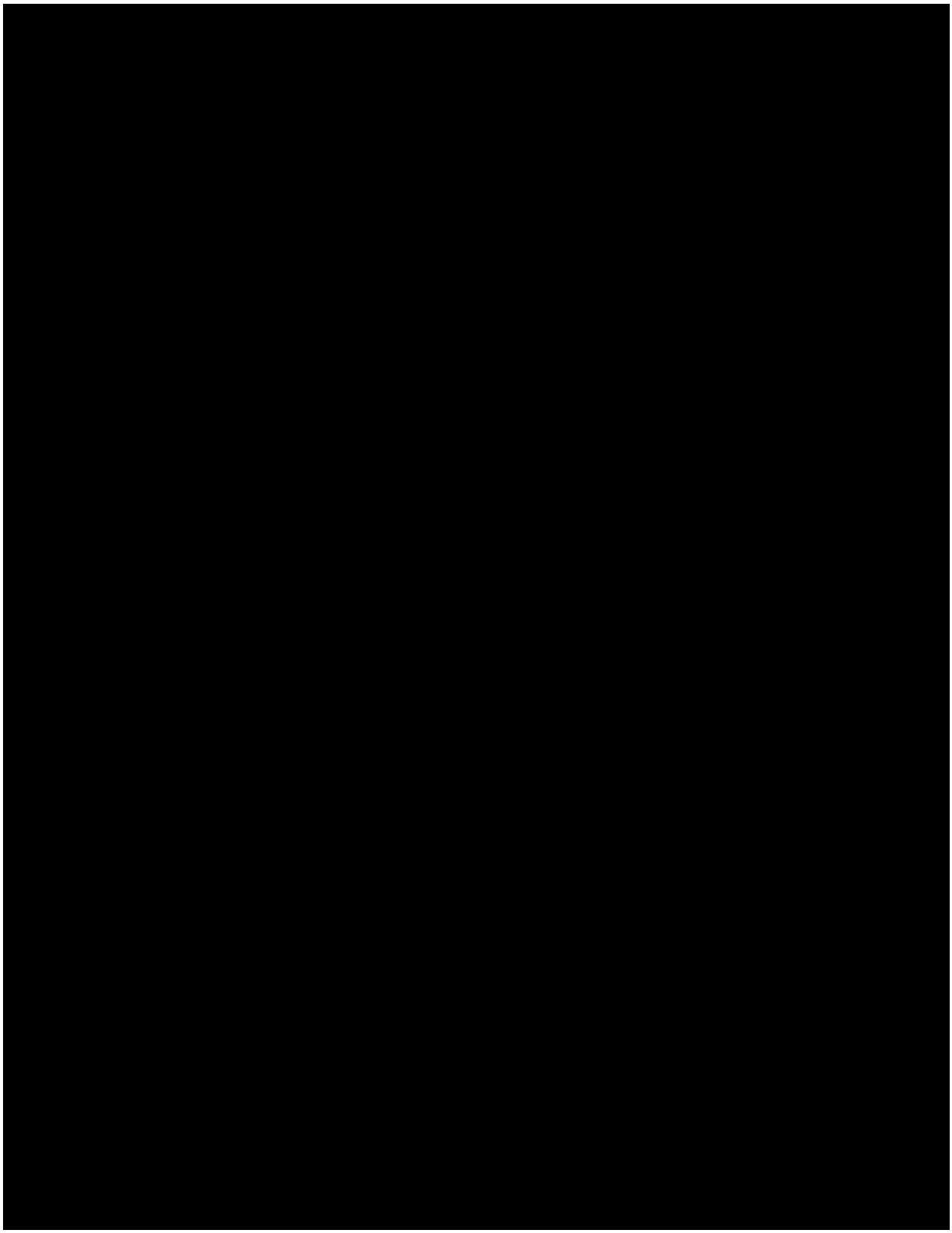


Figure 1-95 – Potentiometric surface map of the Chicot AS
(modified from Mace et al., 2006).

Water quality

The Chicot AS has been the subject of numerous reports, as public awareness of water quality and management on a local and national level are important. Statewide, the water quality is mainly fresh to saline. Water-quality deteriorates southwest from the San Antonio River Basin to Mexico. In Refugio County, most wells are reported to have < 1,000 ppm of TDS (Mace et al., 2006). [redacted] Mason (1963) mentioned a moderately saline (3,000 to 10,000 ppm) area located between Woodsboro and Bayside. Although freshwater occurs in numerous wells, other water properties need to be considered, per the EPA National Secondary Drinking Water Regulations (NSDWR). Water chloride concentration and hardness exceed the NSDWR based on analyses by the Groundwater Database Water Quality Reports (supported by Mace et al., 2006, and Mason, 1963). Table 1-14 demonstrates the well chemistry in the Project AOI for the Chicot AS. The locations of these wells are shown in Figure 1-96, in blue dots.

Table 1-14 – Chicot Aquifer System water-quality characteristics in the Project AOI.

ID	Well Depth (ft)	Temp (°C)	pH, (SU)	Alkalinity (mg/L as $CaC0_3$)	Chloride, Filtered (mg/L as Cl)	Iron, Filtered (µg/L as Fe)	Sulfate Dissolved (mg/L as SO4)	Total Dissolved Solids (mg/L)
[redacted]								

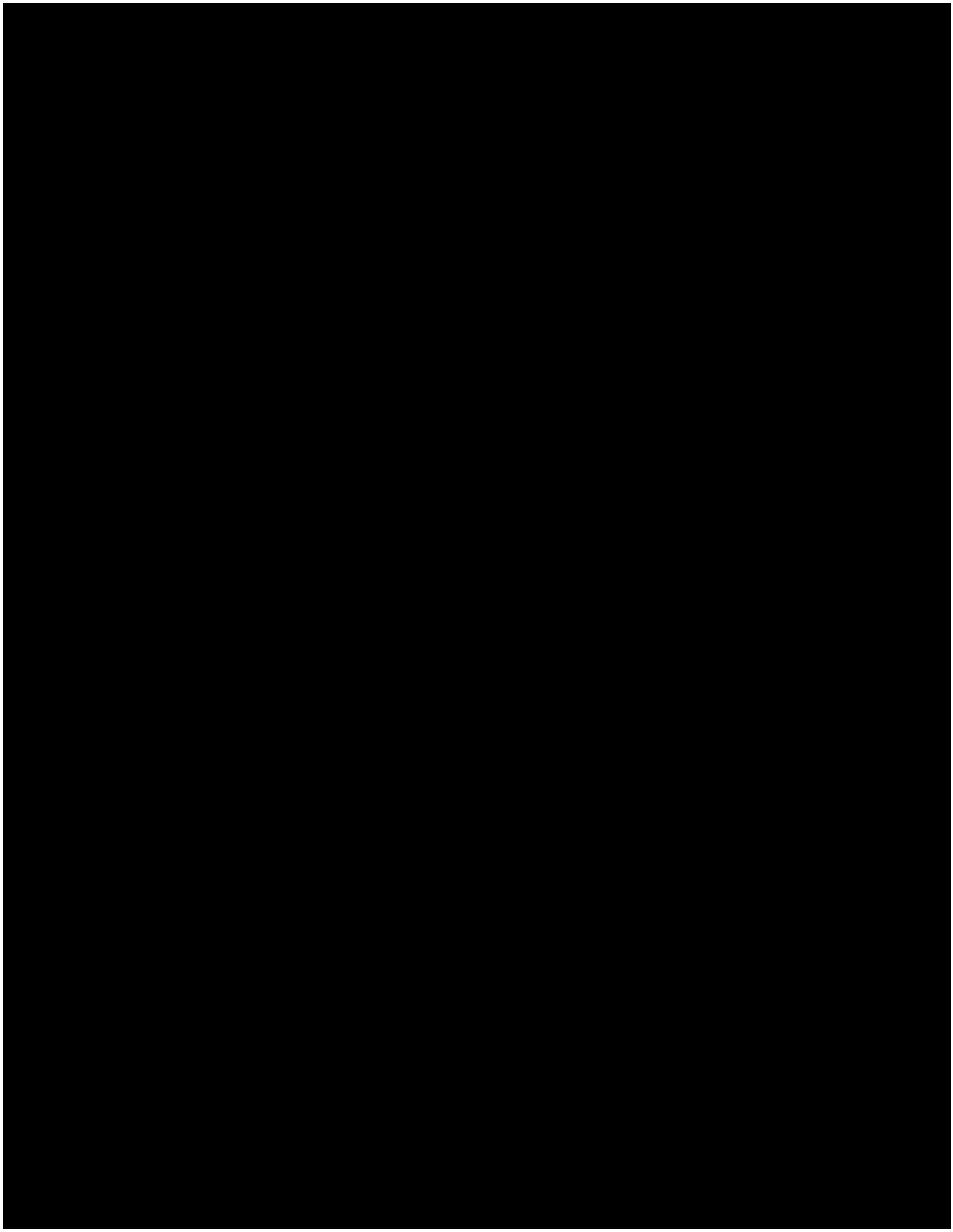


Figure 1-96 – Water well locations and related aquifers within Project AOI.

1.8.2.8 Alluvium Aquifer

The Holocene-age Alluvium aquifer is composed of fine sands, silt, and clays—and only extends to a small portion near the easternmost point in Refugio County. This aquifer has an estimated thickness of 50 ft. The groundwater is somewhat saline—1,000 ppm to 3,000 ppm—and only used for livestock. This aquifer is not considered a sustainable source of groundwater (Mason, 1963). According to the TWDB Groundwater database, only one well has targeted this aquifer in Refugio County.

1.9 Site Evaluation of Mineral Resources

1.9.1 Active Mines Near the Proposed Injection Location

A search was conducted using public data provided by Class VI Data Support Tool Geodatabase. Mines within 50 mi of the proposed site were isolated from the database. Figure 1-97 provides the location of mines within 50 mi of the proposed injection site. All the mines are shallow gravel or sand pits and quarries. Figure 1-98 provides a 10-mi radial search. No mines were identified within the search. The search concluded that no surface mineral impacts will occur from the Project.

1.9.2 Non-hydrocarbon Mineral Resources

Uranium Deposits

Sediment-hosted uranium deposits are known from South Texas, from Karnes, Live Oak, and Duval Counties. The principal source of the uranium is the Miocene Catahoula tuff (Catahoula tuff), from which uranium was leached through weathering and then transported into the permeable rocks of the Oakville, Catahoula, Frio, and other formations (below our injection targets). Hence, those rocks are potential host rocks for these uranium deposits (Eargle, Dickinson, and Davis, 1975). These uranium deposits are usually very shallow (< 300 ft), linked to areas where the Catahoula tuff is outcropping; therefore, the Project area, [redacted] is not favorable for such deposits.

Sulfur Deposits

A search for sulfur mineral extraction was performed using the Texas BEG; Figure 1-99 provides a map of mineral extraction in the state. [redacted] The search concluded that no impacts on sulfur production will occur from the Project.

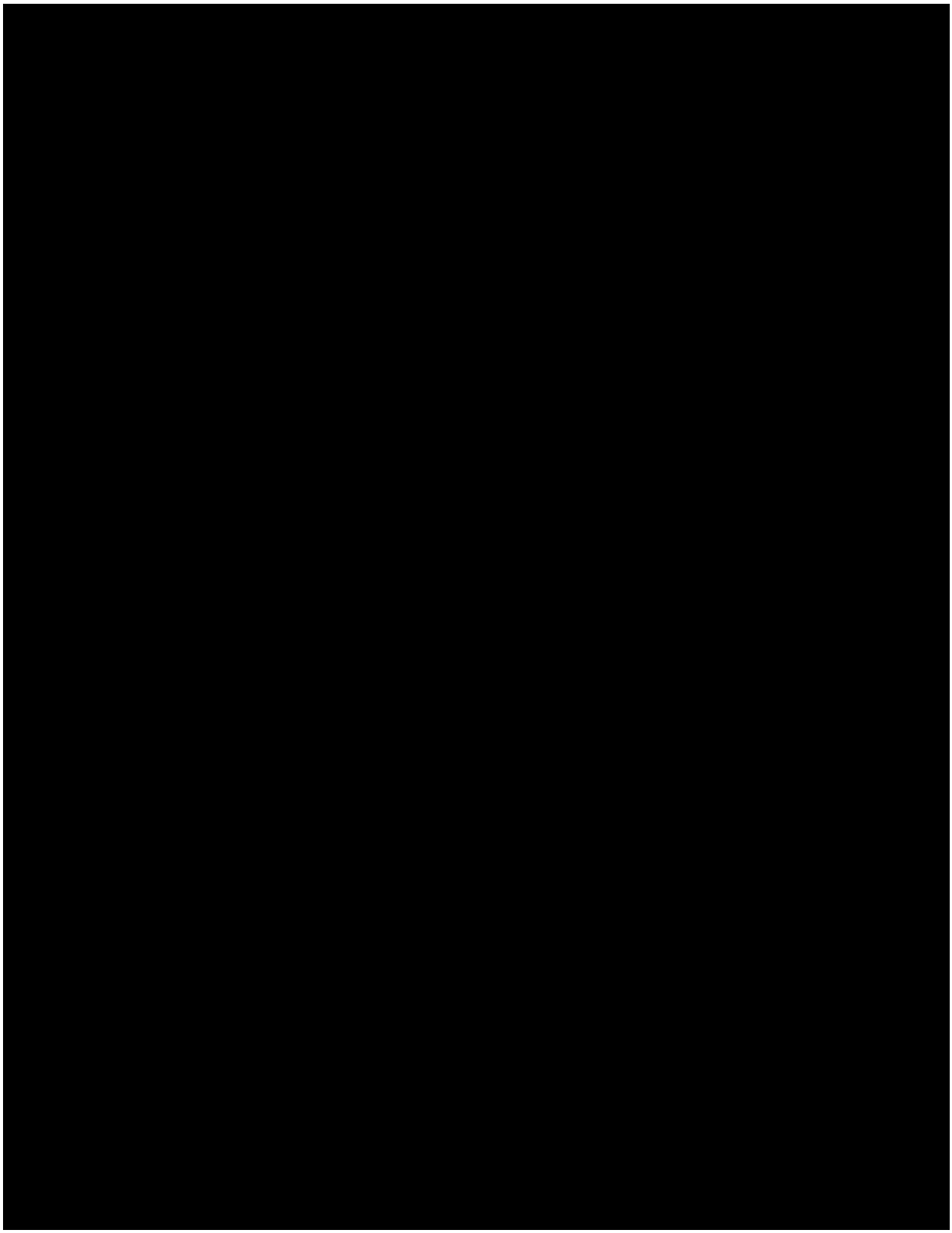


Figure 1-97 – Active mines within 50-mile radius of AOR.

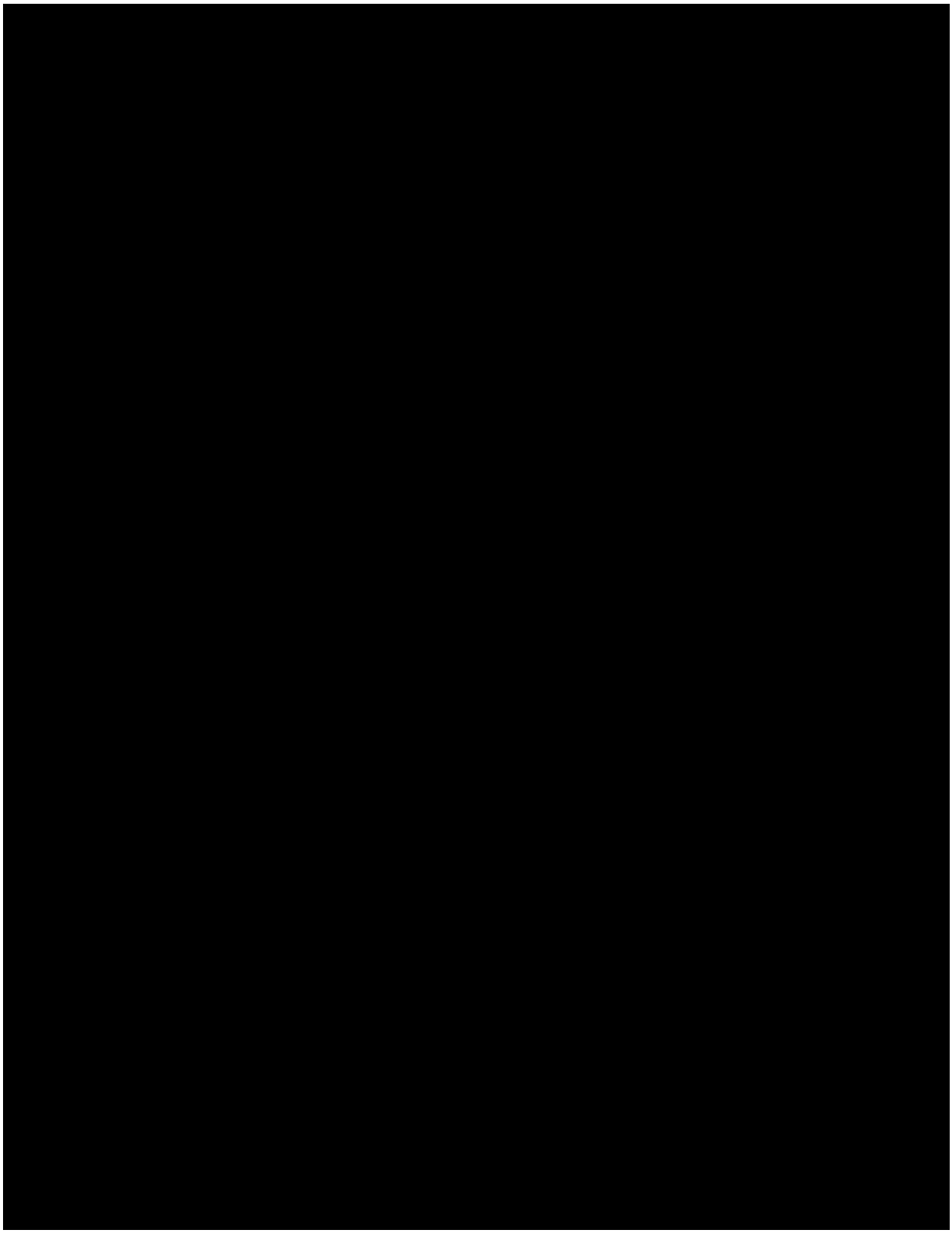


Figure 1-98 – Active mines within 10-mi radius of AOR.

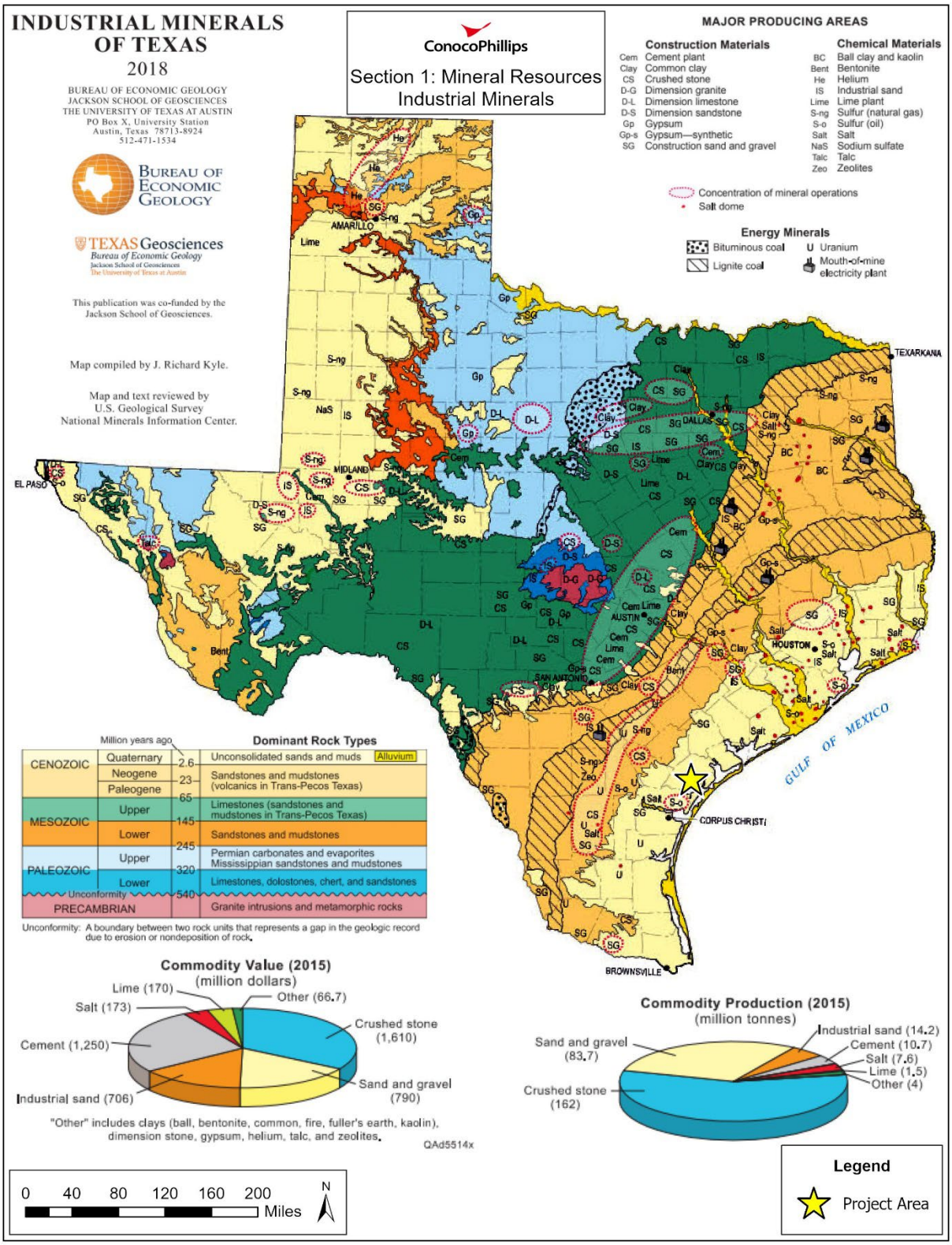


Figure 1-99 – Industrial mineral of Texas map.

1.9.3 [redacted]

[redacted]

Table 1-15 – [redacted]

[redacted]

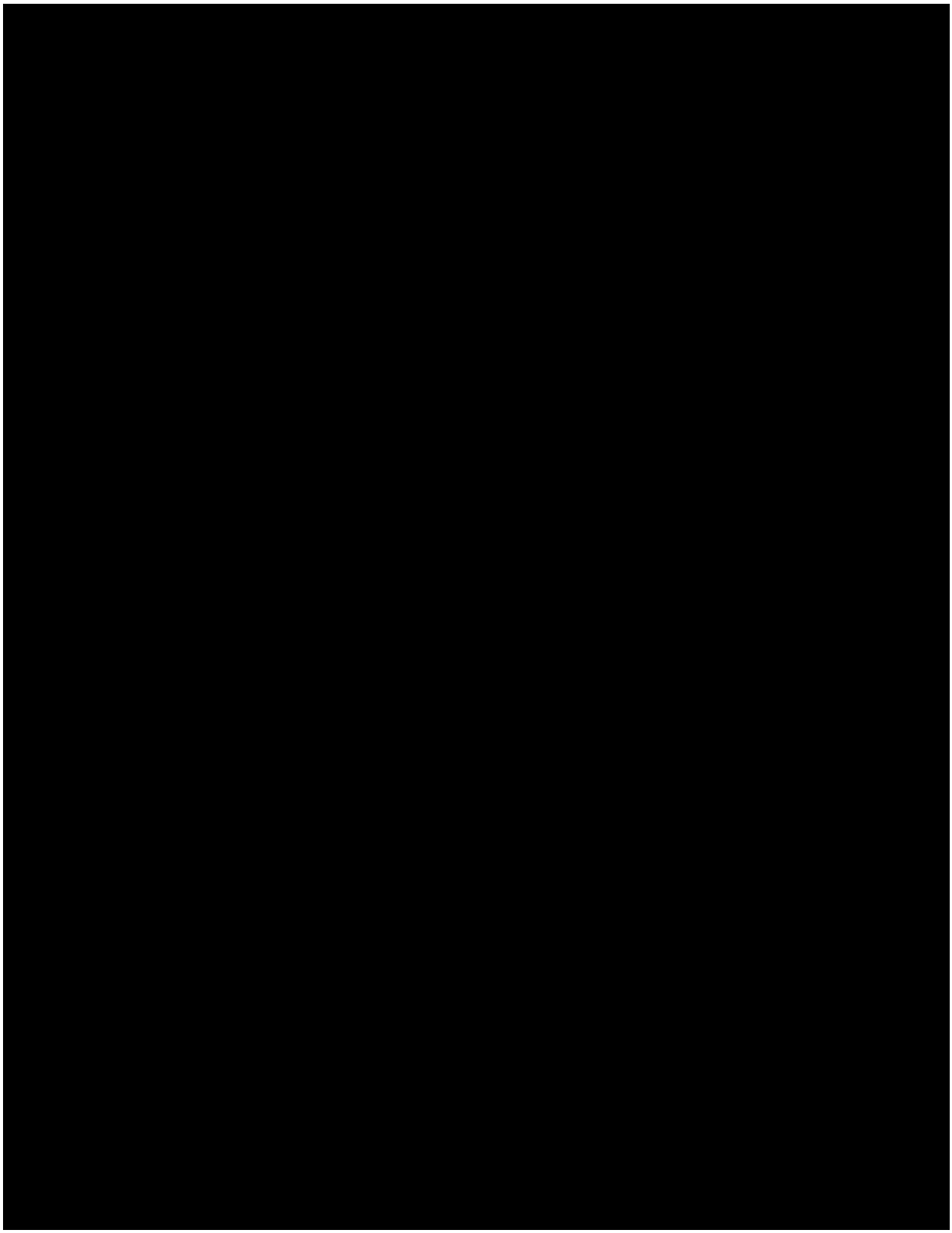


Figure 1-100 –

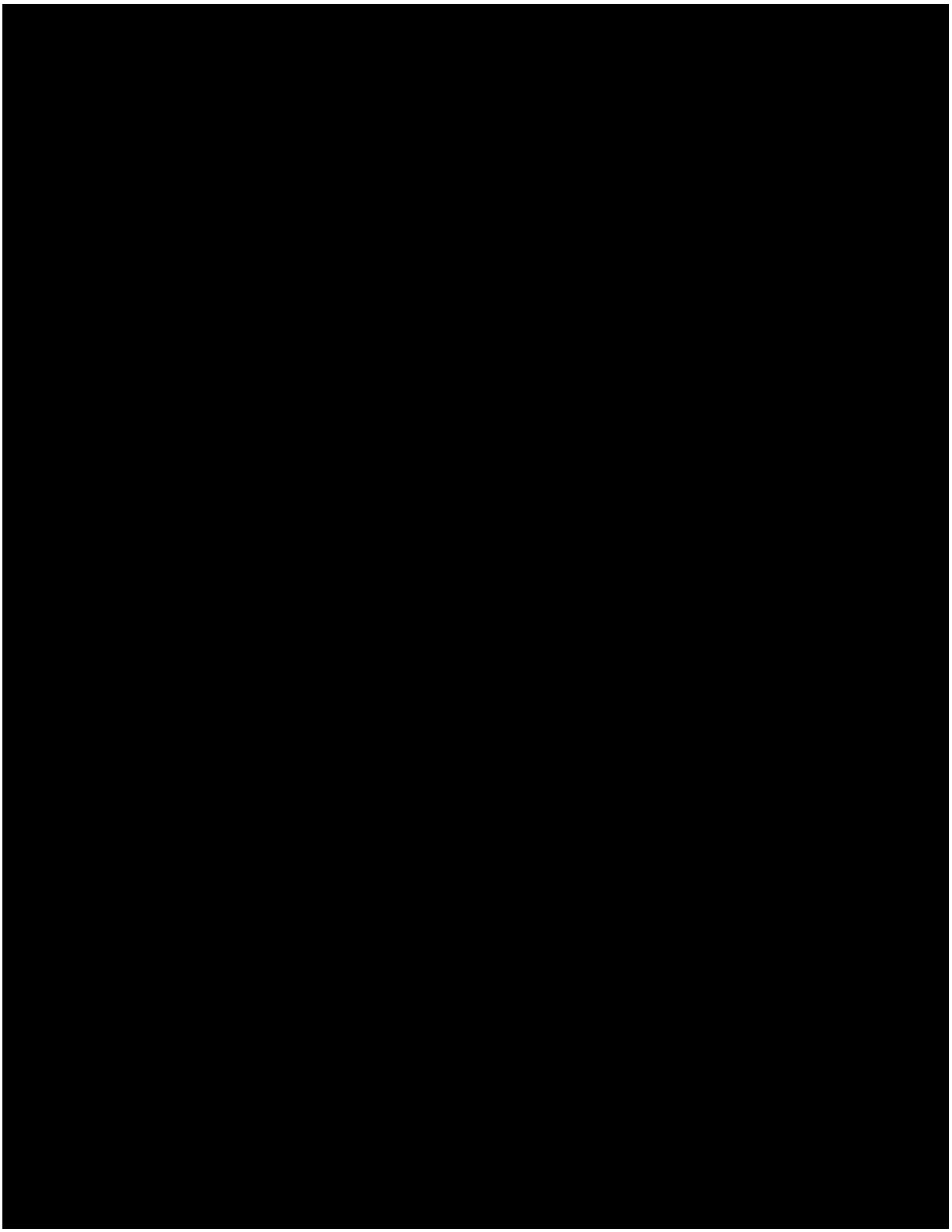
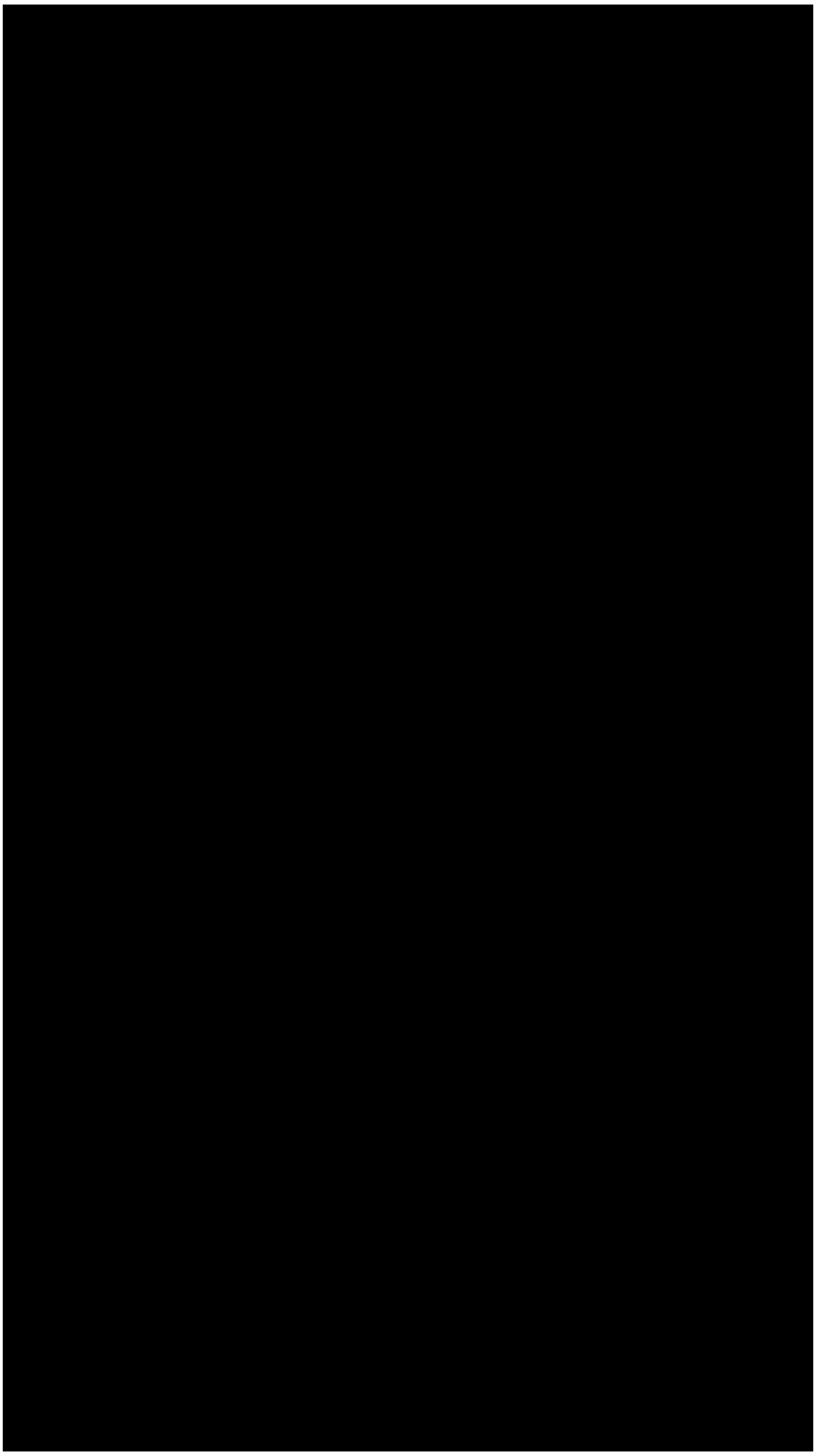
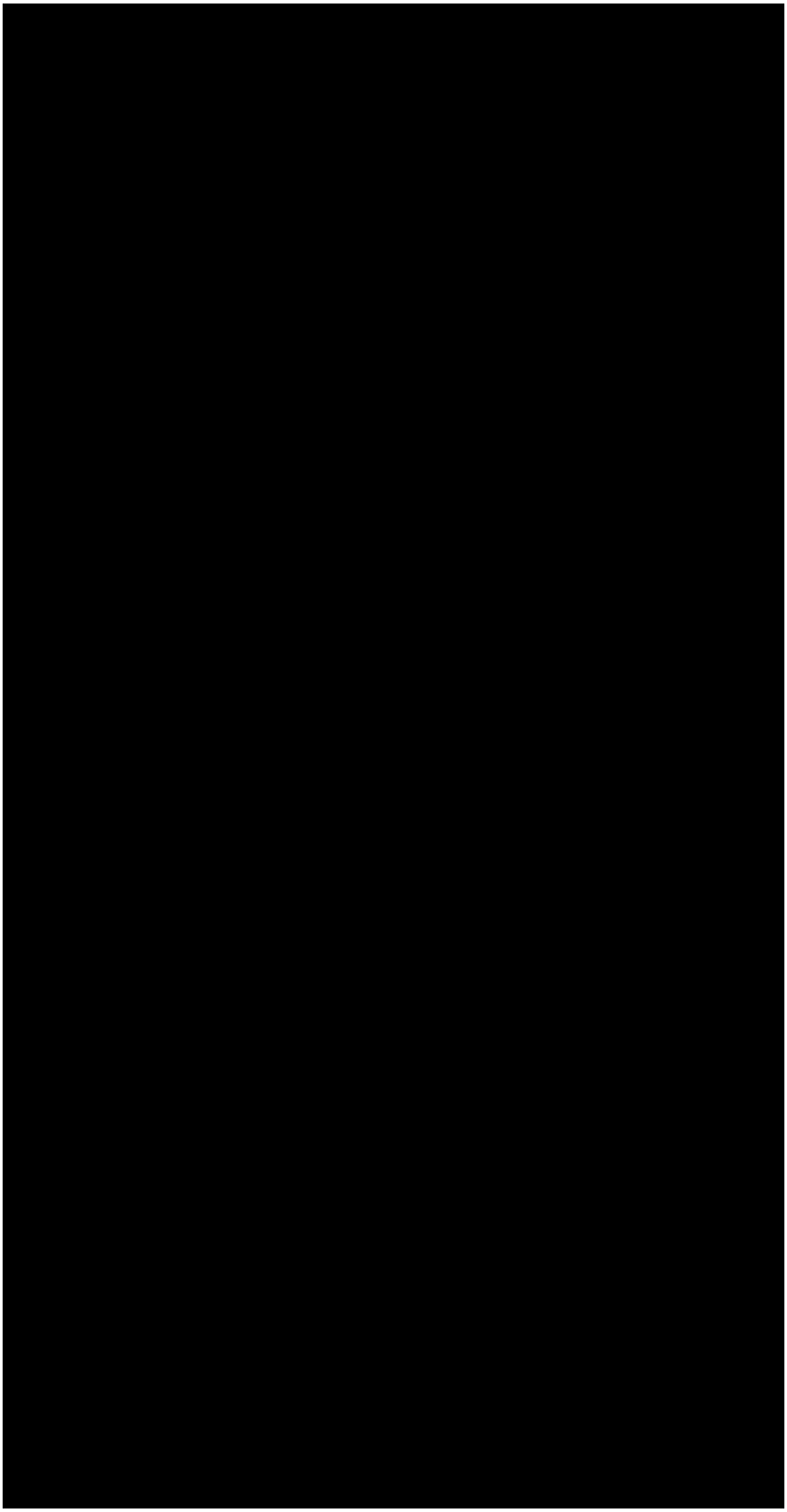


Figure 1-101 –

Table 1-16 – [redacted]





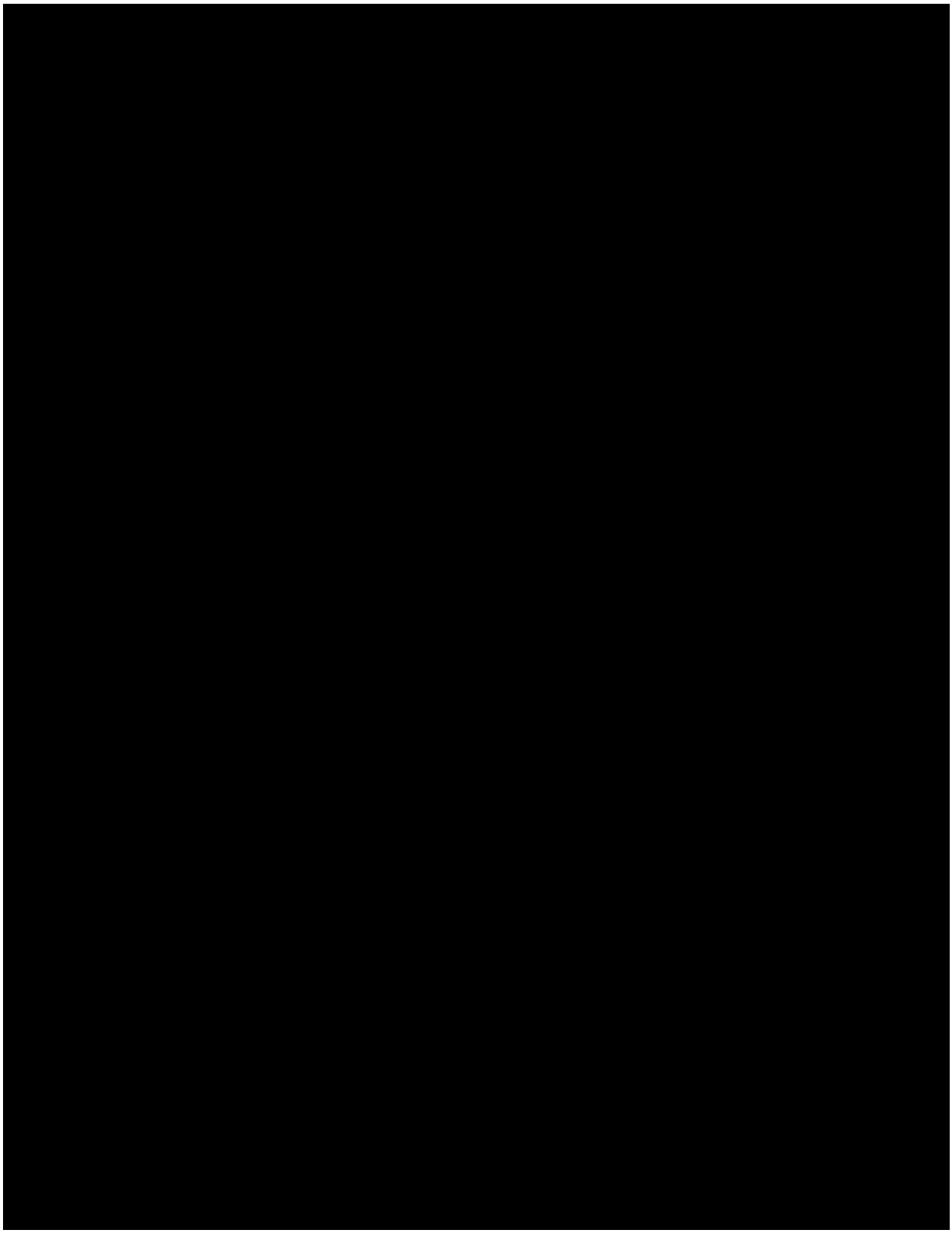


Figure 1-102 –

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[redacted]

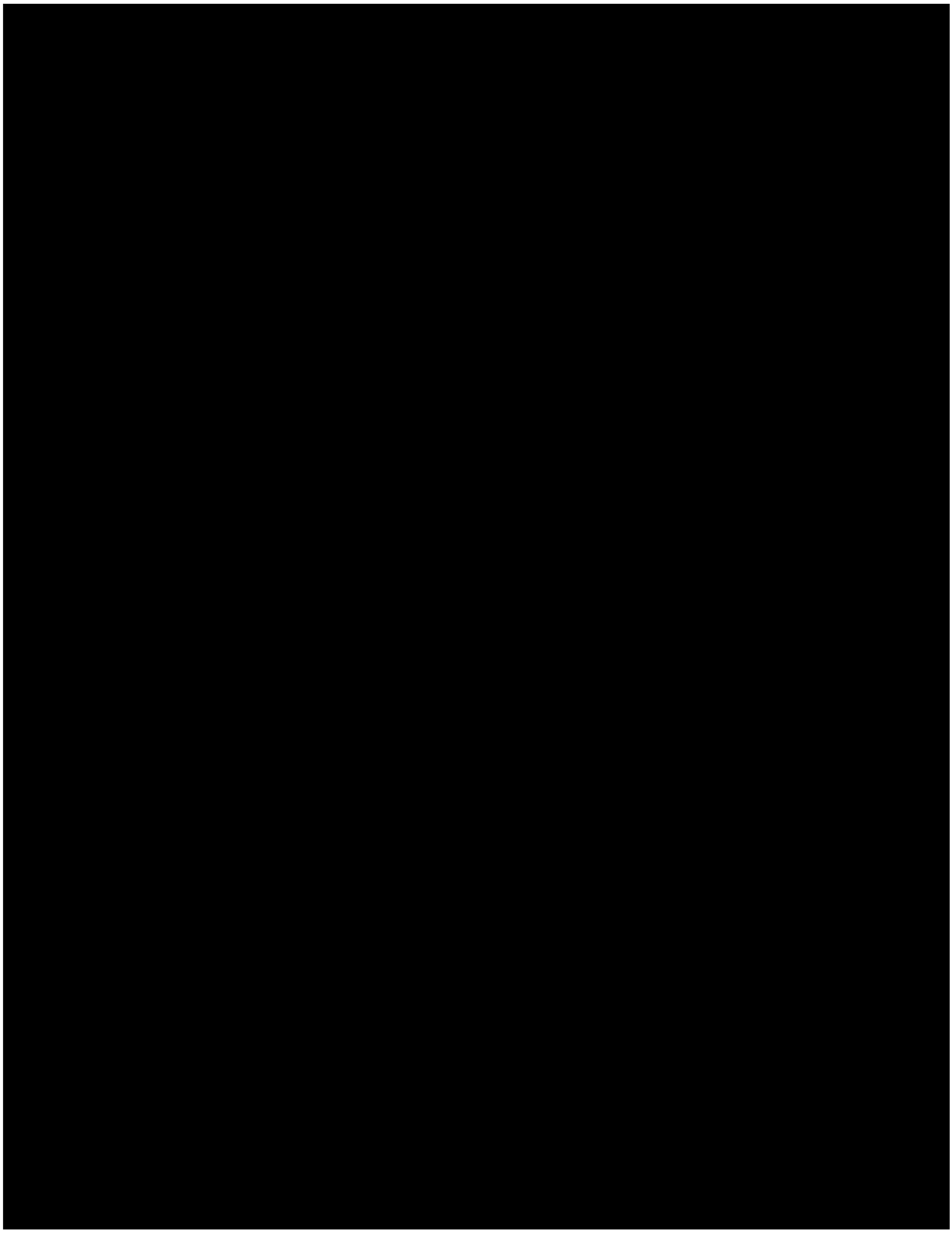

Figure 1-103 – [redacted]

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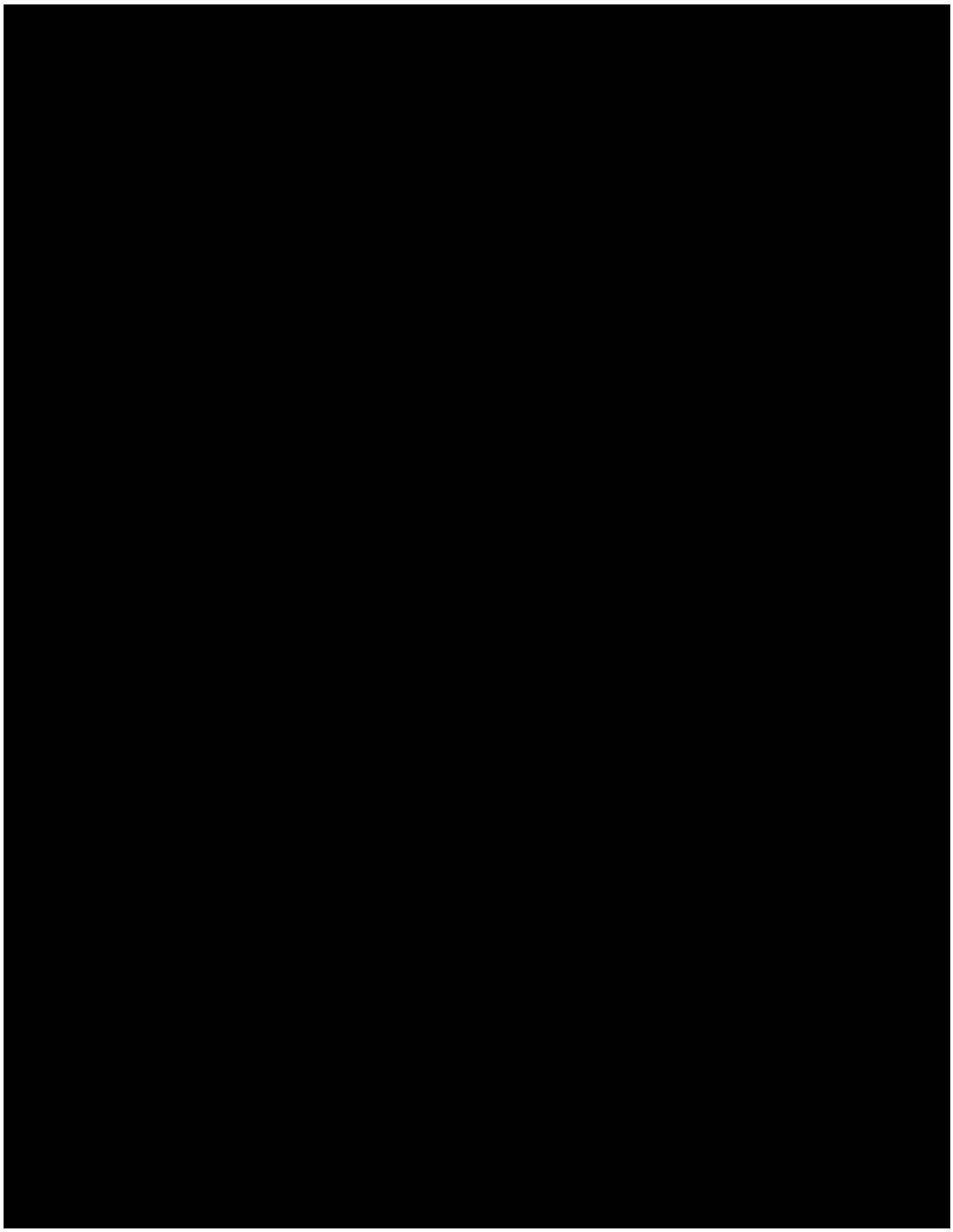

Figure 1-104 – [redacted]

1.9.3.3 [redacted]

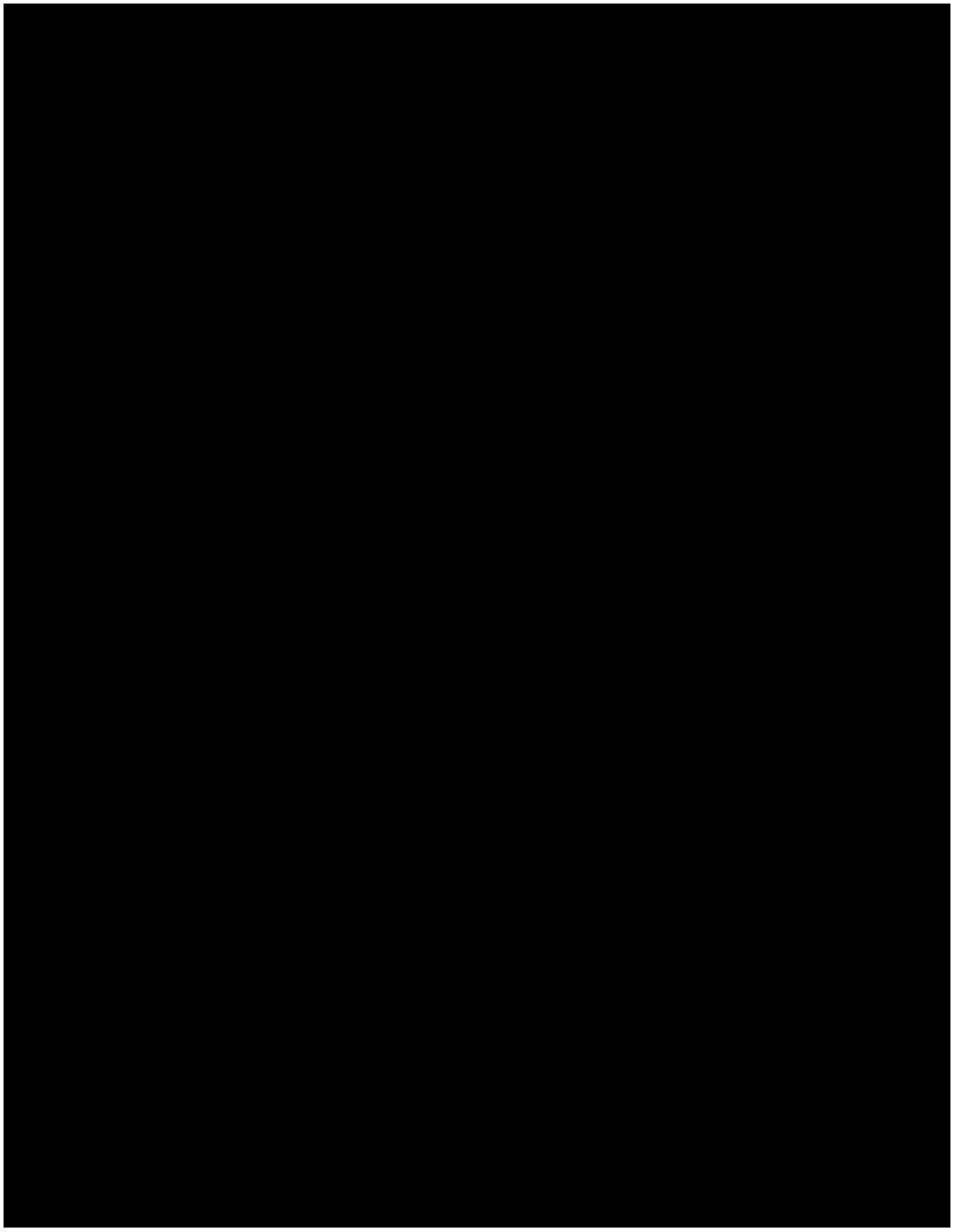

Figure 1-105 – [redacted]

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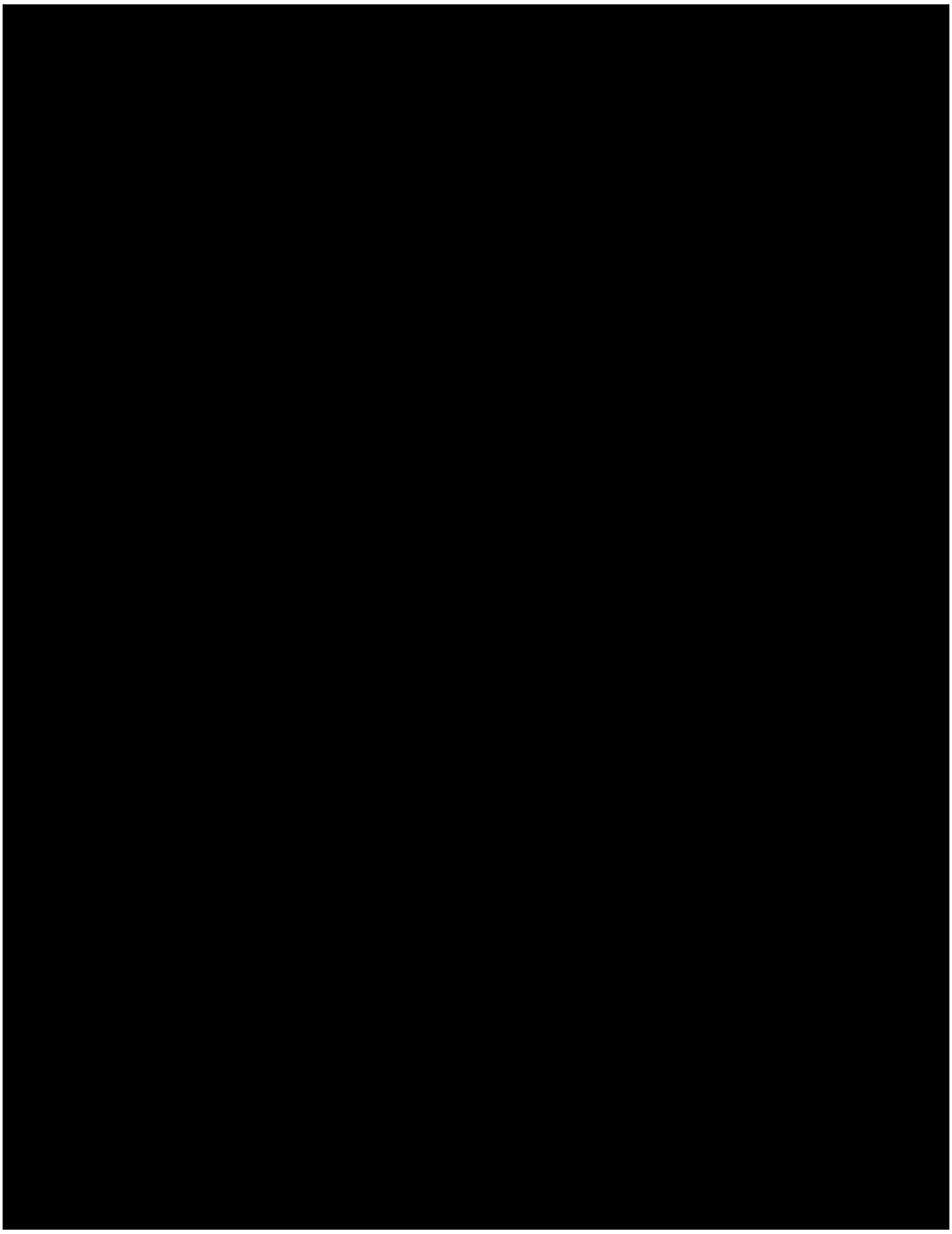

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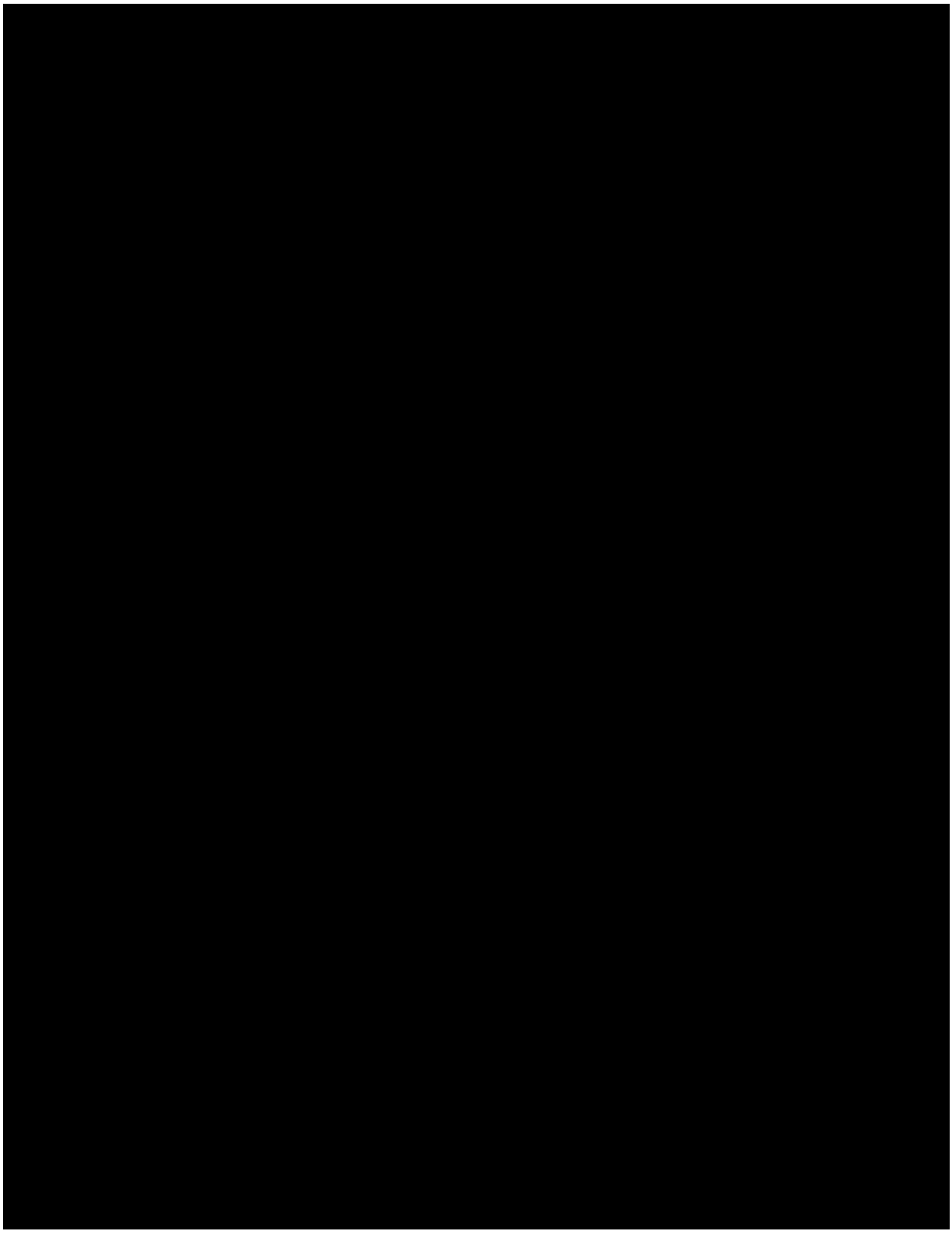

Figure 1-107 – [redacted]

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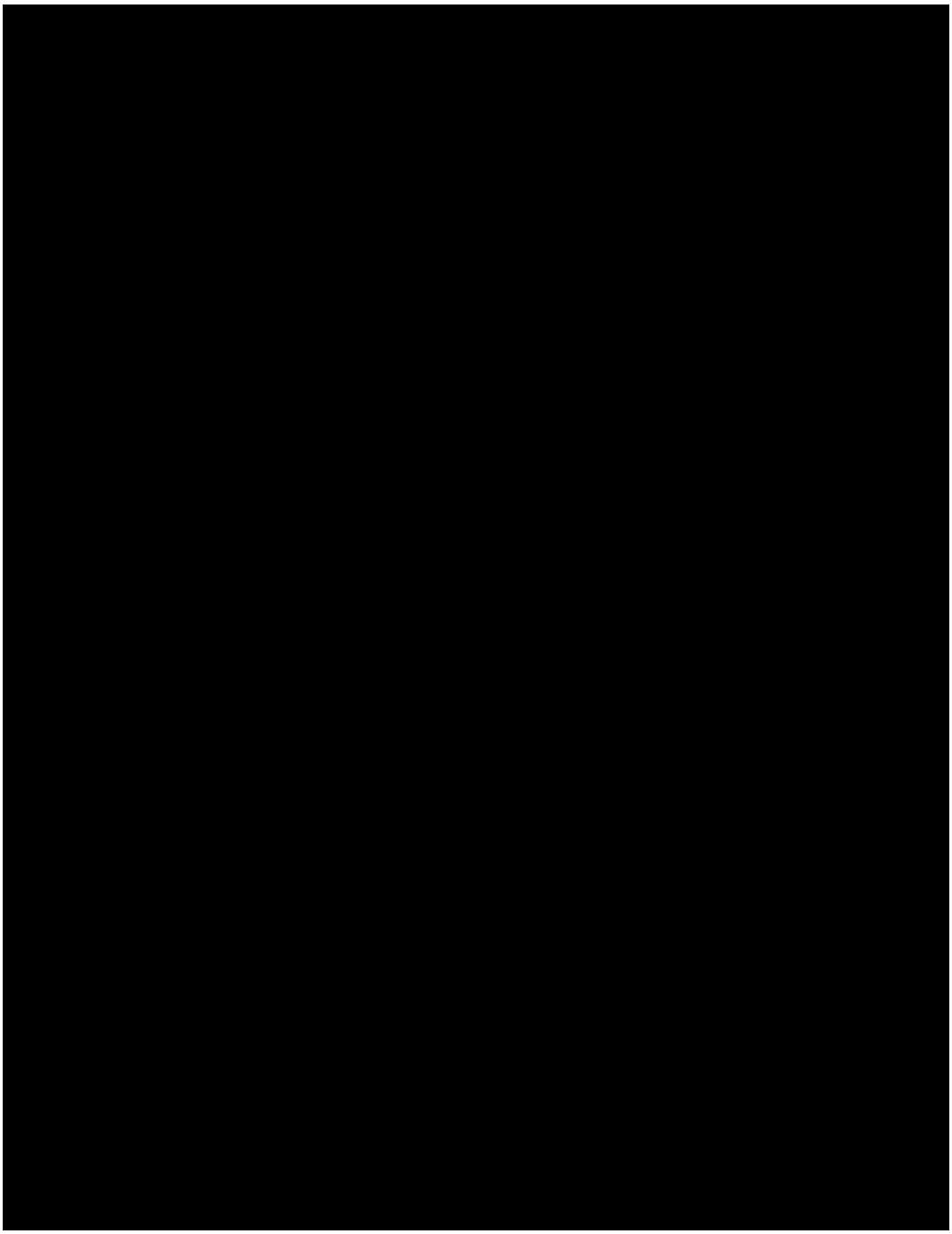

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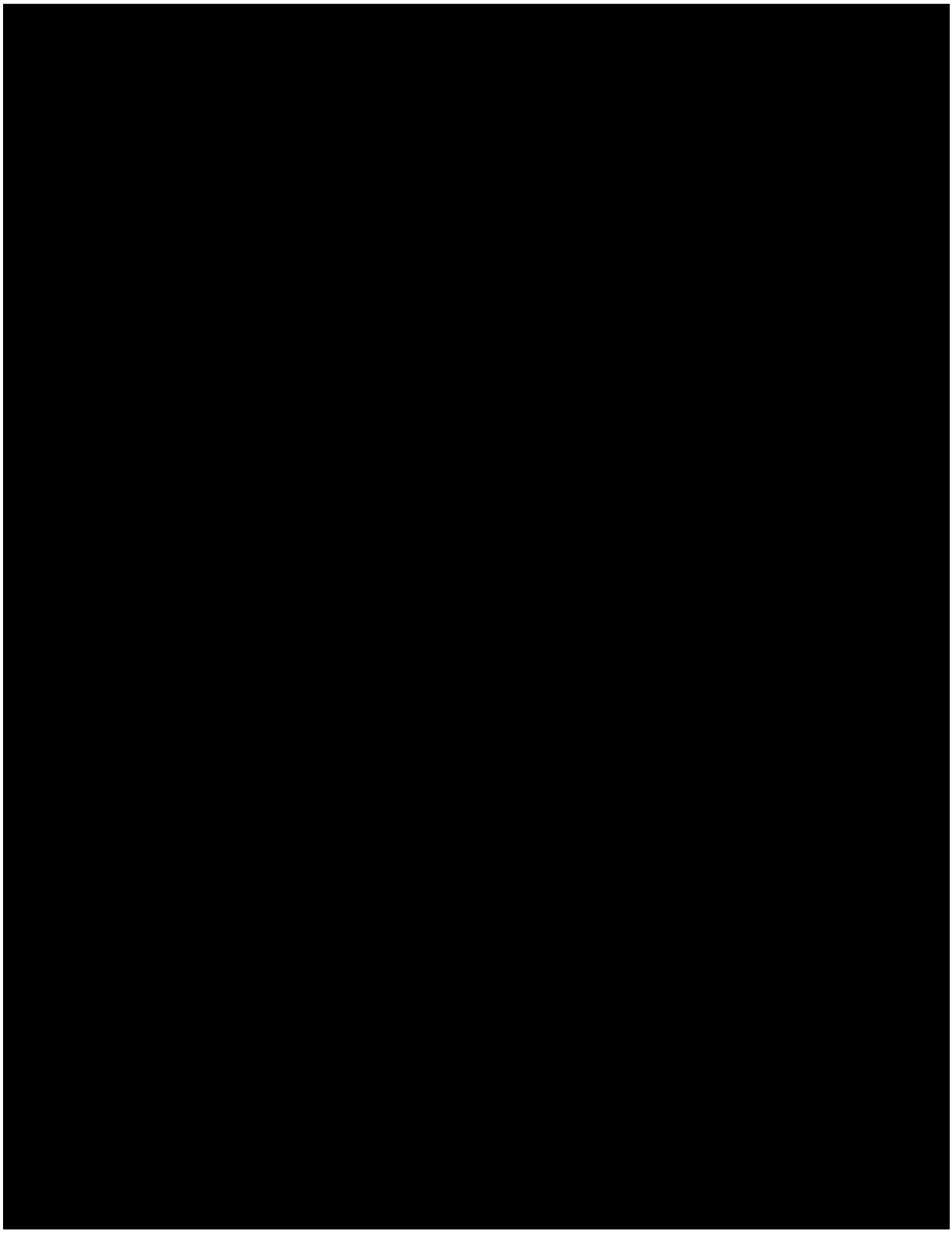

Figure 1-109 – [redacted]

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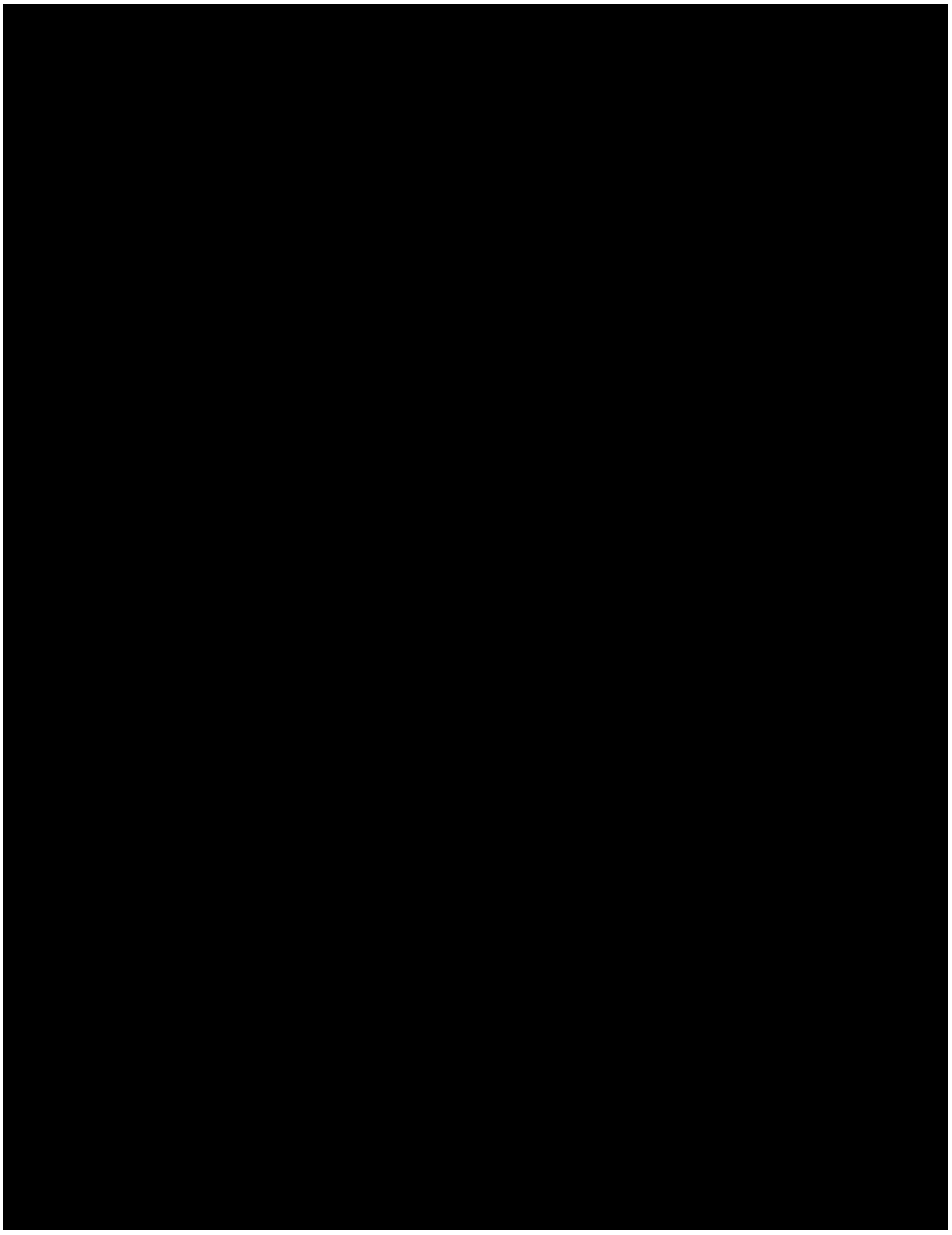

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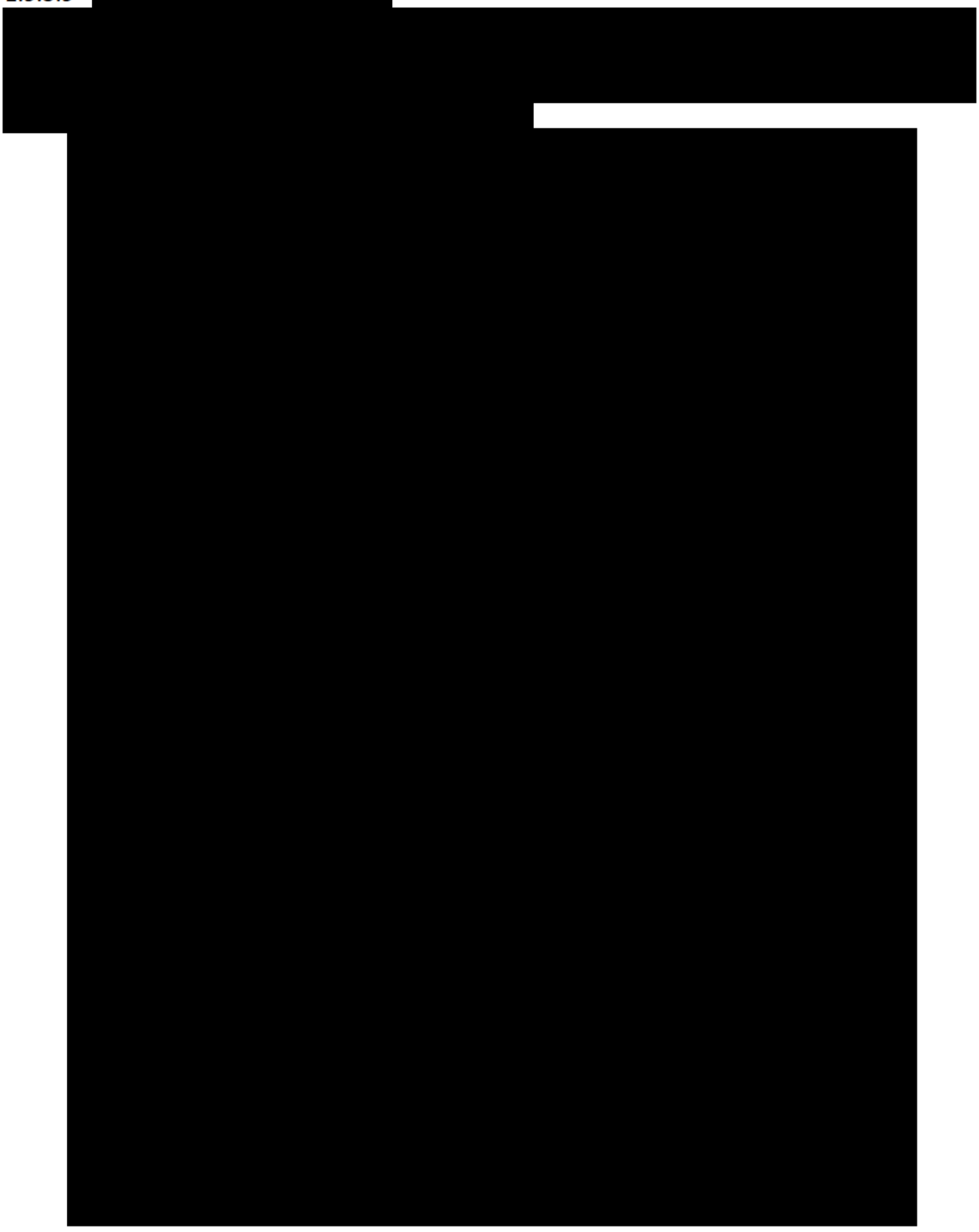

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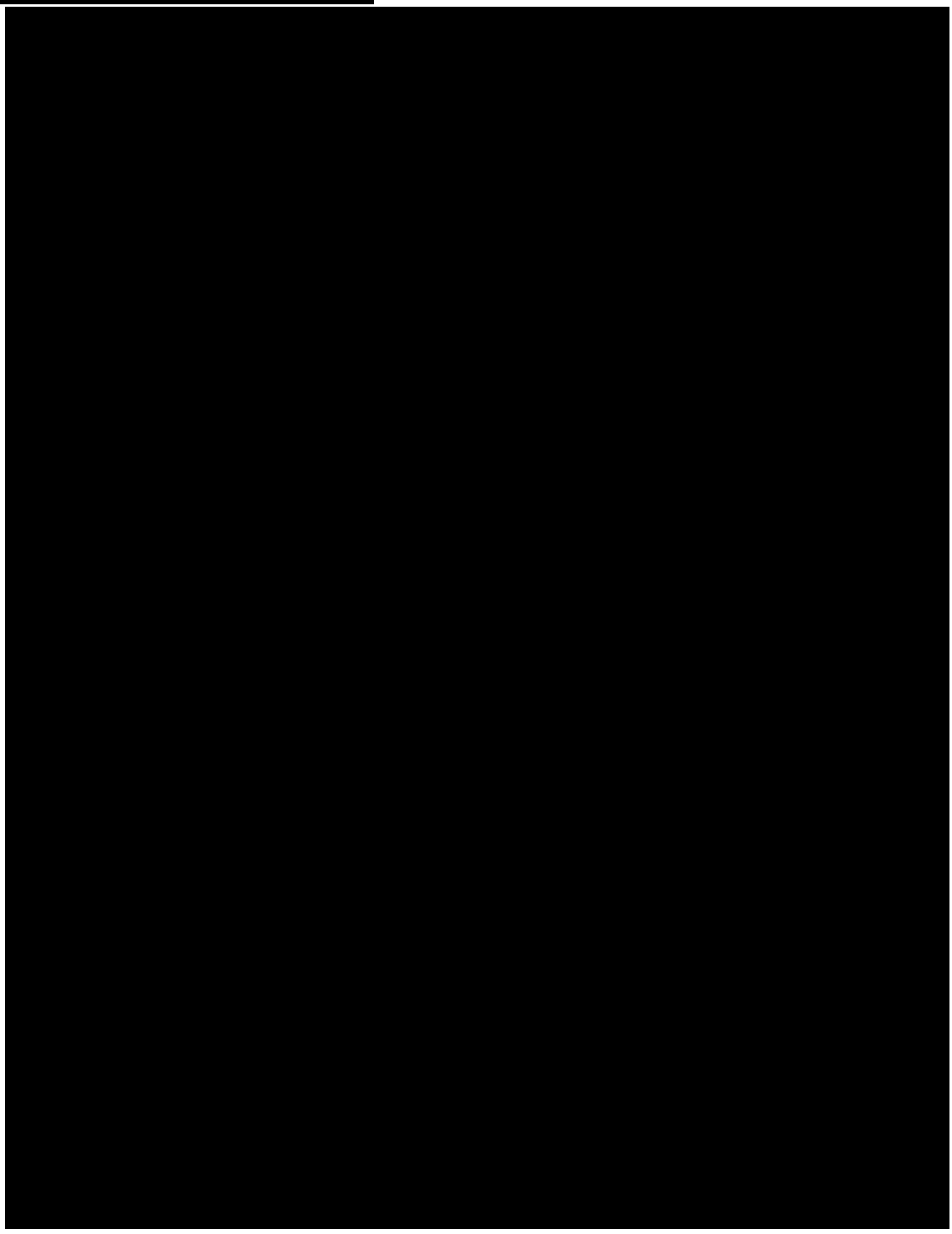

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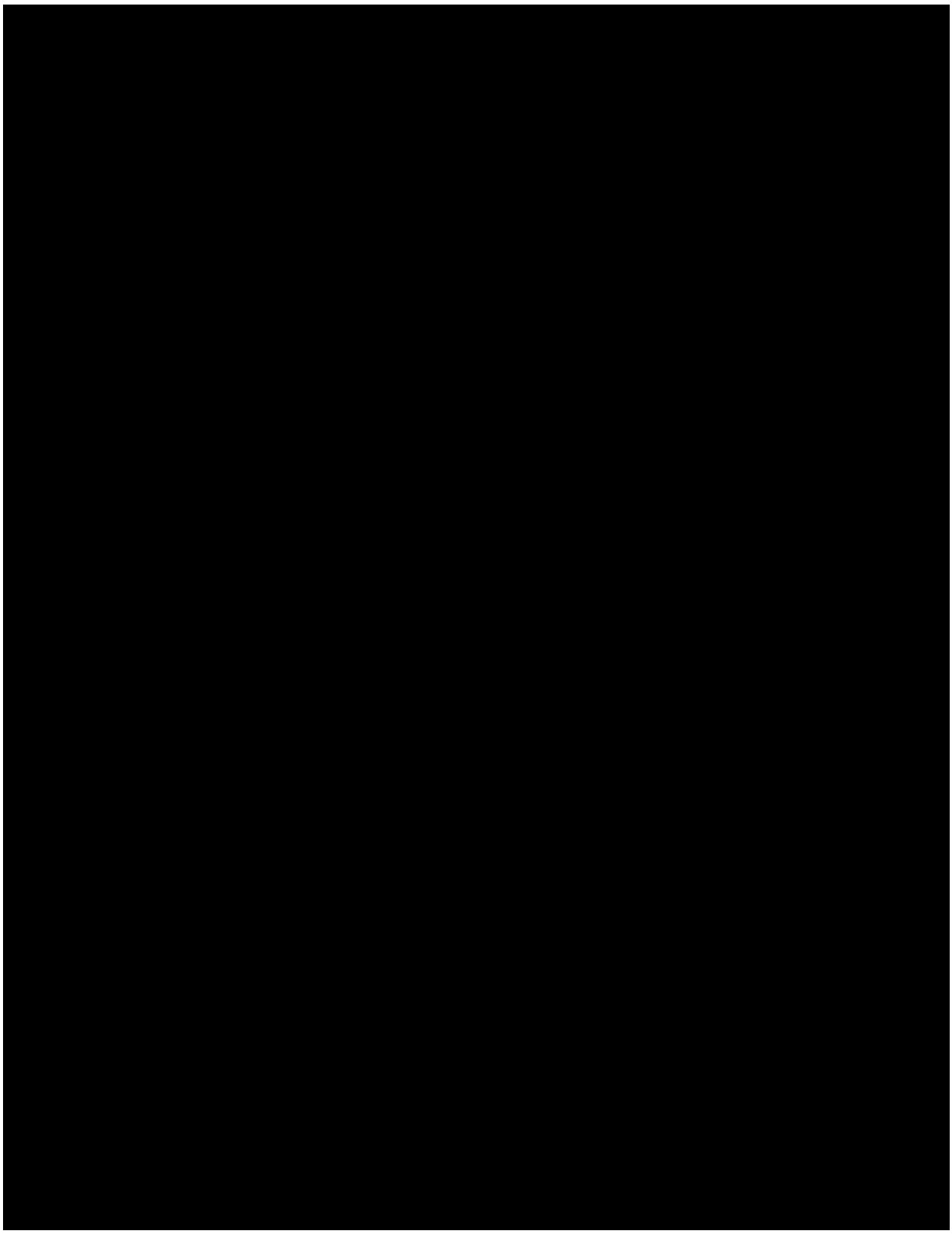

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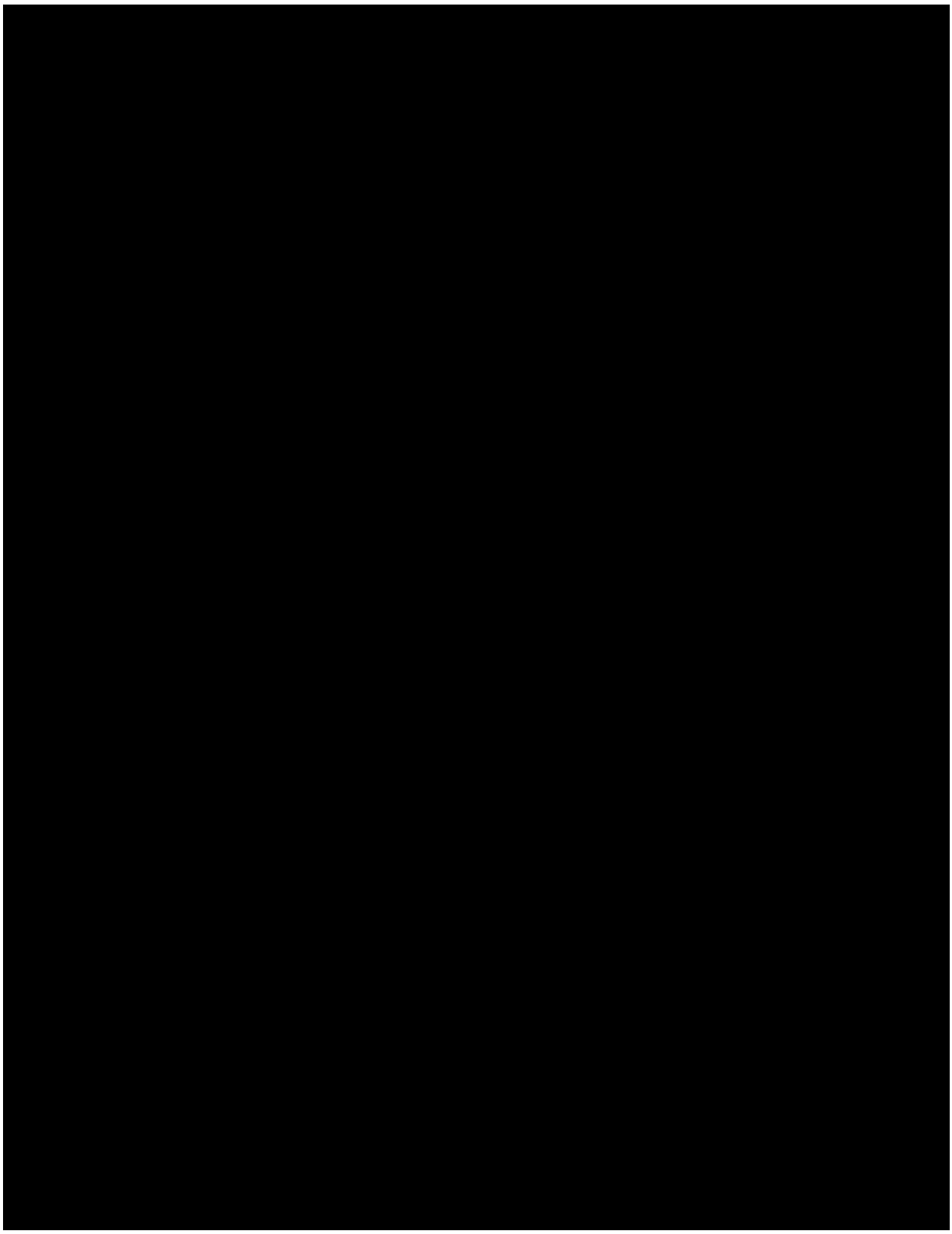

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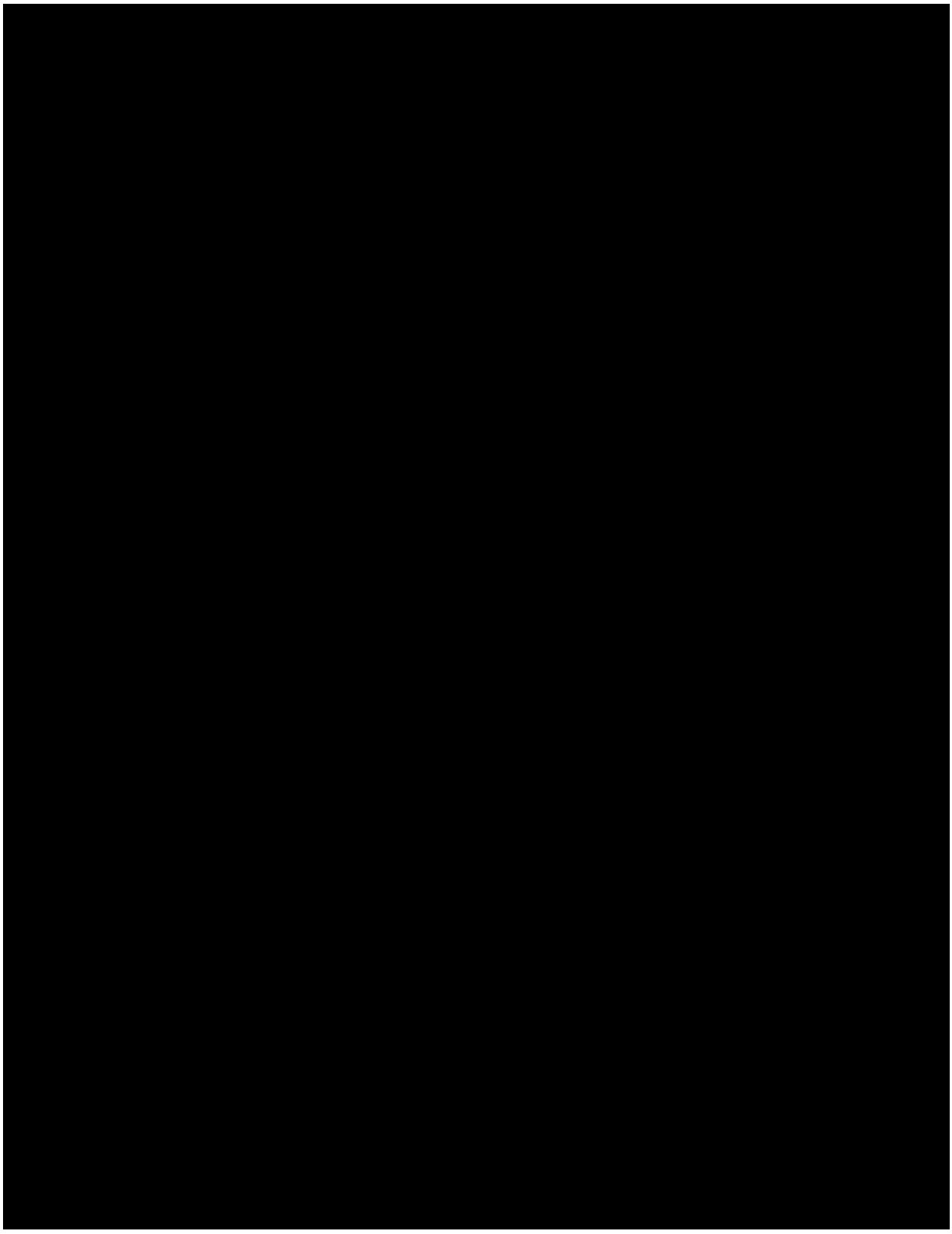

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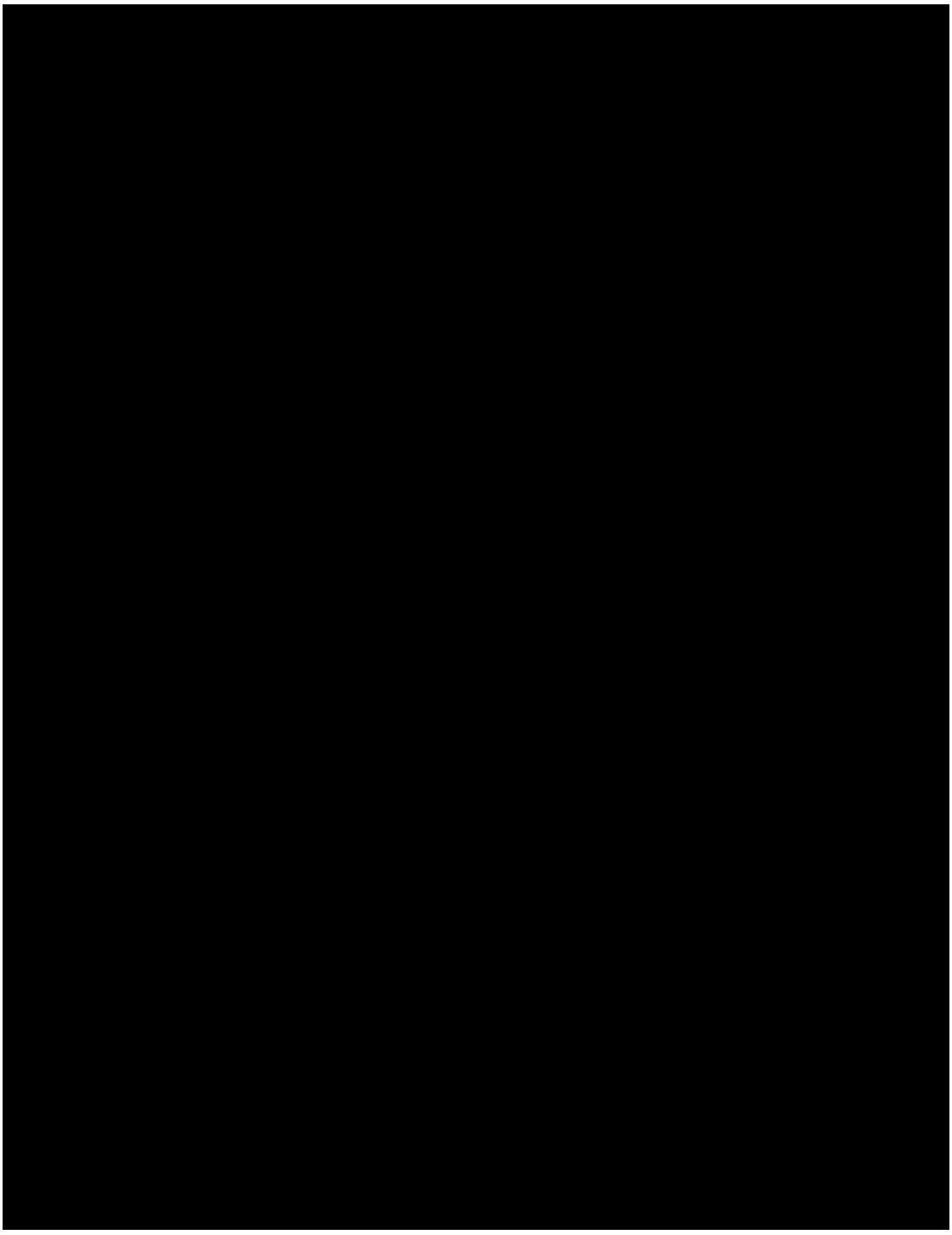

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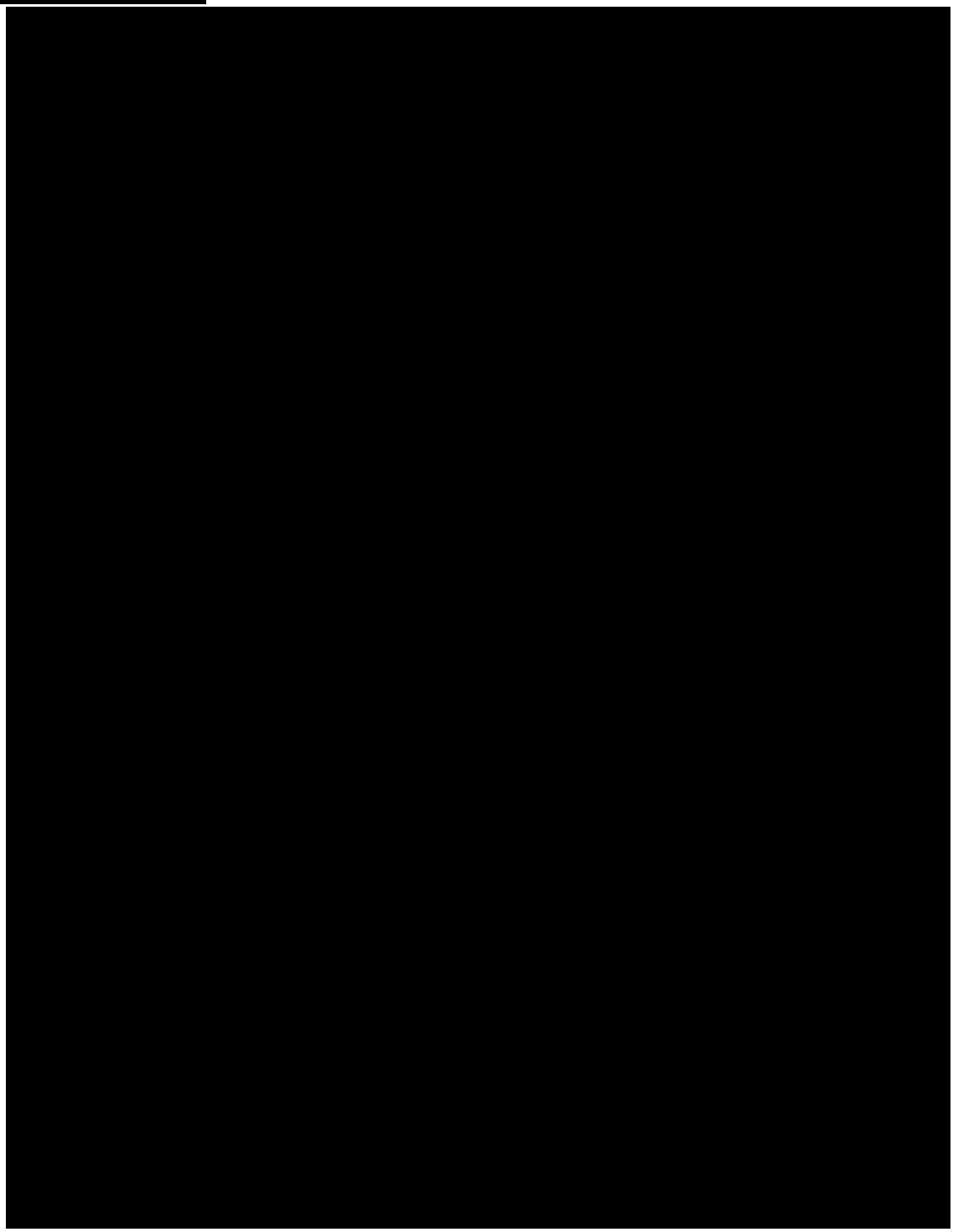

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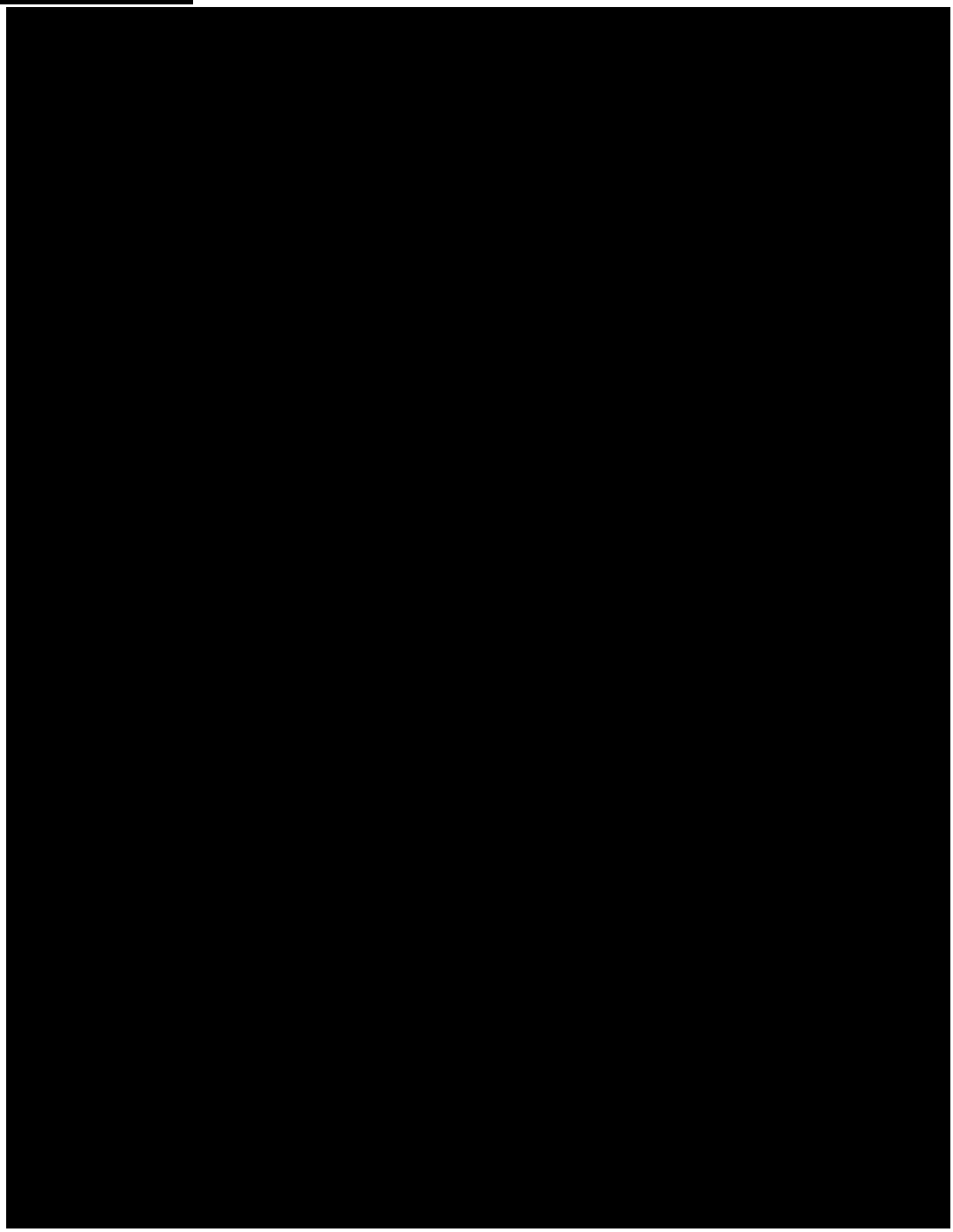

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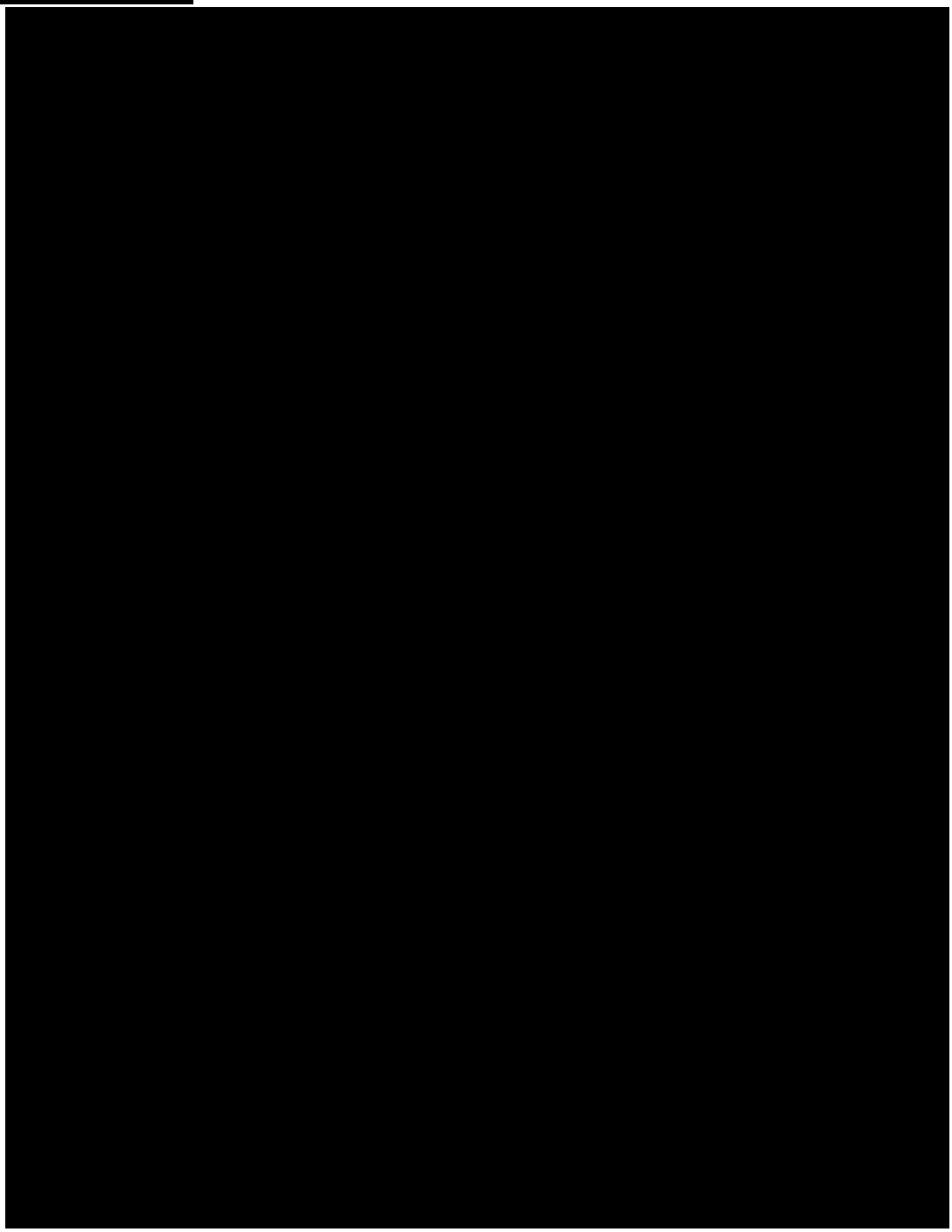

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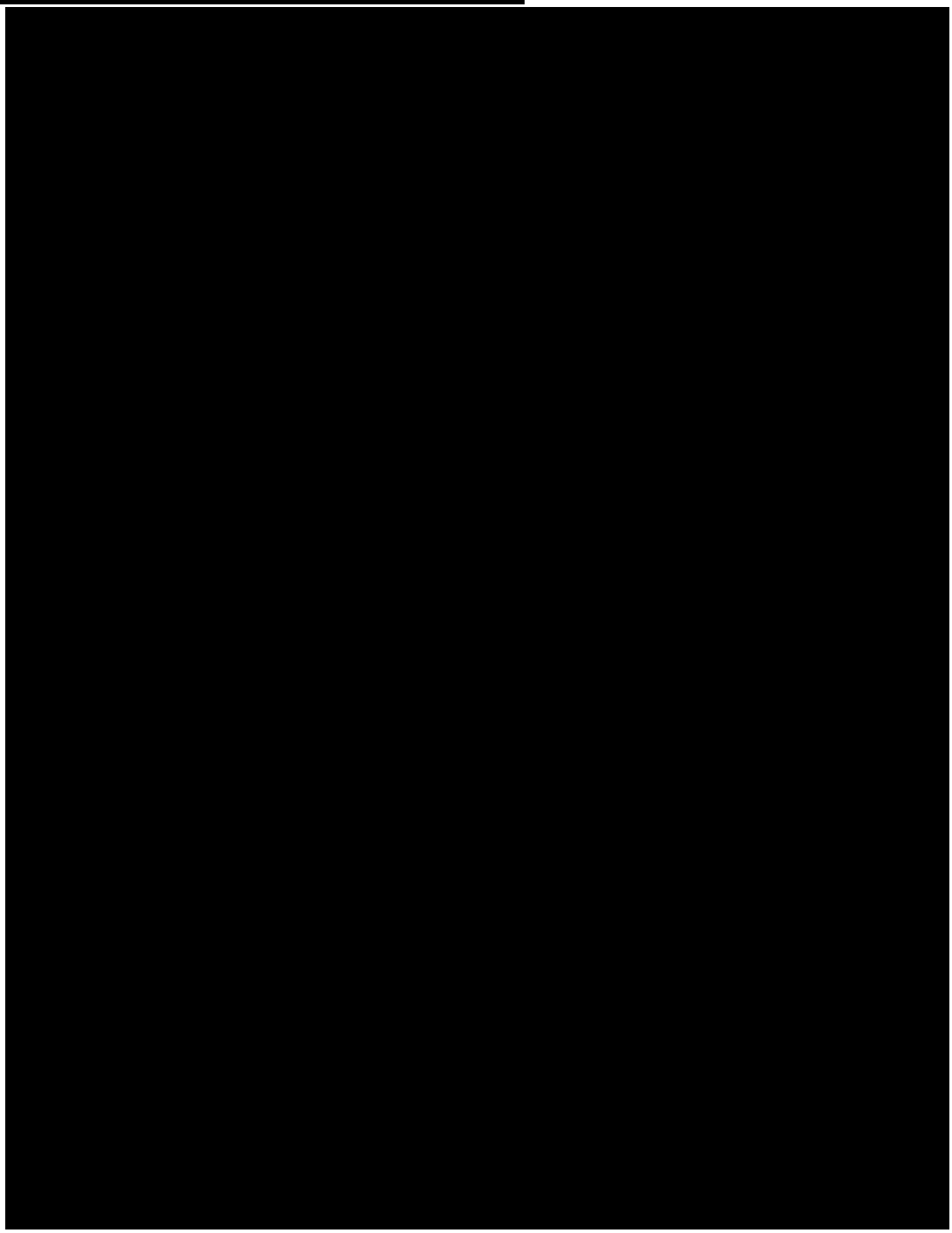

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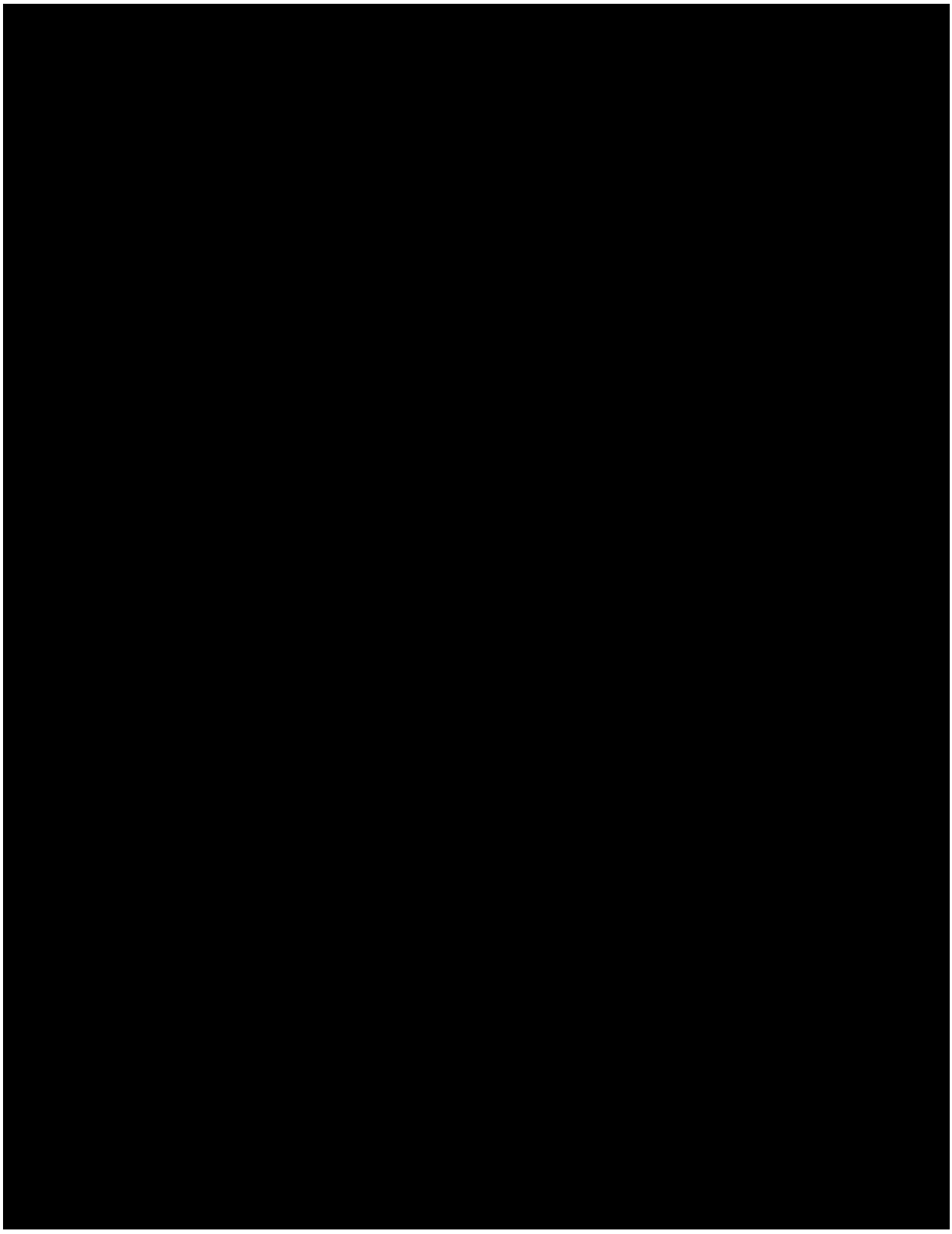

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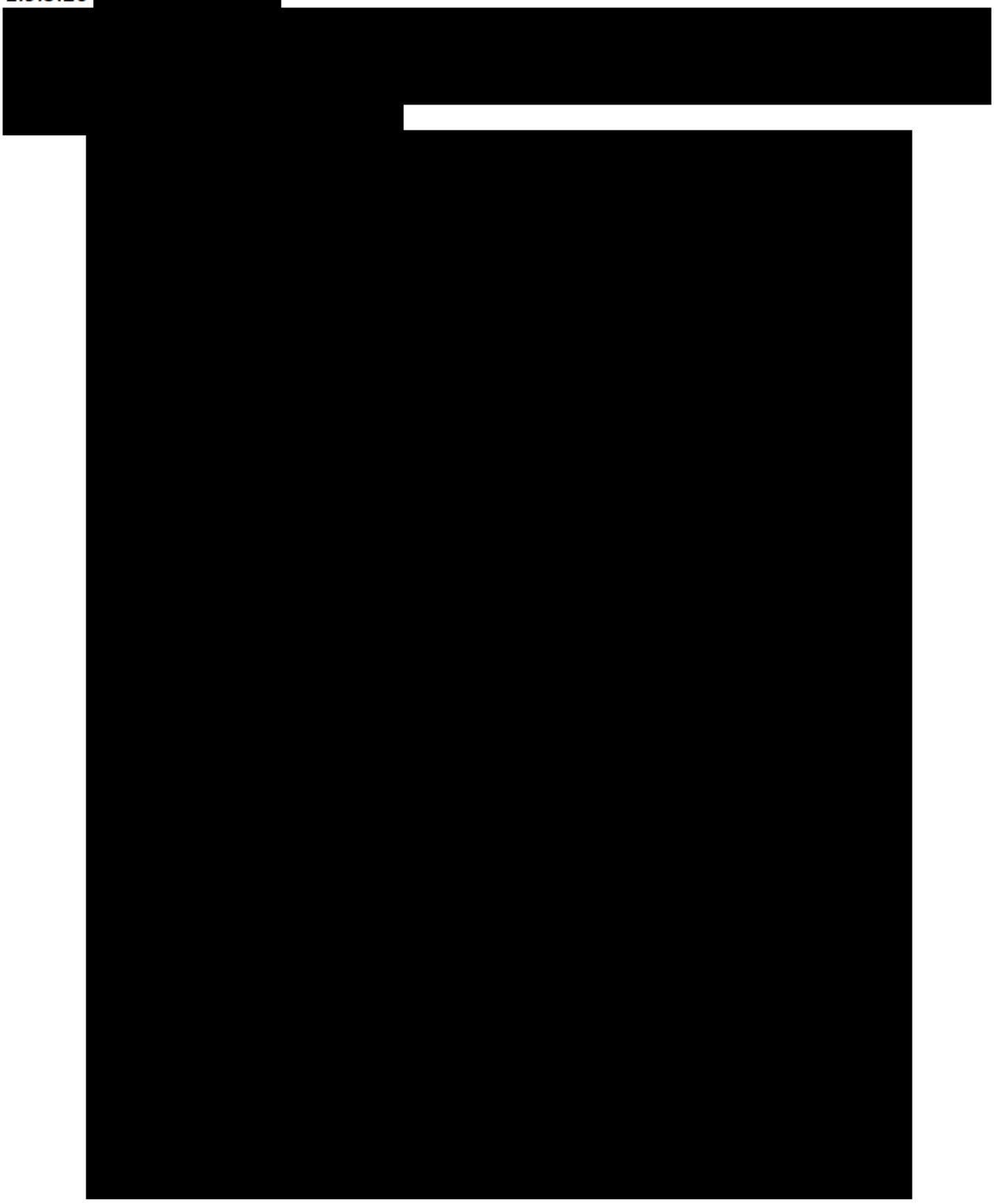

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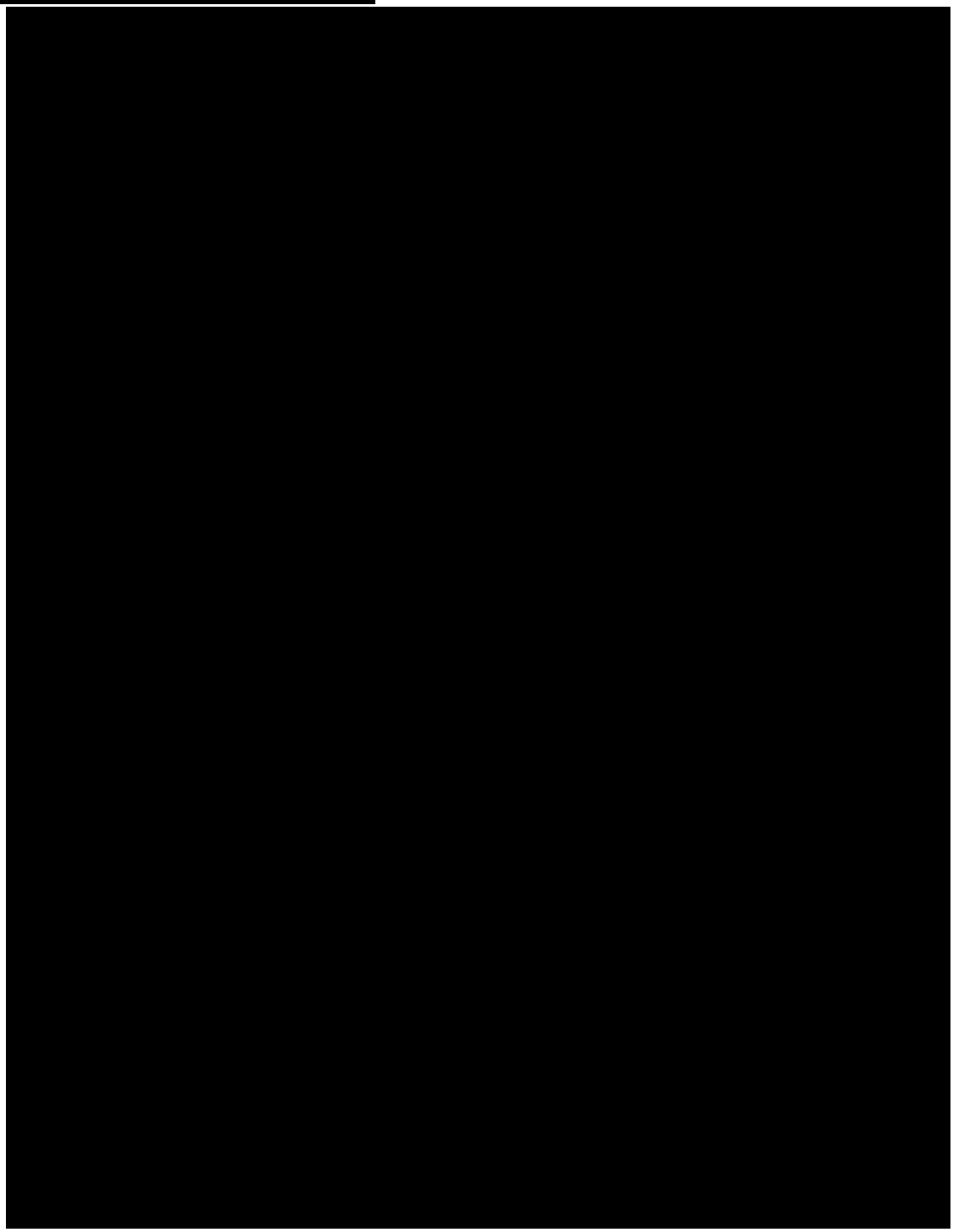

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1.9.3.23 [redacted]

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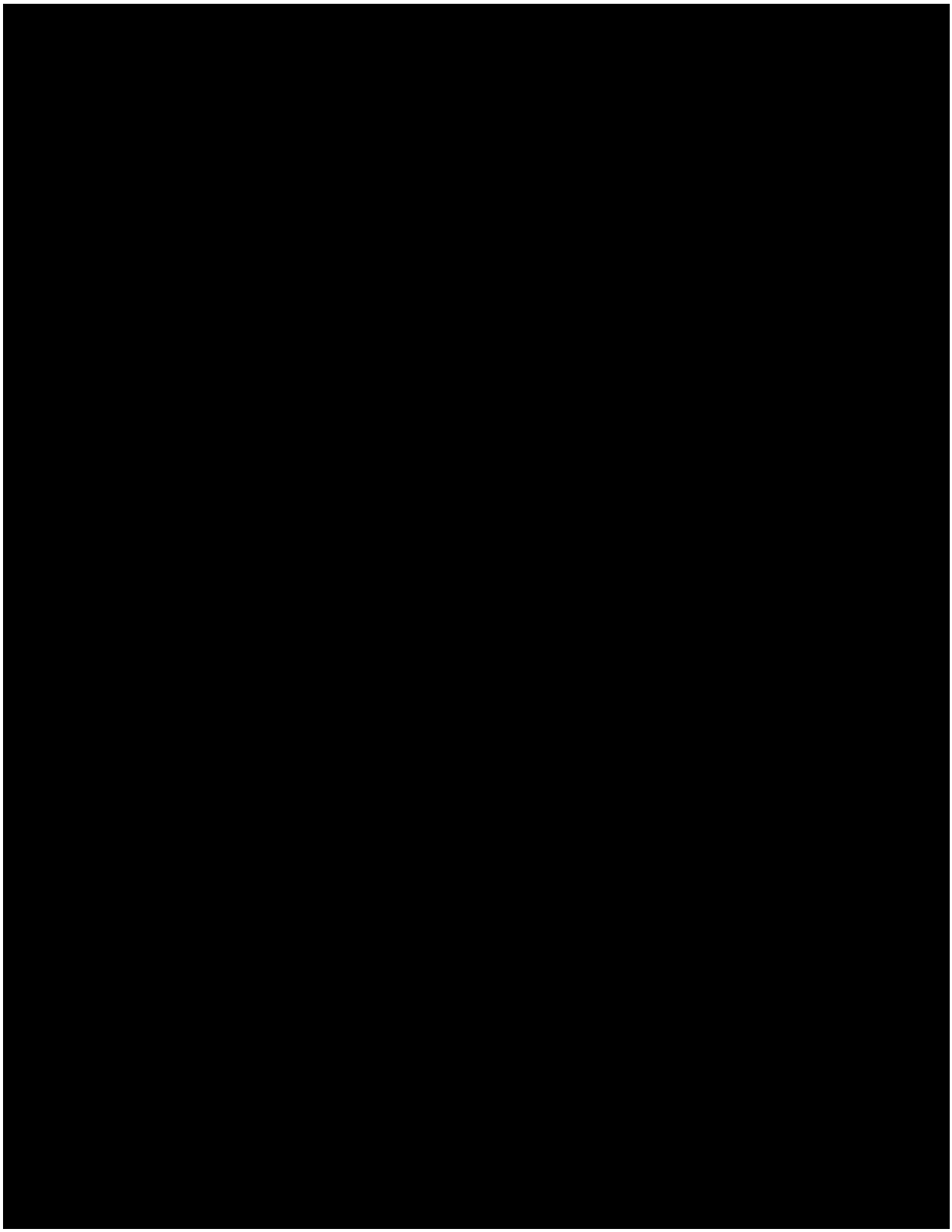

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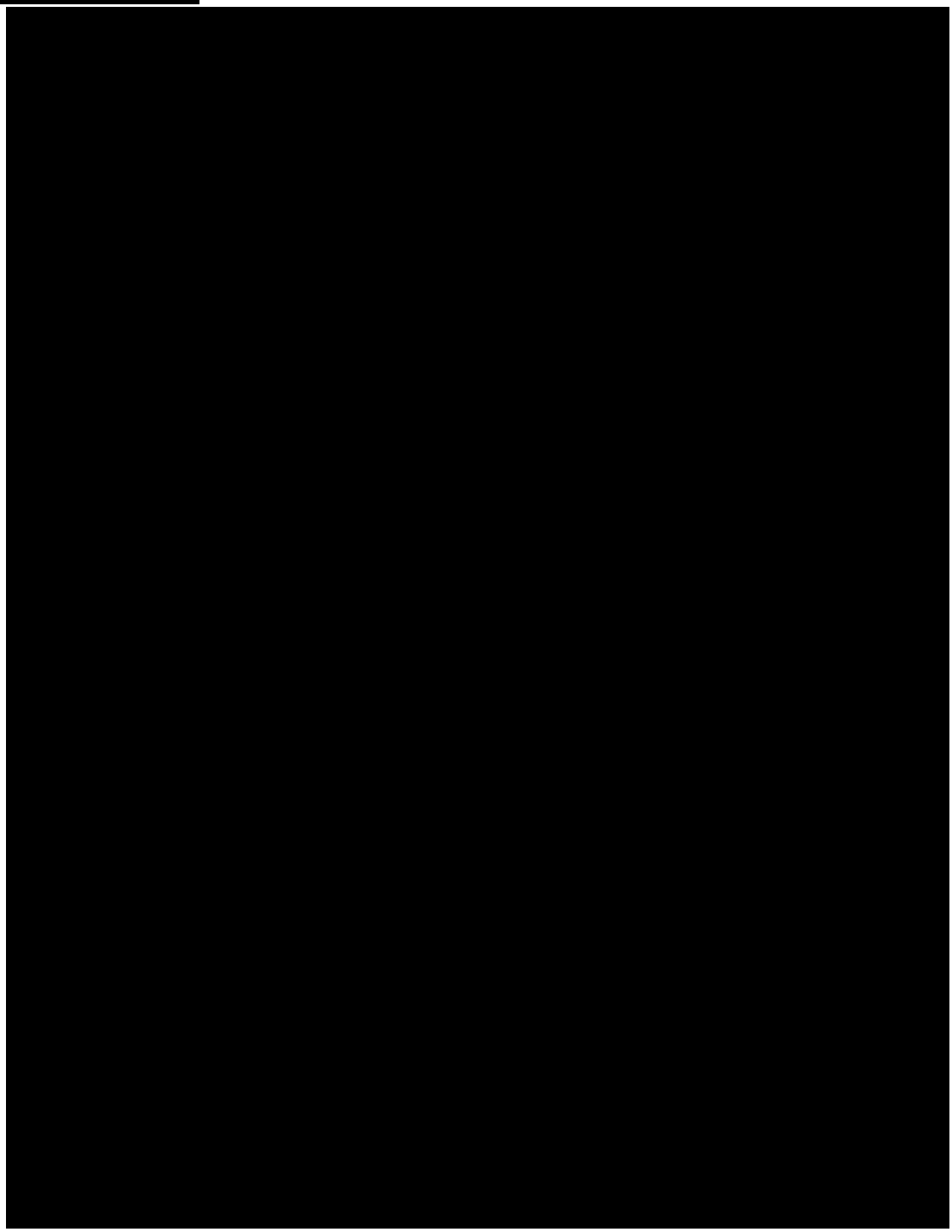

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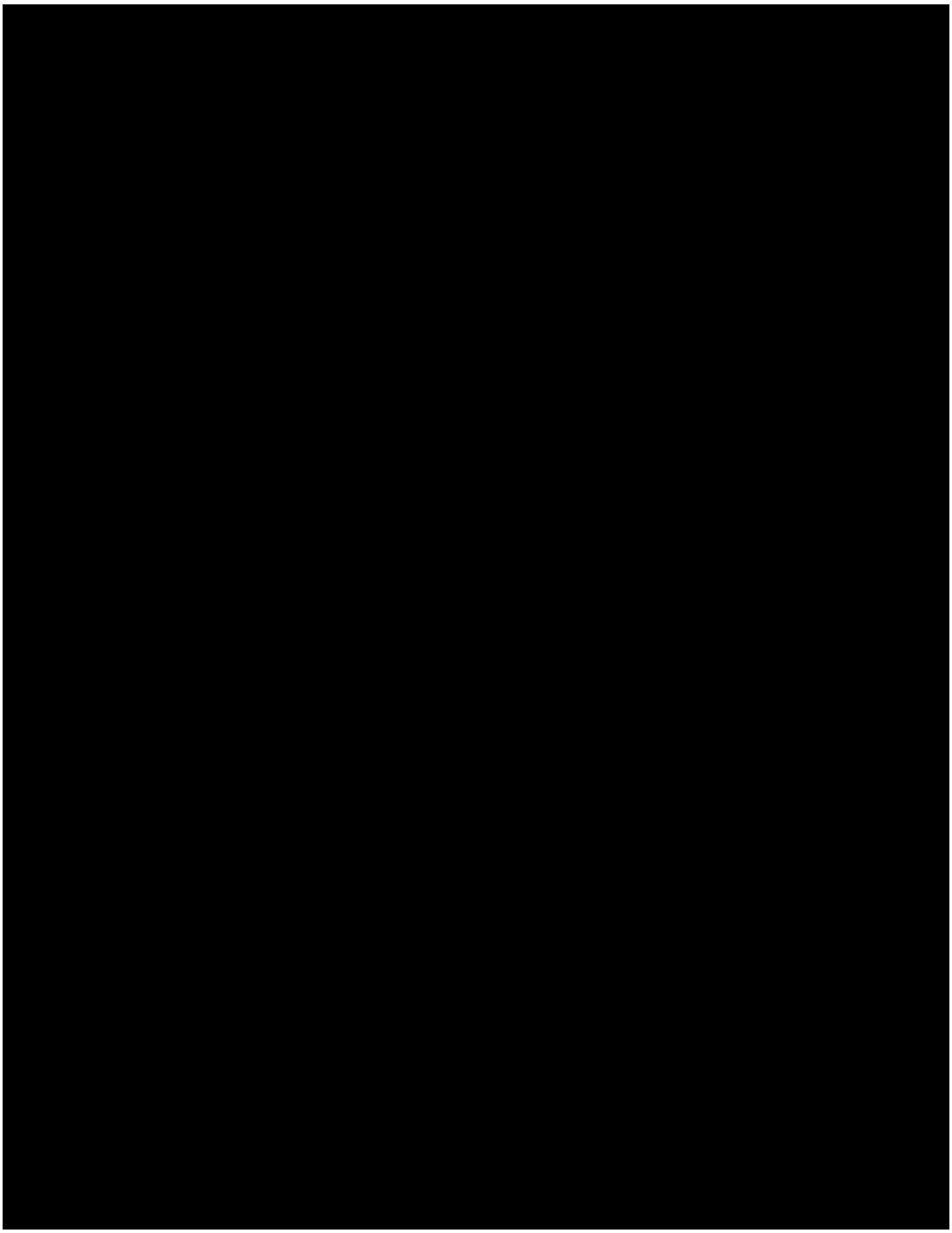

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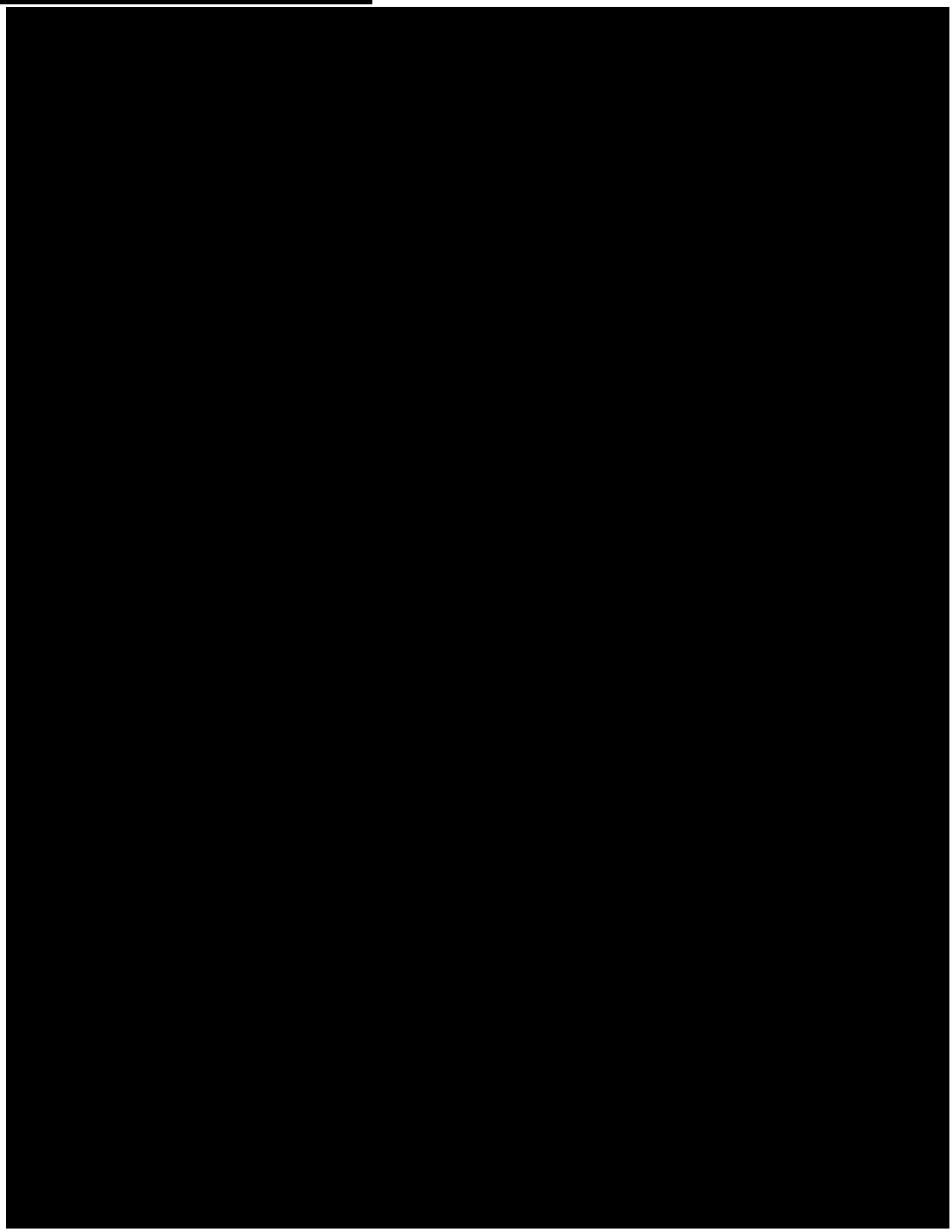
Figure 1-128 – [redacted]

1.9.3.27 [redacted]



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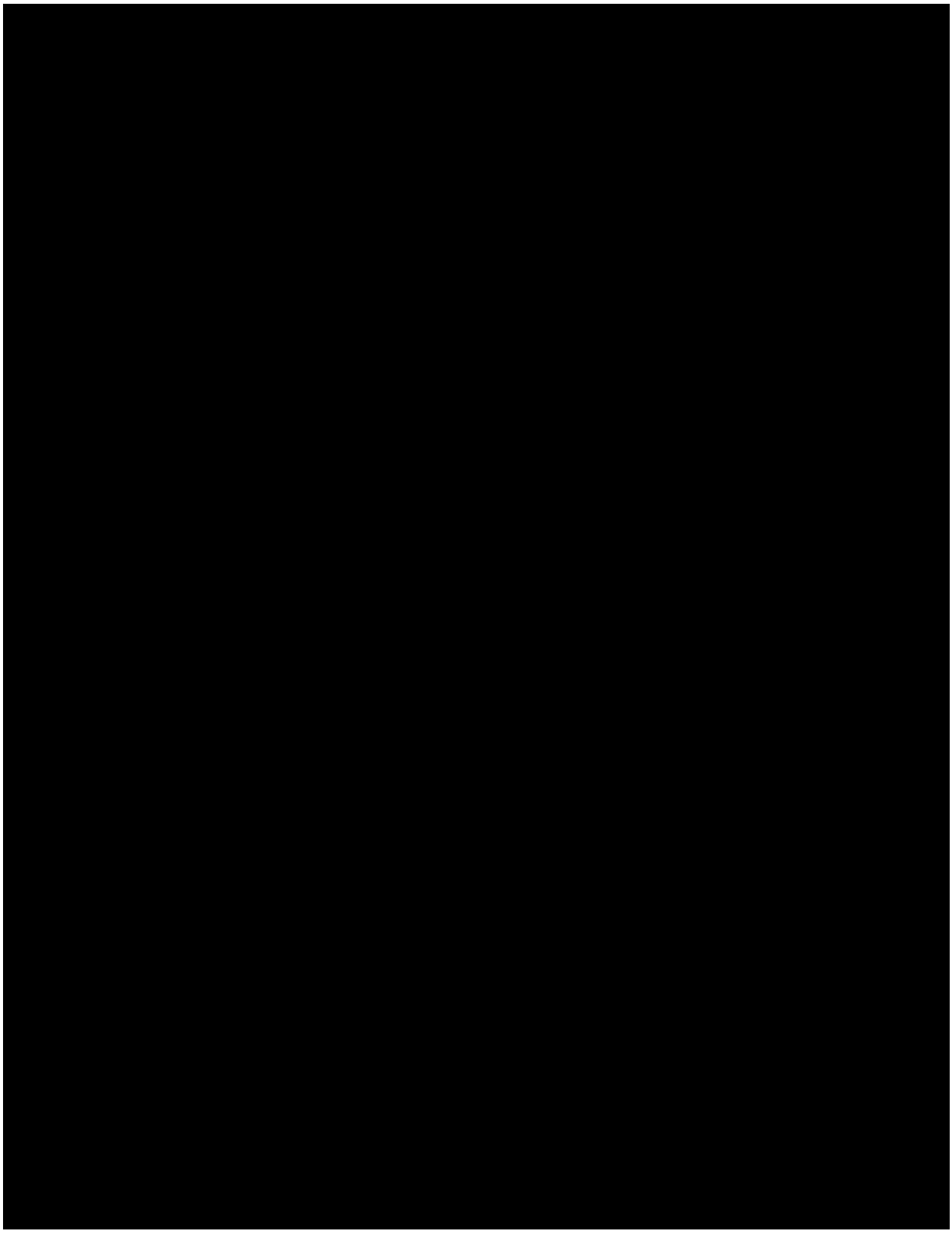

Figure 1-130 – [redacted]

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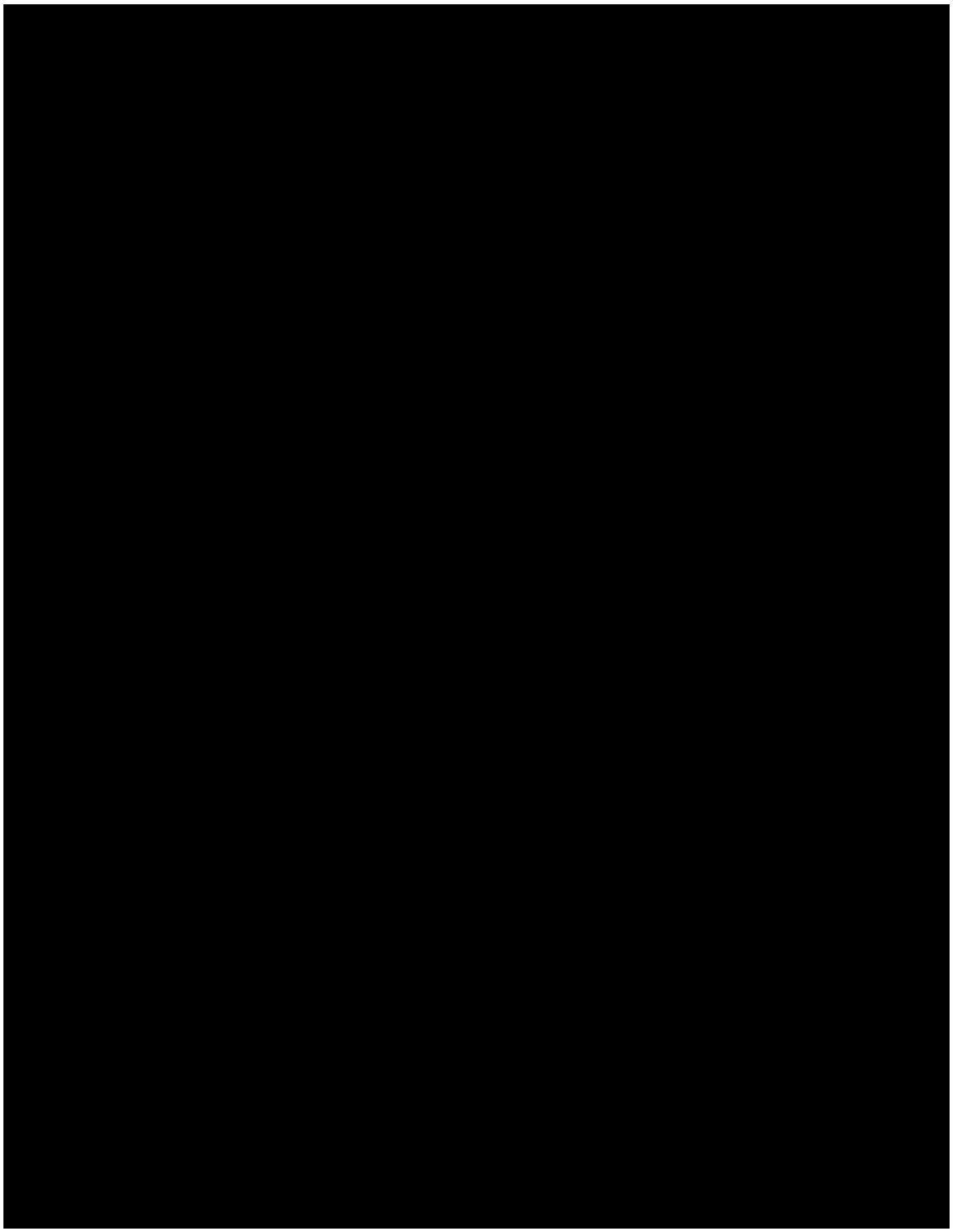

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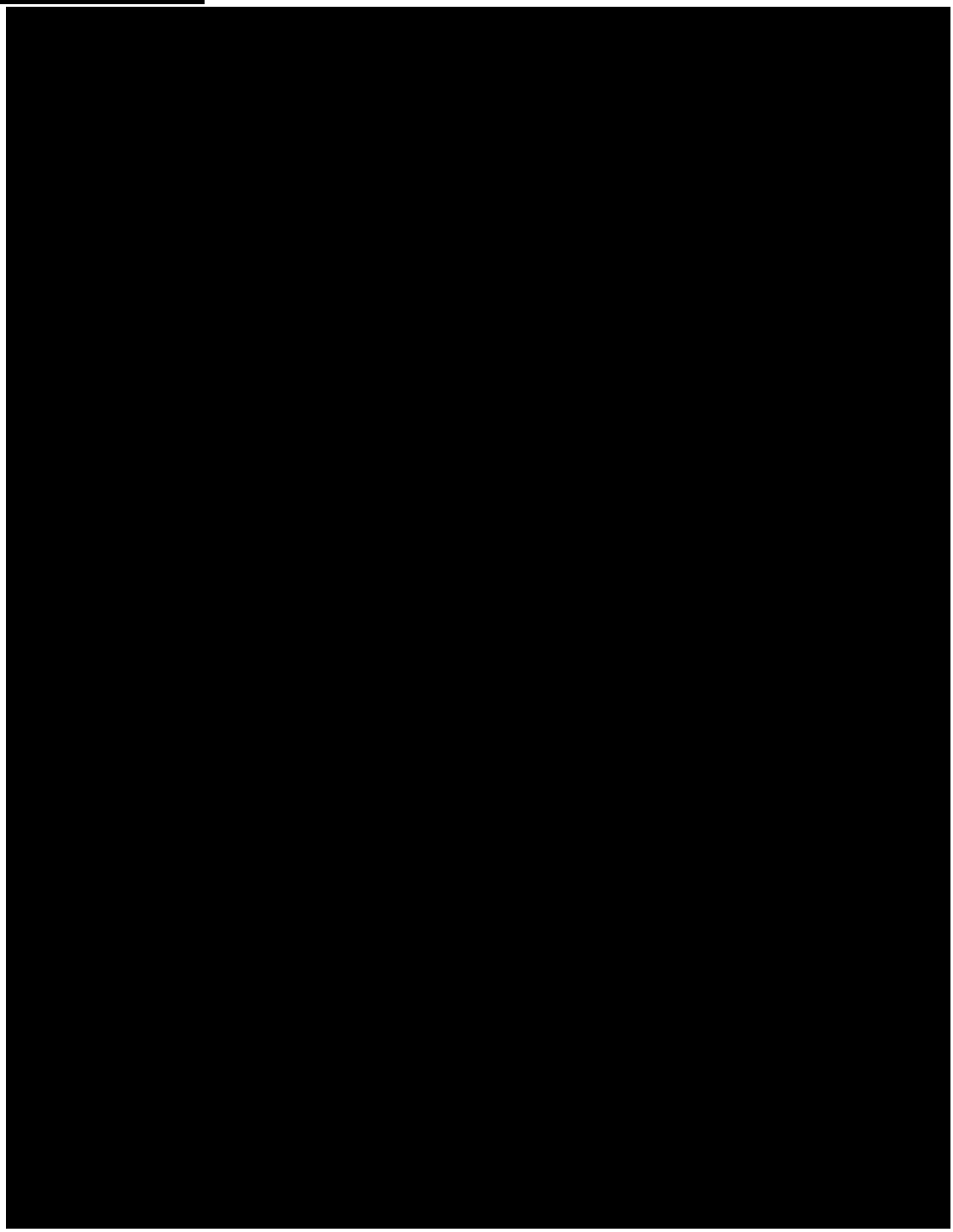

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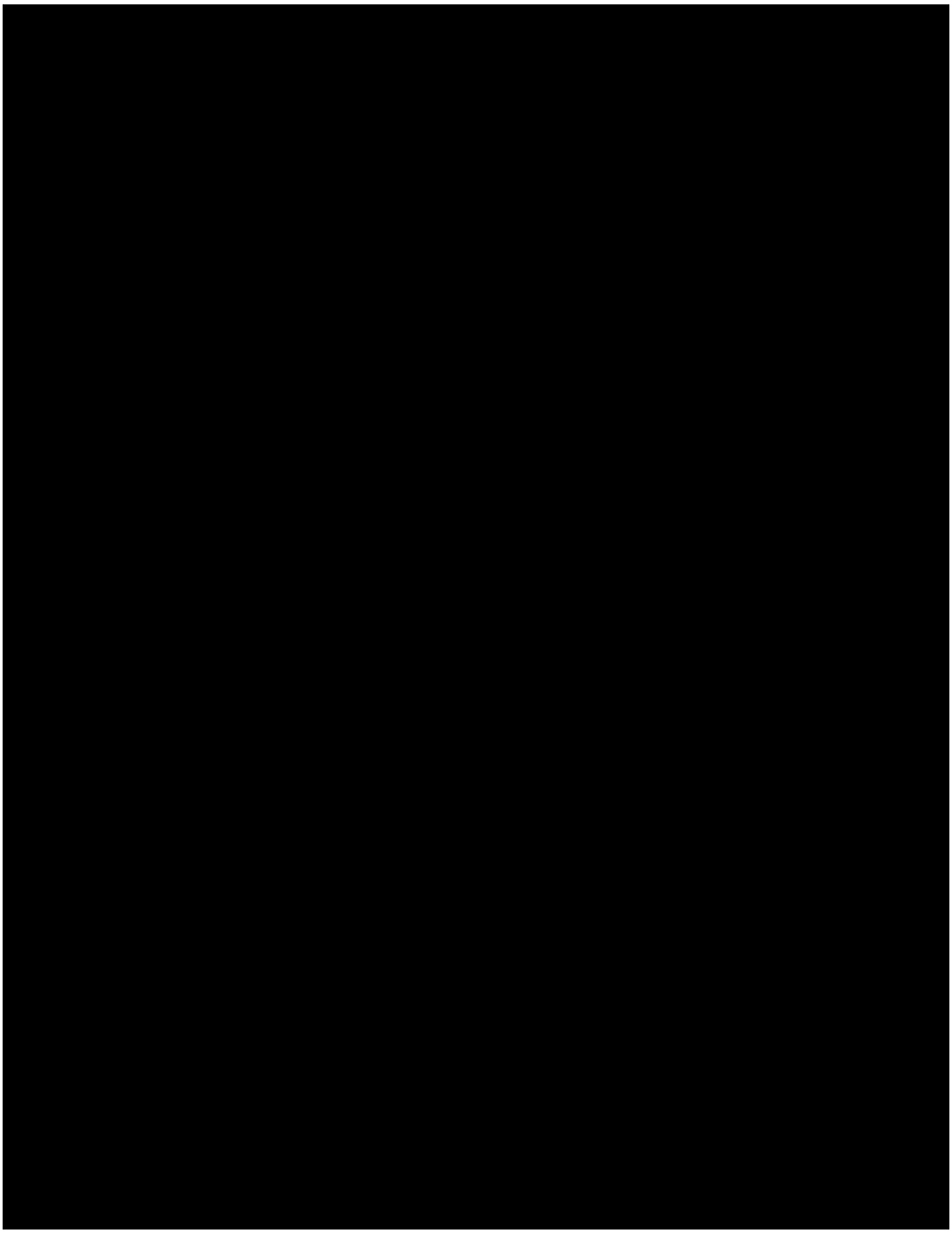

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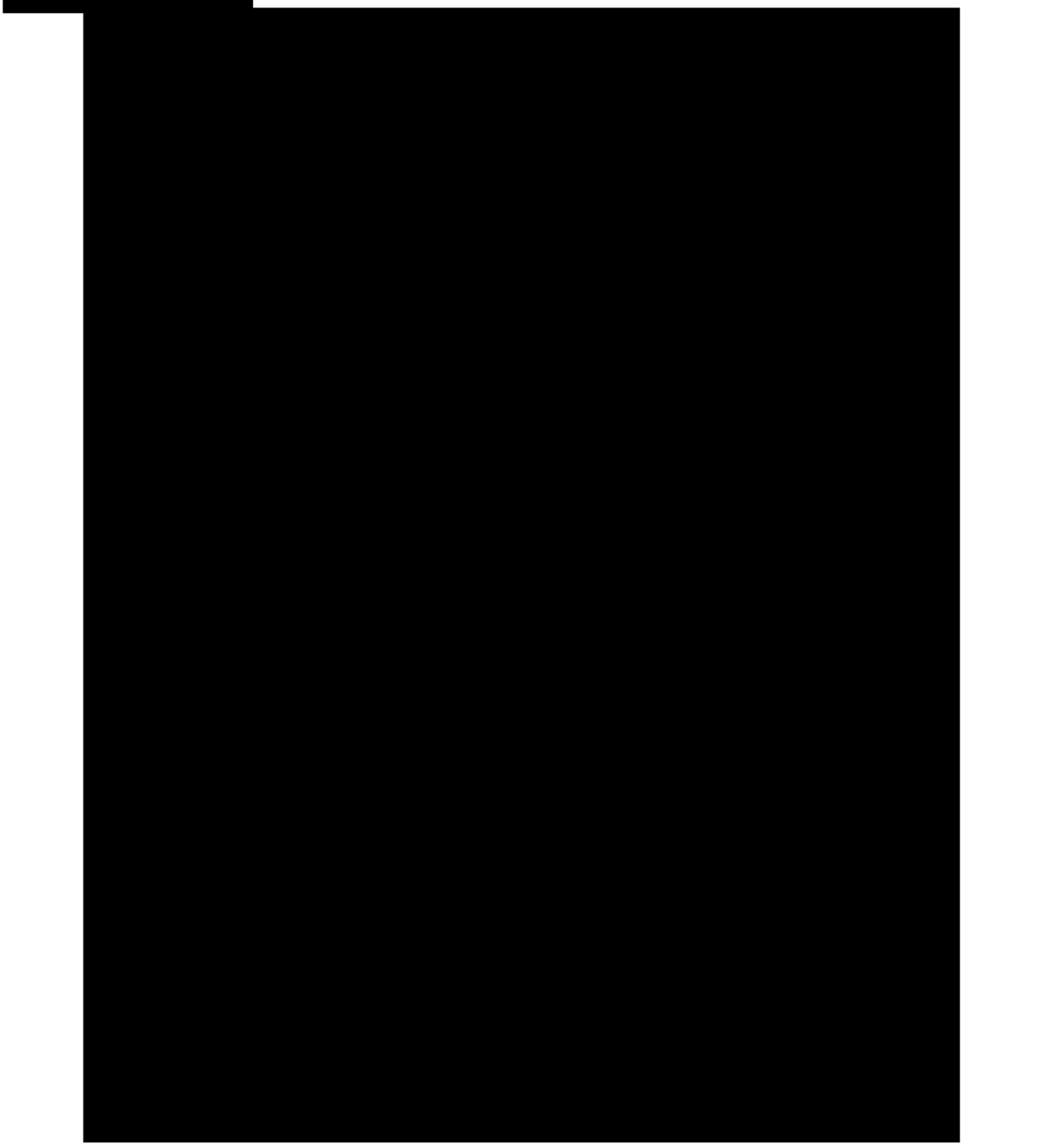

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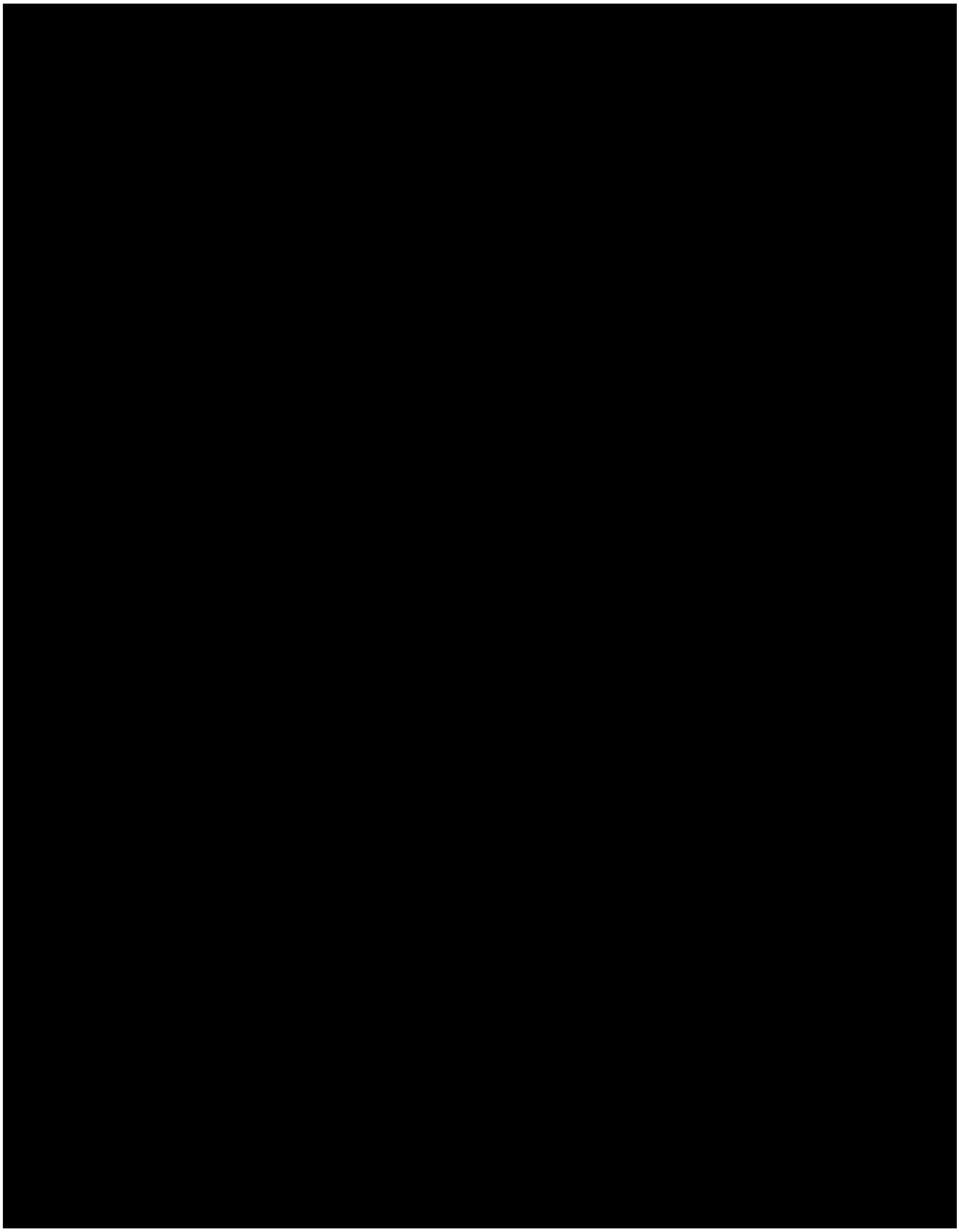
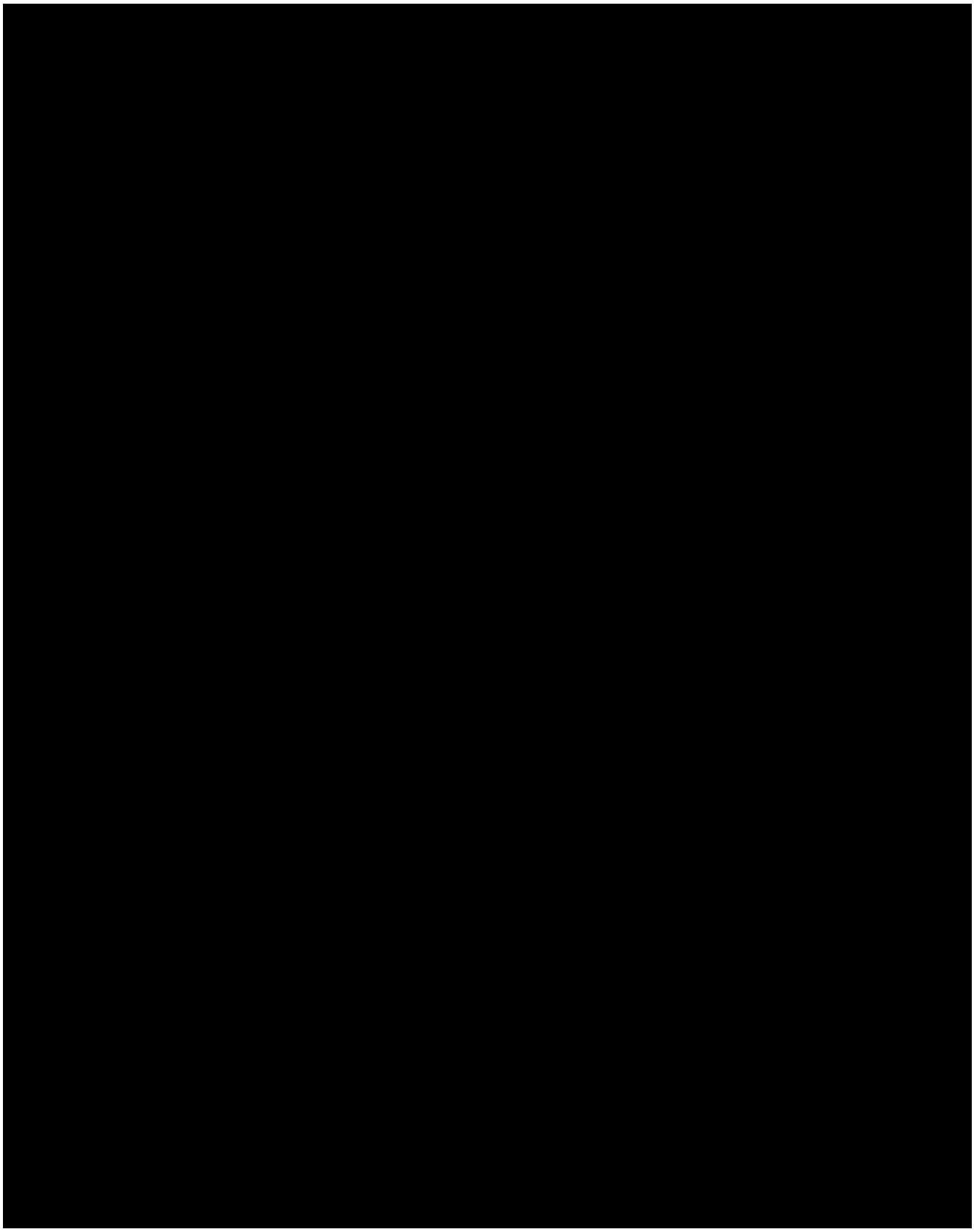
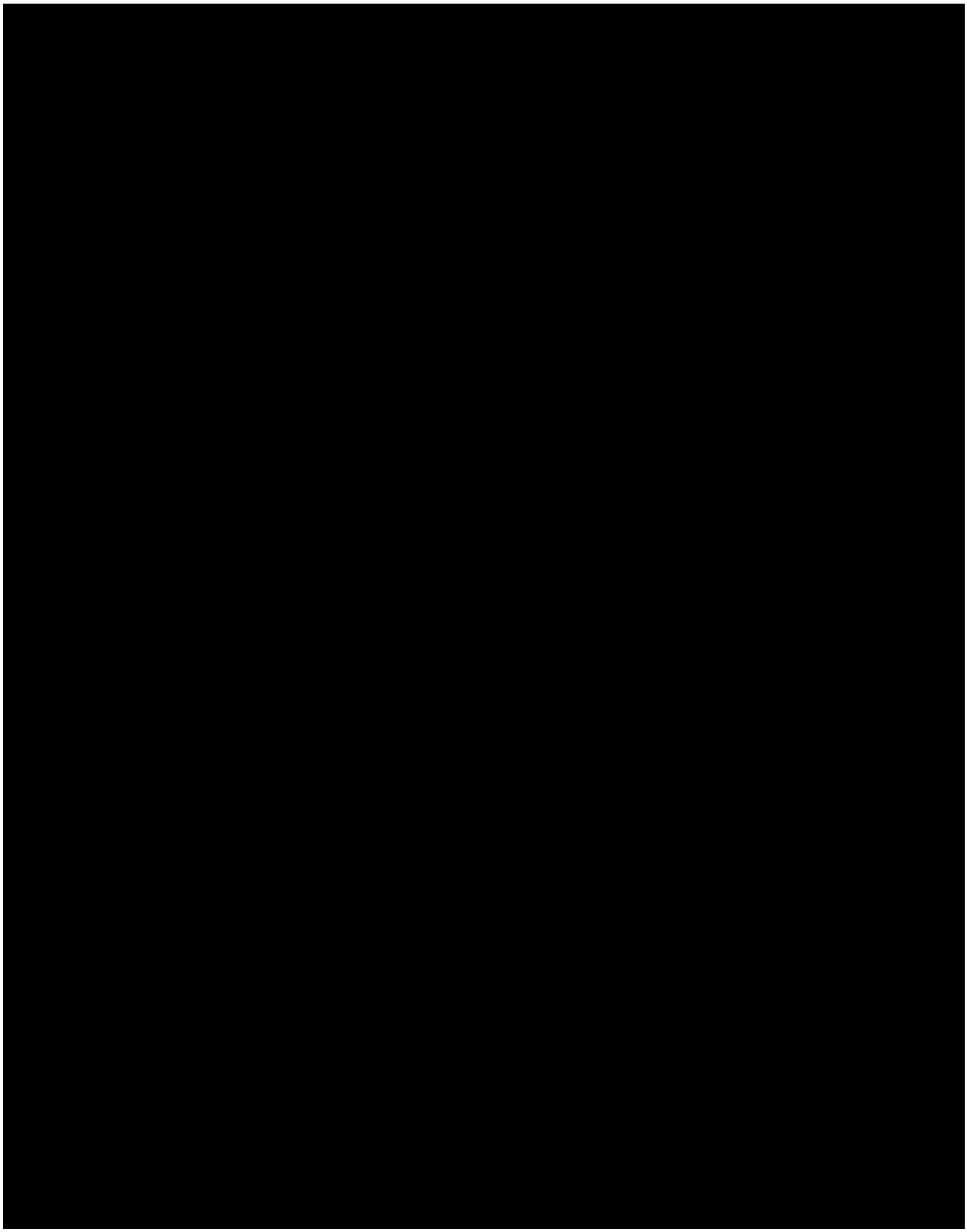
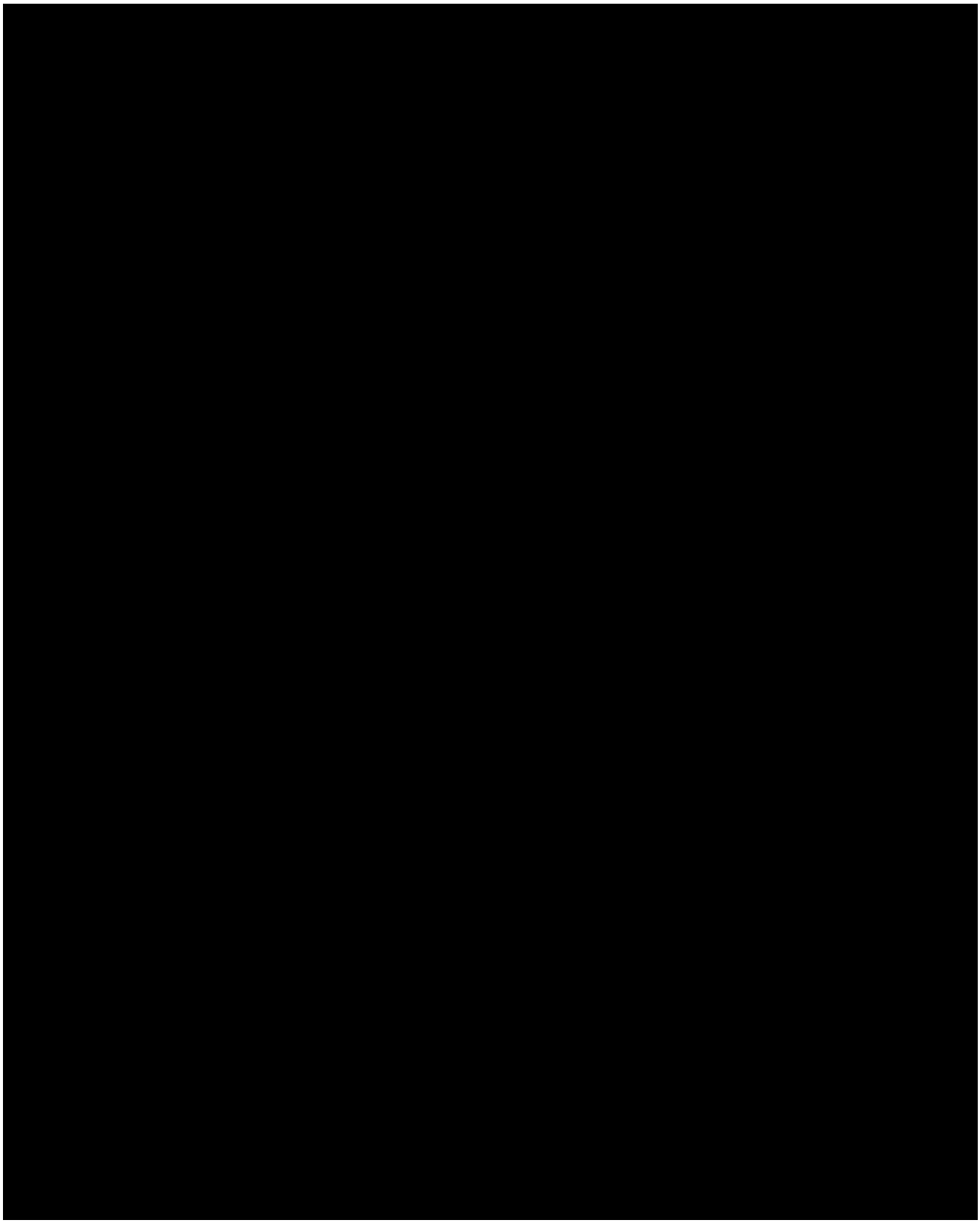
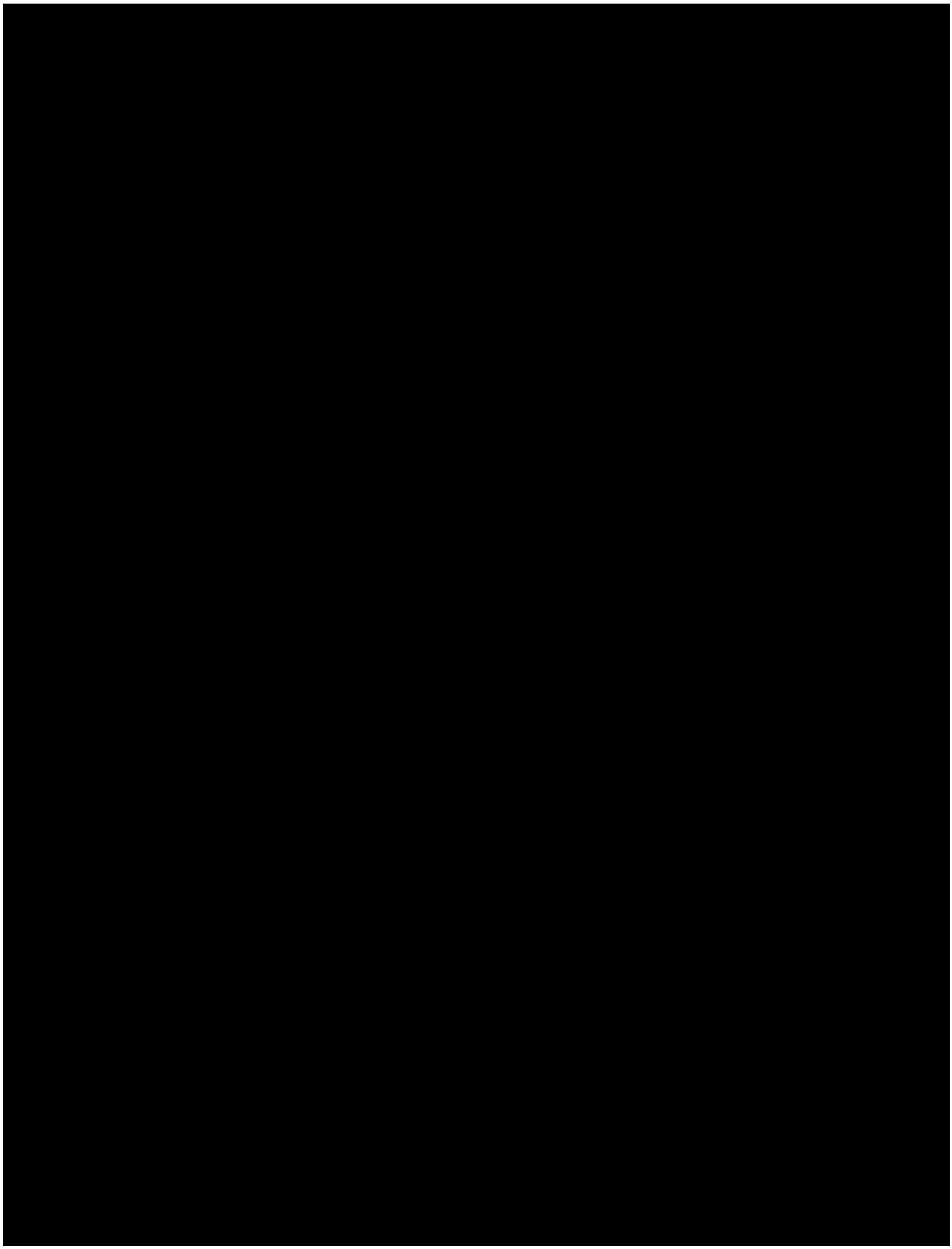
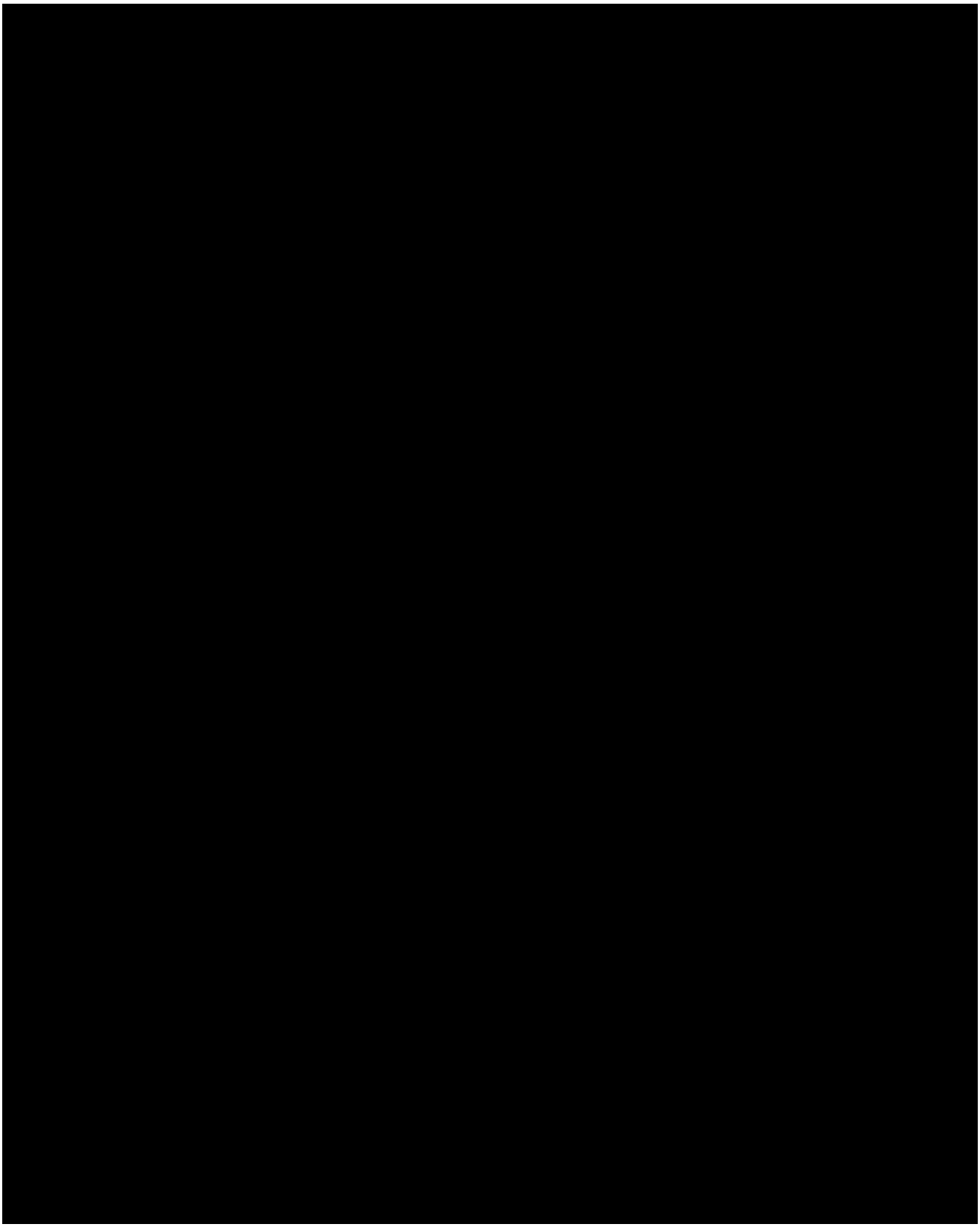












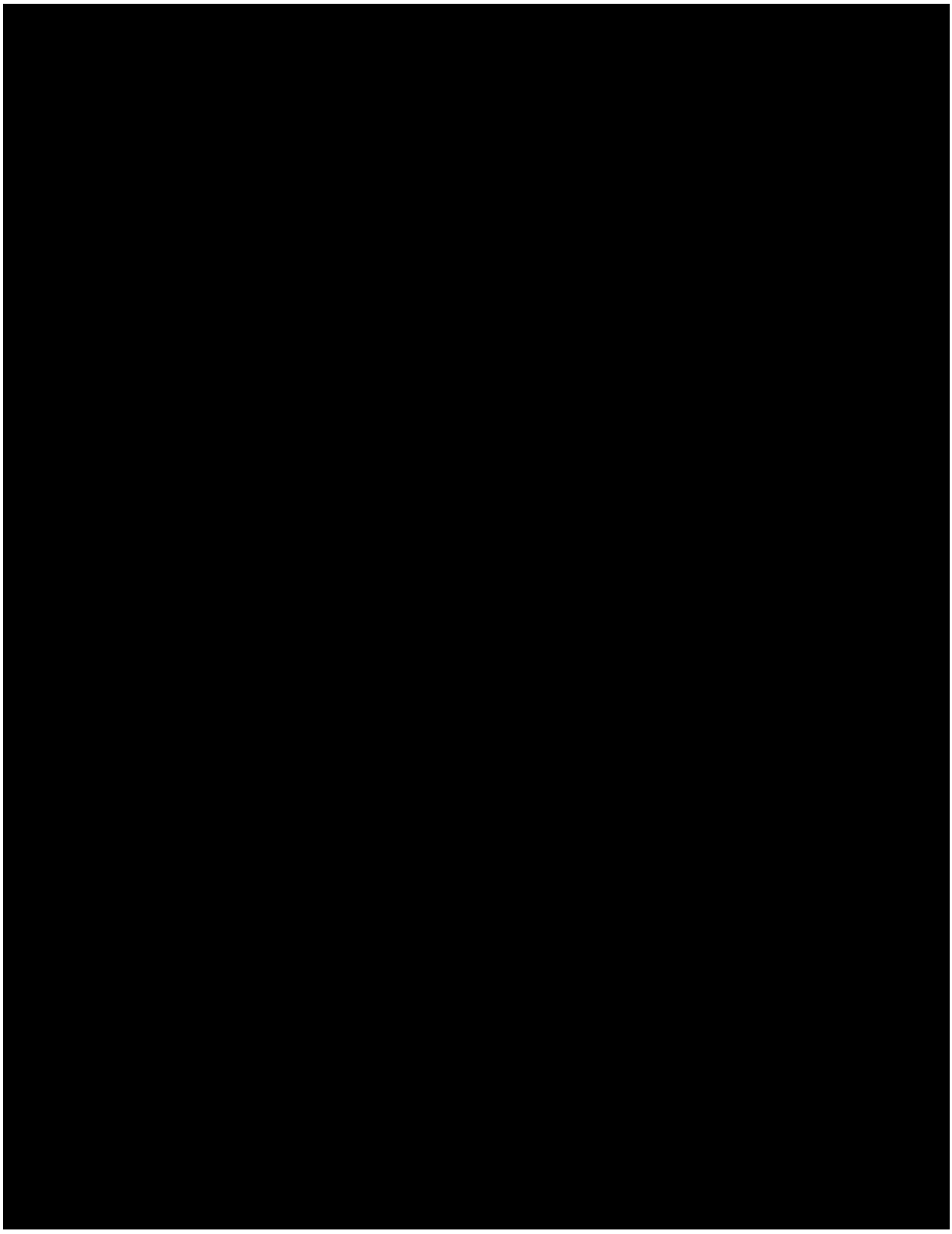
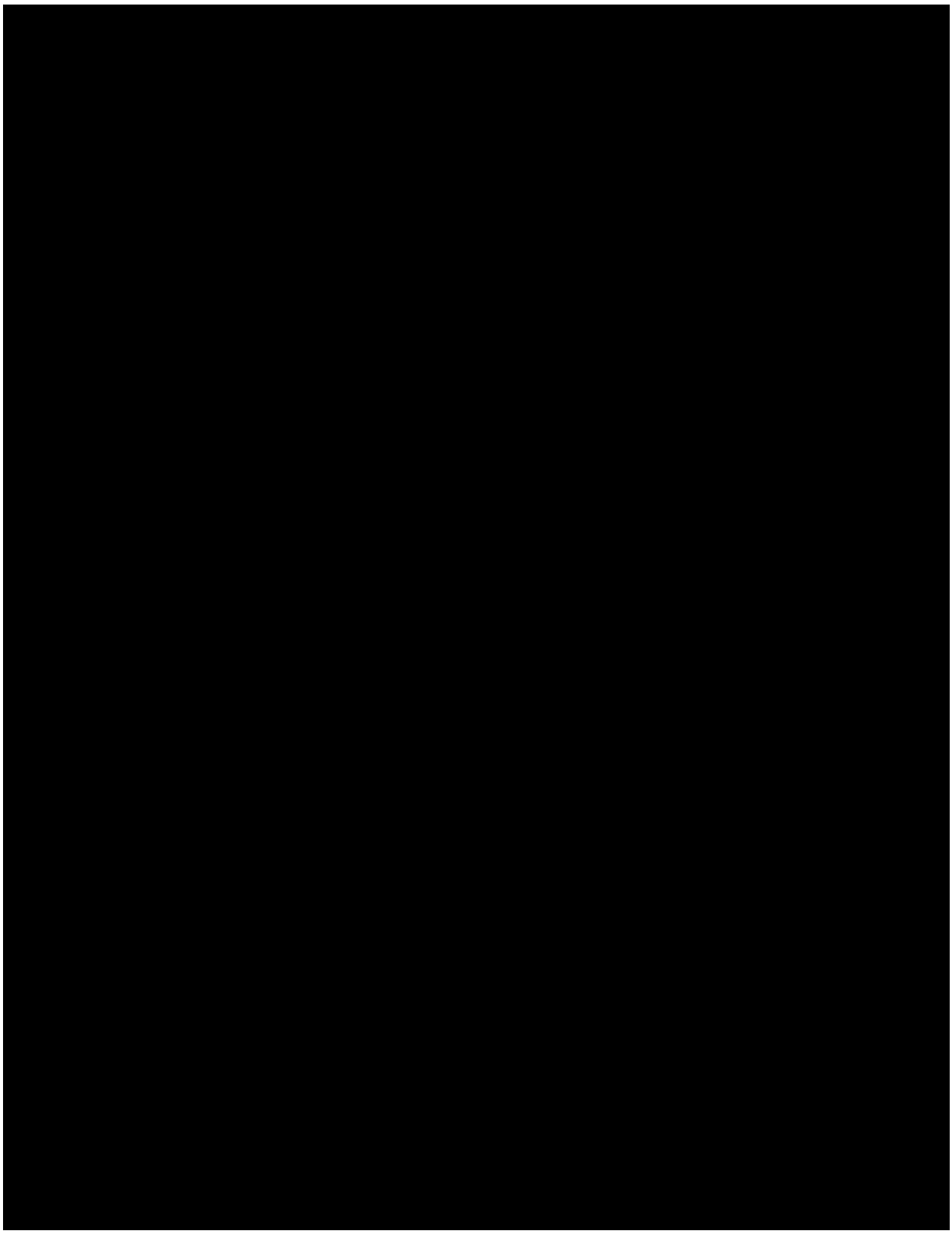


Figure 1-138 –

Figure 1-139 –



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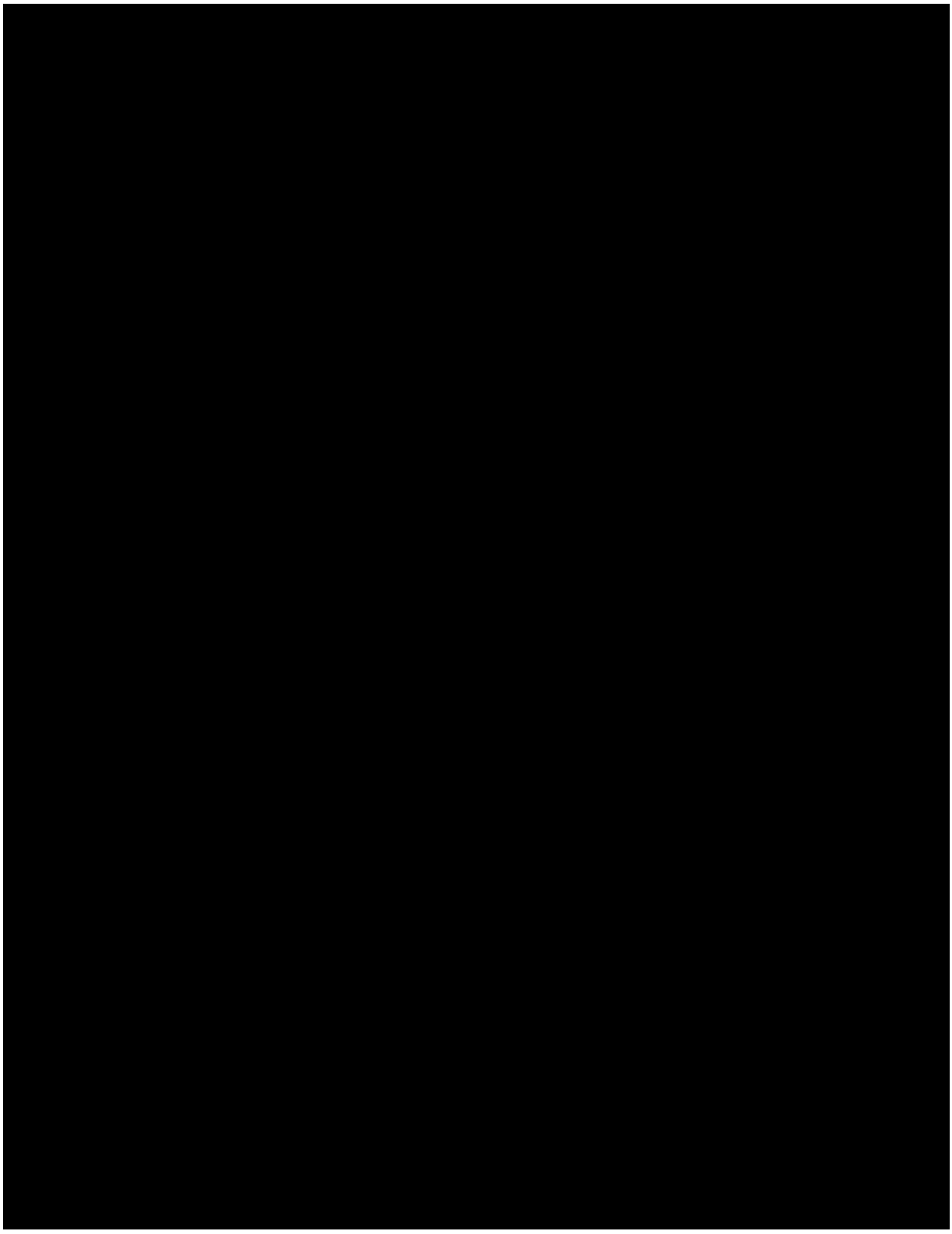

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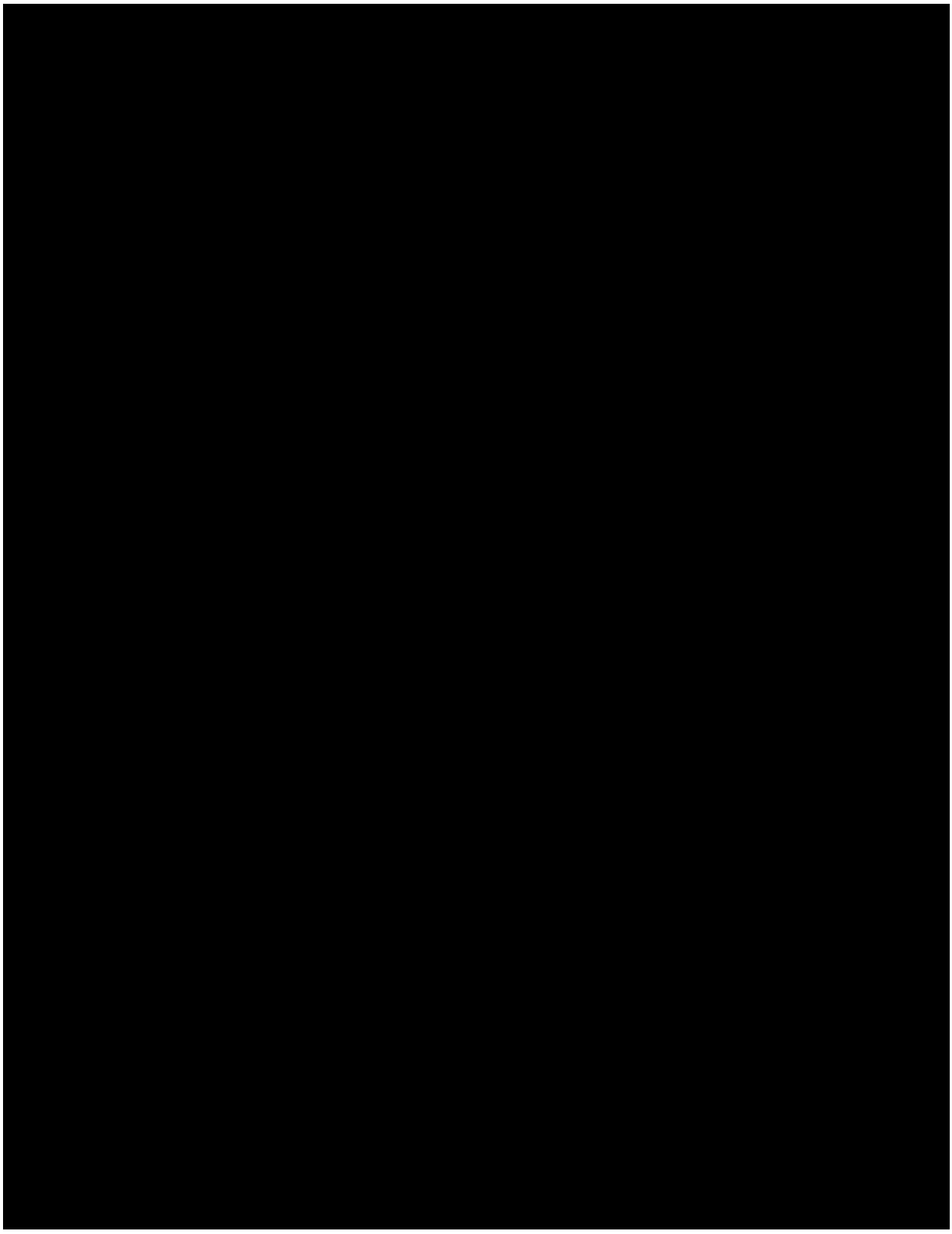

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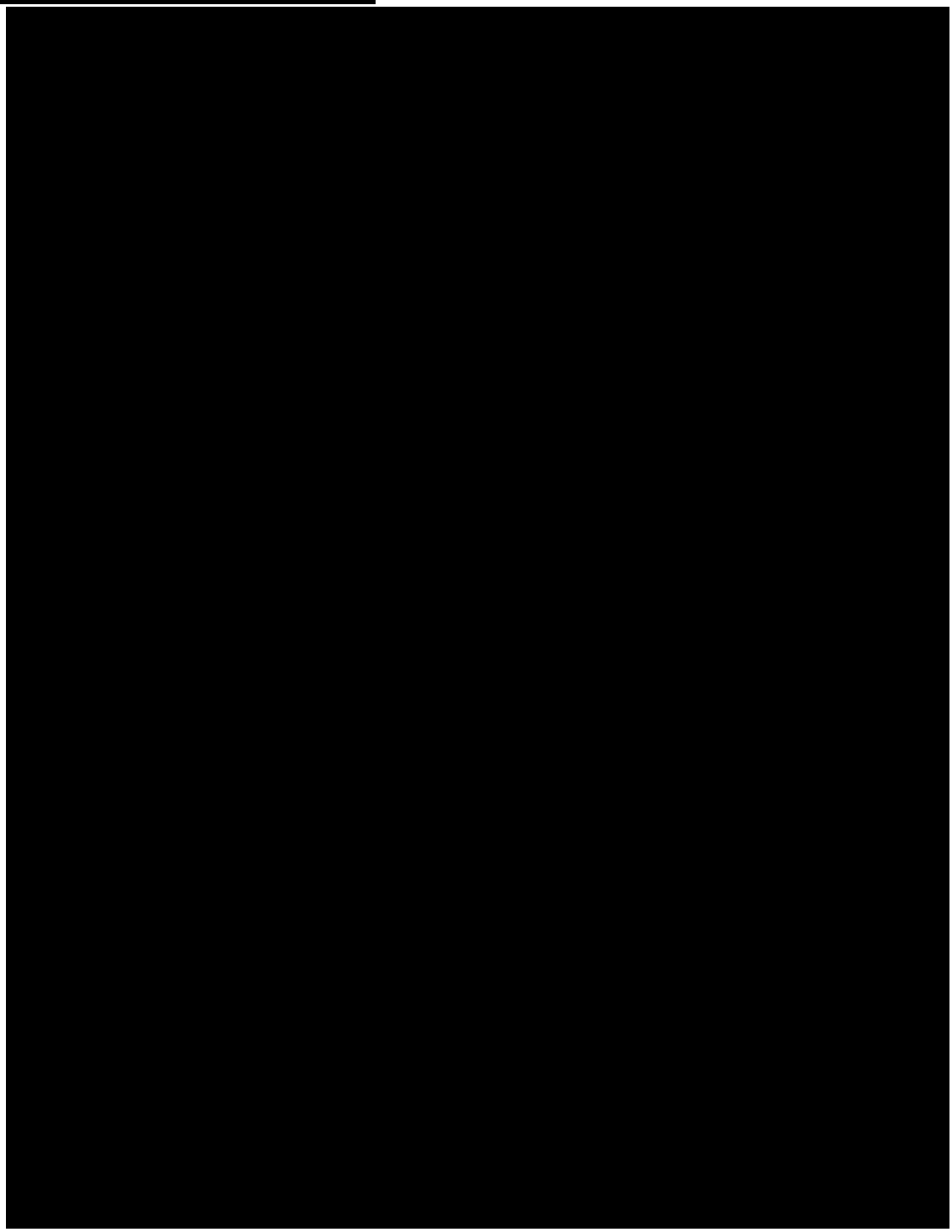

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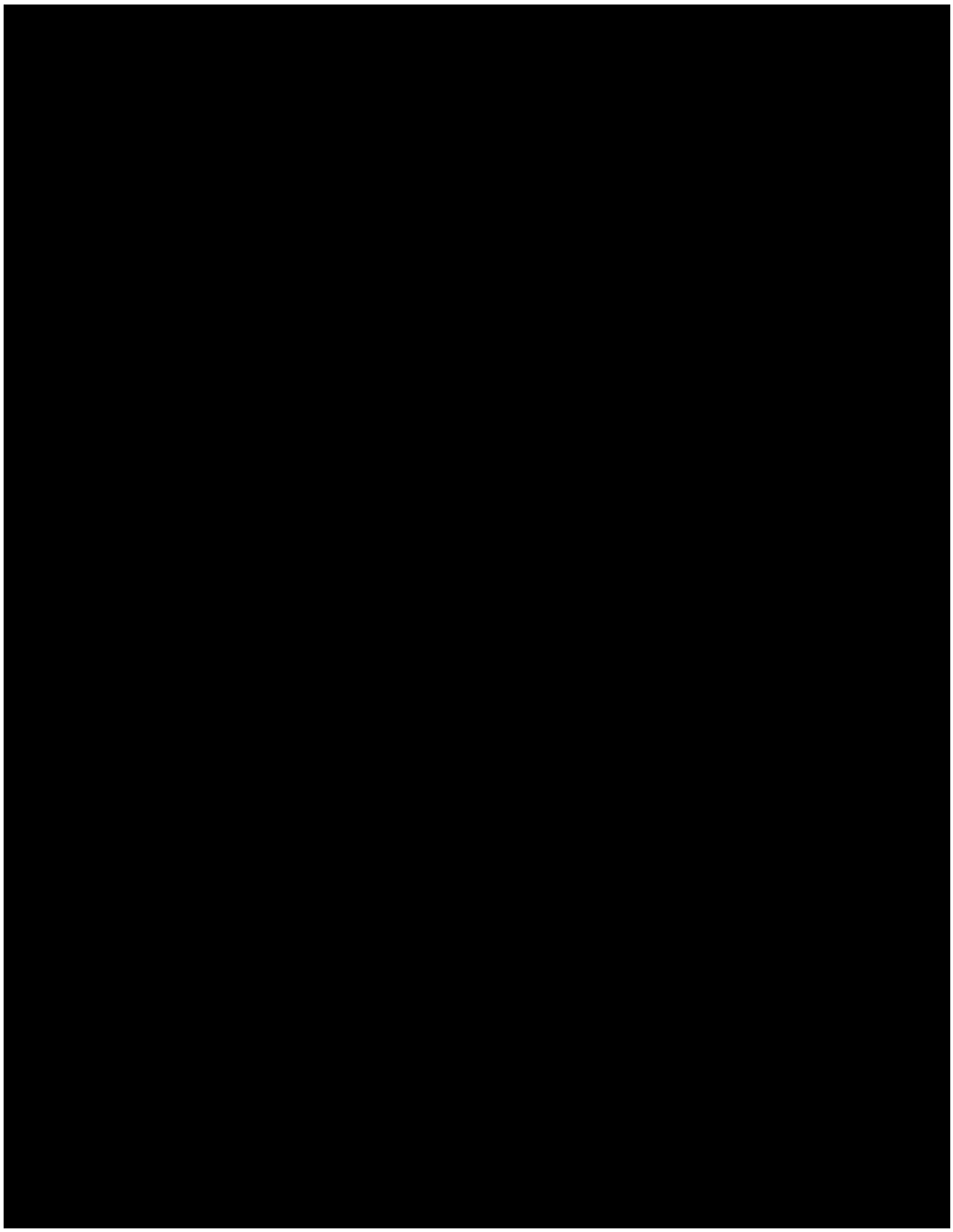

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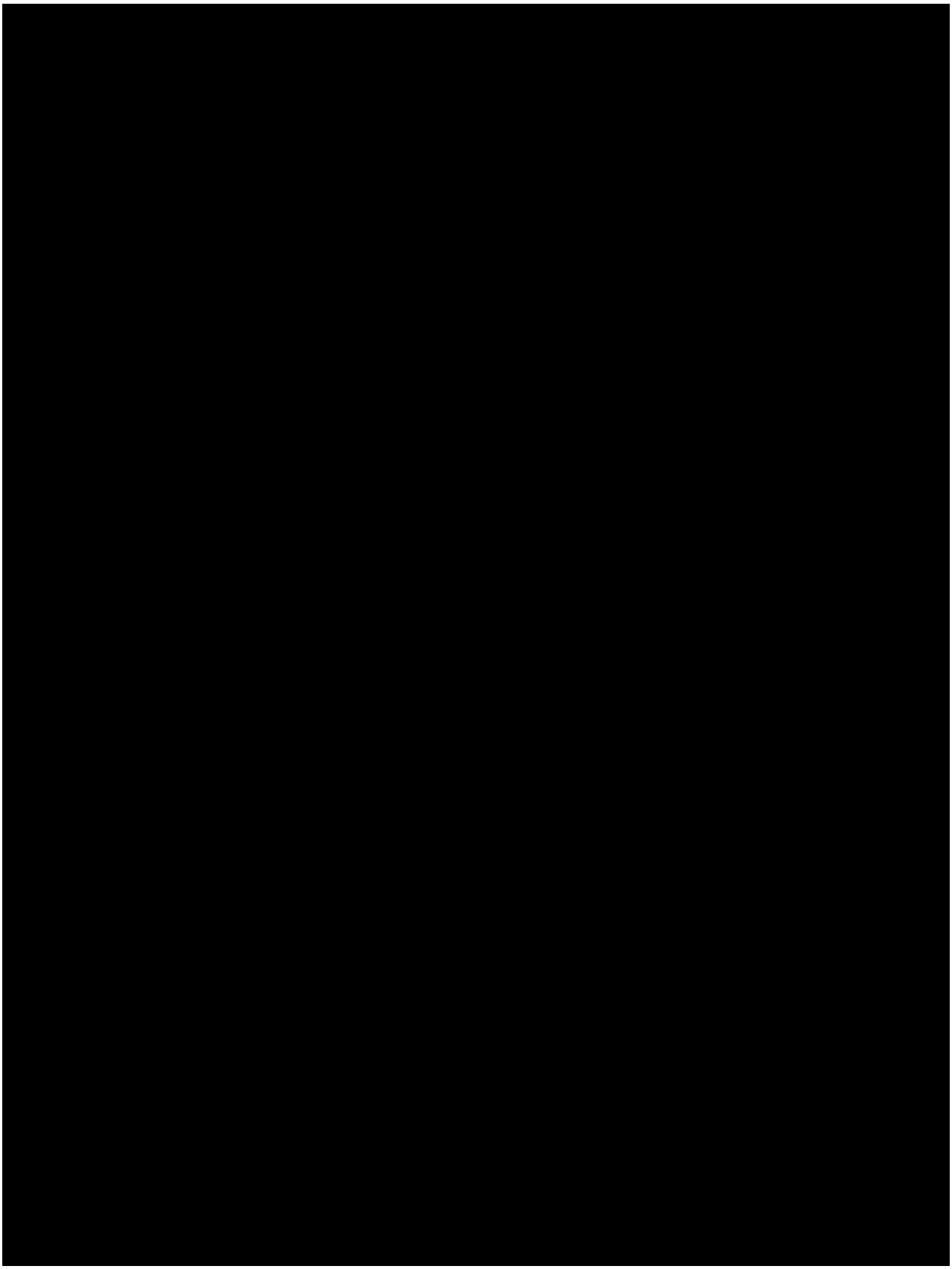
1.9.3.40 [redacted]

Table 1-29 – [redacted]



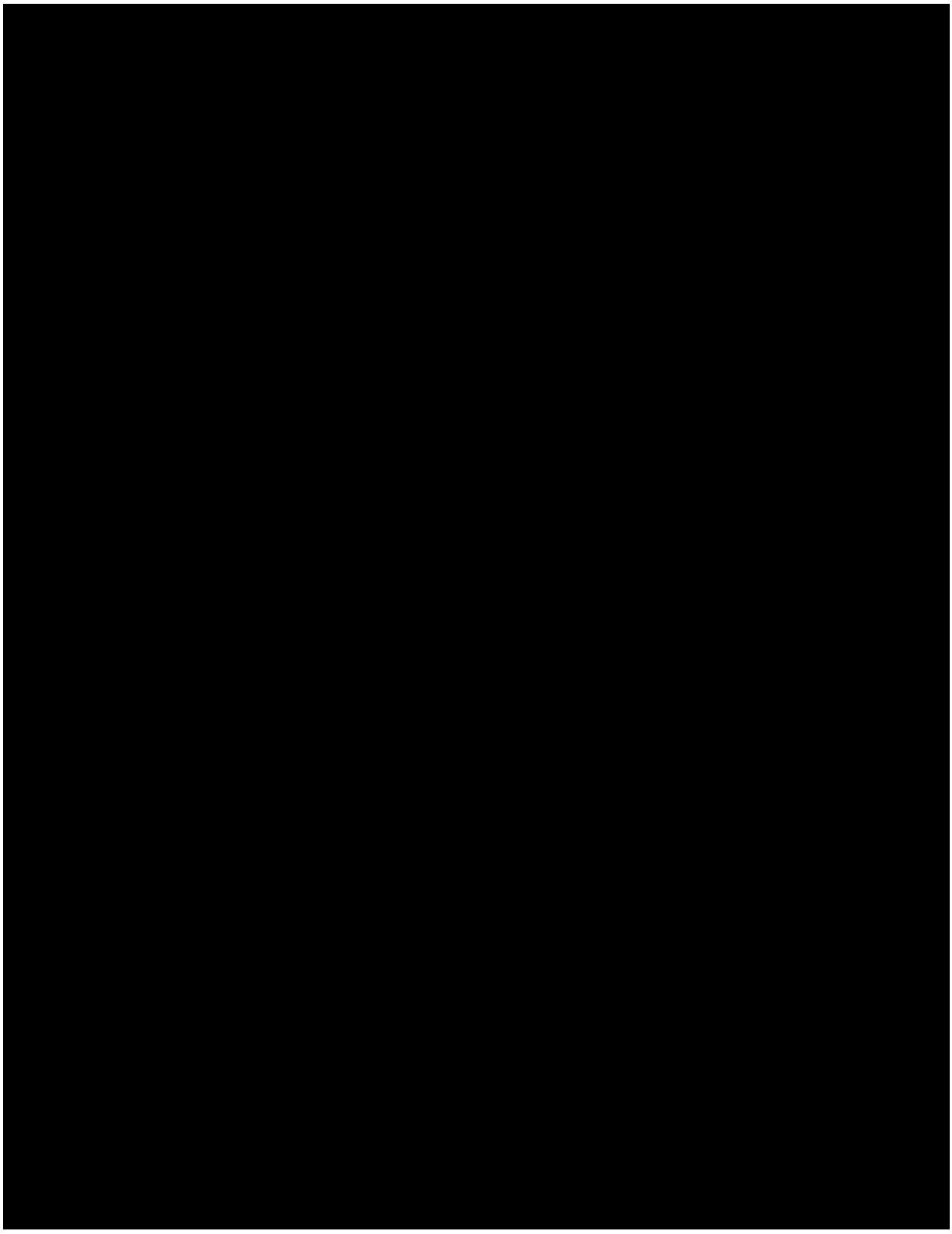


Figure 1-145 – [redacted]

Table 1-30 – [redacted]

[redacted]

Table 1-31 – [redacted]

[redacted]

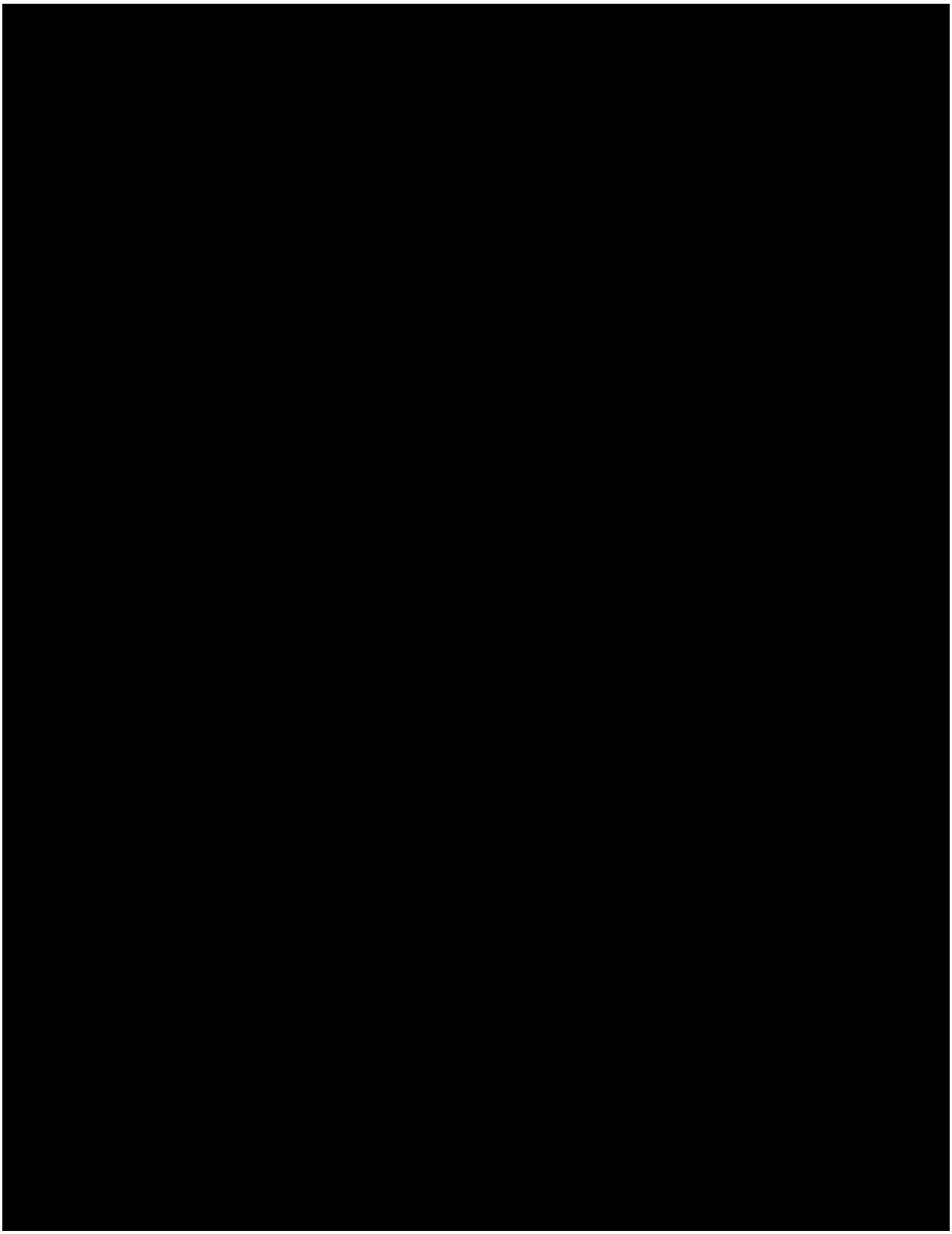


Figure 1-146 – [redacted]

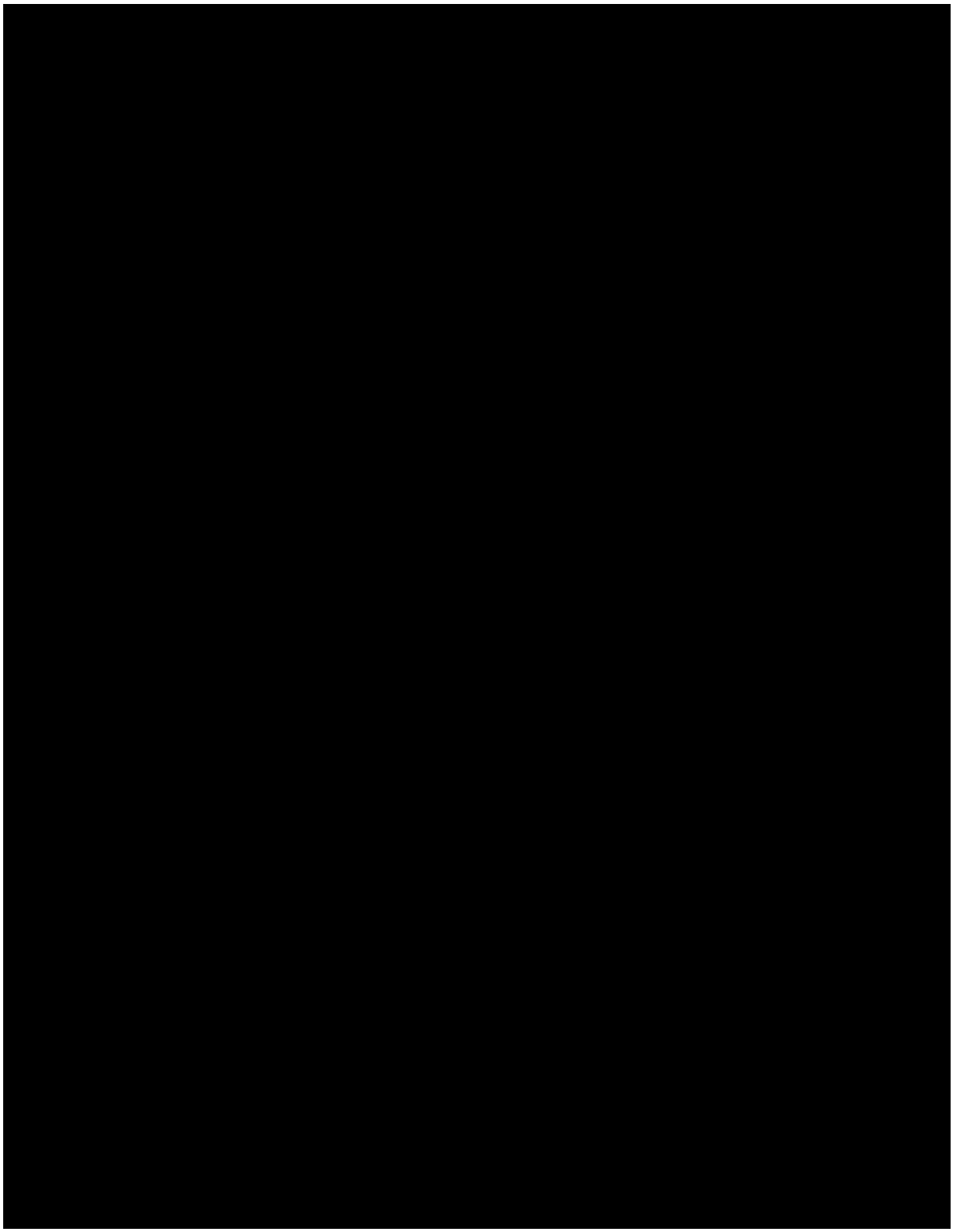


Figure 1-147 –

Figure 1-148 –

1.9.4 [redacted]

[redacted]

1.9.4.1 [redacted]

[redacted]

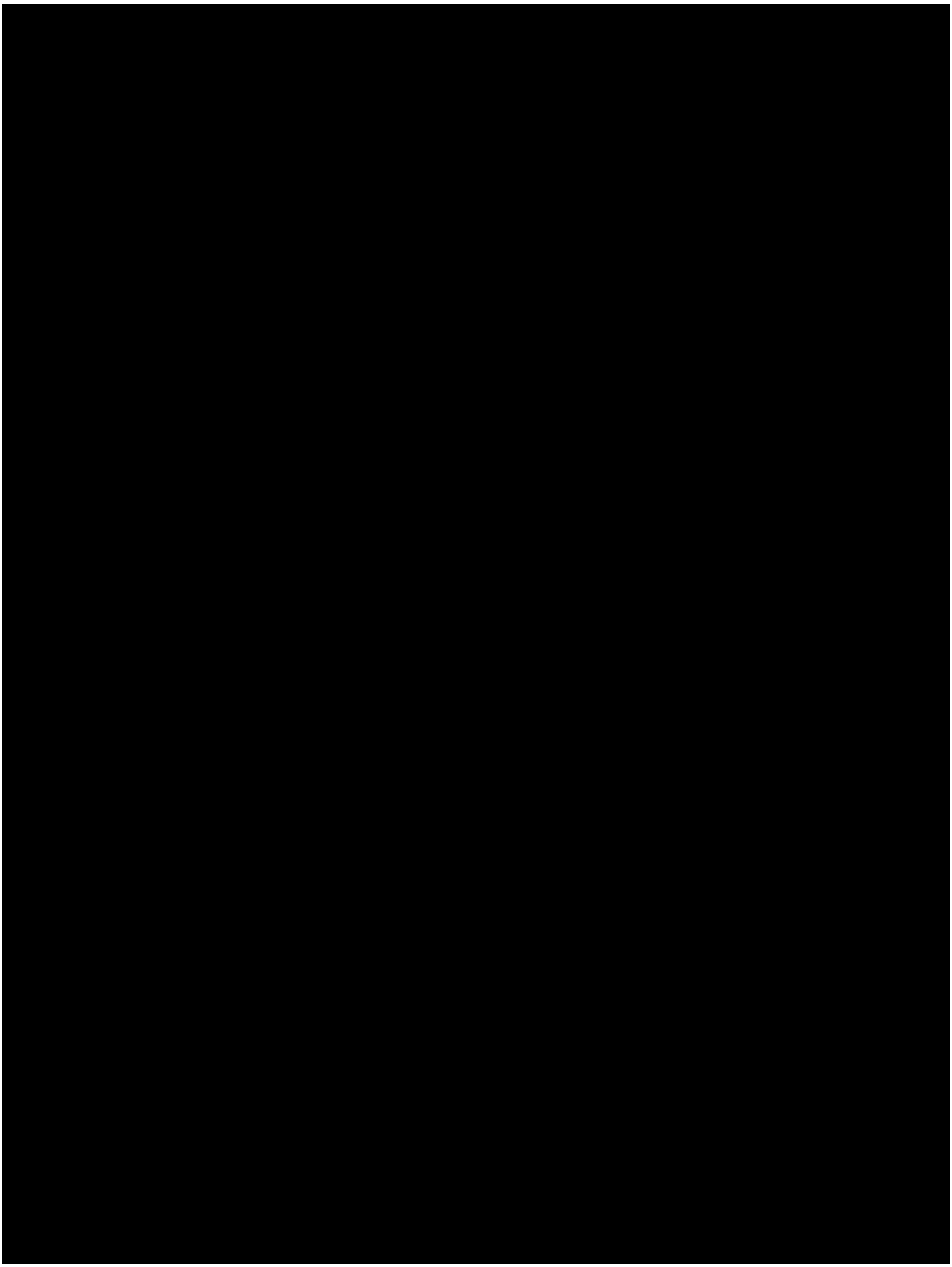
[redacted]

1.9.4.2 [redacted]

[redacted]

Table 1-32 – [redacted]

[redacted]



[redacted]

1.9.4.3 [redacted]

[redacted]

Table 1-33 – [redacted]

[redacted]

1.9.4.4 [redacted]

[redacted]

Table 1-34 – [redacted]

[redacted]

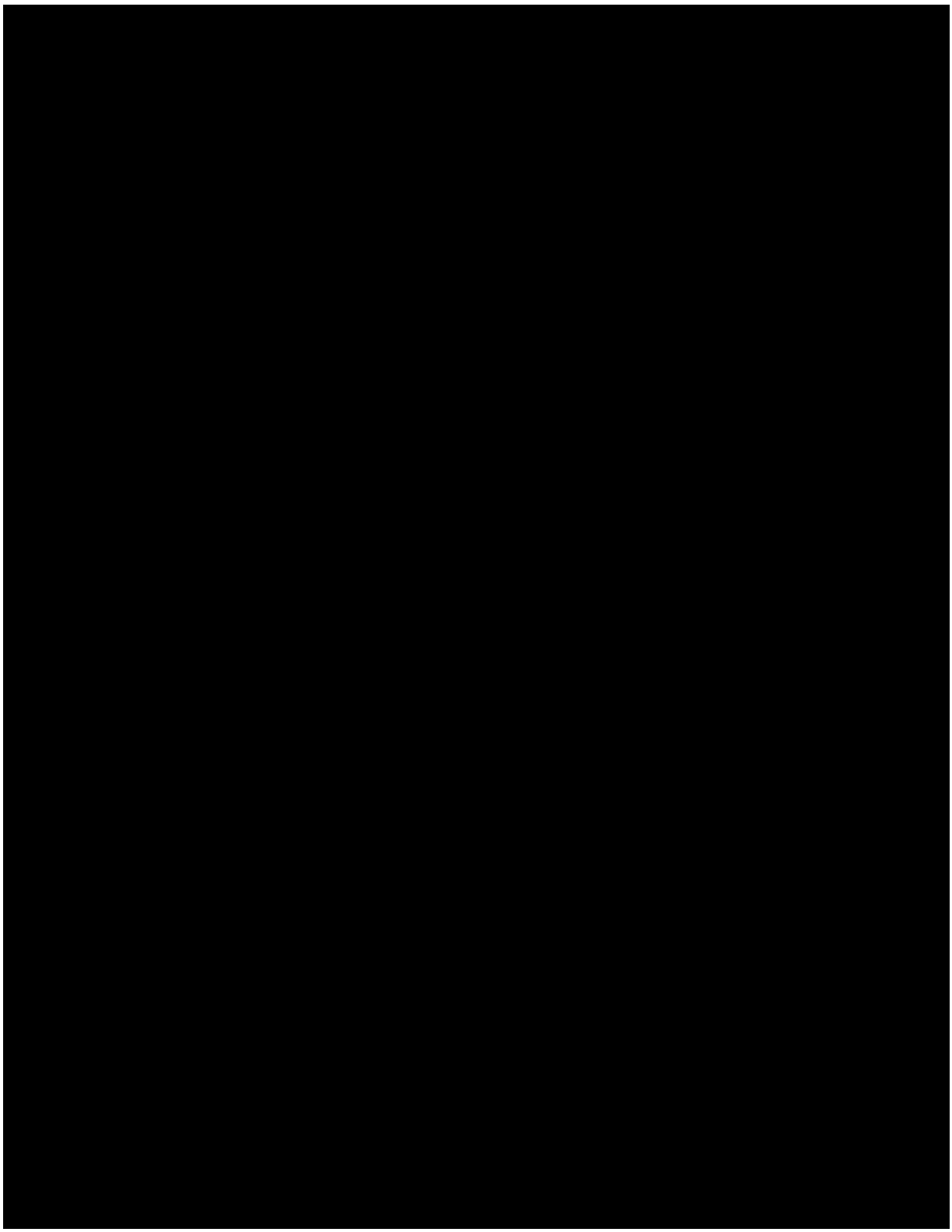


Figure 1-149 – [redacted]

1.10 Seismic History

An important consideration in the design and development of all injection well projects is determining the potential for injection activities to induce a seismic event. The Project is in Refugio and Aransas Counties, Texas, in the Gulf Coast Basin, which is not a tectonically or seismically active region. A four-step review was conducted, including the following:

1. Identification of historical seismic events within proximity to the Project
2. Faulting and determination of operational influences of nearby faults
3. Evaluation of fault stability
4. Seismic hazard review

1.10.1 Identification of Historical Seismic Events

Five seismically active regions exist in Texas: the Delaware Basin, Midland-Odessa, Panhandle, Eagle Ford, and the Cogdell Field. [redacted] The Project's seismic review region (SRR), used to conduct the historical data investigation, was defined to be a 10-mi radius or 16.09 km [redacted] According to the USGS[4] Earthquake Archive Search, from inception to March 28, 2024, no events greater than zero magnitude were recorded within the SRR (Figure 1-150). This finding was also supported by the Texas Seismological Network Earthquake Catalog (TexNet) (Figure 1-151). The SRR is monitored by one TexNet seismic monitoring station located [redacted], and one USGS seismic monitoring station [redacted]

However, since 2019 the USGS uses all TexNet stations as the authoritative array for Texas. To further evaluate the seismic history, secondary research was conducted in the USGS catalog, within a 50-mi radius (Figure 1-152). [redacted]

[4] The USGS Earthquake Catalog is a database of seismographic recordings from a global network of seismological stations around the world.

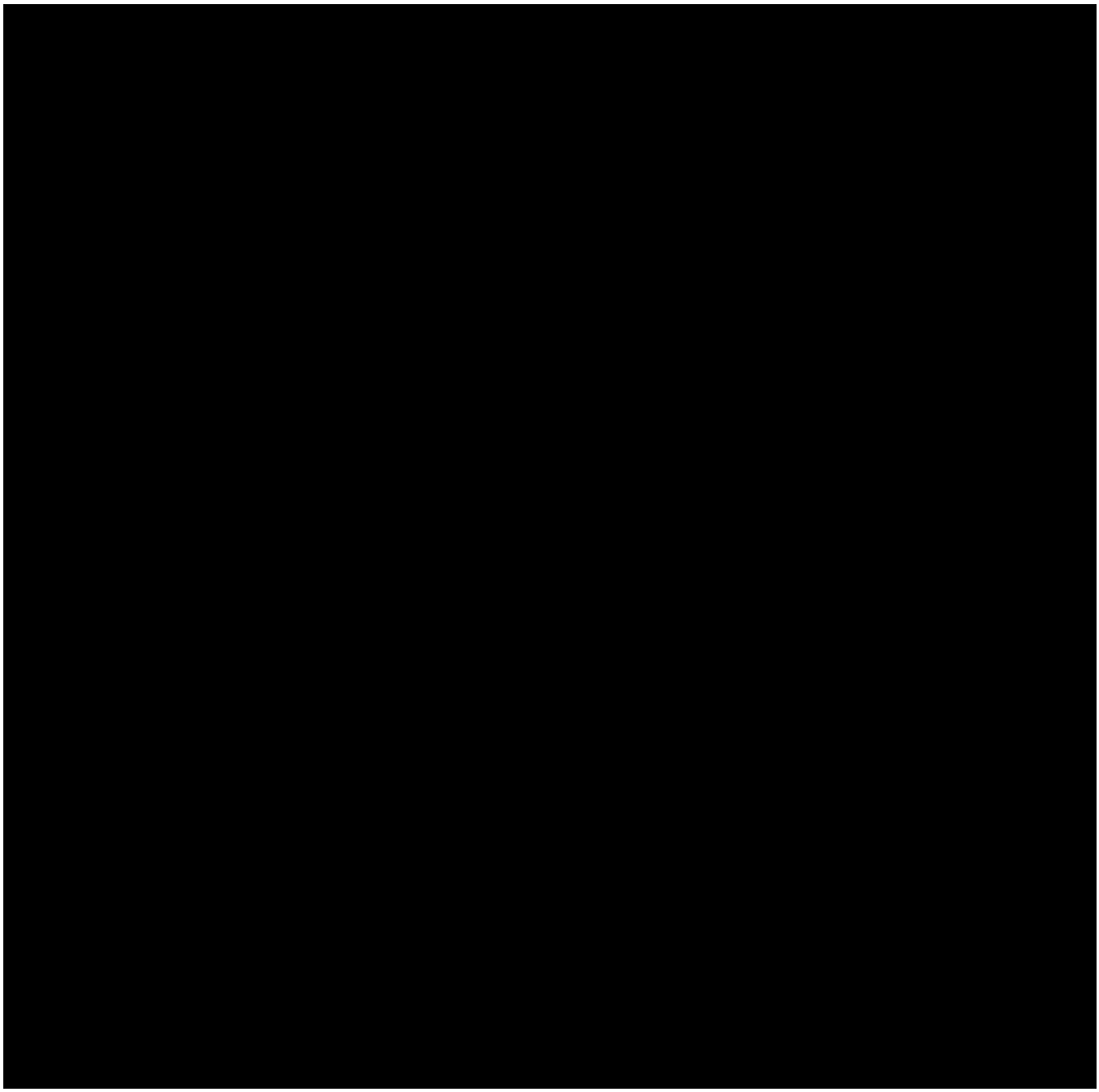


Figure 1-150 – USGS catalog, search parameters, and historical earthquakes within the SRR.

Figure 1-151 – TexNet catalog, historical earthquakes, and seismic monitoring station

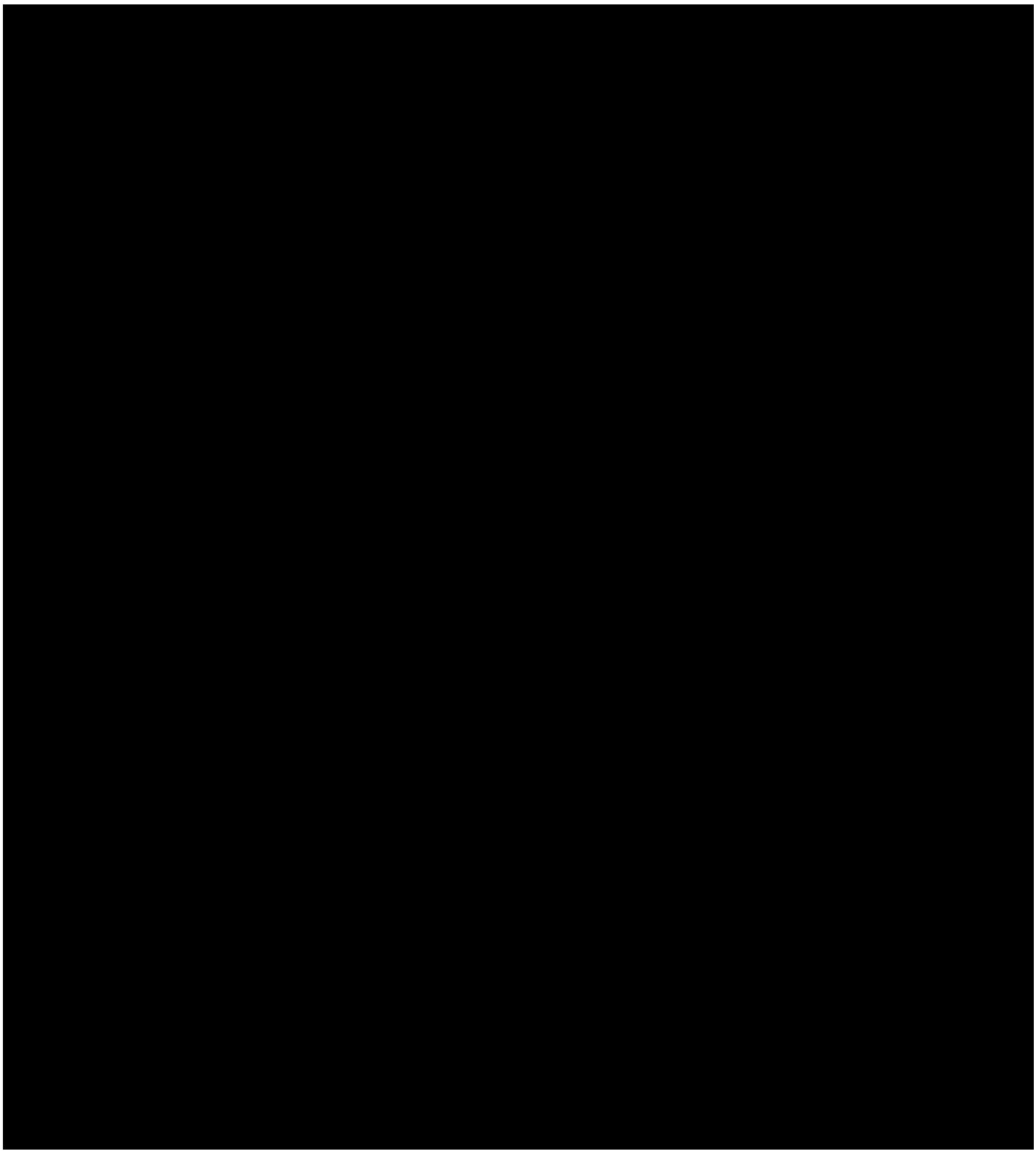


Figure 1-152 – [redacted]

1.10.2 Faults and Influence

Faults in south central Texas are primarily considered "Gulf-margin normal faults (Class B)." The USGS classified these based on an analysis of faults and related folds throughout the United States that was covered under the Data for Quaternary Faults Report. Regionally, faulting is dominated by northeast-southwest striking normal faults—and in poorly lithified sediments unable to sustain the forces necessary for the creation of large seismic ruptures (Crone and Wheeler, 2000). [redacted] This area has a low probability of producing earthquakes. Faults within the AOI have been mapped using 3D reflection seismic data in Schlumberger Petrel™ software and are covered in more detail in *Section 1.5*. In accordance with EPA regulations, a complete understanding of the extent and location of the resultant injection plume was conducted as detailed in *Section 2 – Plume Model*. [redacted] A fault stability analysis (FSA) was conducted, with results presented in *Appendix K*.

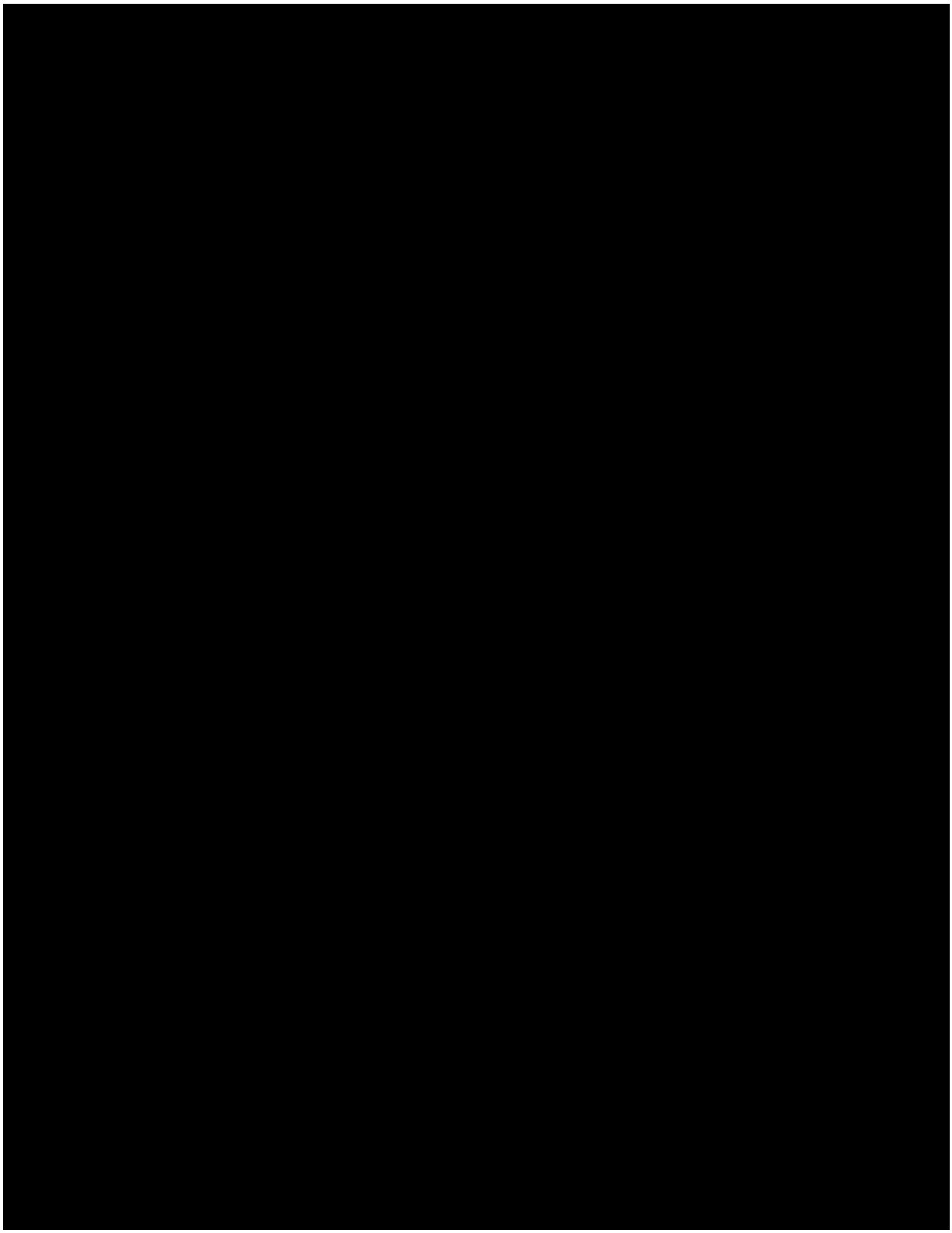


Figure 1-153 – Location of the underground storage easement
and regional northern Gulf of Mexico faults and fault zones (Galloway, 2008).

1.10.3 Fault Stability and Likelihood of Fault Reactivation

Fault stability is critical in any project as pressure increases associated with injection may cause fault reactivation and induced seismicity. The process of injecting CO_2 into subsurface reservoirs will cause an increase in pore pressure adjacent to faults within the pressure front. The increase in pore pressure reduces the effective stress acting normal to the fault plane and can cause the fault to slip (Jaeger and Cook, 1979; Sibson, 1992). Empirical evidence and modeling suggest that fault slip or reactivation can cause dilatant deformation-opening pathways along the fault that can allow along fault flow, fluid leakage, or potentially induced seismicity (Wiprut and Zoback, 2002). It is therefore critical to determine the stability—or the increase in pore pressure—that faults within the increasing pressure front can withstand before failure or shear reactivation. This will inform the Project plan to stay within safe operating parameters.

The pore pressure required for fault reactivation is dependent on the stress state and orientation, pore pressure, fault geometry, and fault rock properties (cohesion and friction angle). These parameters are outlined in *Section 1.5*. The analysis of fault stability examined a low stability case (sealing)—in which fracture gradient and friction angle were set at the low end of uncertainty and a base case scenario (transmissive)—in which average parameters were used. Pore pressure increase was tracked during injection simulation for both sealing and transmissive fault scenarios. [redacted] none of the faults within both simulation models had a pore pressure increase that exceeds the pressure required for failure; therefore, the likelihood of fault reactivation and induced seismicity is low. The full analysis of fault stability is presented in *Appendix K*.

1.10.4 Seismic Hazard

The 2023 USGS National Seismic Hazard Model (NSHM) Project and derived maps are recommended by the EPA as tools to assess seismic hazards. This model integrated and updated the 2018 NSHM including: fault models, seismic catalogs, ground motion models, soil amplification factors, amplified shaking estimates of long-period ground motions, population density, and seismic hazard calculation. The 2023 Modified Mercalli Intensity (MMI[5]) hazard map, with a 50% probability of exceedance in 50 years for a firm rock site, predicts that the Gulf Coast Basin and the Project area will most likely encounter an intensity III[6] earthquake (Figure 1-154). However, in a rare scenario the Project area could experience an intensity IV[7] earthquake (Figure 1-155). An important factor to consider with relation to seismic hazard is population

[5] The Modified Mercalli Intensity (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.

[6] Intensity III: "Weak; Felt quite noticeably by persons indoors, especially on upper floors of buildings. Many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibrations similar to the passing of a tuck. Duration estimated."

[7] Intensity 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."

density, which was taken into consideration on Figure 1-156. This map shows the likelihood of an intensity VI[8] earthquake or higher (damaging earthquake[9]) occurring in the next 100 years. The Project area is considered the lowest risk (< 5%). In terms of a 10,000-year damaging earthquake (Figure 1-157), the prediction conducted by the USGS shows the Gulf Coast Basin to have a less than a 2% risk—the lowest USGS risk rating.

Considering the 2023 NSHM maps, the Project is in one of the U.S. regions with the lowest seismic risk. Earthquakes could occur, but would most likely be of low magnitude and cause minor structural damage, if any. Earthquakes of intensity IX[10] or greater are unlikely to occur near the Project, per the 2023 NSHM.

Seismic risk related to the National Risk Index[11] considers the Project site as "low risk" (Figure 1-158). This assessment considers the risk of natural disasters (earthquakes), the degree to which the public are exposed to them, and the susceptibility of the infrastructure and buildings. This assessment is also supported by the open file Refugio County Multi-Hazard Mitigation Plan 2021, which cites historical seismicity as negligible or nonexistent.

[8] Intensity VI: "strong; Felt by all, and many are frightened. Some heavy furniture is moved; a few instances of fallen plaster occur. Damage is slight."
[9] Damaging earthquake shaking; meaning a level VI or higher earthquake causing slightly to high structural failure.
[10] Intensity IX: "violent; Damage is considerable in specially designed structures; well-designed frame structures are thrown off-kilter. Damage is great in substantial buildings, with partial collapse. Buildings are shifted off foundations. Liquefaction occurs. Underground pipes are broken."
[11] 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.

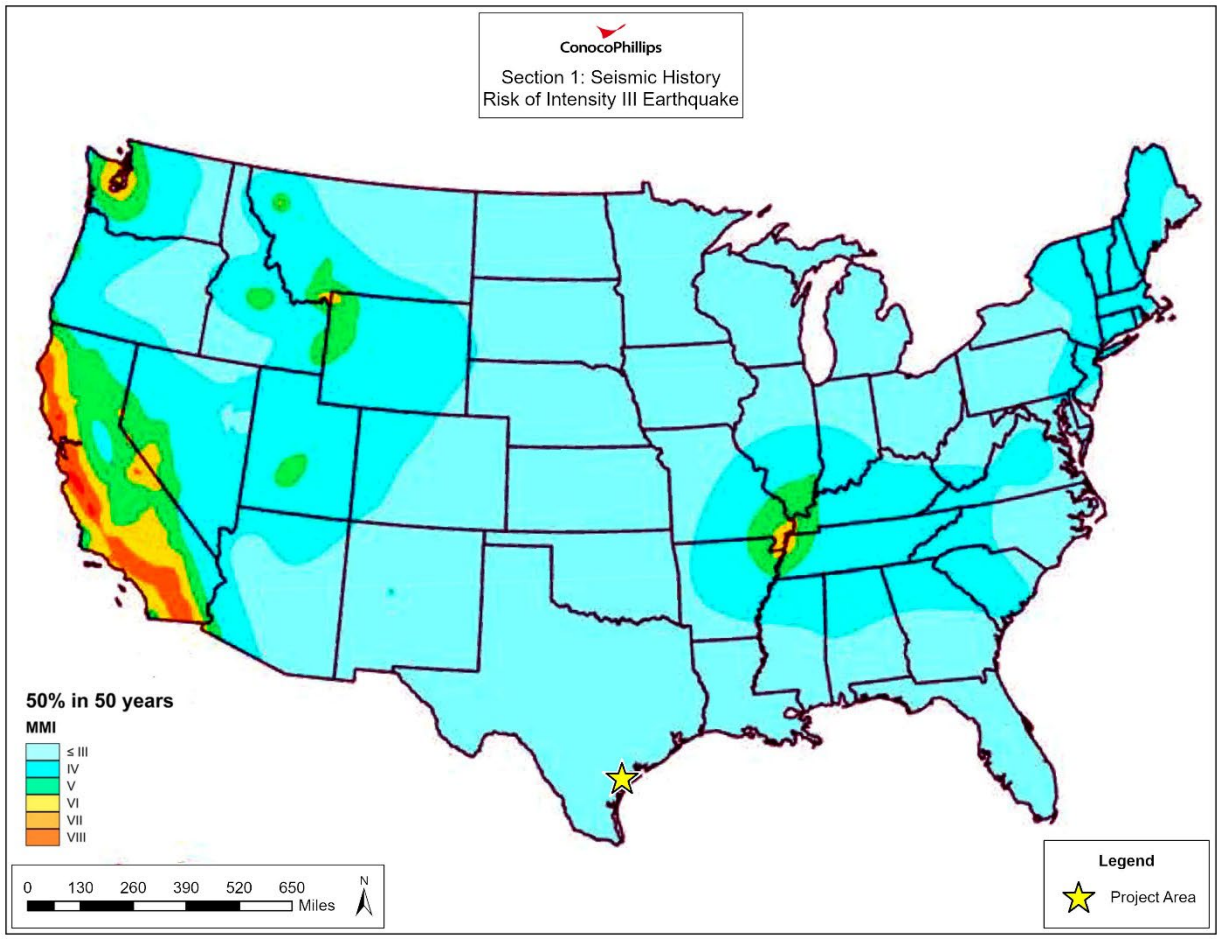


Figure 1-154 – Risk of an intensity III earthquake shaking in 50 years (most likely) in relation to the Project area (Petersen, et al., 2023).

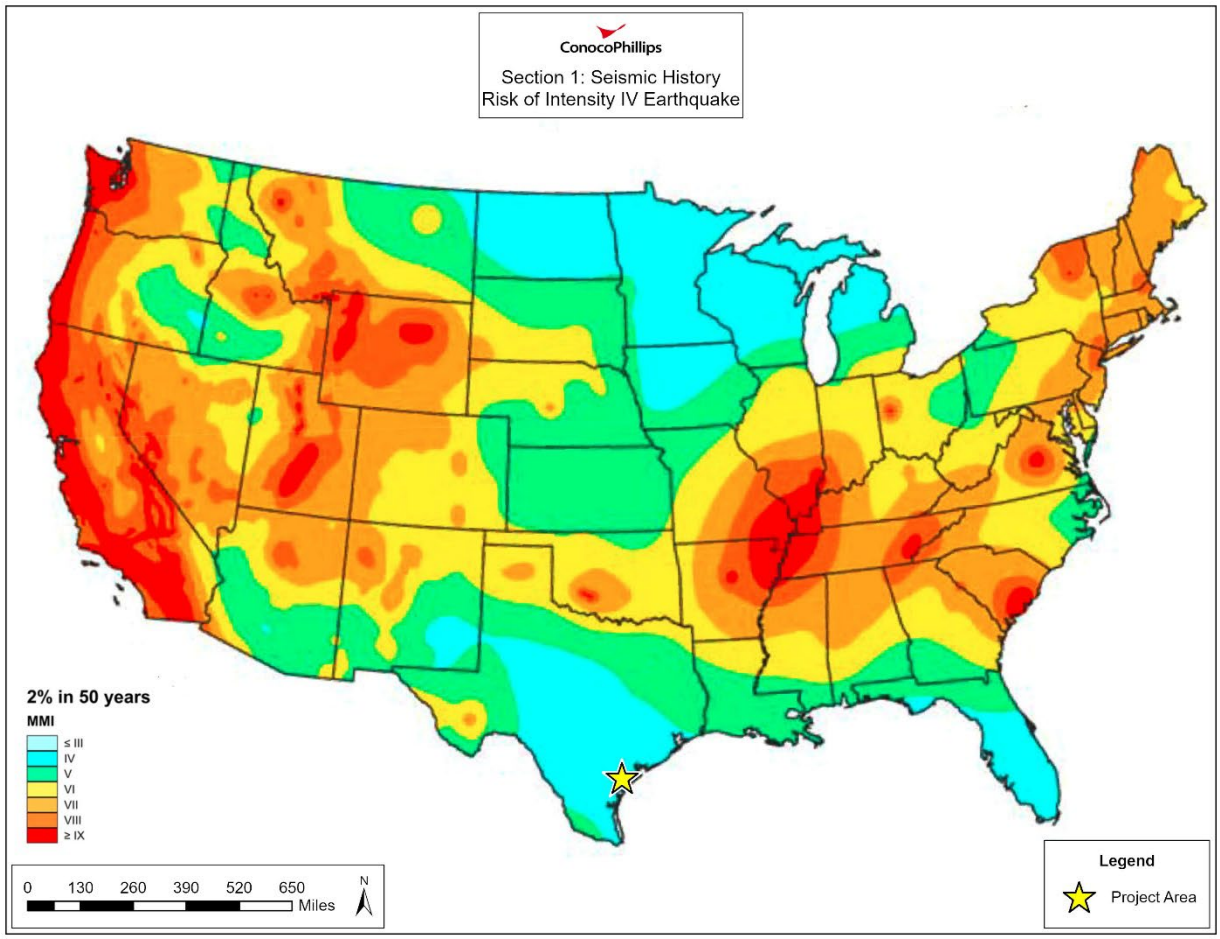


Figure 1-155 – Risk of an intensity IV earthquake shaking in 50 years (rare) in relation to the Project area (Petersen, et al., 2023).

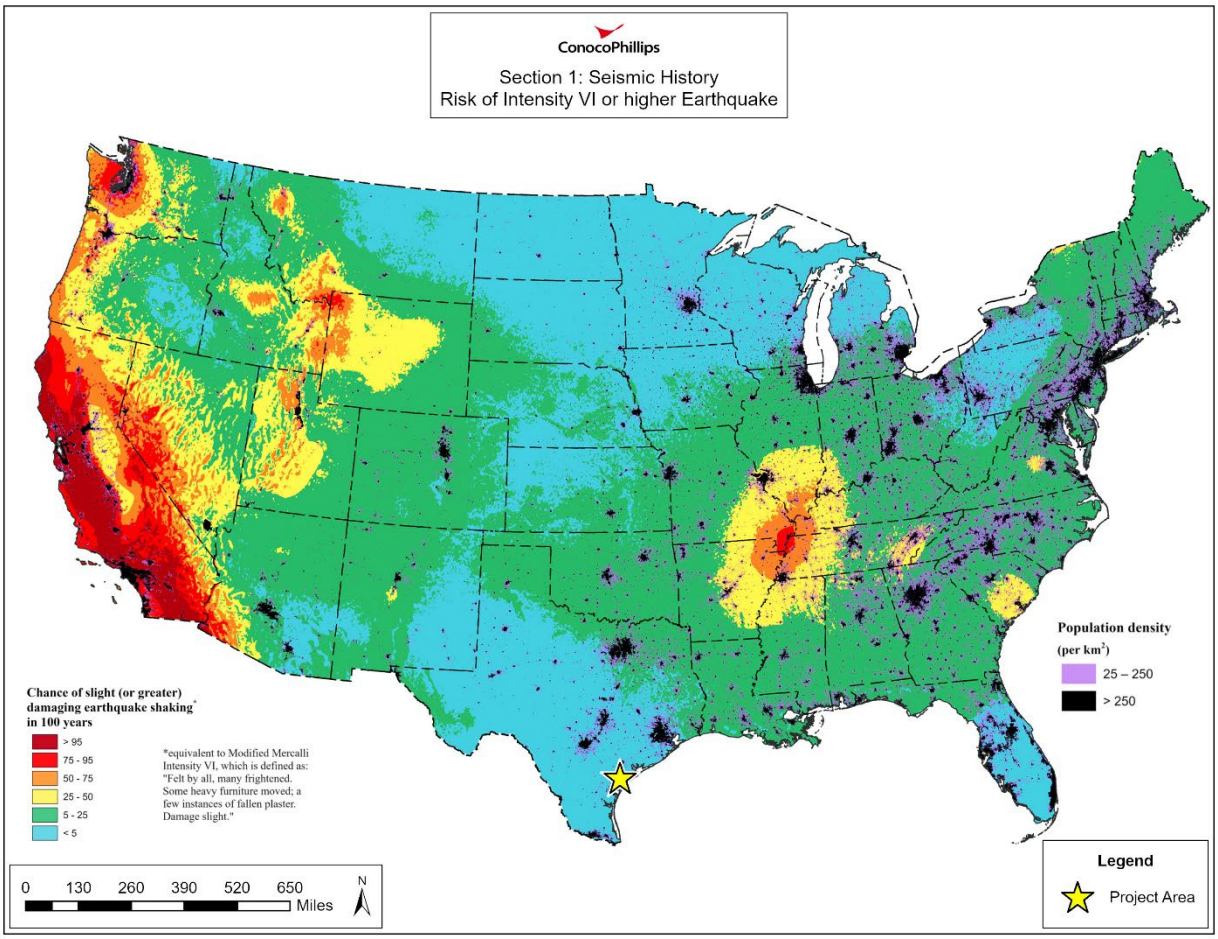


Figure 1-156 – Population density and likelihood of an earthquake equivalent to Mercalli Intensity scale VI or higher to occur in the next 100 years in relation to the Project area (Petersen, et al., 2023).

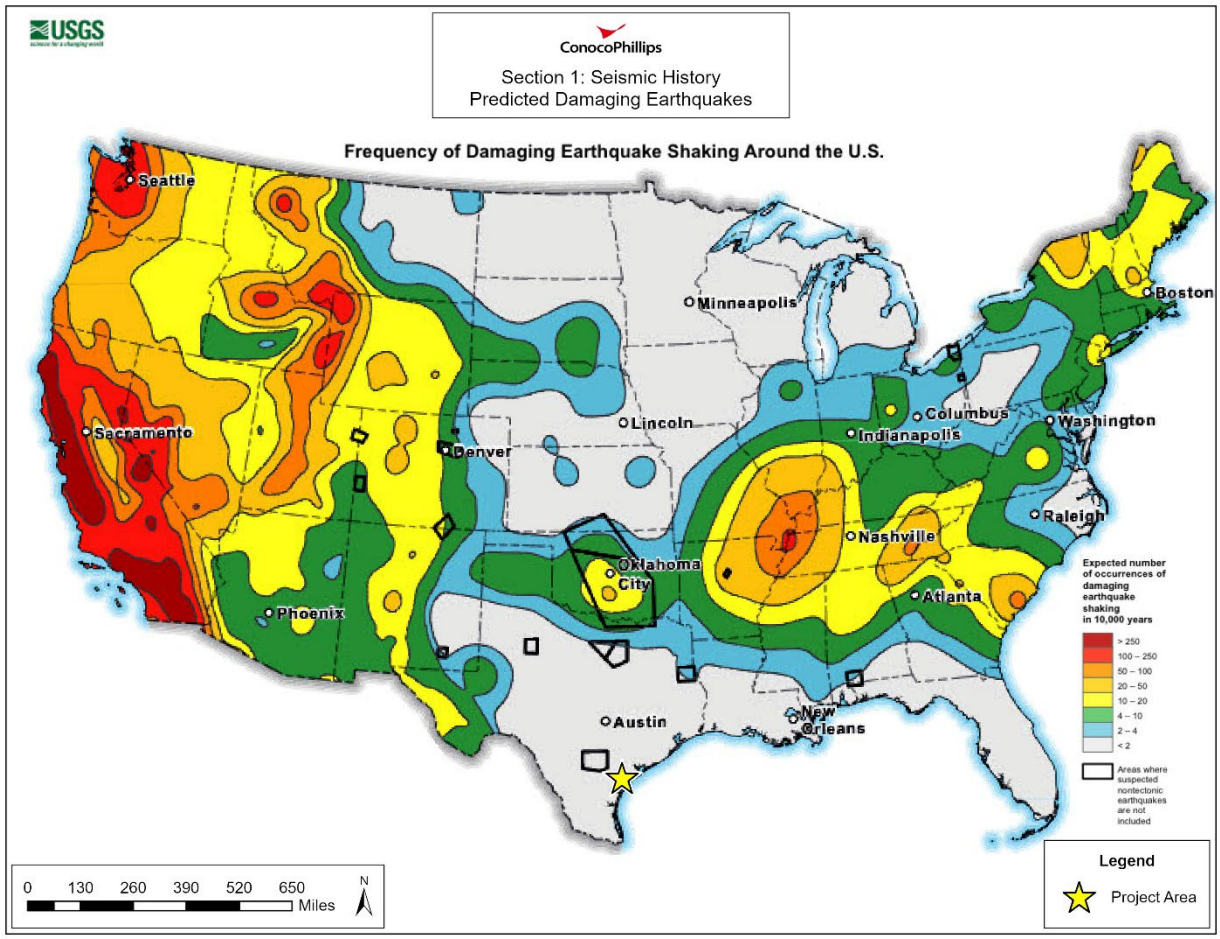


Figure 1-157 – Predicted damaging earthquakes shaking around the U.S. in relation to the Project area ("Frequency of Damaging Earthquake Shaking Around the U.S.", accessed 2024).

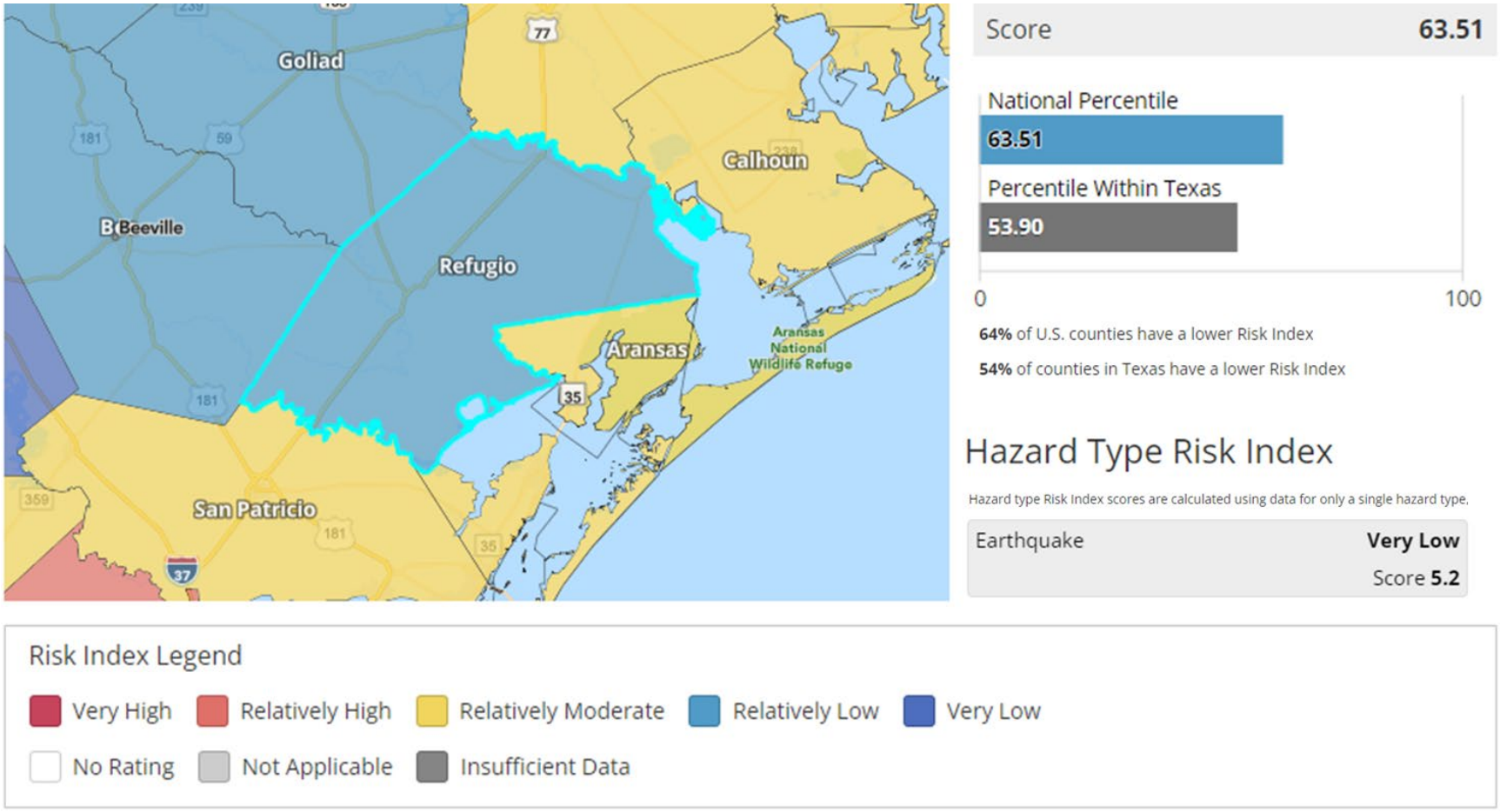


Figure 1-158 – Risk Index Map for Refugio and Aransas Counties, Texas (Nation Risk Index FEMA, 2024).

1.11 Conclusion

The geological setting of the Project presented in this Site Characterization supports the proposed CO_2 injection and storage operations.

The stratigraphy of the Texas Gulf Coast provides an ideal environment for CO_2 storage. Porous and permeable Miocene- and Frio-age sands within the injection interval are of sufficient thickness and lateral continuity to support the proposed injection operations outlined in *Section 4 – Engineering Design and Operating Strategy*. The UCZ and LCZ are of sufficient thickness and lateral continuity to prevent migration of the injectate outside the injection interval. The expected injected fluid composition is compatible with the mineralogy of the injection and confining zones and in-situ brine chemistry.

Data from multiple sources were analyzed and incorporated to identify potential USDWs across the Project AOI. The USDW base was mapped and evaluated to be unaffected by proposed injection operations. Additional protection is conferred by hundreds of feet of regional confining system between the robust UCZ and the base of the USDW, further isolating USDWs.

Investigation of multiple 3D seismic surveys with ample well control did not detect transmissible faults across the UCZ within the bounds of the CO_2 plume. Additionally, there are no known conduits capable of transmitting fluid to USDWs. The Project is in an area of low tectonic activity, and injection operations are designed to maintain peripheral fault stability.

The analyses performed in preparation of the Project's site characterization support CO_2 injection operations and confirm the protection of surrounding USDWs. Furthermore, the minimal number of wells within the AOR and extensive analysis of offset production and well data indicate that mineral resources will not be adversely affected, reinforcing the Project site as an ideal location for CO_2 injection and permanent storage.

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Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 2 – PLUME MODEL

July 2024

SECTION 2 – PLUME MODEL

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2.1 Introduction

The following discussion of the CO_2 plume model used for the ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) project (Project) was prepared by ConocoPhillips Texas Gulf Coast CCS LLC (Operator) to meet the requirements of Texas Administrative Code (TAC) 16, **§203(d)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84**]. This section describes the key details of Operator's dynamic reservoir simulation model for the Project. The extent of the CO_2 plume and the extent of pressures in the simulation model define the pore space rights requirements and area of review (AOR) for the six proposed CO_2 injection wells, monitoring plans, corrective action plan, and the overall viability of the Project. Both *Section 3 – AOR and Correction Action Plan* and *Section 5 – Testing and Monitoring Plan* use results from the dynamic simulation to help determine the best strategies and plans to minimize the impact of permanent CO_2 storage.

The plume model characterizes the performance of the injection wells (Snapper North INJ 1, Snapper North INJ 2, Snapper North INJ 3, Snapper South INJ 1, Snapper South INJ 2, and Snapper South INJ 3), the 3D spatial distribution of the CO_2 plume, and the 3D spatial distribution of pressures over time, both during and after CO_2 injection. The 3D spatial extent of subsurface pressures affected by the injection of CO_2 is used to define the *pressure front*—which, together with the CO_2 plume, will be used to define the Project AOR. The dynamic simulation model incorporates detailed hydrogeologic data together with subsurface flow physics and fluid physical property/phase behavior modeling for both the native fluids and injected CO_2 in the storage interval.

The primary objectives of the dynamic simulation model (alternatively termed the "plume model" in this section) are as follows:

1. Select and evaluate optimal well locations for the injection and storage of CO_2.
2. Develop injection and completion management strategies to optimize the use of available pore space.
3. Evaluate the migration of CO_2 in the subsurface as well as pressure changes over time and space, to:
    a. Delineate the AOR.
    b. Develop strategies to prevent adverse impact on nearby wellbores and geological subsurface features within the AOR, to minimize the risk of endangerment to any Underground Source of Drinking Water (USDW).

2.2 Project Summary

Software

Petrel™ E&P Software [redacted] from SLB (formerly Schlumberger) was utilized to generate the geocellular model for this Project. This software was chosen for its seamless data

integration from seismic data and well log interpretation into the geocellular and dynamic reservoir simulation models, creating a high-quality representation of the reservoir and confining systems.

INTERSECT™ reservoir simulator [redacted]—a high-resolution reservoir simulator developed by SLB and widely used for conventional oil-and-gas reservoir simulation and CO_2 geological sequestration modeling—was utilized for CO_2 plume modeling. This software is designed to handle complex reservoir challenges by integrating advanced physics and high-performance computing.

Data Sources

Data sources needed to build the geologic and dynamic model include 3D seismic data, offset well logs, core data, and publicly available literature such as Society of Petroleum Engineers (SPE) and American Association of Petroleum Geologists (AAPG) peer-reviewed papers. Data used to build the static geologic model is further discussed in *Section 2.4*. The stratigraphic section modeled is the Miocene Oakville Formation to the Oligocene Greta and Frio sands shown in Figure 2-1.

Figure 2-1 – Injection zones stratigraphic section
showing the sands in the Miocene Oakville and Oligocene Greta and Frio sands.

An appraisal program with comprehensive data acquisition is planned to collect site-specific data, including logging and coring operations. The geocellular and dynamic models will be updated as key additional data are acquired.

2.3 Trapping Mechanisms

The primary trapping mechanisms at work in a CCS project and discussed in the following subsections are structural/stratigraphic trapping, capillary trapping (alternatively termed "residual saturation" trapping), solubility in brine, and mineral trapping mechanisms. All these mechanisms [redacted] were incorporated into the current dynamic plume model. Mineral trapping was not modeled due to its slow occurring nature (hundreds or thousands of years, well beyond the injection and post-injection monitoring time frames).

When CO_2 is injected into a subsurface geologic zone (also termed "reservoir," "injection zone," or "storage interval") as part of a CCS project, the CO_2 will initially be in the form of a mobile, CO_2-rich supercritical phase. The injected CO_2 will displace the native reservoir brine as it moves laterally and vertically into the reservoir. As CO_2 is injected, its predominant movement in the near-wellbore zone will be radially away from the wellbore within permeable intervals, driven by pressure gradients between the higher-pressure wellbore and the surrounding reservoir volume. Over time, and with increasing distance from the injection wellbore, the radial pressure gradients become less dominant, allowing for a more significant vertical component to the movement of CO_2. This vertical component is driven by gravity and the contrast in density between the injected CO_2 and the native reservoir brine (i.e., buoyancy effects). Figure 2-2 illustrates these mechanisms at work [redacted]

After injection ceases within a given completion interval, the injection-induced pressure gradients due to darcy flow of fluids within the high-permeability storage interval will rapidly dissipate. Gravity will then dominate the CO_2 movement. The fluid will move vertically until it encounters stratigraphic and structural barriers to flow (e.g., shale and/or silt intervals), after which it will move laterally updip. As the CO_2 migrates, it will contact additional volumes of rock (pore space), where some portion of the CO_2 becomes trapped by capillary forces or dissolution within the aqueous phase. The remaining mobile CO_2 will continue to migrate updip until completely trapped and/or it encounters structural/stratigraphic barriers (traps). Figure 2-3 illustrates this, [redacted] The right panel shows the cross-section line utilized for those snapshots.

Figure 2-2 – Cross section showing CO_2 saturation,
[redacted] after start of injection (left) then [redacted] after start of injection (center).

Figure 2-3 – Cross section showing CO_2 saturation, [redacted] after start of injection (left) then 50 years post-injection (center).

Structural and Stratigraphic Trapping

Structural or stratigraphic trapping is a physical form of trapping where the injected CO_2 is immobilized at boundaries between permeable and impermeable beds or other flow barriers. It is often referred to as buoyant trapping. The CO_2 that is injected into the subsurface is less dense than formation fluid (or brine), and therefore begins to migrate upward by buoyancy. Mobile CO_2 will continue to rise until it encounters a rock that has a capillary entry pressure that is greater than the buoyancy or hydrodynamic forces. If the overlying rock has sufficiently high capillary entry pressure, it will act as a seal, preventing further vertical migration of the CO_2. Where there are structural and stratigraphic features such as anticlinal folds and/or stratigraphic changes, the buoyant CO_2 will accumulate in the same manner as naturally occurring hydrocarbons that are trapped in the subsurface.

In this simulation model, the in situ post-injection CO_2 density ranges between [redacted] and [redacted] pounds per cubic foot (lb/ft^3) at the shallowest and deepest intervals, respectively. This compares to the average native brine density of [redacted] Properties for the fluids (e.g., CO_2 and brine) are calculated internally in the dynamic simulation model using the Modified Peng-Robinson equation of state (EOS) (Peng & Robinson, 1976) (Robinson & Peng, 1978) (Peneloux, Rauzy, & Freze, 1982).

Capillary Trapping

The movement of supercritical CO_2 and native formation fluids will be affected by the gas-liquid relative permeability relationships between the injected CO_2 and the formation brine. Note that at all points within the storage interval, the CO_2 phase will exist as a supercritical gas. In addition to the CO_2 phase, some portion of the injected CO_2 may exist as a dissolved aqueous phase or precipitated solid phase. Only the supercritical gas and the dissolved aqueous phases are present in the dynamic model, as the mineral trapping mechanisms are not activated in this model. Note that the terms "CO_2 phase," "supercritical," and "gas" may be used interchangeably in this section.

Relative permeability effects on fluid flow are dependent on the *direction* of saturation changes. The displacement of brine by injected CO_2 (termed the *drainage* process) behaves differently than the reverse (the *imbibition* process). As CO_2 is injected, it displaces the native brine in the reservoir. The non-wetting CO_2 will initially occupy the most favorable flow channels, allowing the CO_2 to be mobile at very low initial saturations. With increasing volumes of CO_2 moving through a pore network, the CO_2 saturation will increase as the CO_2 phase occupies smaller and less favorable flow channels in the pore space. In the reverse direction, water displaces CO_2 from the pore space under the imbibition process. Increasing saturations of brine will bypass some of the CO_2-occupied pores, leaving a portion of the CO_2 phase in an immobile condition (Land C. S., 1971).

The imbibition process becomes important in the movement and trapping of the CO_2 after injection ceases. As the CO_2 rises or moves updip (driven by buoyancy effects) within the reservoir, the volume formerly occupied by the CO_2 will be filled by formation brine. The amount

of residual (i.e., trapped) CO_2 saturation present in a rock volume will be a function of the maximum trapped gas parameter and the CO_2 saturation at the beginning of the imbibition process (Land C. , 1968). The higher the maximum CO_2 saturation "seen" by a rock volume, the higher the amount of CO_2, which will be trapped in that rock volume. This phenomenon is termed *relative permeability hysteresis* and is implemented in the INTERSECT simulator using the Carlson and Land method (Carlson, 1981).

A value of [redacted] was chosen for the maximum trapped-gas saturation parameter. This number represents a reasonably conservative value when compared to values calculated for the average porosity in the simulation model. This parameter is further discussed in *Section 2.5*, on the dynamic plume model. A less conservative (i.e., higher) value for this parameter would result in additional residual-gas trapping and slower plume migration.

Solubility Trapping

Solubility trapping is a form of chemical trapping in which the CO_2 becomes dissolved within the aqueous phase. The capacity for the native brine to store dissolved CO_2 is affected by the salinity, pressure, and temperature of the system. For the reservoir conditions represented in Operator's dynamic simulation model, brine contacted by the CO_2 phase can have up to [redacted] mole percent of dissolved CO_2. The CO_2-saturated brine will be slightly denser than the original-in-place brine. Over centuries, this density difference may affect the convective mixing of the water phases, resulting in the solubility trapping of additional moles of CO_2 within the aqueous phase.

The solubility of CO_2 is incorporated into the INTERSECT compositional simulator. Solubility tables for CO_2 in brine were generated with the Calsep PVTsim software, using the modified Peng-Robinson EOS (Robinson & Peng, 1978) (Peng & Robinson, 1976) (Peneloux, Rauzy, & Freze, 1982) with Huron-Vidal (Huron & Vidal, 1979) mixing rules.

Mineral Trapping

Mineral (or geochemical) trapping is another form of chemical trapping that occurs because of reactions between CO_2 and the geochemistry of the formation. At present, there are no site-specific, quantitative mineralogical composition data for the proposed storage interval. As discussed in *Section 1.7.4*, while geochemical trapping may 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. Furthermore, because the expected reactions occur over long time frames, the precipitation of minerals will not impact the injectivity of CO_2 during injection.

[redacted]

Trapping Summary

The mechanisms by which CO_2 is trapped in the storage reservoir are illustrated in Figure 2-4. This figure shows the mass of injected CO_2 in the respective mobile and trapped phases over time, from Project start to 50 years post-injection. The amount of mobile CO_2 quickly decreases following the end of injection. After 50 years post-injection, only [redacted] of the CO_2 remains potentially mobile (this includes volumes that are structurally trapped). The remainder of the CO_2 is in trapped phases, with [redacted] and [redacted] of the total injected volume being trapped as immobile residual CO_2 and dissolved CO_2, respectively.

Figure 2-4 – CO_2 trapping mechanisms summary over time.

2.4 Conceptual Site Model

Static (Geocellular) Model

The geocellular model was designed to encompass several of the 3D seismic surveys—and expanded to include areas where log data is available to capture the coverage of the geological and geophysical data for the Project area. The model area covers approximately [redacted] Figure 2-5 summarizes the distribution of well log and seismic data as well as the extent of the 3D geocellular model, shown on the map as the area of interest (AOI). The term "area of interest" is used to describe the broader geocellular model area.

Figure 2-5 – Map of the Project area showing the AOI and more
(underground storage easement, 3D seismic outline, wells with formation tops, and locations of stratigraphic test and proposed injection wells).

The geocellular model construction includes the following major steps:

- Building the structural framework and creating the 3D grid
- Distributing facies and properties through the model

Petrel E&P Software [redacted] from SLB was used to generate the geocellular model for the Project. This software is chosen for its seamless integration from seismic and well log interpretation to geocellular modeling to reservoir simulation, enabling the accurate modeling of the reservoir and confining systems.[1]

Structural Framework

The structural model was built based on the interpretation of seismic and formation tops. Seismic time horizons were converted to depth and integrated with the formation tops from [redacted]

[1] www.software.slb.com/products/petrel/petrel-geology-and-modeling

wells inside the areal extent of the model for [redacted] Table 2-1 summarizes the model horizons and sources used to generate them.

Table 2-1 – Summary of the model horizons and sources used to generate them.

No.	Horizon Name	Well Tops Used	Seismic Horizon Used
[redacted]			

[redacted]

Figure 2-6 – 3D view of the main zones of the model

Using this structural model (Figure 2-6, depths shown in true vertical depth subsea (TVDss)), the 3D grid was created with horizontal cell dimensions of Vertically, a proportional layering method was applied, leading to the vertical cell dimensions ranging from with an average of Table 2-2 provides a summary of the model zones and their gridding parameters. The number of grid cells in the constructed model totaled

The seismic volumes, attributes, and lithological data from the well logs provided insights into the sealing capacities for the proposed confining zones and main depositional trends. The analysis also confirms the good regional sealing capacities of the Anahuac deep marine shale. The injection intervals are formed by amalgamated shoreface/barrier clean and well-sorted sands.

Table 2-2 – Summary of the model zones and their gridding parameters.

[redacted]

Zone	Top	Base	No. of Layers	Min Thickness (ft)	Max Thickness (ft)	Mean Thickness (ft)
[redacted]						

Rock Property Distribution

For regional scale facies trend maps (net-to-gross sand and shale), [redacted] wells were used. Lithofacies were interpreted in the model AOI for [redacted] wells with spontaneous potential (SP) or gamma ray (GR) derived shale volume (VSH) logs, which are shown in Figure 2-7. [redacted]

Figure 2-8 shows an example of a facies log interpretation. The interpreted logs were then upscaled for use in the facies property model and the information obtained from the seismic and log data facies-distribution analysis.

Figure 2-7 – Map of the Project area showing wells with VSH logs used for model population and more (underground storage easement, 3D seismic outline, geocellular outline (AOI), well cross section shown in Figure 2-8, location of stratigraphic test and proposed injection wells).

Figure 2-8 – Well cross section example

Figure 2-9 – Facies distribution
The blue rectangle is the AOI (coincidental with geocellular outline), and the white squares are control points for the distribution map.

The facies distribution trends from the well logs were used in conjunction with variogram trends for each zone to distribute facies within the model layers. Variogram parameters were estimated Table 2-3 summarizes variogram parameters and facies distribution for each of the model zones.

Table 2-3 – Facies distribution: variogram parameters and facies fractions for the model zones.

Zone	Variogram Parameters				Facies Fractions (%)			NTG Sand and Shale Trend Maps Used
	Major Range (ft)	Minor Range (ft)	Vertical Range (ft)	Major Azimuth (deg)	Sand	Silt	Shale	
[redacted]								

The facies analysis also included an estimation of the facies proportions and distributions within the zones based on the upscaled logs (Figure 2-10). These calculated proportions were used as an additional constraint in the property modeling. [redacted] The results of the output are shown in Figures 2-11 and 2-12.

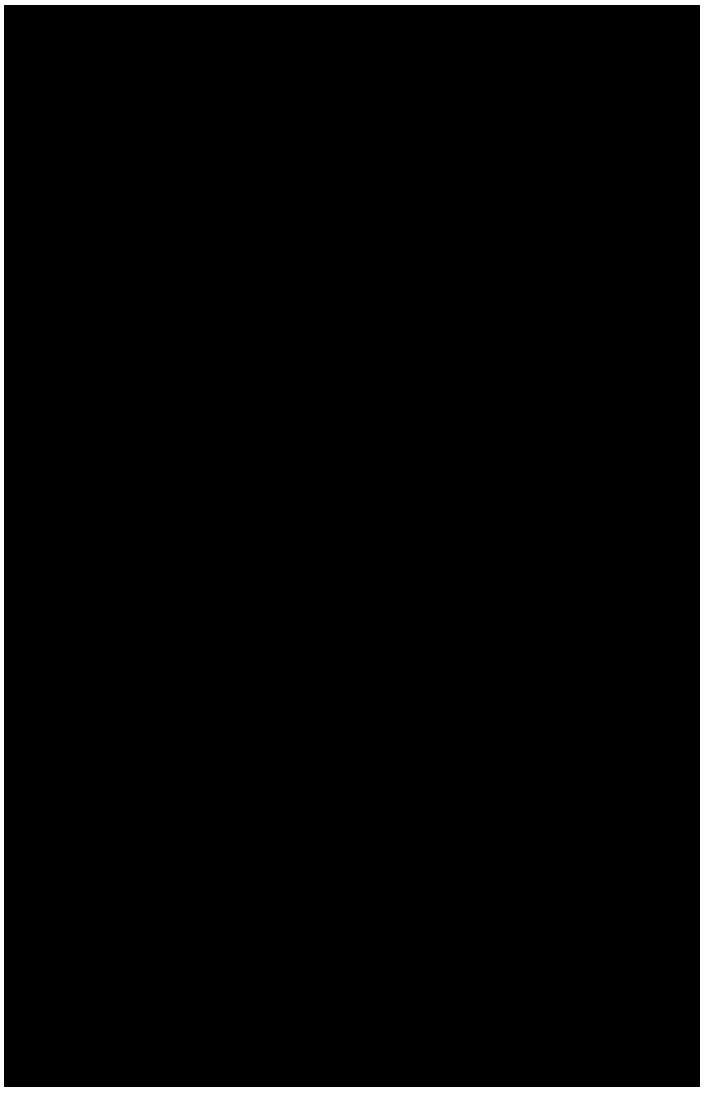


Figure 2-10 – Example of estimated facies vertical proportions

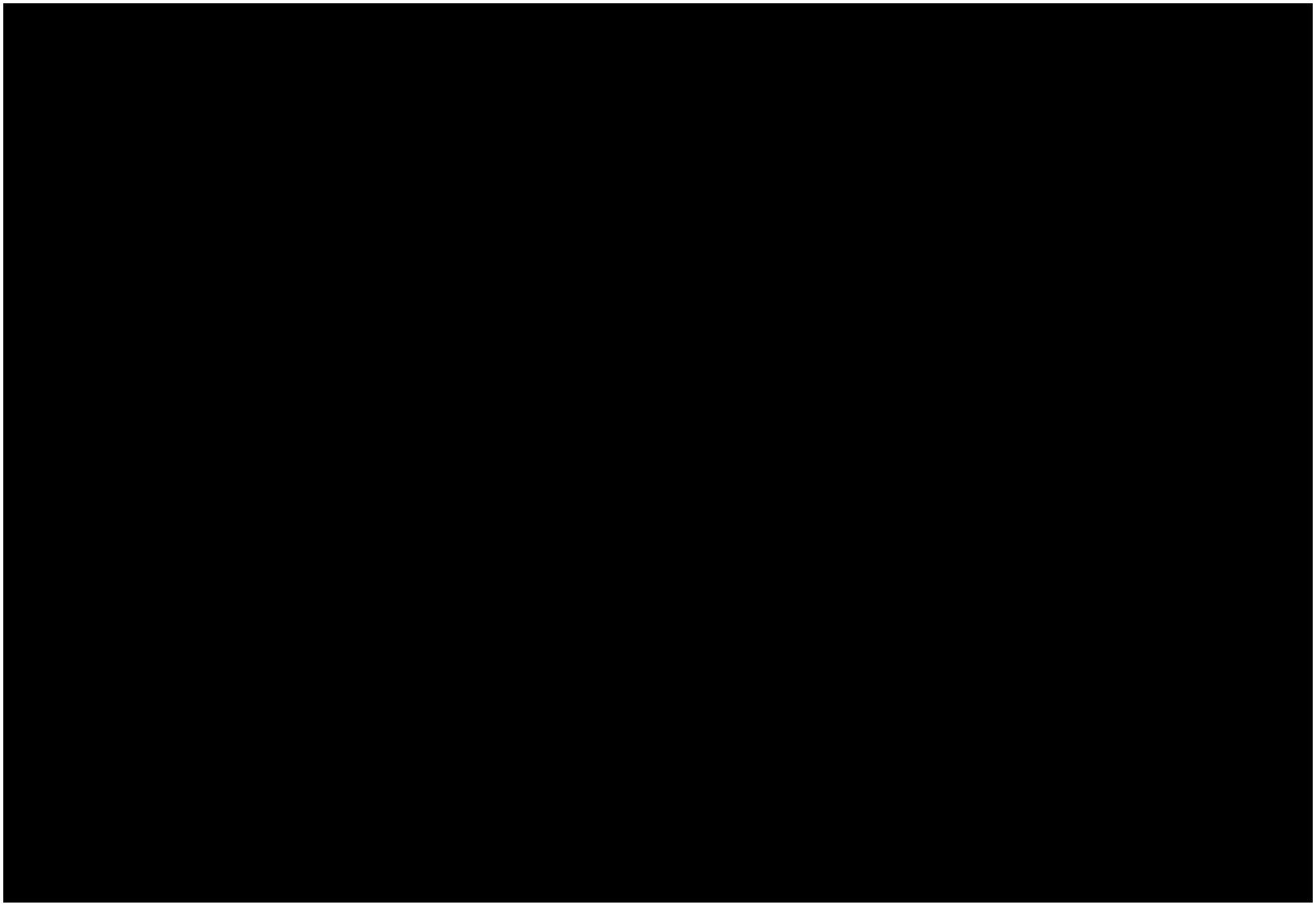


Figure 2-11 – Facies distribution within the 3D geocellular model. Depths are TVDss.

Figure 2-12 – Cross section across the injection wells, showing a facies distribution within the 3D geocellular model

Permeability/Porosity Distribution

A relationship for permeability (k) based on total porosity (ϕ_T) was derived from core porosity and permeability data [redacted] shown in Figure 2-13. [redacted]

Eq. 2-1 $Log_{10}(k) =$ [redacted]

[redacted] yields the following relationship for permeability (in millidarcy (mD)) as a function of fractional porosity:

Eq. 2-2 $k =$ [redacted]

[redacted]

Figure 2-13 – Porosity and permeability relationship.

For the geocellular model porosity and permeability distribution, the porosity logs calculated during petrophysical analysis were conditioned to facies [redacted] (Figure 2-14). Figure 2-15 shows a porosity-distribution histogram indicating that log porosity values were accurately preserved during the upscaling and model construction. Permeability was also upscaled into the model conditioned to facies. Permeability values (derived from porosity-permeability cross plots) were distributed into the model [redacted] (Figure 2-16).

Figure 2-14 – Cross section across the injection wells, showing a porosity distribution within the 3D geocellular model

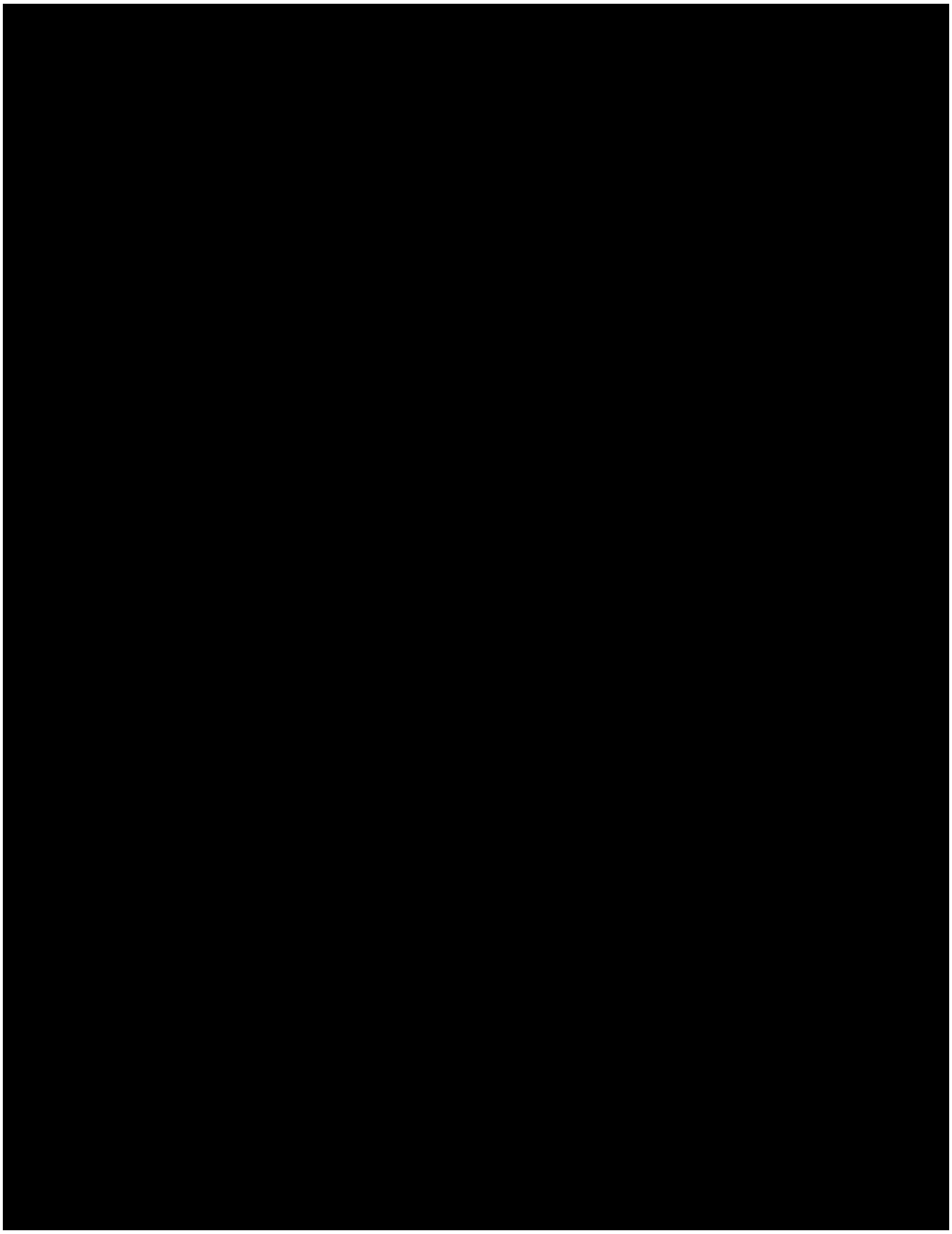


Figure 2-15 – Histogram comparing porosity
from raw logs, upscaled logs, and property model.

Figure 2-16 – Cross section across the injection wells, showing a permeability distribution within 3D geocellular model

2.5 Dynamic Plume Model

Model Orientation and Gridding Parameters

Spatial Conditions

The geocellular model for the plume modeling provides a representation of the subsurface geology for the core AOI, which spans [redacted] A cartesian grid is utilized, which contains [redacted] gridblocks in the x-direction, [redacted] gridblocks in the y-direction, and [redacted] gridblocks in the z-direction, with a total number of gridblocks of [redacted] The grid block size is [redacted] in the horizontal directions and the block thickness varies from [redacted], with an average of [redacted] The selection of gridblock sizes was carefully considered to balance simulation run time with sufficient resolution to capture the dynamic CO_2 saturation front, as determined from a grid-size sensitivity study of CO_2 injection simulation.

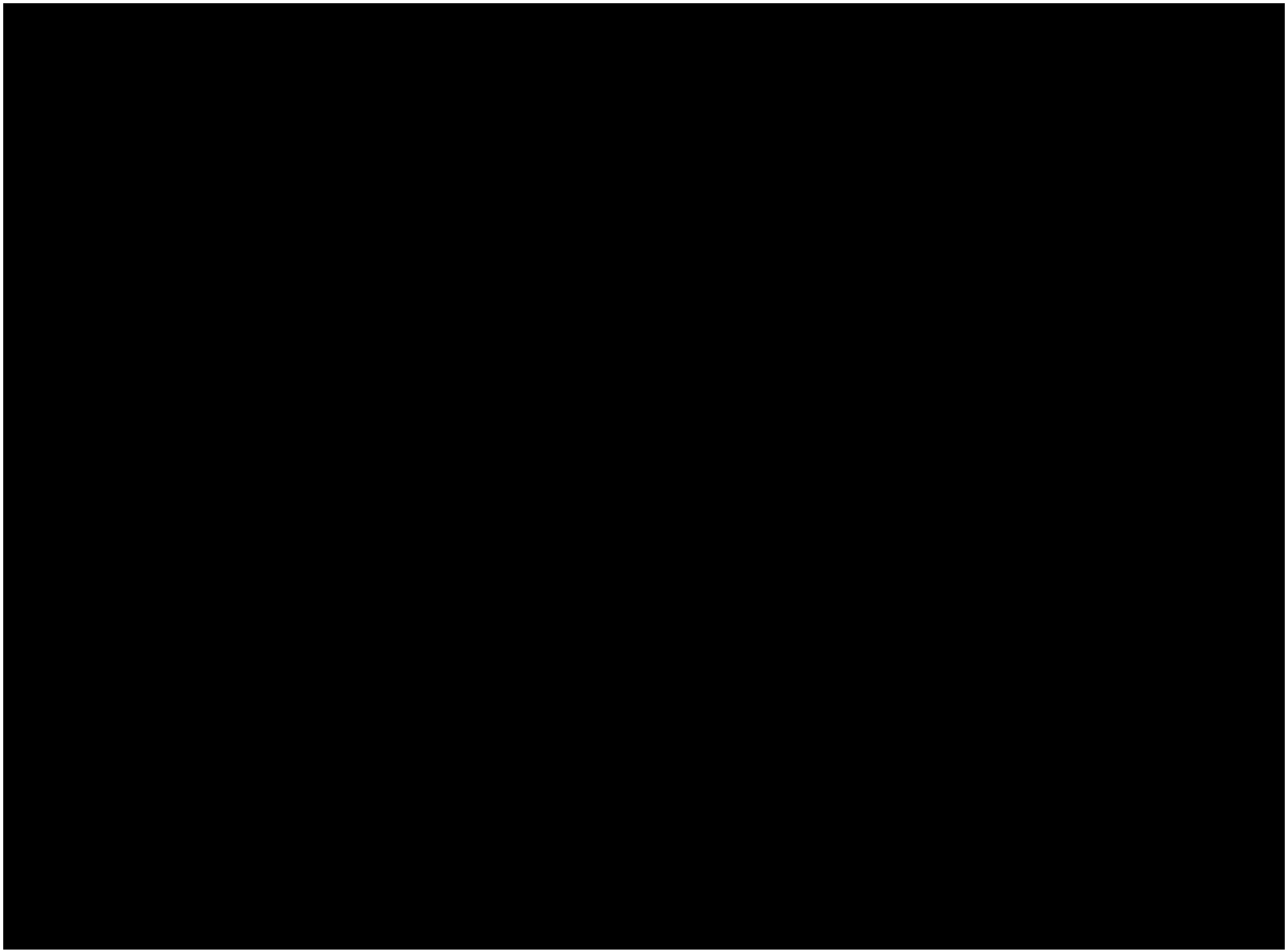


Figure 2-17 – Cross section showing porosity and permeability properties.

Fault Representation in Dynamic Simulation Model

Faults created in the static geocellular model have been incorporated into the dynamic simulation model. The dynamic model identifies faults based on offset corner-point coordinates for adjacent gridblocks (e.g., in the same layer). [redacted] For purposes of this discussion, a *transmissible* fault is one that permits fluid flow and pressure communication normal to the fault between gridblocks juxtaposed with one another (e.g., in the horizontal plane). A *conductive* fault would be one that allows fluid flow and pressure communication *within* the fault plane (e.g., a fault that permits pressure communication to occur vertically between zones at differing depths).

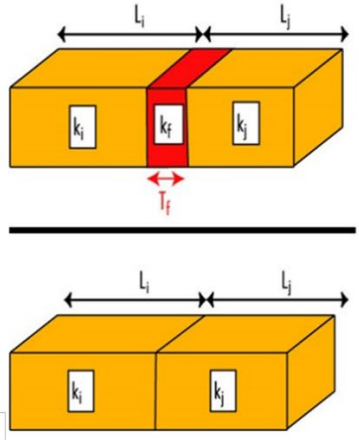
[redacted]

Transmissibility modifiers (TMs) were calculated from the 3D geomodel following the method presented by Manzocchi et al. (1999). Fault TM is the ratio of the faulted transmissibility to the unfaulted inter-block transmissibility, varying from 0 (sealing fault) to 1 (no fault), and is determined by the following formula, where faulted transmissibility ($Trans_{if}$) depends on the grid cell size (L_i, L_j), the thickness of the fault (T_f), and the permeability of the wall rock (k_i, k_j), and the fault permeability (k_f).

$$TM = \frac{Trans_{ij} = \left(\frac{2}{\frac{L_i - t_f}{k_i} + \frac{2t_f}{k_f} + \frac{L_j - t_f}{k_j}} \right)}{Trans_{ij} = \left(\frac{2}{\frac{L_i}{k_i} + \frac{L_j}{k_j}} \right)}$$

Faulted transmissibility

Non-faulted transmissibility



TM varies between:

0 – sealing
1 – juxtaposition/no fault

From SLB©

Fault permeability in the static geomodel was calculated from the shale gouge ratio (Yielding et al., 1997) and calibrated to porosity-permeability data from core taken in the [redacted]—using the method presented in Grant (2019). Fault thickness is calculated as a function of fault throw. Globally, fault thickness/throw relationships vary considerably depending on lithologic type and fault evolution (thickness:throw, 1:10 to 1:400)[redacted] The determination and

implementation of transmissibility modifiers within the Petrel Model become more complex than the previous example, as the cross-fault juxtaposed area will usually be nonorthogonal.

Boundary Conditions

An infinitely acting aquifer is assumed in the simulation due to the regional characterization of aquifers in Gulf Coast areas. A pore volume multiplier factor of [redacted] is applied to the boundary gridblocks of the model, as illustrated in Figure 2-18.

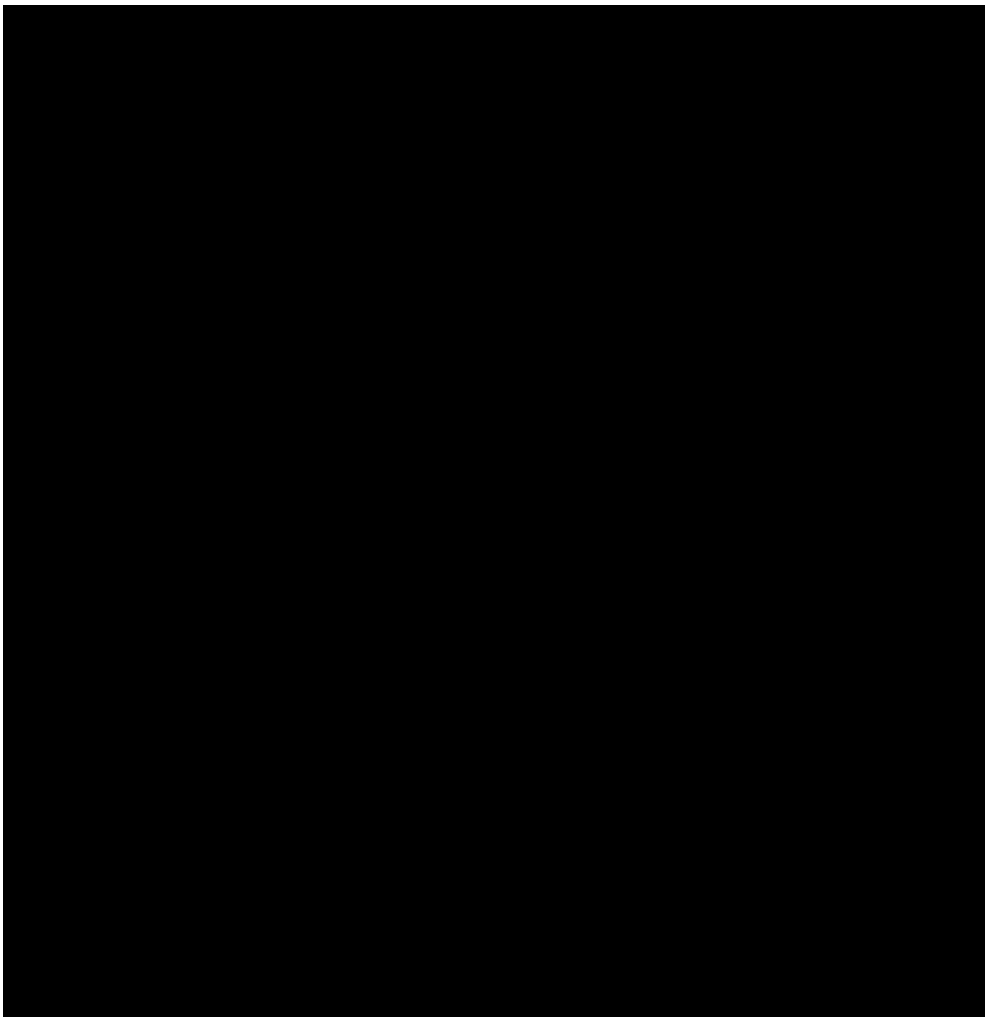


Figure 2-18 – Model boundary conditions.

Model Time Frame

The model was run for [redacted] followed by 50 years of post-injection monitoring to allow for pressure and plume growth stabilization. Figure 2-19, showing plume area and growth rate vs. years from the start of injection, illustrates that the plume growth reaches a stabilization level [redacted]

Figure 2-19 – CO_2 plume size and growth rate vs. time.

Initial Conditions

Table 2-4 provides a summary of the initial conditions input into the model.

Table 2-4 – Initial model input conditions summary.

Inputs	Values
Average Porosity (%)	[redacted]
Average Permeability (mD)	
Initial Water Saturation (%)	
K_v/K_h Ratio in Sand / Silt / Shale	
Datum Pressure (psi)	
Depth for Datum Pressure (ft subsea)	
Calculated Brine Density at Datum Depth (lb/ft^3)	
Calculated Brine Viscosity at Datum Depth (centipoise)	
Formation Compressibility (psi^{-1})	
Brine Compressibility (psi^{-1})	

Porosity/Permeability Discussion

Gridblock permeability was determined with Equation 2-2, in which permeability in mD is calculated as a function of fractional porosity. The data from which this relationship is derived are displayed in Figure 2-13.

The formula [redacted] is assumed—and used to account for the typical [redacted] assumption used for oil/gas reservoirs and the facies difference contributing to the vertical flow.

Reservoir Pressure Discussion

Reservoir pressure within the dynamic simulation model is distributed internally by the simulator using the calculated in situ brine densities at each gridblock's respective temperature and pressure. [redacted] This datum pressure is based on a gradient of established from measurements taken from [redacted]

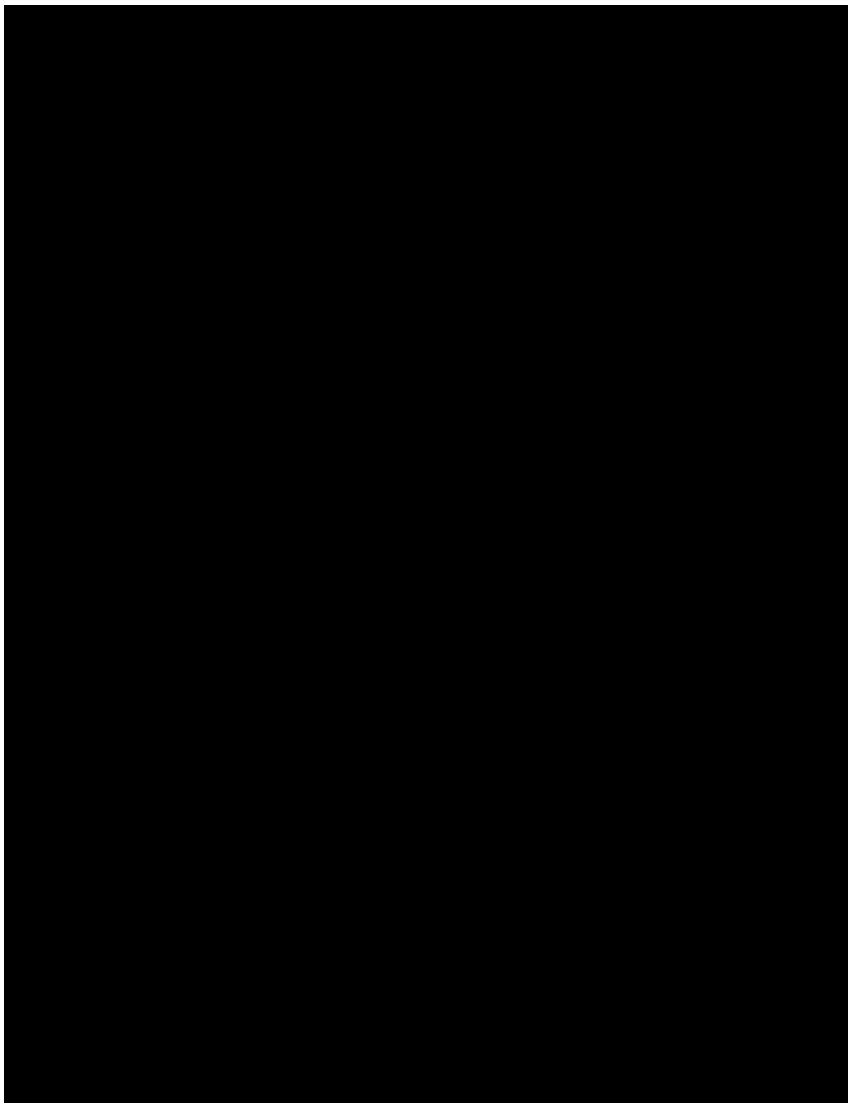


Figure 2-20 – Pressure data

Pressures throughout the storage interval will be updated with the collection of formation pressure data from the planned stratigraphic test wells. Dynamic modeling will be updated to incorporate the data when available.

Fracture Gradient Calculation

Eaton's method (Eaton, 1969), widely acknowledged as a standard practice for the determination of fracture gradients, was used to calculate the pressure required to fracture the injectable rock. The method uses a relationship between Poisson's ratio (ν), overburden gradient (OBG), and the pore pressure gradient (PG) to determine the fracture gradient (FG) (Eq. 2-4). Table 2-5 provides the values of each input.

Table 2-5 – Fracture gradient calculation assumptions – Eaton's method.

Inputs	Miocene "Oakville" and Oligocene "Greta"	Oligocene "Frio"
Poisson's Ratio	[redacted]	
Overburden Gradient (psi/ft)		
Pore Pressure Gradient (psi/ft)		

Poisson's ratio was informed through a literature review and calculated using a petrophysical relationship between compressional and shear sonic. [redacted] Poisson's ratio for lithologic units can be obtained from compressional (Vp) and shear (Vs) velocities (Eq. 2-3, e.g., Mavko et al., 2009), and this was the approach taken for the Project [redacted] During the drilling of the stratigraphic test wells, core samples will be collected and tested, and correlated with log data to estimate the fracture gradient more accurately.

Eq. 2-3 $$Poisson\ Ratio\ (\nu) = \frac{Vp^2 - 2Vs^2}{2(Vp^2 - Vs^2)}$$

[redacted]

With the inputs, it is possible to calculate a fracture gradient. Equation 2-4 highlights the necessary steps for calculating the gradient for Miocene/Greta and Frio formations. Per 16 TAC **§5.203(i)(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] to injection wells based on the injection formation.

Eq. 2-4 $$FG = \frac{\nu}{1-\nu}(OBG - PG) + PG$$

[redacted]

Reservoir Temperature Discussion

The formation temperature was estimated from well logs near the Project area. The wells selected for this evaluation are [redacted] and the distances from those wells to the injection wells range from [redacted] The formation temperature was calculated separately in two different zones. [redacted]

Reservoir Salinity Discussion

A constant salinity of [redacted] (ppm) total dissolved solids (TDS) was input for the entire model. This value is based on a combination of measured sample data and estimates calculated from well logs using apparent water resistivity (R_{wa}) derived from application of Archie's equation, converted to salinity using standard service-company (e.g., Schlumberger) petrophysical charts.

Rock Properties Hysteresis Modeling

Rock Compressibility

[redacted] For the purposes of this simulation, a value of [redacted] was chosen. This assumption will be updated as needed based on data collection during appraisal and initial Project implementation phases.

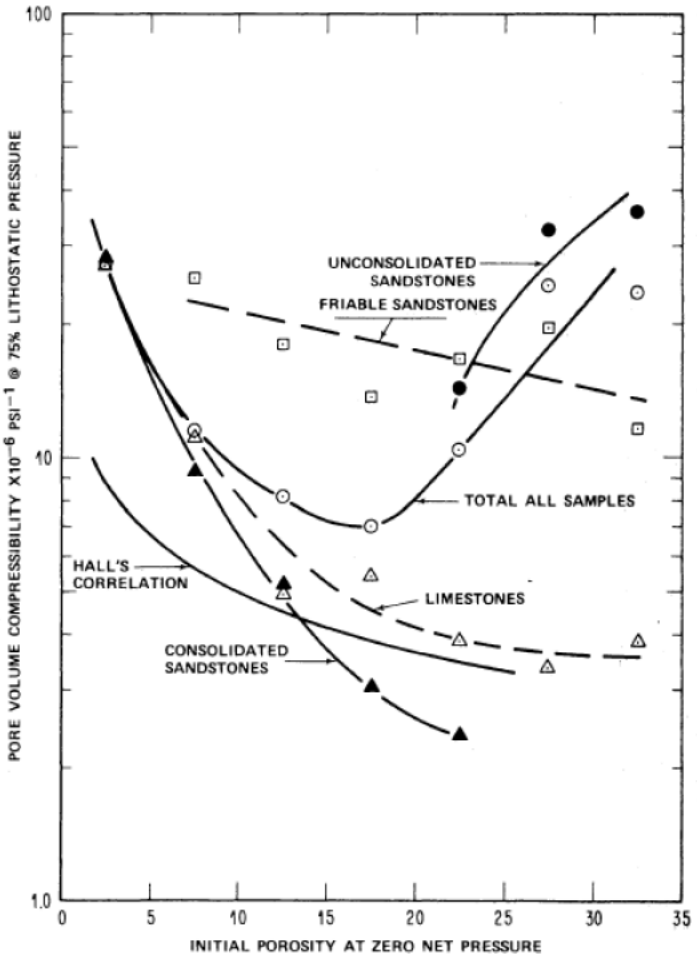


Figure 2-21 – Pore-volume compressibility vs. initial sample porosity (Newman, 1973).

Residual Gas (Non-Wetting Phase) Saturation

The value for residual gas saturation is a complex parameter dependent on the saturation history and direction of saturation changes for a particular rock volume. As CO_2 is injected into the reservoir, the gas saturations will increase until they exceed a critical value, above which the gas (or supercritical CO_2) becomes mobile. Under conditions of increasing CO_2 (non-wetting phase) saturation, the CO_2 phase finds the "easiest" flow paths to move through the pore space and is therefore mobile at very low saturations above the critical value. As its saturation increases, the CO_2 finds its way into progressively smaller and less accessible flow paths and pore spaces. While CO_2 is being injected, it is moving radially away from the injection wellbore, driven by injection-

induced pressure gradients (i.e., viscous forces) and vertically within the reservoir, driven by buoyancy of the lower density CO_2 (i.e., gravity forces). During injection, the near-wellbore region is dominated by the viscous forces; saturations will increase until injection ceases or the water saturation is driven down to its irreducible value. With increasing distance from the wellbore, the injection-induced pressure gradients become smaller, allowing gravity forces to become more significant. Likewise, once injection ceases within a particular zone of the reservoir, the viscous forces quickly dissipate. Gravity-driven flow becomes the dominant driver of fluid movement. Much of the reservoir will experience decreasing CO_2 saturations as gravity forces will cause the injectate to migrate vertically and laterally (updip) until it becomes trapped.

With decreasing CO_2 content, pore volume is "backfilled" by the influx of water. The CO_2 that had moved into the smallest pore spaces becomes a discontinuous immobile phase as water displaces the CO_2 from the larger flow paths. This immobile phase is the *residual* or *trapped* gas phase. The magnitude of the residual trapping is a variable dependent on the saturation history for a particular rock volume. It is modeled using empirical correlations developed by Land (Land C. , 1968) (Land C. S., 1971). The key parameter input for calculating the residual gas (CO_2) saturation at any point is the maximum residual-gas saturation (alternatively termed maximum trapped-gas saturation) parameter. This parameter corresponds to the residual trapped gas saturation for a rock volume where S_g has reached its maximum value (i.e., S_w driven down to irreducible by gas displacement).

The input maximum residual-gas saturation parameter (S_{grm}) for the dynamic plume model is based on a relationship derived by Holtz (Holtz, 2005). Figure 2-22 shows a relationship between porosity and maximum residual-gas saturation. In the simulation model, permeable sands have an average porosity of [redacted], which would suggest a maximum residual-gas saturation of [redacted] Given scatter in the data contained in this figure, a conservative value of [redacted] was chosen for the S_{grm} parameter in this simulation model.

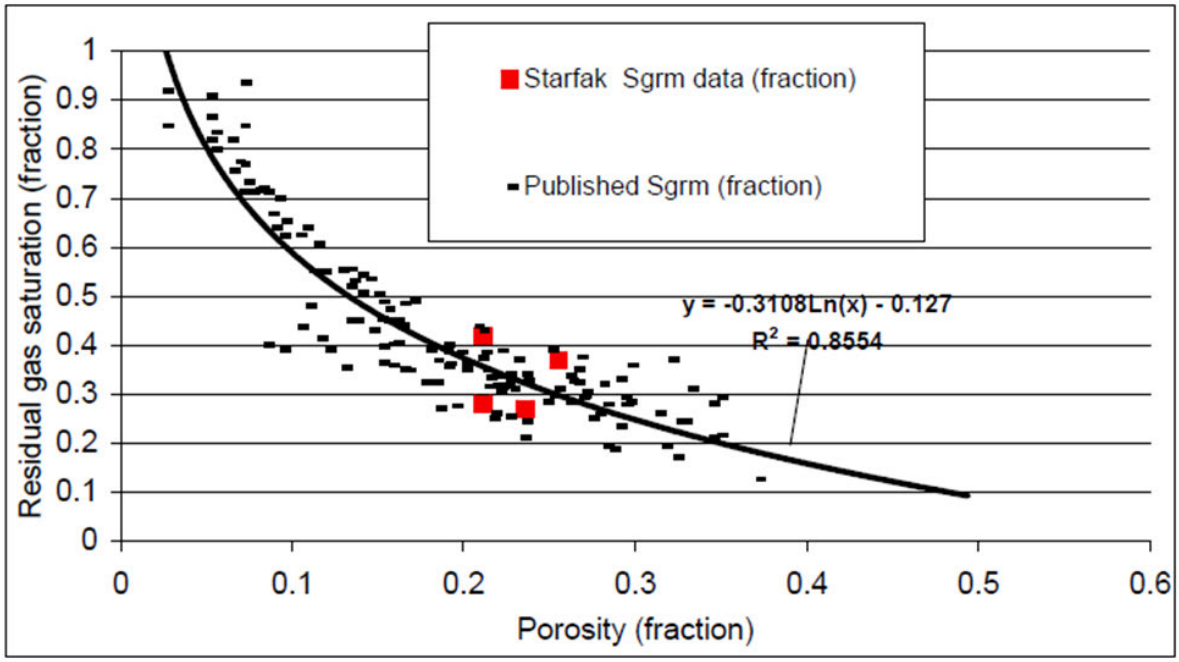


Figure 2-22 – Porosity vs. residual-gas saturation relationship (Holtz, 2005).

Relative Permeability Curves and Capillary Pressure

Relative permeability curves were generated using the industry-standard power-law model based on the approach developed by Brooks and Corey (Brooks & Corey, 1964). In this model, the relative permeability for the respective water and supercritical gas phases are based on the normalized saturation, scaled between the end points of mobility for a respective phase, and raised to an exponent value (termed the "Corey exponent"). The relative permeability curves were generated using Corey exponents [redacted] Irreducible water saturation was set at [redacted] The resulting relative permeability curves are shown in Figure 2-23.

Figure 2-23 – Two-phase relative permeability curves.

Current Project plans premise collection of core samples during stratigraphic test well drilling. Data from core samples and initial injectivity testing will be used to update model inputs and refine design and operational parameters.

2.6 Well Operations Setup

The Project consists of six injection wells, called the Snapper North INJ 1, INJ 2, and INJ 3—and the Snapper South INJ 1, INJ 2, and INJ 3. These injection wells are designed for flexible operations to allow the management of pressure response and plume growth throughout the storage interval. Figure 2-24 depicts a theoretical example of how this may be implemented in a CCS project. Under this strategy of operation, the well is first completed in the

deepest interval(s) and then sequentially isolated as perforations move uphole to subsequent shallower intervals.

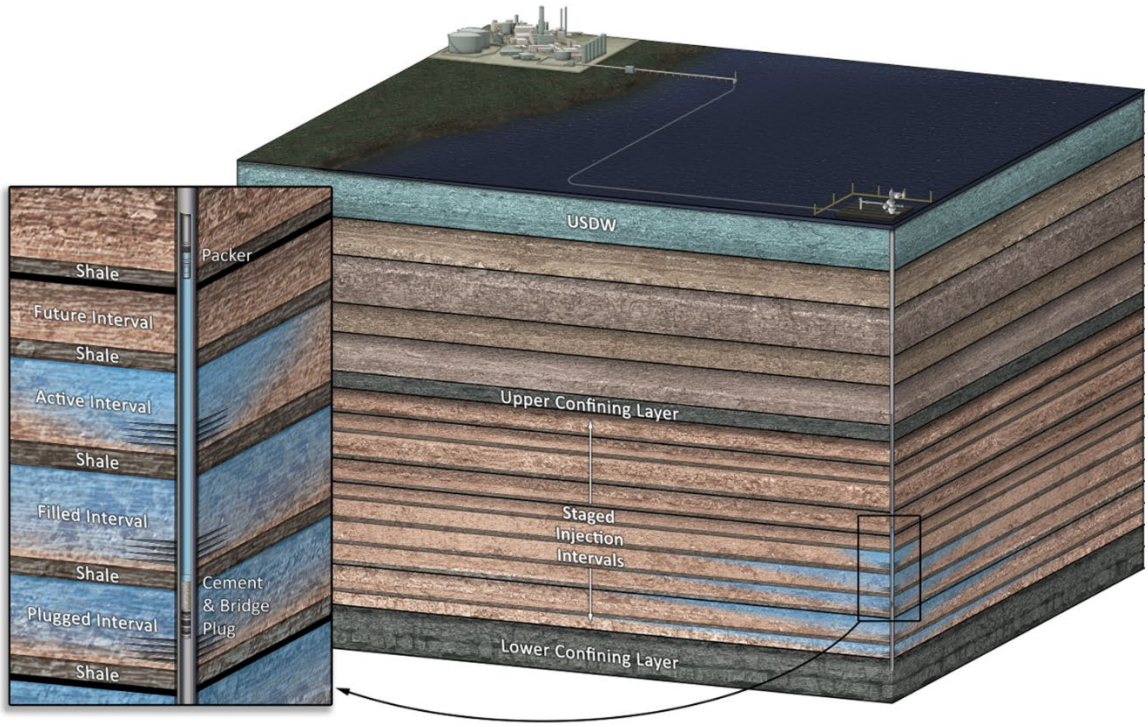


Figure 2-24 – Illustration of staged completion intervals strategy.

In the dynamic simulation model, the reservoir storage interval is divided into [redacted] completion intervals for CO_2 plume extent and pressure front management. [redacted] Each well will be completed sequentially, deeper to shallower, in [redacted] those sub-intervals in a manner to manage plume and pressure front extent—while staying within injection pressure limits for each well's respective active completion interval.

The modeled completion strategy is illustrated in Tables 2-6 and 2-7, showing the number of wells injecting in each formation sub-interval and how each well's active completion interval changes over time. Respective completion interval formations are color coded on the two tables.

Table 2-6 – Well count per formation sub-interval over time.

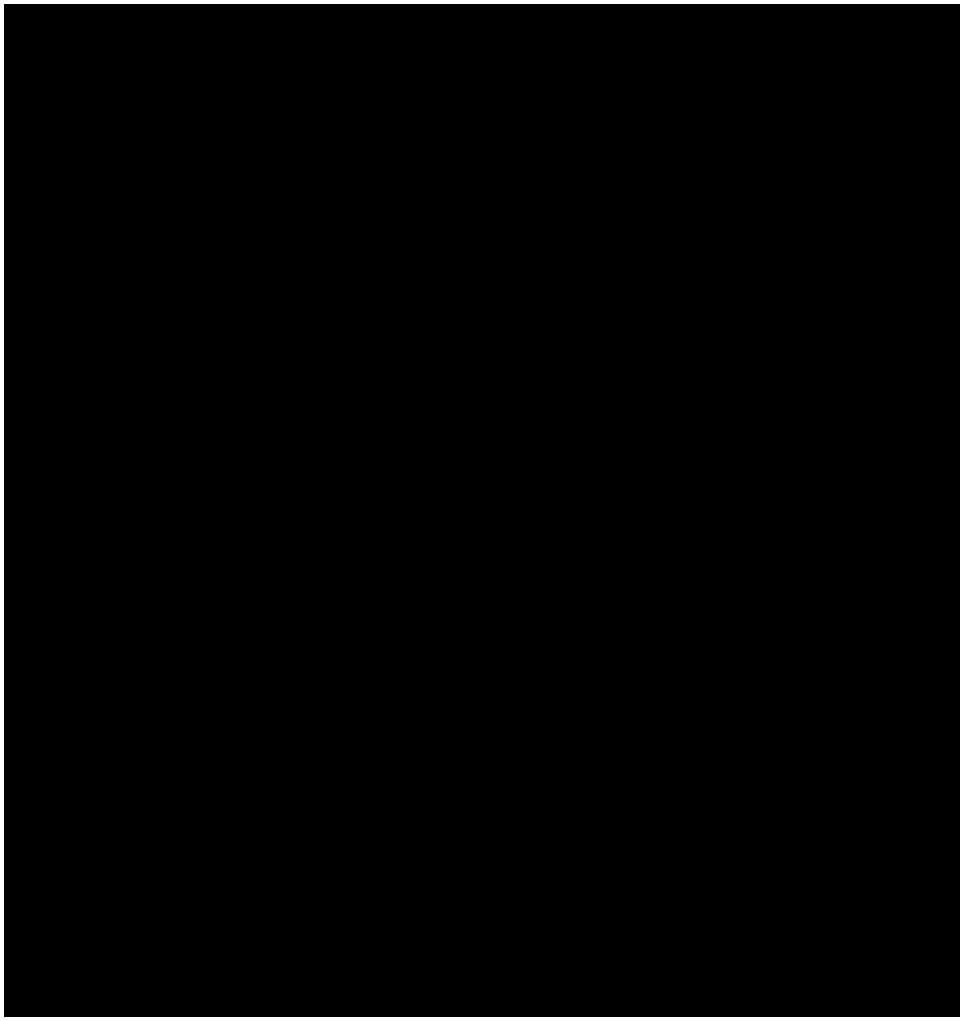


Table 2-7 – Injection rate by well over time, color coded by formation sub-interval.

Tables 2-8 through 2-13 show data for the planned completion intervals by well. These data include the formation sub-intervals, perforation depths in the simulator model, thickness data, stage duration in months, and maximum injection pressure limits based on 90% of the calculated fracture pressure. During recompletion activities, the deeper interval(s) can be isolated below a bridge plug or other isolation device.

Table 2-8 – Summary of completion intervals for Snapper North INJ 1.

Stage	Injection Interval	Depth – TVD ft*		Thickness – ft		Stage Duration (months)	Maximum Allowable Injection Pressure (psi)
		Top Perf	Base Perf	Gross Interval	Net Pay		
[redacted]							

*Datums for TVD are shown in *Section 3.1 – Project Information*

Table 2-9 – Summary of completion intervals for Snapper North INJ 2.

Stage	Injection Interval	Depth – TVD ft*		Thickness – ft		Stage Duration (months)	Maximum Allowable Injection Pressure (psi)
		Top Perf	Base Perf	Gross Interval	Net Pay		
[redacted]							

Table 2-10 – Summary of completion intervals for Snapper North INJ 3.

Stage	Injection Interval	Depth – TVD ft		Thickness – ft		Stage Duration (months)	Maximum Allowable Injection Pressure (psi)
		Top Perf	Base Perf	Gross Interval	Net Pay		
[redacted]							

Table 2-11 – Summary of completion intervals for Snapper South INJ 1.

Stage	Injection Interval	Depth – TVD ft		Thickness – ft		Stage Duration (months)	Maximum Allowable Injection Pressure (psi)
		Top Perf	Base Perf	Gross Interval	Net Pay		
[redacted]							

Table 2-12 – Summary of completion intervals for Snapper South INJ 2.

Stage	Injection Interval	Depth – TVD ft		Thickness – ft		Stage Duration (months)	Maximum Allowable Injection Pressure (psi)
		Top Perf	Base Perf	Gross Interval	Net Pay		
[redacted]							

Table 2-13 – Summary of completion intervals for Snapper South INJ 3.

Stage	Injection Interval	Depth – TVD ft		Thickness – ft		Stage Duration (months)	Maximum Allowable Injection Pressure (psi)
		Top Perf	Base Perf	Gross Interval	Net Pay		
[redacted]							

The dynamic plume model directly outputs the wellbore pressure at the perforation depths. Calculation of wellhead pressure requires application of wellbore hydraulics calculations which factor in the completion design as well as the injected CO_2 rates and conditions. [redacted]

Tables 2-14 through 2-19 show the input parameters used in the wellbore hydraulics calculations for each of the six injection wells. Pipeline outlet conditions are used to estimate wellhead temperatures based on Joule-Thomson (JT) cooling across the choke between the pipeline and the wellhead. [redacted]

Table 2-14 – Well hydraulics input summary for Snapper North INJ 1.

Inputs	[redacted]
Maximum Injection Rate (MTPA)	
Pressure Constraint Gradient (psi/ft)	
Injection Duration (years)	
Internal Diameter (in.)	
Absolute Roughness (in.)	
Pipeline Outlet Pressure (psi)	
Pipeline Outlet Temperature (°F)	

Table 2-15 – Well hydraulics input summary for Snapper North INJ 2.

Inputs	[redacted]
Maximum Injection Rate (MTPA)	
Pressure Constraint Gradient (psi/ft)	
Injection Duration (years)	
Internal Diameter (in.)	
Absolute Roughness (in.)	
Pipeline Outlet Pressure (psi)	
Pipeline Outlet Temperature (°F)	

Table 2-16 – Well hydraulics input summary for Snapper North INJ 3.

Inputs	[redacted]
Maximum Injection Rate (MTPA)	
Pressure Constraint Gradient (psi/ft)	
Injection Duration (years)	
Internal Diameter (in.)	
Absolute Roughness (in.)	
Pipeline Outlet Pressure (psi)	
Pipeline Outlet Temperature (°F)	

Table 2-17 – Well hydraulics input summary for Snapper South INJ 1.

Inputs	[redacted]
Maximum Injection Rate (MTPA)	
Pressure Constraint Gradient (psi/ft)	
Injection Duration (years)	
Internal Diameter (in.)	
Absolute Roughness (in.)	
Pipeline Outlet Pressure (psi)	
Pipeline Outlet Temperature (°F)	

Table 2-18 – Well hydraulics input summary for Snapper South INJ 2.

Inputs	[redacted]
Maximum Injection Rate (MTPA)	
Pressure Constraint Gradient (psi/ft)	
Injection Duration (years)	
Internal Diameter (in.)	
Absolute Roughness (in.)	
Pipeline Outlet Pressure (psi)	
Pipeline Outlet Temperature (°F)	

Table 2-19 – Well hydraulics input summary for Snapper South INJ 3.

Inputs	[redacted]
Maximum Injection Rate (MTPA)	
Pressure Constraint Gradient (psi/ft)	
Injection Duration (years)	
Internal Diameter (in.)	
Absolute Roughness (in.)	
Pipeline Outlet Pressure (psi)	
Pipeline Outlet Temperature (°F)	

Figures 2-25 through 2-30 present plots of injection rates and bottomhole pressures vs. time. Each figure also shows the maximum bottomhole pressure (BHP) limit based on 90% of the calculated fracture pressure for reference.

Figure 2-25 – Injection pressures and rates of Snapper North INJ 1.

Figure 2-26 – Injection pressures and rates of Snapper North INJ 2.

Figure 2-27 – Injection pressures and rates of Snapper North INJ 3.

Figure 2-28 – Injection pressures and rates of Snapper South INJ 1.

Figure 2-29 – Injection pressures and rates of Snapper South INJ 2.

Figure 2-30 – Injection pressures and rates of Snapper South INJ 3.

Pressure Buildup Discussion

Figures 2-31 through 2-36 show the change in bottomhole pressure relative to initial static pressure (known as pressure buildup or Δp) for each of the six injection wells. Each plot shows the highest Δp at the start of each completion stage, when initially low CO_2 saturations affect lower relative permeability to CO_2, requiring increased Δp to inject at the specified rate. This effect is exacerbated by a simulation phenomenon termed "numerical dispersion," in which volumes added to a gridblock are dispersed throughout the gridblock as they are added, resulting in artificially low saturations and relative permeabilities very early during a completion stage's injection. As the CO_2 saturations in the injection well's gridblocks increase with continued injection over time, the relative permeability to CO_2 will increase, resulting in falling Δp over time.

The trend of falling Δp will also be assisted by the expanding CO_2 plume of lower viscosity (relative to brine) CO_2. This trend may be offset by increasing average pressure in the target formation later during the completion stage's injection period: [redacted]

In addition to the injection Δp values, these plots present the bottomhole injection gradient, calculated by the BHP divided by the depth of injection during each completion stage. The maximum injection gradient based on 90% of fracture pressure is shown for reference. At no time do any of the wells' injection gradients exceed the injection gradient limit.

Figure 2-31 – Pressure buildup for Snapper North INJ 1 during active injection operations.

Figure 2-32 – Pressure buildup for Snapper North INJ 2 during active injection operations.

Figure 2-33 – Pressure buildup for Snapper North INJ 3 during active injection operations.

Figure 2-34 – Pressure buildup for Snapper South INJ 1 during active injection operations.

Figure 2-35 – Pressure buildup for Snapper South INJ 2 during active injection operations.

Figure 2-36 – Pressure buildup for Snapper South INJ 3 during active injection operations.

[redacted]

Table 2-20– Injection schedule [redacted]

Stage	CO_2 Injection Rate (MTPA)						
	Snapper North INJ 1	Snapper North INJ 2	Snapper North INJ 3	Snapper South INJ 1	Snapper South INJ 2	Snapper South INJ 3	Total
[redacted]							

Figure 2-37 – Injection pressures and rates of Snapper North INJ 1

Figure 2-38 – Injection pressures and rates of Snapper North INJ 2

Figure 2-39 – Injection pressures and rates of Snapper North INJ 3

Figure 2-40 – Injection pressures and rates of Snapper South INJ 1

Figure 2-41 – Injection pressures and rates of Snapper South INJ 2

Figure 2-42 – Injection pressures and rates of Snapper South INJ 3

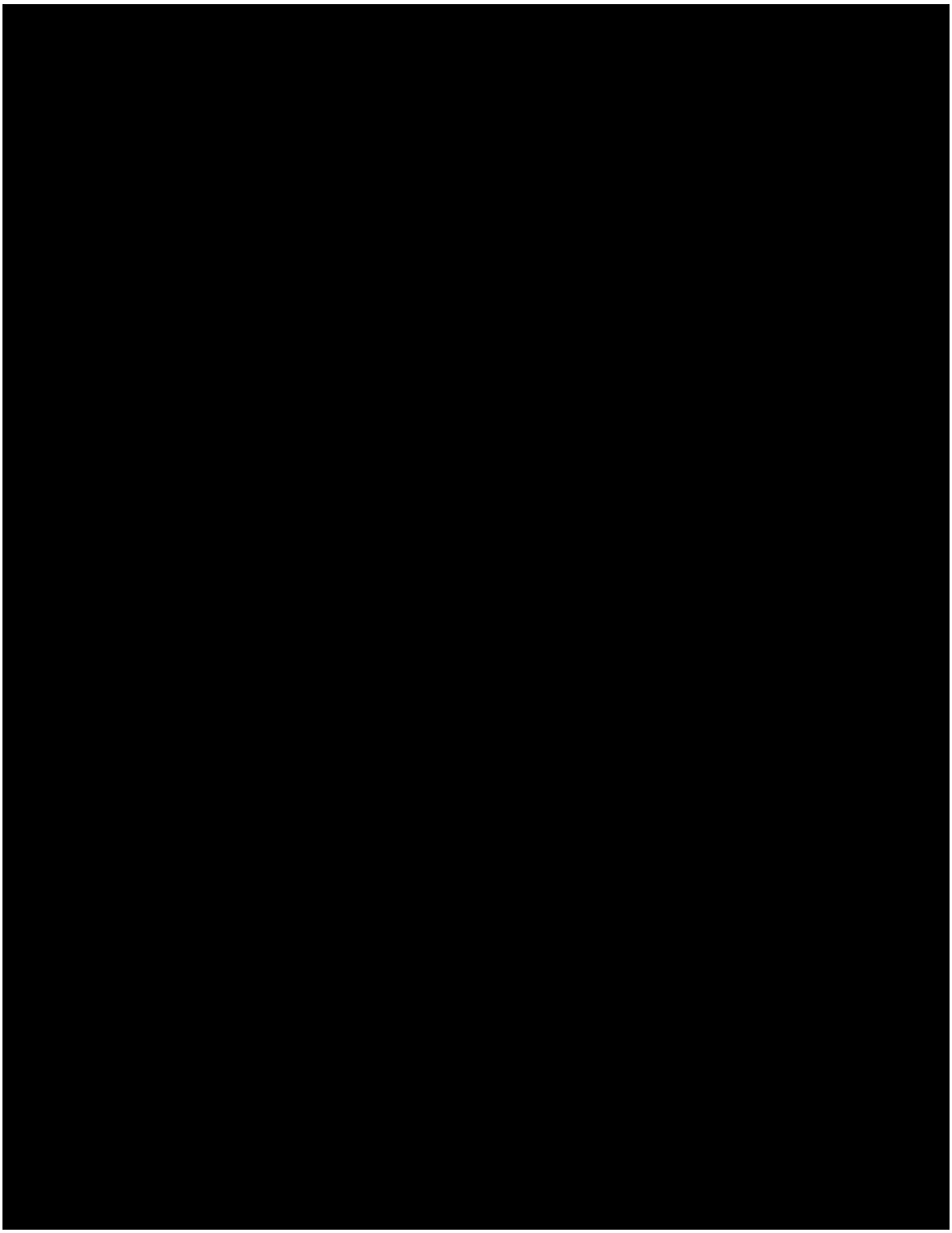


Figure 2-43 – Comparison of CO_2 plumes at the end of 50 years of post-injection

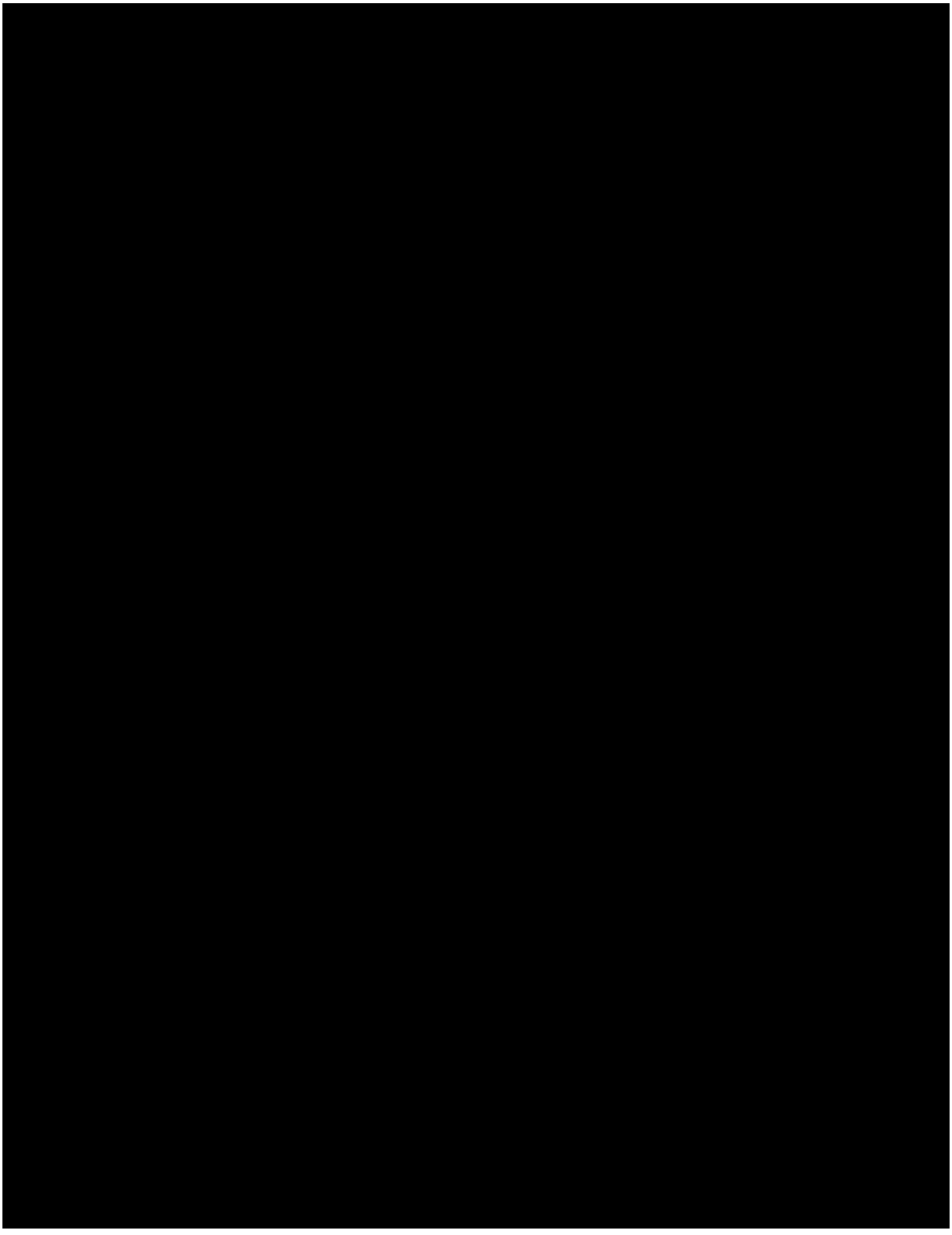


Figure 2-44 – Comparison of pressure fronts

2.7 Model Results

Active Injection Operations of Proposed CO_2 Injection Well

As shown in Figures 2-25 through 2-30, BHP and wellhead pressure (WHP) are outputs by the simulation model, calculated using completion details for each stage together with estimated average surface and downhole injection temperatures. These results are summarized in Tables 2-21 through 2-26.

Table 2-21 – Model outputs for Snapper North INJ 1.

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-22 – Model outputs for Snapper North INJ 2.

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-23 – Model outputs for Snapper North INJ 3.

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-24 – Model outputs for Snapper South INJ 1.

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-25 – Model outputs for Snapper South INJ 2.

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-26 – Model outputs for Snapper South INJ 3.

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

[redacted]

Table 2-27 – Model outputs for Snapper North INJ 1 [redacted]

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-28 – Model outputs for Snapper North INJ 2 [redacted]

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-29 – Model outputs for Snapper North INJ 3 [redacted]

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-30 – Model outputs for Snapper South INJ 1 [redacted]

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-31 – Model outputs for Snapper South INJ 2 [redacted]

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 2-32 – Model outputs for Snapper South INJ 3 [redacted]

Stage	Start Month	Max Rate (MTPA)	Avg Rate (MTPA)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

2.8 CO_2 Plume Migration for AOR Delineation

According to 16 TAC **§5.203(d)** [40 CFR **§146.84**], the AOR is determined by the maximum extent of the CO_2 plume and the critical pressure front. The first component of the AOR calculation is the extent of the CO_2 plume, discussed as follows.

Movement of the injected CO_2 in the subsurface is complex, occurring in multiple directions and varying with time. This movement is driven by gravity and viscous forces (described earlier in *Sections 2.3* and *2.5*). It will be affected by the injection zone structure and stratigraphy as well as intrinsic flow and storage property variations (e.g., permeability and porosity) within the injection zone. As described in *Section 2.6*, CO_2 is injected into six injection wells, each premised on multiple completion stages and/or injection rates that change over time.

The injected CO_2 will initially spread radially away from each wellbore, driven by pressure differentials induced by the injection. It will continue moving vertically within each sub-interval associated with the respective completion stag [redacted] Once the migrating CO_2 encounters these barriers to vertical flow, it will migrate updip, [redacted] The movement will continue until the CO_2 plume is stabilized by one or more of the trapping mechanisms described in *Section 2.3.* Figure 2-45 shows a 3D image of the CO_2 plume taken 50 years after the cessation of injection, together with an image showing a map view of the maximum extent of CO_2 saturation with [redacted] cutoff for all modeled layers at the same time. [redacted]

Figure 2-45 also shows views of the stabilized CO_2 plumes taken 50 years after the end of injection. The two panels present 3D and map views of the plume extent. Figures 2-46 through 2-51 show orthogonal cross-sectional views of the stabilized plume for each of the six injection wells. [redacted]

Figure 2-45 – 3D and 2D view of CO_2 plume migration, 50 years post-injection.

Figure 2-46 – Cross section views showing CO_2 plume at 50 years post-injection for Snapper North INJ 1.

Figure 2-47 – Cross section views showing CO_2 plume at 50 years post-injection for Snapper North INJ 2.

Figure 2-48 – Cross section views showing CO_2 plume at 50 years post-injection for Snapper North INJ 3.

Figure 2-49 – Cross section views showing CO_2 plume at 50 years post-injection for Snapper South INJ 1.

Figure 2-50 – Cross section views showing CO_2 plume at 50 years post-injection for Snapper South INJ 2.

Figure 2-51 – Cross section views showing CO_2 plume at 50 years post-injection for Snapper South INJ 3.

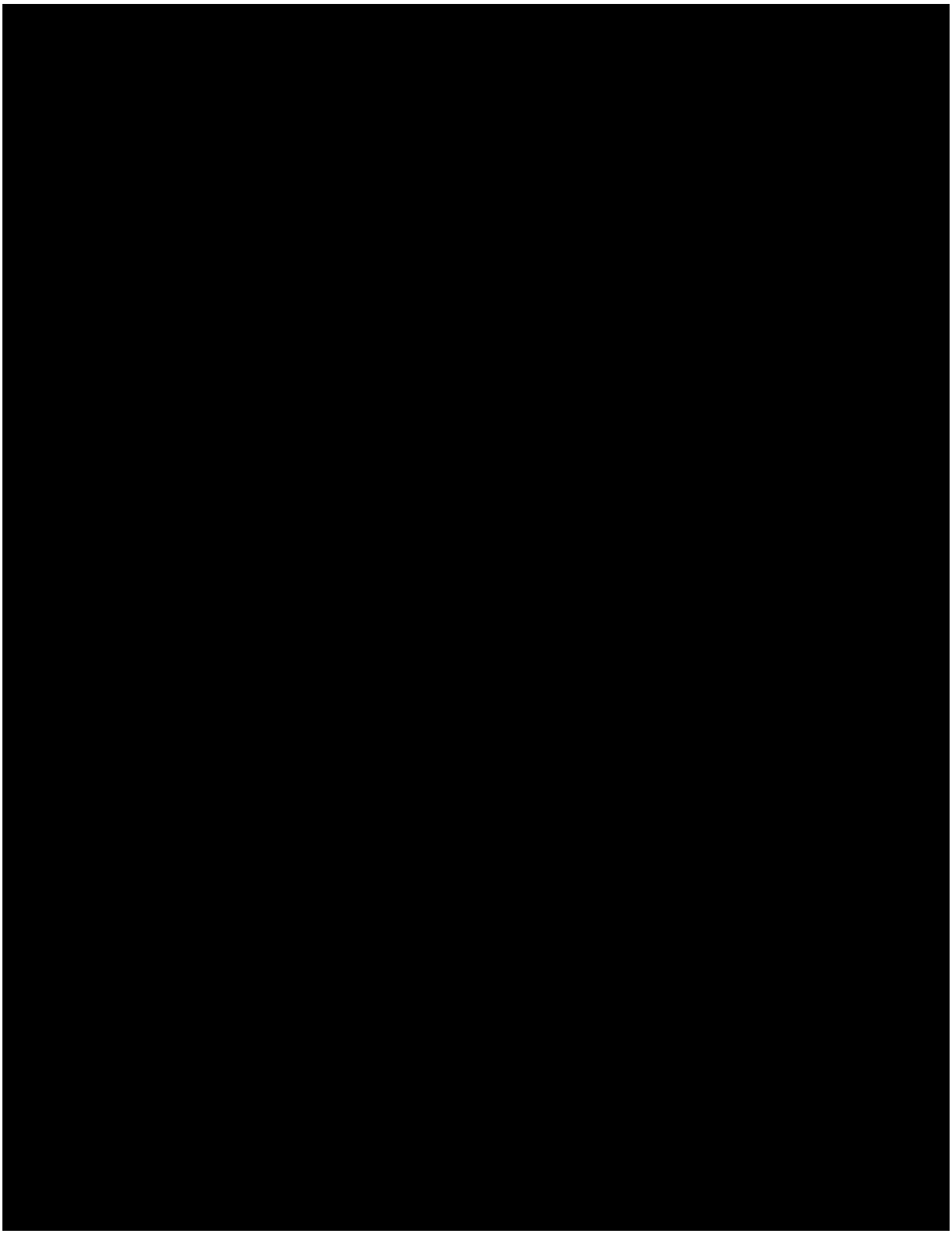


Figure 2-52 – Map view of CO_2 plume outline, 50 years post-injection.

2.8.1.1 Stabilized Plume

Plume stabilization is considered to occur when the rate, growth, or positional change has slowed to a nearly imperceptible annual rate. At that point, the CO_2 plume is considered hydrodynamically trapped within the pore space. The stabilization time is determined by the model output at the point when the areal growth rate becomes less than [redacted]

A graph of the plume area, together with the plume growth rate, is shown in Figure 2-19 (*Section 2.5*; the same figure is shown in Figure 2-53). The time scale represents years from the start of injection. The growth rate on this plot represents [redacted] This resulting slope (acres per year) is divided by the representative plume area to obtain the fractional or percentage growth rate. This figure shows that the CO_2 plume reaches stabilization at [redacted] from start of injection, or [redacted] after injection ends.

Figure 2-53 – CO_2 plume size and growth rate vs. time.

2.9 Critical Pressure Front for AOR Delineation

In accordance with 16 TAC **§5.203(d)** [40 CFR **§146.84**], the AOR is delineated using computational modeling (based on available site characterization, monitoring, and operational data) that accounts for the physical and chemical properties of the injected CO_2 stream. The AOR

is defined as the region surrounding a geologic sequestration project where USDWs may be endangered by injection activity. The extent of the AOR is determined by the maximum extent of the stabilized CO_2 plume and/or the extent of pressure differentials required to cause movement of injected or formation fluids into a USDW.

The pressure differential (Δp) is the change in formation pressure (relative to initial pressure) created by the injection of fluids during the Project. The value at which this Δp is sufficient to affect movement into USDWs through a hypothetical open conduit is termed the *critical pressure* (alternatively the *critical threshold pressure* or *critical pressure rise*). The maximum extent of Δp values in excess of the critical pressure is the *critical pressure front*. The critical pressure front is used in combination with the stabilized CO_2 plume extent to determine the AOR.

The EPA has identified potential methodologies for determination of the critical pressure values. For this Project, where initial formation pressures are at hydrostatic equilibrium, the EPA's *Method 2* is applicable. Method 2 is also known as "Nicot's Method"; key assumptions are initial pressures at hydrostatic equilibrium, linear varying density in the hypothetical open flow path between injection zone and the USDW, and constant density within in this flow path once the injection zone fluid is lifted to the USDW (Nicot, Oldenburg, Bryant, & Hovorka, 2008) (Bandilla, Kraemer, & Birkholzer, 2012).

In a simple case where one injection well injects into a single completion stage, the value for the critical pressure may be calculated using the prescribed methodology. Table 2-33 contains data [redacted] These inputs will be used in the example calculations for the critical threshold pressure following the table.

Table 2-33 – Critical pressure calculation parameters [redacted]

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

The application of Nicot's Method involves the use of two equations. First, calculate a linear coefficient (ξ) for the variation of fluid density with depth.

Eq. 2-5 $$\xi = \frac{G_i - G_u}{D_i - D_u}$$

[redacted]

Second, calculate the critical pressure value (ΔP_c) using the following Equation 2-6. Inputs include the linear coefficient (ξ) from Equation 2-5 and the depths for the base of the USDW (D_u) and top of the injection zone (D_i).

Eq. 2-6 $$\Delta P_c = \frac{1}{2} \times \xi \times (D_i - D_u)^2$$

[redacted]

In this example, the resulting ΔP_c is positive, indicating the reservoir pressure may be safely increased by approximately [redacted] without risk of fluid migration to the USDW.

Similar methodology has been applied for the calculation of critical pressures where a single well has been sequentially completed in multiple completion stages. Critical pressures unique to the sub-intervals affected by each stage can be calculated based on the depths and properties of each completion stage. Each completion stage will affect a critical pressure front based on whether that stage's injection-induced Δp exceeds the respective ΔP_c value for that completion stage. The AOR component defined by the critical pressure front will be a composite of maximum extent of the critical pressure fronts for each (completion stage) sub-interval over time. The actual AOR will be the maximum extent of this composite critical pressure front and the stabilized CO_2 plume.

[redacted]

[redacted] Figure 2-54 shows the map of USDW depths over the model area. [redacted]

Figure 2-55 shows the resulting maximum extension of the pressure front.

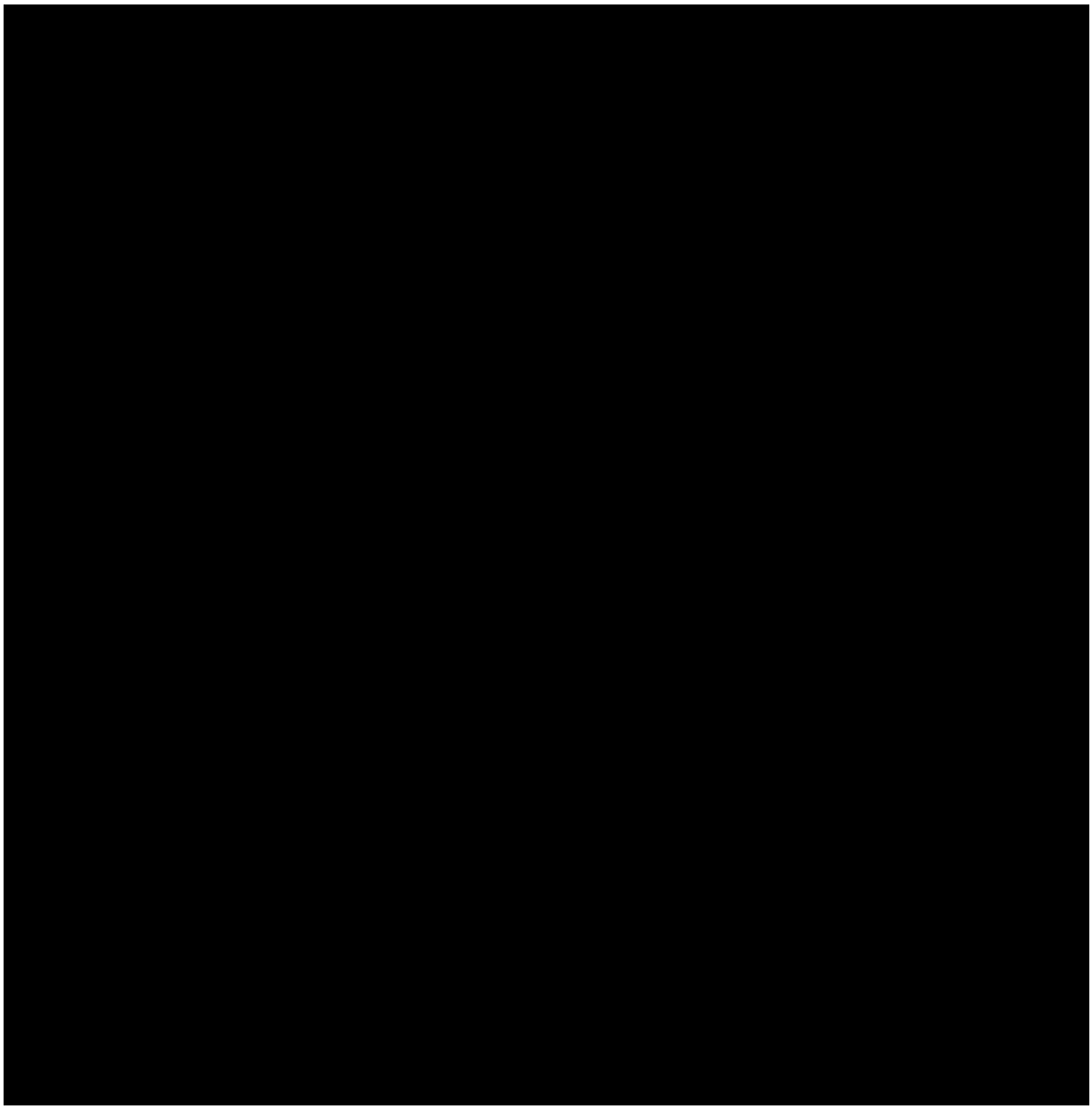


Figure 2-54 – USDW depth map used for critical pressure cutoff calculations.

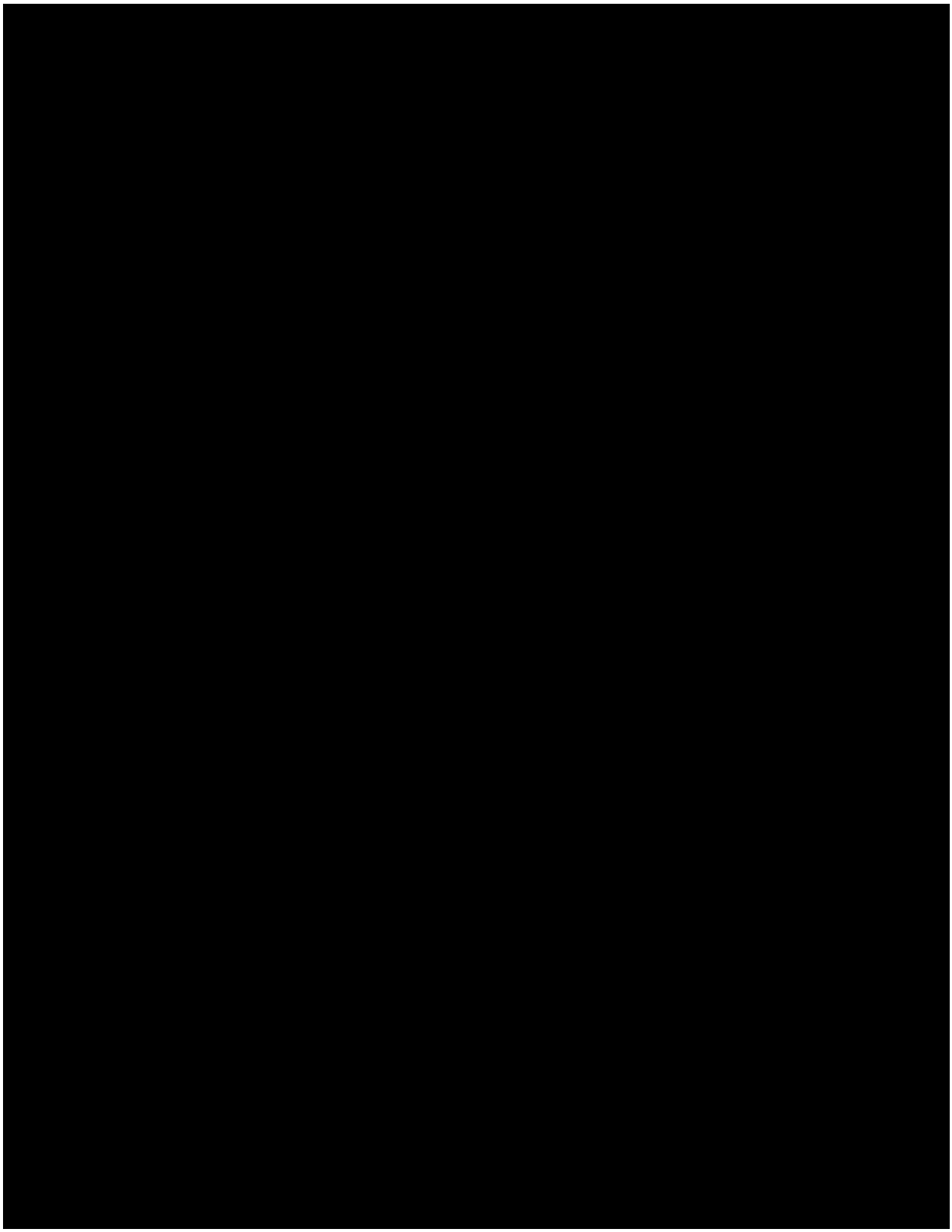


Figure 2-55 – Maximum extent (composite) of critical pressure front.

2.10 Pressure Buildup Against Fault

Calculation of the critical pressure front for AOR determination has shown that the critical pressure front reaches mapped faults. Evaluation of the fault faces shows that faults reached by the critical pressure front will not serve as conductive pathways for fluid movement. Figures 2-56 and 2-57 show the facies juxtaposition and shale gouge ratio (SGR) [redacted]

Figure 2-56 – Facies juxtaposition [redacted]

Figure 2-57 – Shale gouge ratio [redacted]

Independent of fault zone permeability, empirical evidence and modeling suggest that fault slip or *reactivation* can cause dilatant deformation opening pathways along the fault that can allow along-fault flow and leakage (Ferrill and Morris, 2003; Wiprut and Zoback, 2002; Zhang et al., 2009). Increasing pore pressure adjacent to fault—reducing the effective stress acting normal to the fault plane—can cause the fault to slip (Jaeger and Cook, 1979; Sibson, 1992).

The Mohr-Coulomb failure criteria was used to calculate the increase in pore pressure required for each fault to fail—and that value was compared to the increased pore pressure at the faults tracked by the dynamic simulation model. For the worst-case scenario (highest differential stress, weakest fault friction coefficient), the dynamic simulator was run under the scenario where the faults were made to be completely non-transmissive (sealing), allowing for maximum buildup of pressure against each fault. Figure 2-58 shows the output Δp buildup at each fault face, as exported from the dynamic simulation model. The analysis of fault stability concludes that none of the faults within the simulation model have a pore pressure increase that exceeds the pressure required for fault failure. Detailed discussion of the use of these data to compare to fault failure pressures resides in the full analysis of fault stability in *Appendix K.*

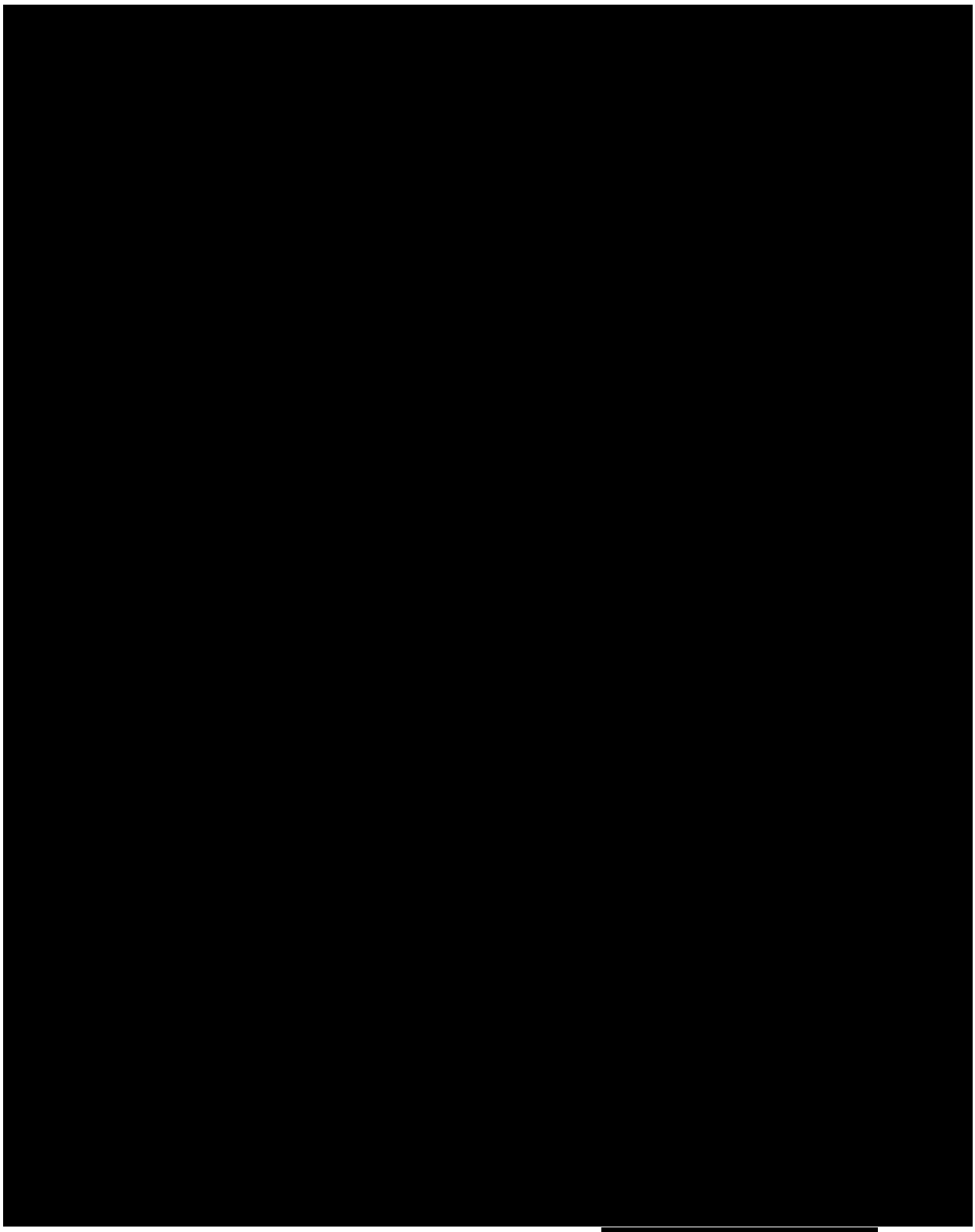


Figure 2-58 – Representative pressure change at faults [redacted]

2.11 Final AOR

The maximum CO_2 plume and critical pressure fronts delineate the AOR, and the AOR determines the necessary evaluation and corrective action steps 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. A gas saturation cutoff of [redacted] has been used to determine the final extent of the CO_2 plume. [redacted] Critical pressure threshold is defined as the increase in reservoir pressure required to push in situ brine out of the injection zone and into the lowermost USDW. The critical pressure front is determined by the greatest areal extent of pressures exceeding the threshold for all six injection wells and their respective completion intervals. Figure 2-59 provides the final AOR outlines for the Project.

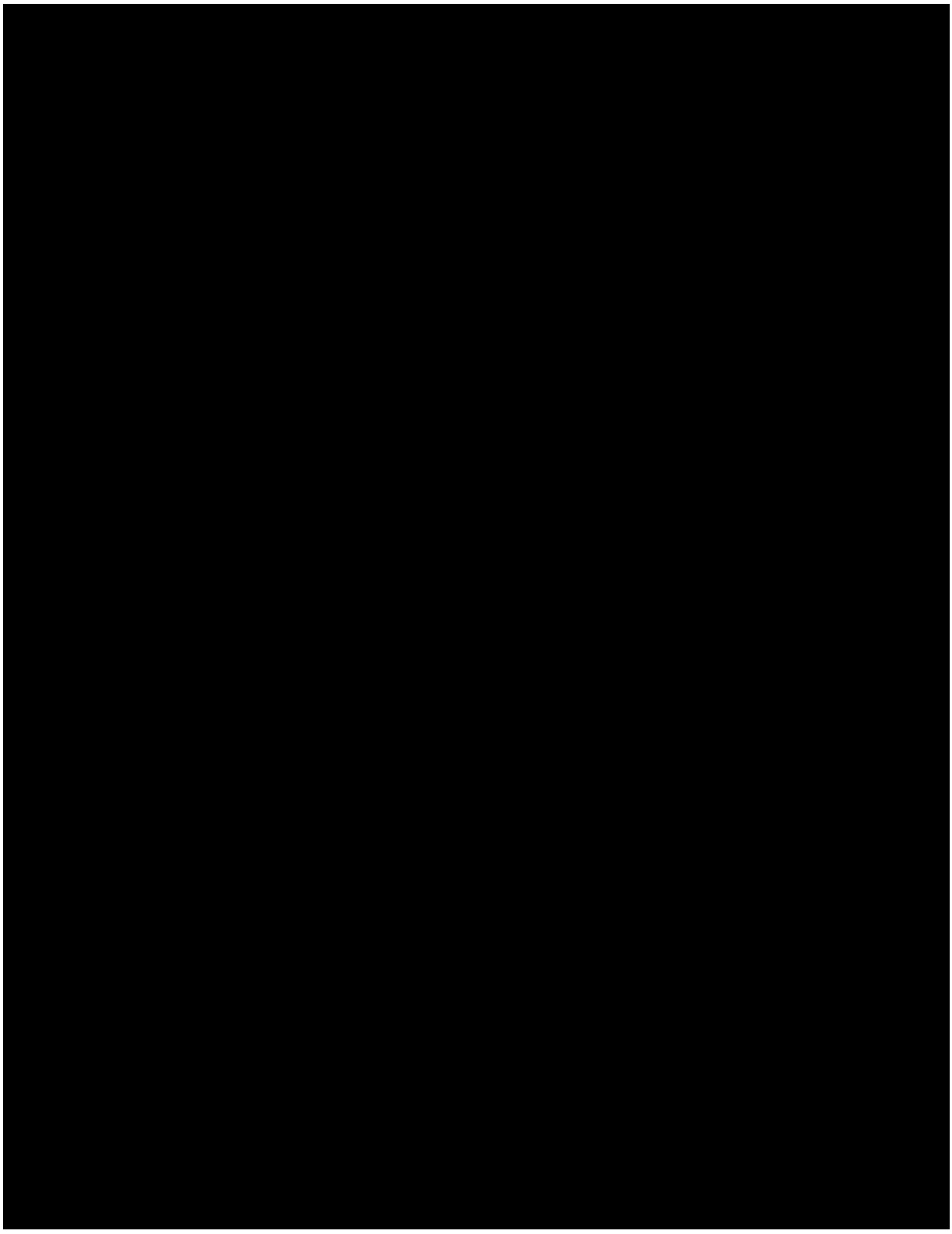


Figure 2-59 – Project AOR outlines.

Large format figures from this section are included in *Appendix D: Plume Model Outputs*.

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Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

July 2024

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.1 Project Information

Project Name: ConocoPhillips Texas Gulf Coast CCS (Project)

Operator Name: ConocoPhillips Texas Gulf Coast CCS LLC (Operator)
925 North Eldridge Parkway
Houston, Texas 77079

Project Contact: [redacted]

Injection Well Locations:

Well Name	County	Latitude (NAD 27)	Longitude (NAD 27)	Latitude (NAD 83)	Longitude (NAD 83)	Datum
Snapper North INJ 1	Refugio	[redacted]				
Snapper North INJ 2	Aransas					
Snapper North INJ 3	Aransas					
Snapper South INJ 1	Refugio					
Snapper South INJ 2	Refugio					
Snapper South INJ 3	Refugio					

*NAD 27 – North American Datum of 1927
NAD 83 – North American Datum of 1983

[redacted]

3.2 Computational Modeling

Modeling Software Name: INTERSECT™ [redacted]

Modeling Software Authors/Institution: SLB (Schlumberger Ltd.)

Description of Model Software: INTERSECT is a high-resolution reservoir simulator including equation of state (EOS) modeling and full flow physics, used widely in the energy and carbon capture and storage (CCS) industries.

Model Inputs and Assumptions: The parameters for the INTERSECT model are summarized in Table 3-1.

Table 3-1 – Model input parameters and assumptions per injection well

Input	Value
Average Injection Rate (MTPA)	[redacted]
Average Porosity (%)	
Average Permeability (mD)	
K_v/K_h Ratio in Sand / Silt / Shale	
Reference Depth (ft)	
Pore Pressure Gradient (psi/ft)	
Fracture Pressure Gradient (psi/ft)	
Mean Surface Temperature (°F)	
Temperature Gradient (°F/100 ft)	
Brine Salinity (ppm)	

*MTPA – million (metric) tonnes per annum
mD – millidarcy
psi/ft – pounds per square inch per foot
ppm – parts per million

3.3 Area of Review Discussion

In accordance with 16 Texas Administrative Code (TAC) **§5.203 (d)(1)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**] an area of review (AOR) investigation must be conducted for a Class VI CCS permit application. The Project AOR was determined based on the greater of (1) the maximum extent of the separate-phase plume (pore occupancy plume or CO_2 plume), and (2) the critical pressure front. Critical pressure threshold is defined as the increase in reservoir pressure required to push in situ brine out of the injection zone and into the lowermost Underground Source of Drinking Water (USDW). The critical pressure front is determined by the greatest areal extent of pressures exceeding the threshold for all injection wells and their respective completion intervals. To delineate the AOR, computational modeling was used to predict the migration of CO_2 from the commencement of injection until the plume movement ceases, and pressure differentials that may be sufficient to cause the movement of injection fluids or formation fluids into the USDW are no longer present. The extent of the AOR determines the necessary evaluation and corrective action steps needed for any offset wells, as well as completion and operating strategy.

3.3.1 Area of Review: Pore Occupancy Plume

Using computational modeling of both chemical and physical properties of all phases of the injected CO_2 stream, a pore occupancy CO_2 plume was generated and mapped. Data for this modeling effort was collected through site characterization, monitoring, operational data, and literature. *Section 2 – Plume Model* comprehensively discusses this modeling effort.

The pore occupancy plume was generated to identify and assess three major elements: (1) artificial penetrations, (2) subsurface characteristics, and (3) pore space rights requirements.

Artificial penetrations identified within the pore occupancy plume which penetrate the primary injection zone must comply with Class VI regulations. To ensure these wells meet the standards of these regulations, an investigation into the wells was conducted to ensure they were plugged with proper procedures and materials. Any wellbore identified within the CO_2 plume that penetrates the upper confining zone (UCZ) and is not appropriately plugged necessitates a corrective action plan. The purpose of the corrective action plan is to ensure that no wellbore serves as a conduit for the escape of stored CO_2 or reservoir fluids from containment. Any wellbore situated within the AOR boundary that does not penetrate the UCZ is deemed to have no impact on the safe storage of CO_2 and, therefore, will not be included in Operator's corrective action plan.

Figure 3-1 shows 3D and areal views of the aggregate (stabilized) CO_2 plumes from all injection wells, taken at 50 years post-injection. Figure 3-2 shows cross-sectional views of the CO_2 plume at the location of one of the northern injection wells. The 3D and cross-sectional views illustrate the complexity of the CO_2 plume shapes. Initial placement of CO_2 in the subsurface is outlined by Operator's completion and operational strategies for each of the six injection wells. Subsequent movement of the CO_2 away from the wellbores is affected by formation properties (e.g., porosity and permeability), the presence and distribution of stratigraphic and structural barriers to flow (e.g., shale and/or silt intervals), and the influence of other injection wells and/or fault barriers on pressure distribution within the reservoir intervals. As the injected fluid moves through the reservoir, driven by injection-induced pressure gradients and buoyancy forces, it becomes trapped in the storage interval. Detailed discussion of trapping mechanisms, with a summary of trapping mechanisms over time, is included in *Section 2*.

Figure 3-1 – 3D and areal views of CO_2 plume at 50 years post-injection.

Figure 3-2 – Cross section views of CO_2 plume at 50 years post-injection

3.3.2 Area of Review: Pressure Front

The critical pressure front generated during the injection of fluids into a reservoir previously in a state of equilibrium was also considered when calculating the Project AOR.

The critical pressure can be described as the pressure threshold at which the migration of reservoir fluid up through an open (or improperly sealed) wellbore and into the USDW becomes

possible. Wells inside of the pressure front that are open at both the upper boundary of the injection zone and the lower boundary of the USDW are at risk of facilitating this fluid migration.

The base of the USDW is expected to be encountered at an average depth of [redacted] feet (ft) true vertical depth subsea (TVDss) approximately, with a depth range of [redacted] across the area of interest (AOI), based on the hydrogeological evaluation detailed in *Appendix C*. The evaluation results indicate that below the average depth of the base of the USDW the salinity is higher than 10,000 ppm. The determination of the USDW is further discussed in *Section 1.8.1*. A map showing USDW depths in the model area utilized for critical pressure cutoff calculations is featured in Figure 3-3 (*Appendix E-1*).

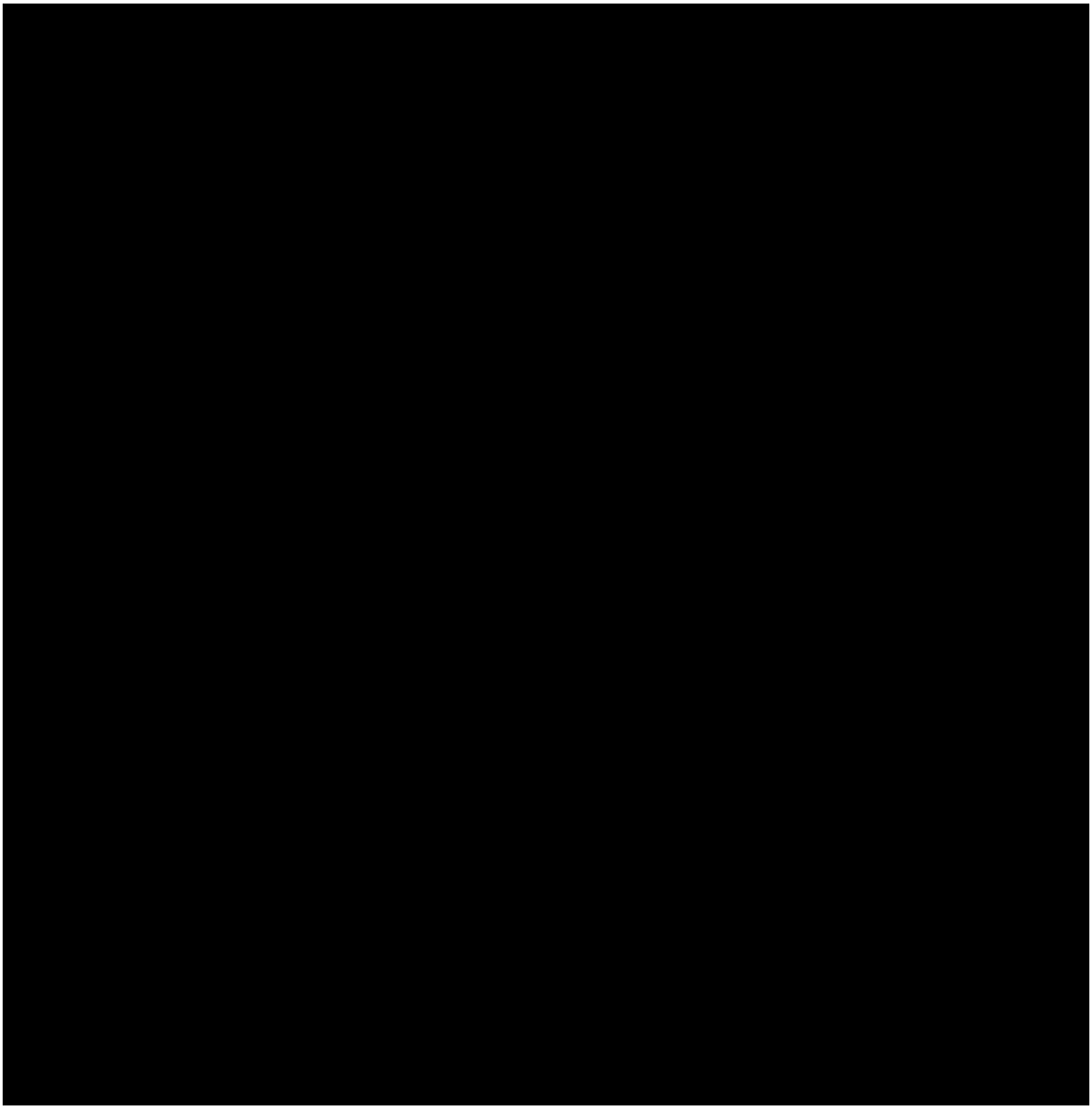

Figure 3-3 – USDW depth map.

The critical pressure front was also determined in accordance with 16 TAC **§5.203(d)** [40 CFR **§146.84**].

The EPA has identified potential methodologies for determination of the critical pressure values. For this Project, where initial formation pressures are at hydrostatic equilibrium, the EPA's Method 2, also known as "Nicot's Method," is applicable. Key assumptions used in this method are initial pressures at hydrostatic equilibrium, linear varying density in the hypothetical open flow path between injection zone and the USDW, and constant density within this flow path once the injection zone fluid is lifted to the USDW (Nicot, Oldenburg, Bryant, & Hovorka, 2008) (Bandilla, Kraemer, & Birkholzer, 2012).

In the case where one injection well injects into a single completion stage, the value for the critical pressure may be calculated using the prescribed methodology. Table 3-2 contains data [redacted] These inputs will be used in the example calculations for the critical threshold pressure following the table.

Table 3-2 – Critical pressure calculation parameters [redacted]

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

The application of Nicot's Method involves the use of two equations:

First, a linear coefficient (ξ) is calculated to estimate the fluid density variation with depth

Eq. 3-1 $$\xi = \frac{G_i - G_u}{D_i - D_u}$$

[redacted]

The next step is to calculate the critical pressure value (ΔP_c) using the following Equation 3-2. Inputs include the linear coefficient (ξ) from Equation 3-1 and the depths for the base of the USDW (D_u) and top of the injection zone (D_i).

Eq. 3-2 $$\Delta P_c = \frac{1}{2} \times \xi \times (D_i - D_u)^2$$

[redacted]

The critical pressure rise, as calculated for the shallowest injection stage of the [redacted] indicates that the reservoir pressure can be safely increased by [redacted] pounds per square inch (psi) without causing the migration of fluid to the USDW. The calculated critical threshold pressures for each of the completion stages for all six injection wells are included in Tables 3-3 through 3-8. [redacted]

The maximum areal extent of that pressure front over all times is captured as the maximum pressure front extent used to define the AOR and is shown as Figure 3-4 (*Appendix E-2*).

Tables 3-3 through 3-8 show the calculation of the critical threshold pressure values for each injection well [redacted]

Table 3-3 – Snapper North INJ 1 critical threshold pressure [redacted]

[redacted]

Table 3-4 – Snapper North INJ 2 critical threshold pressure [redacted]

[redacted]

Table 3-5 – Snapper North INJ 3 critical threshold pressure [redacted]

[redacted]

Table 3-6 – Snapper South INJ 1 critical threshold pressure [redacted]

[redacted]

Table 3-7 – Snapper South INJ 2 critical threshold pressure [redacted]

[redacted]

Table 3-8 – Snapper South INJ 3 critical threshold pressure [redacted]

[redacted]

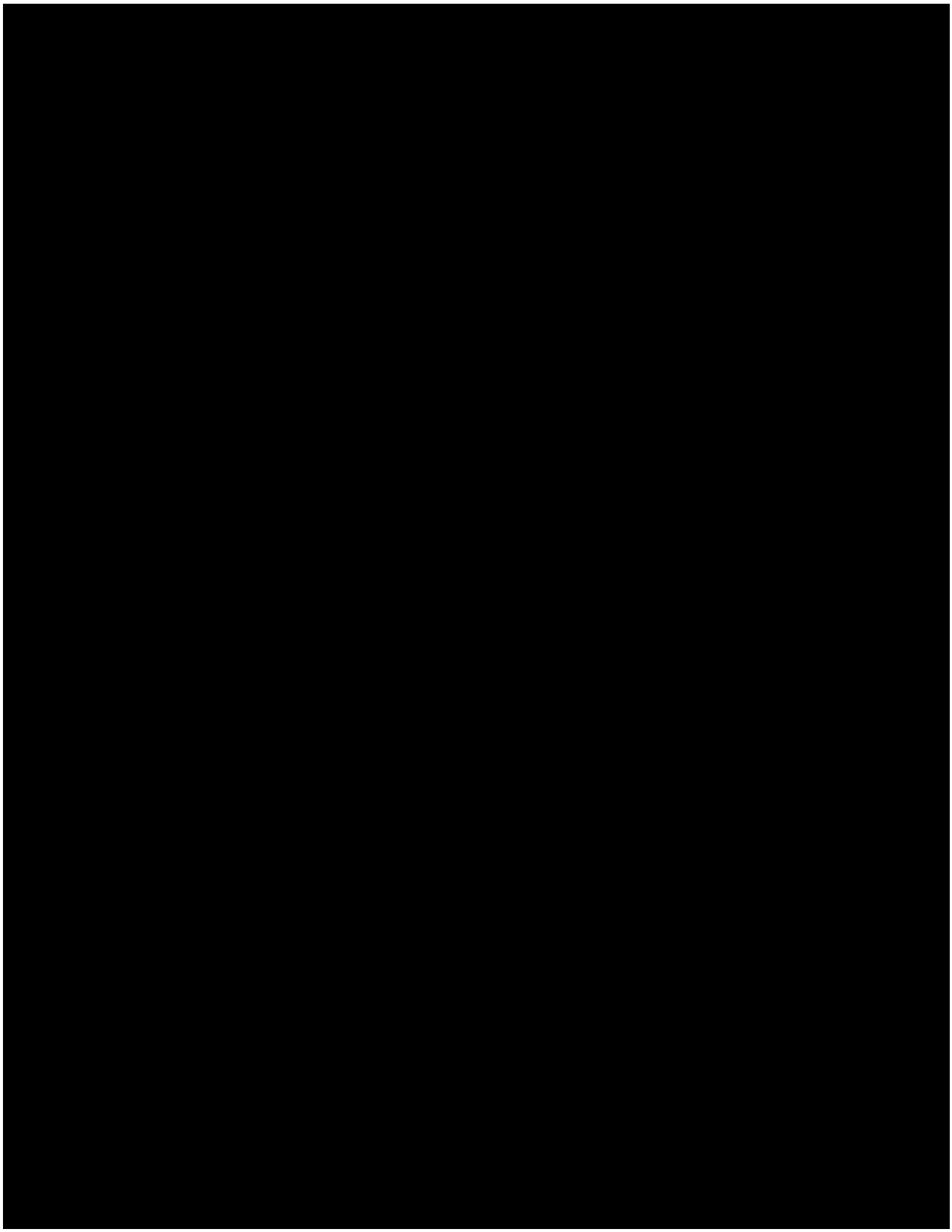

Figure 3-4 – Pressure front.

The comprehensive Project AOR encompasses the combined region of both the CO_2-occupied pore space and pressure front areas. Any named fault or artificial penetration detected within either of these zones has been assessed for its ability to adequately safeguard the USDW.

3.3.3 Operating Strategies Influencing Reservoir Modeling Results

The Project includes six injection well [redacted] called the Snapper North INJ 1, INJ 2, and INJ 3, and the Snapper South INJ 1, INJ 2 and INJ 3 wells[redacted] These wells are designed for flexible operations to allow the management of pressure response and plume growth throughout the storage interval. To manage the pressure front and CO_2 plume extent, the injection wells are designed to be completed in different sub-intervals of the overall storage interval. [redacted] Figure 3-5 depicts a theoretical example of how this may be implemented in the Project. Under this strategy of operation, the well is first completed in the deepest interval(s) and then sequentially isolated as perforations are moved uphole to subsequent shallower intervals. Typical isolation methods for the deeper inactive zones would include a bridge plug with cement.

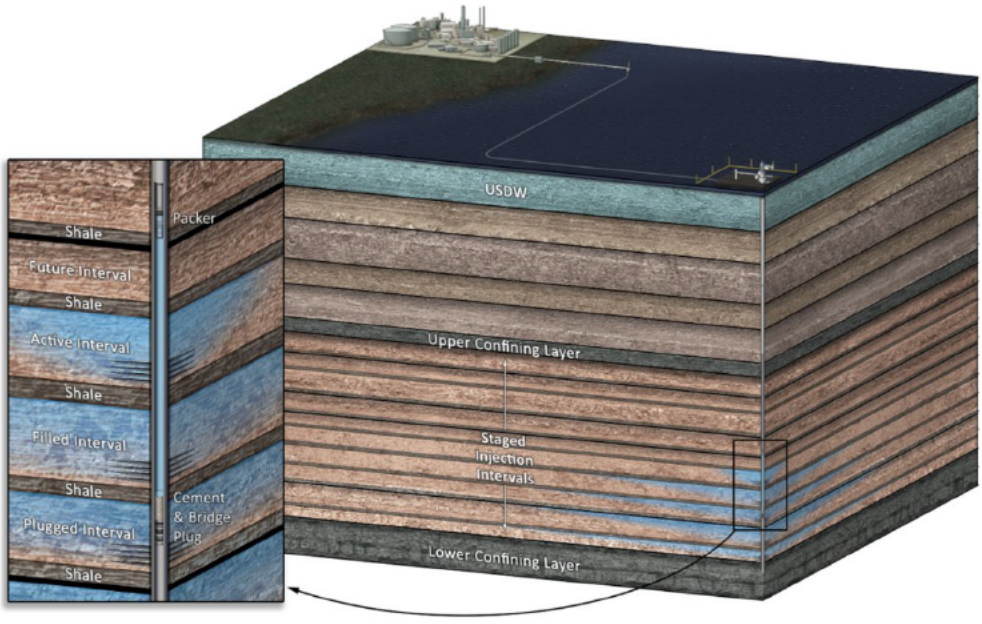

Figure 3-5 – Illustrative example of staged completion intervals strategy.

In the dynamic simulation model, the reservoir storage interval is divided into [redacted] intervals for plume extent and pressure front management. [redacted] Each well will be completed sequentially, deeper to shallower, [redacted]

[redacted], and in a manner that manages plume and pressure front extent, while staying within injection pressure limit for the respective active completion interval of each well.

The modeled completion strategy is illustrated in Tables 3-9 and 3-10 below, showing the number of wells in each formation sub-interval, and how the active completion interval changes over time. Respective completion sub-interval formations are color coded on the two tables.

Table 3-9 – Well count per formation sub-interval over time.

Table 3-10 – Injection rate by well over time, color coded by formation sub-interval.

[redacted]

These tables show how each well is completed in [redacted] completion intervals over its [redacted] injection life. Injection rates are tailored to each completion interval's characteristics (porosity, permeability, stratigraphic barriers) to manage the extent of the CO_2 plume and maximum pressure front extent over the life of the Project. Overall injection rate is maintained at [redacted]

[redacted]

The CO_2 plume extent and the pressure front were combined and digitized from the simulation output and imported into ArcGIS to define the Project AOR. In accordance with 16 TAC **§5.203(d)** [40 CFR **§146.84**], a thorough investigation was conducted to identify artificial penetrations or any other features that pose a threat to the lowermost USDW during injection activities or operational processes. During this review, maps were created to illustrate the AOR and the man-made structures found within its boundaries. Subsequently, these artificial penetrations and other man-made elements were evaluated based on their depth of completion, construction specifications, and adequacy of their plugging and abandonment (P&A) procedures. The goal of this assessment was to identify any artificial penetrations that could potentially compromise the integrity of the CO_2 storage intervals or the USDW.

The maps and associated lists generated during this effort are contained in *Appendix E*. Figure 3-6 (*Appendix E-4*) identifies the Project AOR.

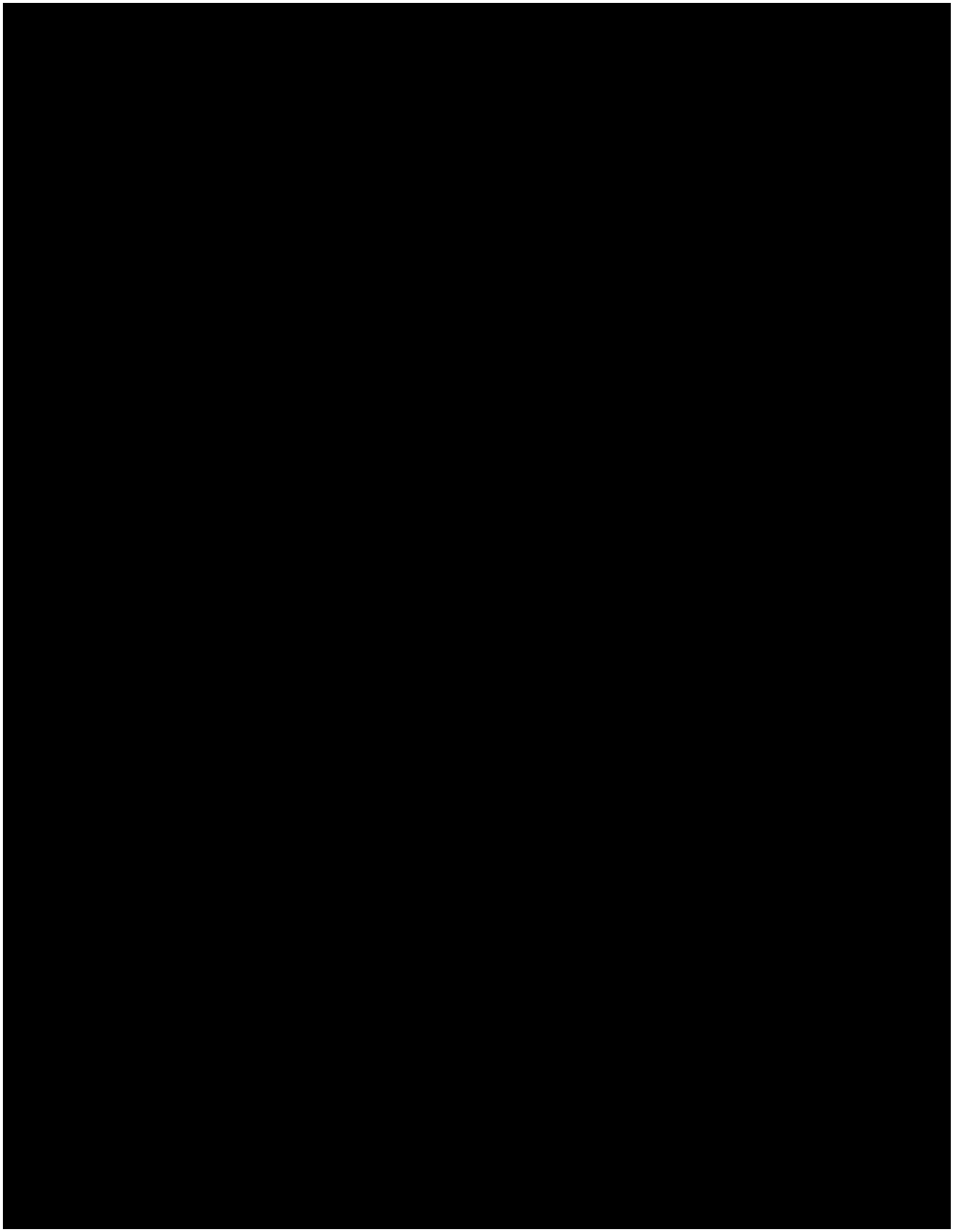

Figure 3-6 – Final AOR map.

3.3.4 Area of Review Results

An exhaustive multi-database search was conducted to identify artificial penetrations into the injection zone, within the final AOR. Oil and gas well data was primarily gathered from the Railroad Commission of Texas (TRRC), supplemented with data from additional databases, including IHS and Enverus. Supplemental data was used to reduce potential historical well omissions and data inaccuracies. Water well data was sourced 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 within the AOR. Operator plans to perform an aerial magnetometer survey to confirm that no additional wellbores exist within the AOR.

[redacted]

[redacted]

In accordance with 16 TAC **§5.203(b)(2)** [40 CFR **§146.82**], Figure 3-9 (*Appendix E-9*) is a site review map. No subsurface cleanup sites, springs, mines, quarries, hazardous waste sites, or structures intended for human occupancy were identified within the AOR. Figure 3-10 (*Appendix E-10)* is a topographic map of the AOI in accordance with 40 CFR **§146.82(a)(3)(vi)**.

To ensure the absence of any orphan wells within the AOR, Operator will commission a third-party service to execute an aerial magnetometer survey. This survey, conducted using advanced magnetometer technology mounted on a low-flying aircraft, will scan the Project site to detect magnetic anomalies that could indicate the presence of abandoned wells within the AOR. The raw data collected from the survey will be processed using specialized software to generate magnetic field intensity contour maps, which will provide a visual representation of the magnetic field variations across the Project area. The processed data and contour maps will be compiled into a comprehensive report. This report will detail the survey methodology, interpret the results, and pinpoint anomaly locations that could potentially indicate the presence of artificial penetrations.

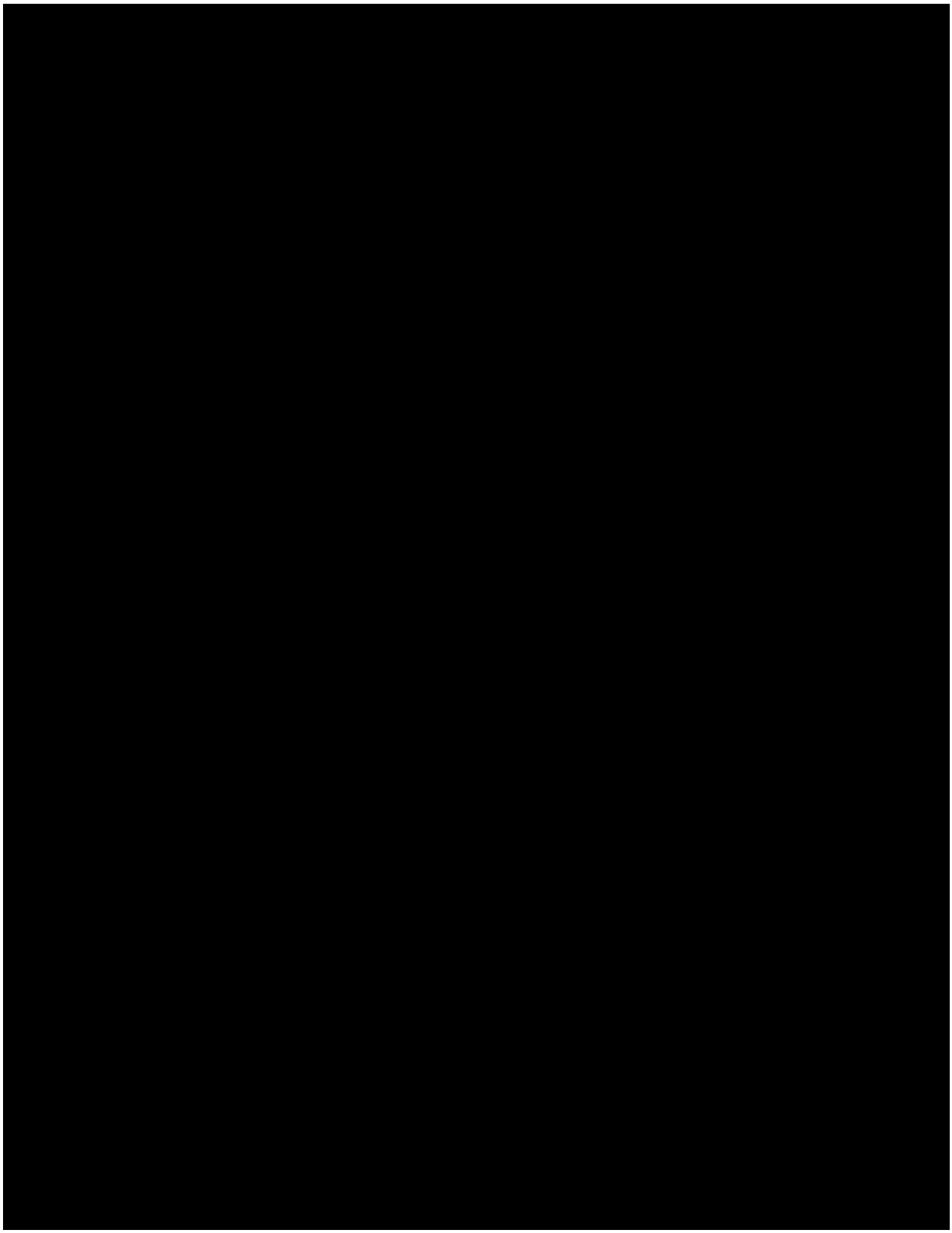

Figure 3-7 – AOR with existing wells.

Table 3-11 – Oil and gas well penetrator list.

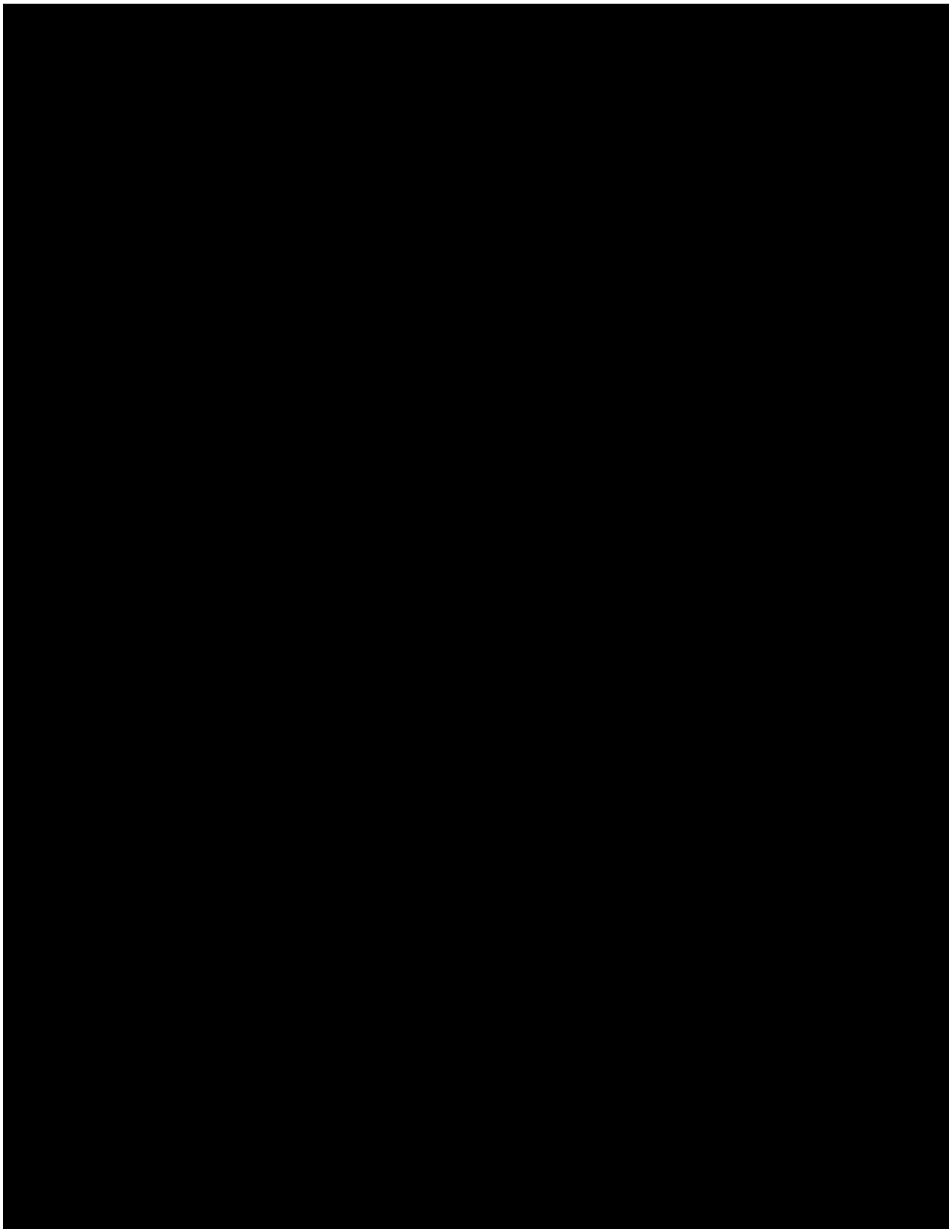

Figure 3-8 – AOR with groundwater wells.

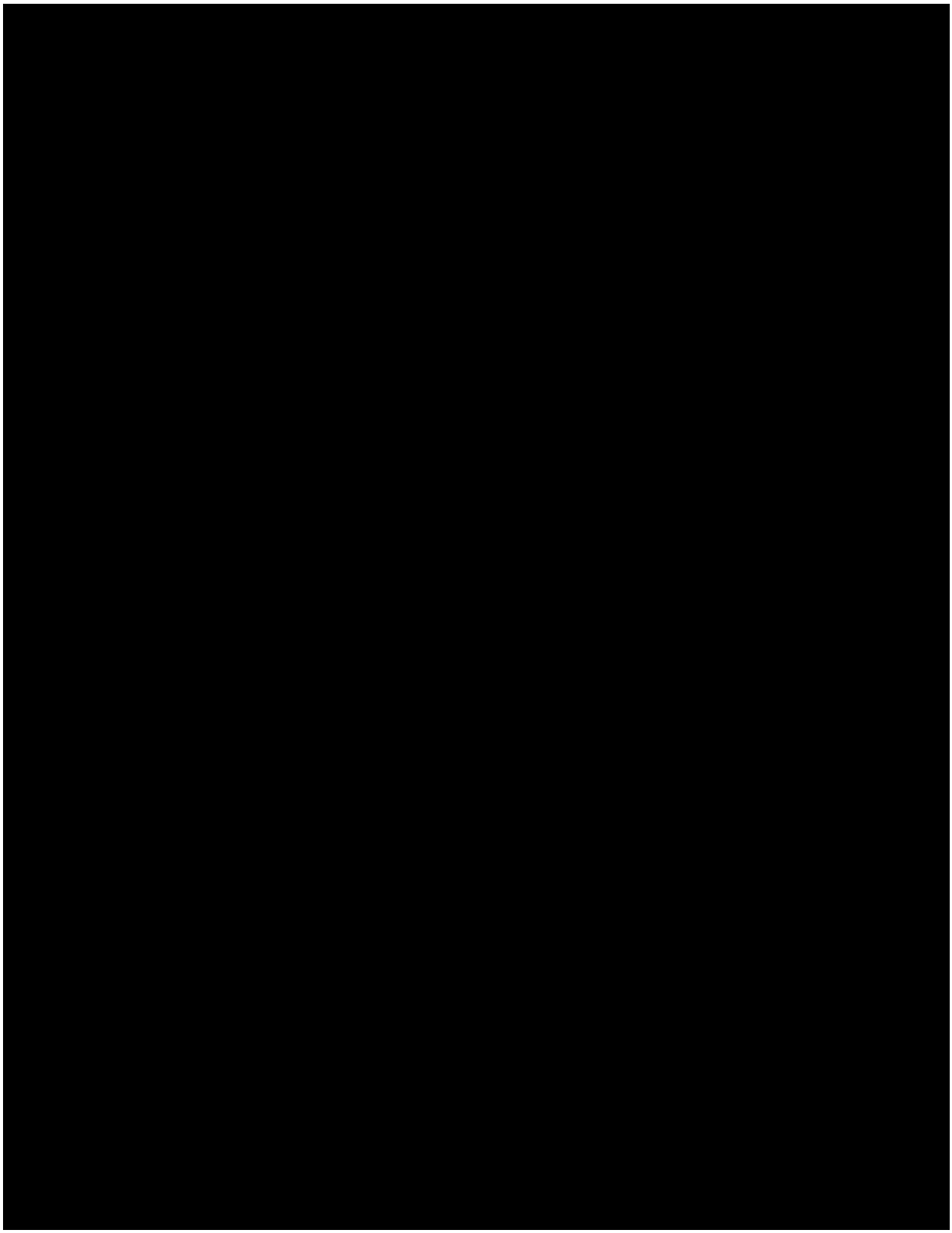

Figure 3-9 – Site review map.

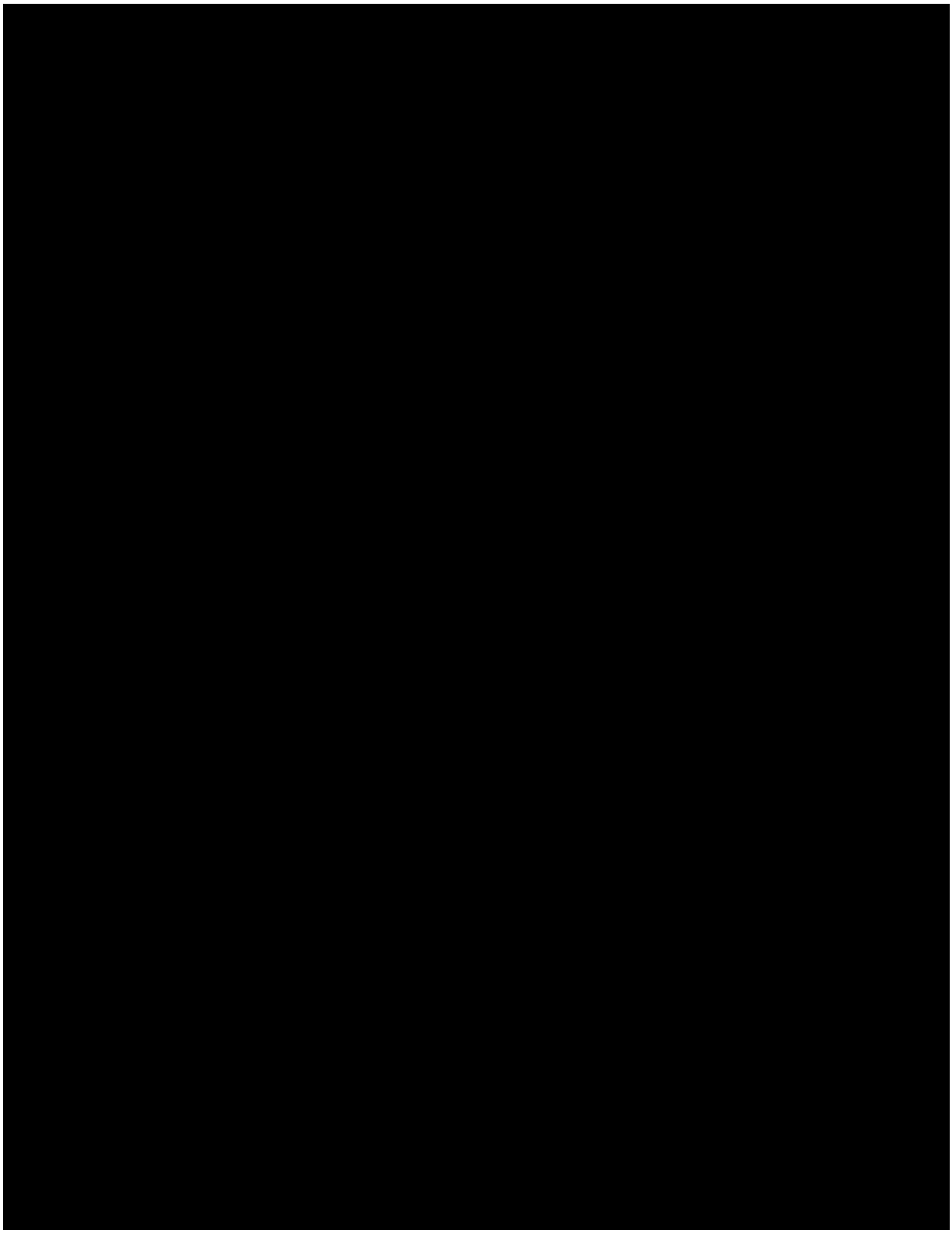

Figure 3-10 – Topographic map of AOI.

Table 3-12 – Groundwater wells within AOR.

3.4 Corrective Action Plan and Schedule

The primary objective of a corrective action plan is to ensure proper containment of CO_2 and other fluids involved in CCS projects. This plan is strategically crafted to ensure neither CO_2 nor other formation fluids migrate from the injection zone beyond the impermeable shale barrier of the UCZ.

The wells identified in Table 3-11 were assessed for proper plugging procedures and materials.

[redacted] The general reentry process for corrective action includes the following:

- Locate wellbore.
- Install new wellhead on existing casing.
- Move in and rig up workover rig.
- Drill out old P&A plugs in wellbore, as necessary.
- Perform logging, if required.
- Set new P&A plugs, as necessary.
- Rig down and move out workover rig.

Table 3-13 – Corrective action well list.

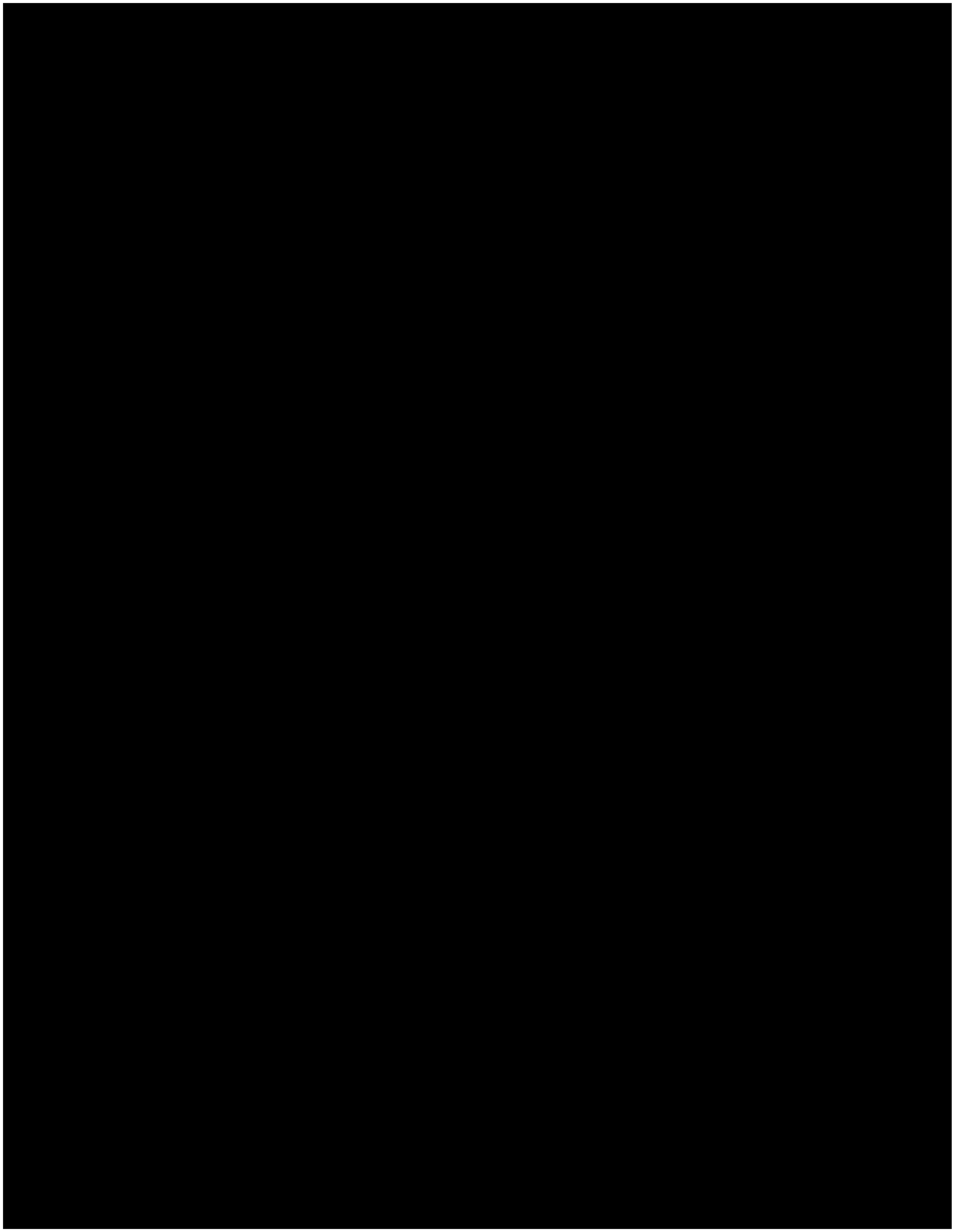

Figure 3-11 – Wells with planned corrective action.

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 needed, adjustments to the corrective action plan will be made to encompass additional wells. Operator will guarantee site access is maintained for any future corrective action.

3.4.1 In-Depth Review of Wells Needing Corrective Action

[redacted]

Figure 3-12 – [redacted]

Figure 3-13 –

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Figure 3-14 –

Figure 3-15 – [redacted]

[redacted]

Figure 3-16 – [redacted]

Figure 3-17 – [redacted]

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 structures that could impact long-term CO_2 storage.
2. Identify subsurface geological features that could influence the capacity for indefinite storage of CO2.
3. Identify pore space rights affected by the expansion of the injection plume over the modeled time frame.

In accordance with 16 TAC **§5.203(d)(2)(B)(i)** [40 CFR **§146.84(b)(2)(i)**], Operator will reevaluate the AOR at each of the following intervals:

- Minimum frequency of 5 years
- Detection of a significant change in the CO_2 plume or pressure front
- 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 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, Operator 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 at least 10 years.

3.5.1 Proposed Reevaluation Cycle

The ongoing monitoring of CO_2 plume growth and migration may necessitate more frequent reevaluations of the AOR than the scheduled 5-year intervals.

[redacted]

If actual injection rates fall short of the modeled capacity, the CO_2 plume migration would likely not reach the extents initially modeled. In such a scenario, the duration of each discrete completion zone's effectiveness would be prolonged. However, if the observed plume behavior exceeds the initially modeled boundaries, the model will be revised and the AOR reevaluated.

Table 3-14 lists some of the possible triggers for an AOR reevaluation.

Table 3-14 – Triggers for AOR reevaluations.

Reevaluation Trigger	Measure to be Taken	Schedule for Reevaluation
16 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 CO_2 plume migration survey identifies a greater extent than modeled.	Re-run the reservoir plume model with new data. If CO_2 plume extent increases, reevaluate the AOR.	[redacted]
Annual CO_2 plume migration survey identifies the plume direction is different than modeled.		
Operational Change: Injection rate increases to a rate greater than modeled.		
Operational Change: Injectate composition changes to a new mixture.		
Operational Change: Injection pressures are significantly higher than modeled.		
New site characterization data is produced.		
New operations are being brought online within or near the CO_2 plume extents.		
Anomalous seismicity detected above background.	Evaluate monitoring data for pressure analysis and reevaluate AOR.	

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

- Appendix E-1 USDW Depth Map
- Appendix E-2 Pressure Front Map
- Appendix E-3 CO_2 Plume Map
- Appendix E-4 Final AOR Map
- Appendix E-5 AOR with Existing Wells Map
- Appendix E-6 Oil and Gas Well Penetrator List
- Appendix E-7 AOR with Groundwater Wells Map
- Appendix E-8 Groundwater Wells within AOR list
- Appendix E-9 Site Review Map
- Appendix E-10 Topographic Map of AOI
- Appendix E-11 [redacted]
- Appendix E-12 [redacted]
- Appendix E-13 [redacted]
- Appendix E-14 [redacted]
- Appendix E-15 [redacted]
- Appendix E-16 [redacted]
- Appendix E-17 [redacted]

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

July 2024

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

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4.1 Introduction

The engineering design details and operational strategies utilized during the planning of the six ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) project (Project) injection wells are described in this section. 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 EPA Underground Injection Control (UIC) program has jurisdiction over all details regarding the design, construction, and operation of Class VI injection wells. These wells are designed solely for the safe injection of CO_2 into specific zones for permanent storage. Protecting the Underground Source of Drinking Water (USDW) is a primary consideration of all Project phases—including drilling, completion, injection, and plugging.

ConocoPhillips Texas Gulf Coast CCS LLC (Operator) proposes to inject CO_2 into the Miocene Oakville and Oligocene Greta and Frio Sands. Across the area of interest, the injection targets range from [redacted] in thickness of highly permeable, porous, saline filled sands, with a mean of [redacted] The properties of this reservoir make it an ideal candidate for the safe injection and permanent storage of CO_2.

The specific requirements for the design of a CCS Class VI injection well are described in the following sections.

4.2 Engineering Design

When designing the Project injection wells, consideration was given to the volumes and rates of injection, chemical composition of the injection stream, physical properties of the injectate fluid, corrosion and metallurgical evaluations, and operational requirements to maintain wellbore integrity for the life of the wells.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Operator plans to inject [redacted] CO_2 into each of the six proposed injection wells. The average and maximum modeled volume injection rates for each injection well over time are displayed in Table 4-1. Reservoir modeling performed for these rates took into consideration 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.

[redacted] The Project injection wells are designed to the necessary specifications

suitable for the highest modeled injection rates (as shown in Table 4-1).

Table 4-1 – Average and maximum modeled injection rates per well [redacted]

[redacted]

Table 4-2 shows the standard CO_2 conditions used in the modeling and flow calculations.

Table 4-2 – Standard CO_2 conditions.

[redacted]

*psia – pounds per square inch absolute
lbm – pound mass

[redacted] The current anticipated chemical composition of the pipeline CO_2 is outlined in Table 4-3.

Table 4-3 – CO_2 injectate parameters.

[redacted]

The input injection parameters from the model, for the six injection wells, are shown in Table 4-4. [redacted]

Table 4-4 – Model input injection parameters for the Project injection wells.

[redacted]

4.2.1 Snapper North INJ 1 Engineering Design

The CO_2 stream in the Snapper North INJ 1 well will be injected into the [redacted] and contained by impermeable shale layers to ensure long-term storage. Shale layers throughout the injection zone will be employed to separate the injection into discrete injection stages. The shale layers will act as vertical barriers allowing greater control of the available pore space. This completion design will minimize CO_2 plume migration while maximizing the use of available pore space. The injection interval sands are located from approximately [redacted] TVD. The sand formations are porous and permeable, making them favorable for CO_2 injection and storage.

[redacted] The CO_2 plume will be monitored during and after injection and compared to the modeled expectations. Adjustments to the operation plan will be made as necessary.

Table 4-5 – Snapper North INJ 1 operational strategy.

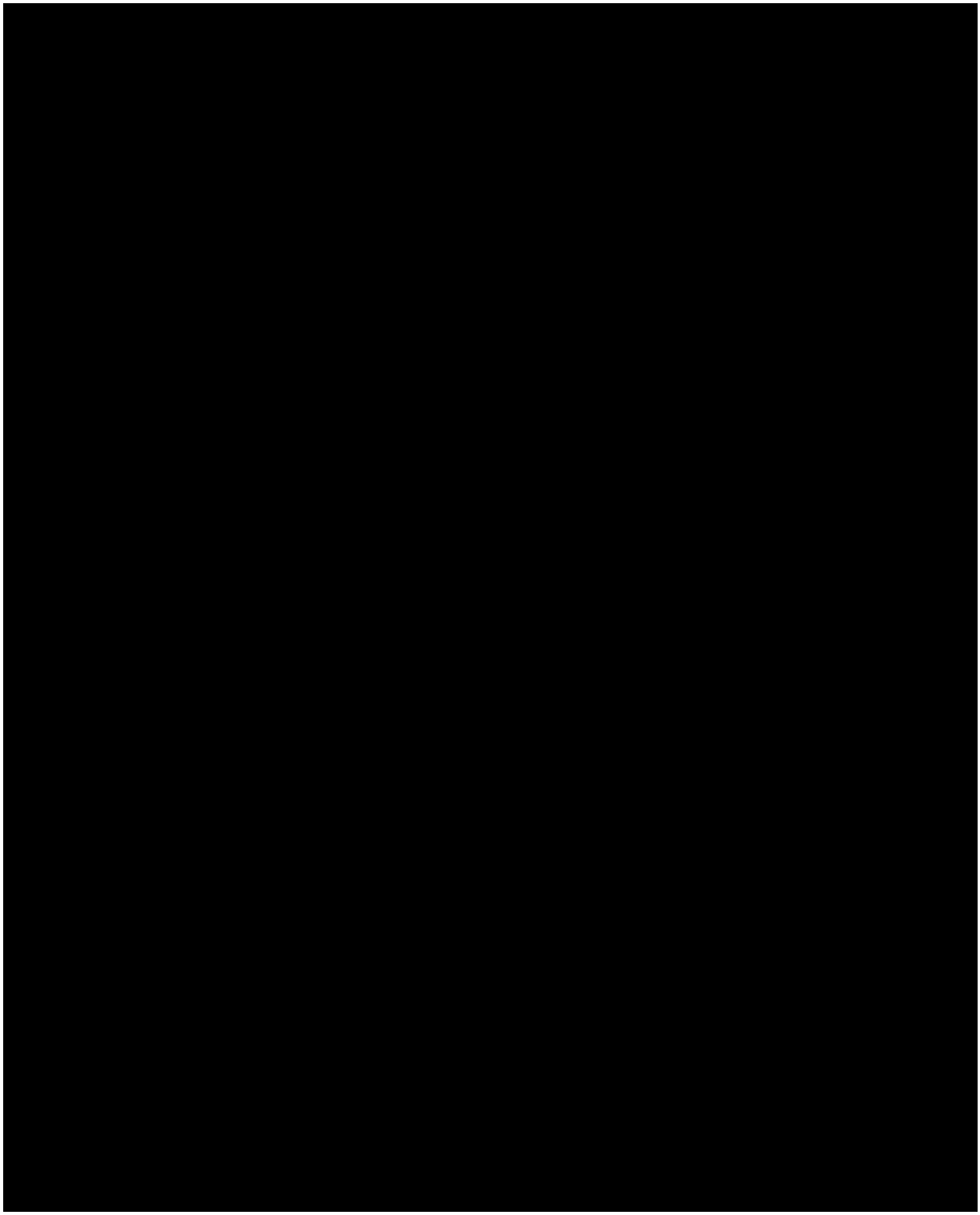
[redacted]

[redacted] These monitoring strategies will ensure that wellbore and mechanical integrity are maintained throughout the life of the project.

Figure 4-1 (*Appendix F-1*) shows the proposed injection well design for the Snapper North INJ 1.

Figure 4-1 – Snapper North INJ 1 wellbore diagram.

The drilling and completion design for Snapper North INJ 1 is as follows:



A detailed drilling-and-completion prognosis is included in *Appendix F-2*.

4.2.2 Snapper North INJ 1 Detailed Discussion of Injection Well Design

Operator plans to inject a volume of [redacted] MTPA of CO_2 into the proposed well. As previously discussed, Operator recognizes that both planned and unplanned downtime will be encountered, and a sensitivity model was run to ensure that a maximum system injection rate [redacted] can be maintained if one well is shut in. The maximum injection rate allocated to the Snapper North INJ 1 during this sensitivity model was [redacted] MTPA. [redacted] Reservoir modeling was performed for this rate, taking into consideration 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. The Snapper North INJ 1 is designed to the necessary specifications suitable for the highest modeled injection rate for the well. The maximum injection rates [redacted] for the Snapper North INJ 1 are displayed in Table 4-6.

Table 4-6 – Snapper North INJ 1 maximum modeled injection rates.

[redacted]

Figure 4-2 – Injection pressure plot for Snapper North INJ 1.

Model-generated well operating parameters [redacted] are detailed in Tables 4-7 and 4-8.

Table 4-7 – Model outputs for Snapper North INJ 1 [redacted]

Table 4-8 – Model outputs for Snapper North INJ 1 [redacted]

The model results indicate that [redacted] tubing is the appropriate size to inject the desired volumes of CO_2 into the well. Under expected operating conditions, the CO_2 will be in the dense phase (either liquid or supercritical) throughout the injection wellbore, and in the supercritical

phase in the storage formation.

[redacted]

[redacted]

4.2.2.1 Conductor Pipe

Conductor pipe will be used to ensure that the hole integrity is maintained during the initial drilling of Snapper North INJ 1. [redacted]

The conductor pipe specifications were chosen to support the desired bit-size requirement for drilling the surface casing. [redacted] Once the conductor pipe is installed, the pipe will be flushed out and cleaned, and drilling will commence.

4.2.2.2 Surface Casing

The surface hole will be drilled to [redacted] A string of [redacted] casing will be run and cemented with the casing centered using centralizers in the open hole. Cement will be circulated to surface. [redacted]

Summaries of engineering calculations for the surface casing are displayed in Table 4-9. The engineering calculations for all six Project injection wells were performed assuming identical wellbore conditions and setting depth for surface casing. Snapper North INJ 1 surface casing annular geometries are displayed in Table 4-10 and surface casing volume calculations are displayed in Table 4-11.

Table 4-9 – Snapper North INJ 1 surface casing engineering calculations.

[redacted]

*bbl – barrels
ppg – pounds per gallon

Table 4-10 – Snapper North INJ 1 surface casing annular geometries.

[redacted]

Table 4-11 – Snapper North INJ 1 surface casing volume calculations.

[redacted]

[redacted]

4.2.2.3 Long String Casing

The long string casing will be run to TD and cemented from the casing-shoe setting depth back to surface utilizing conventional cementing.

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

[redacted]

A metallurgical analysis was performed considering the chemical composition of the injectate and the downhole conditions detailed earlier in this section (Table 4-6). [redacted]

The long string casing will be cemented with CO_2-resistant cement [redacted] This will provide a sufficient barrier to prevent CO_2 movement out of the injection interval. [redacted]

The engineering and design parameters for the long string casing are summarized in Tables 4-12 through 4-14.

Table 4-12 – Snapper North INJ 1 long string casing engineering calculations.

[redacted]

Table 4-13 – Snapper North INJ 1 long string casing annular geometries.

[redacted]

Table 4-14 – Snapper North INJ 1 long string casing volume calculations.

[redacted]

4.2.2.4 Centralizers

Bow spring centralizers will be utilized in the [redacted] surface casing to ensure that a continuous column of cement is present [redacted] The recommended locations are as follows:

[redacted]

Bow spring centralizers will also be utilized [redacted] to ensure that a continuous column of cement is present throughout the annulus. The recommended locations are as follows:

[redacted]

4.2.2.5 Injection Tubing

The [redacted] injection tubing [redacted] were selected based on modeling results from planned injection volumes, rates, and injectate composition. [redacted] A complete summary of the metallurgical analysis is included in *Appendix G-1*. Table 4-15 provides the tubing engineering design calculations for the Snapper North INJ 1 injection well.

Table 4-15 – Tubing engineering design calculations – Snapper North INJ 1.

[redacted]

4.2.2.6 Packer Discussion

[redacted] Once the packer and tubing are installed, the tubing/long string casing annulus will be pressure tested for verification.

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

Figure 4-3 provides an example schematic of the planned packer assembly.

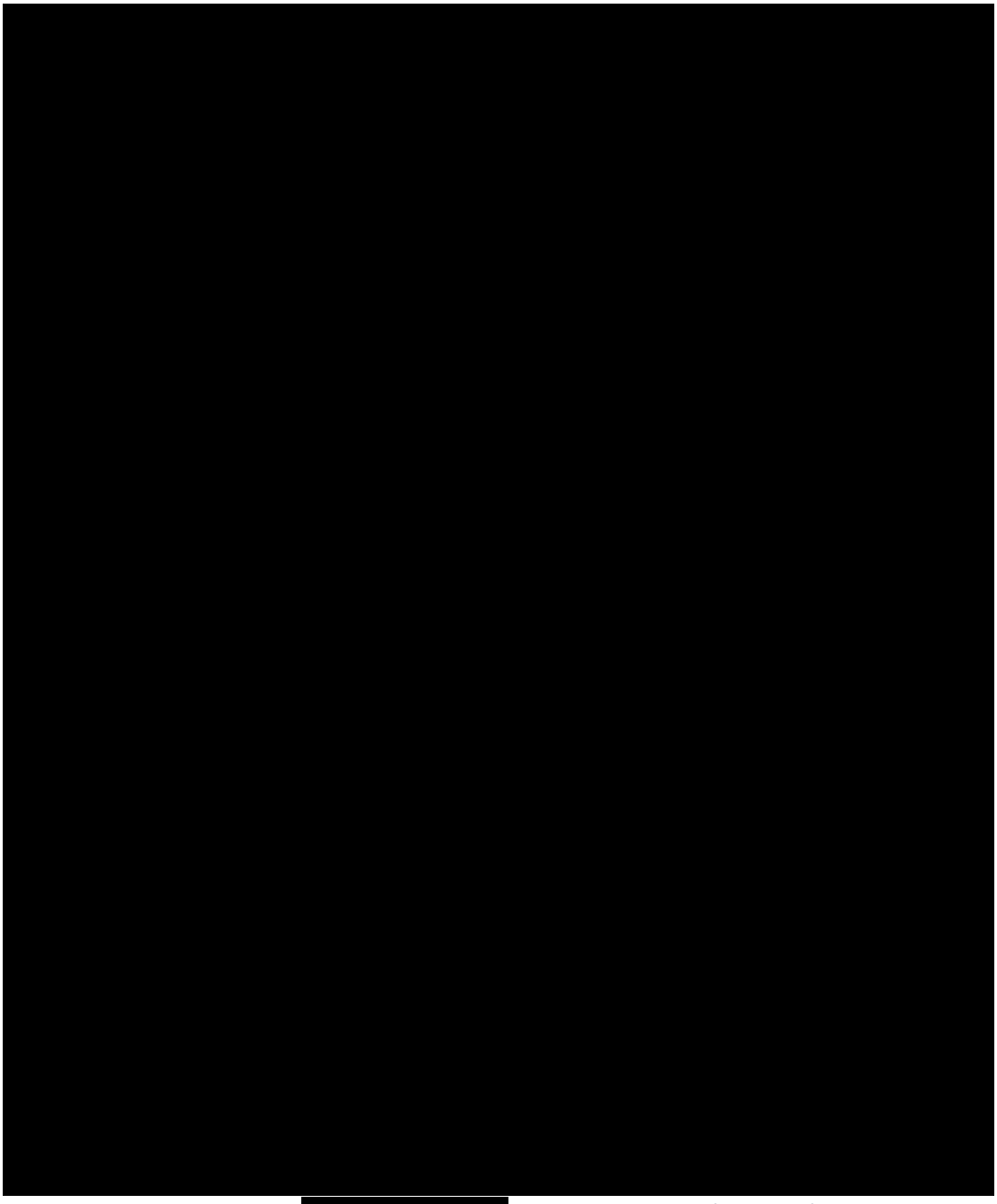


Figure 4-3 – [redacted] packer schematic (example).

4.2.2.7 Subsurface Injection Valve

In accordance with 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted]-80 tubing above the packer.

Figure 4-4 provides an example schematic of the planned SSIV assembly.

Figure 4-4 – [redacted] SSIV schematic (example).

4.2.2.8 [redacted]

4.2.2.9 Wellhead Discussion

The wellhead is designed to control working pressures and corrosion complications. [redacted]

[redacted]The final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as illustrated in Figure 4-5 (*Appendix F-4)*. The wellhead design and manufacturer shown may change based on well and commercial factors determined before drilling.

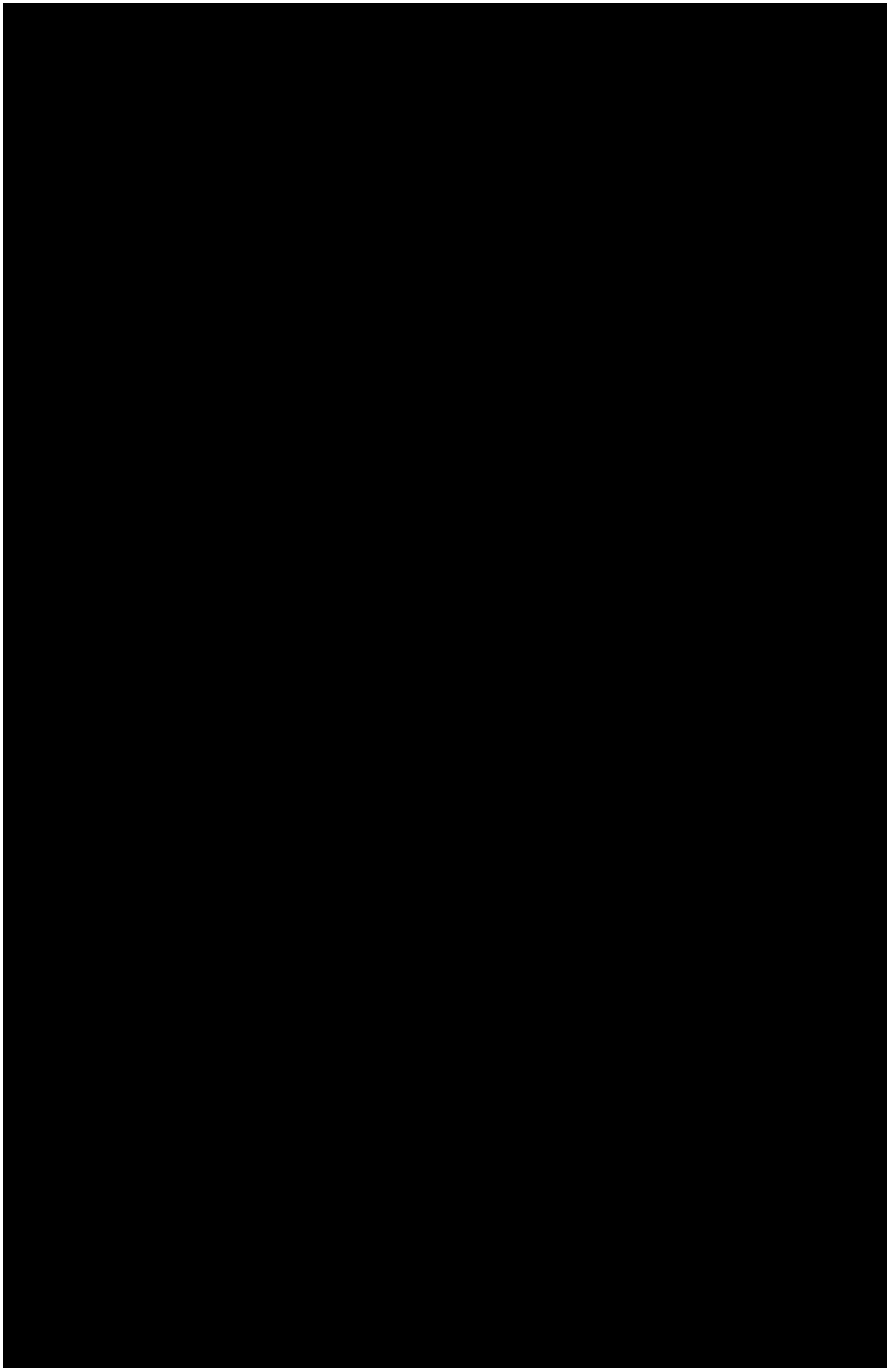


Figure 4-5 – Preliminary wellhead design.

4.2.3 Snapper North INJ 1 Completion/Stimulation Plans

The proposed Snapper North INJ 1 injection well may be stimulated during completion operations to clean up the well after drilling and/or to improve injection performance. Stimulation may include but is not limited to flowing fluids into or out of the well, increasing or connecting pore spaces throughout the injection formation, or other activities intended to allow the injectate to move more readily into the injection zone. Final stimulation designs will be determined based on the conditions met during drilling. Operator will submit proposed stimulation procedures to the EPA or the UIC Director at least 30 days prior to beginning such operations, per 40 CFR **§146.91(d)(2)**. Such procedures may include the following standard industry stimulation:

- Wellbore clean up [redacted]
- Wellbore stimulation [redacted]

4.2.4 Snapper North INJ 2 Engineering Design

The CO_2 stream in the Snapper North INJ 2 well will be injected into the [redacted] and contained by impermeable shale layers to ensure long-term storage. Shale layers throughout the formation will be employed to separate the injection into discrete injection intervals. The shale layers will act as vertical barriers allowing greater control of the available pore space. This completion design will minimize CO_2 plume migration while maximizing the use of available pore space. The injection interval sands are located from approximately [redacted] TVD. The sand formations are porous and permeable, making them favorable for CO_2 injection and storage.

[redacted] The CO_2 plume will be monitored during and after injection and compared to the modeled expectations; adjustments to the operation plan will be made as necessary.

Table 4-16 – Snapper North INJ 2 operational strategy.

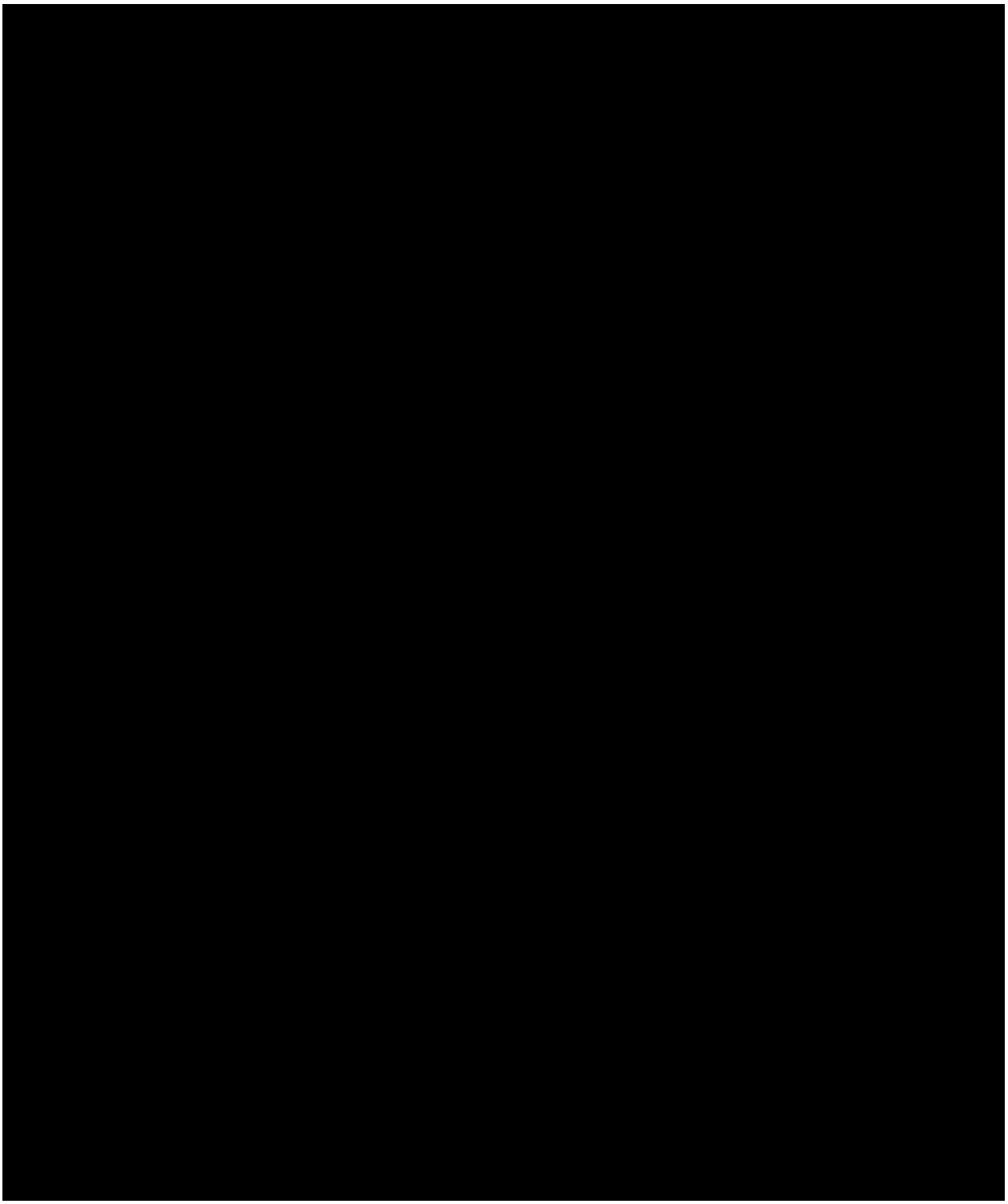
[redacted]

These monitoring strategies will ensure that wellbore and mechanical integrity are maintained throughout the life of the project.

Figure 4-6 (*Appendix F-1*) shows the proposed injection well design for the Snapper North INJ 2.

Figure 4-6 – Snapper North INJ 2 wellbore diagram.

The drilling and completion design for Snapper North INJ 2 is as follows:



A detailed drilling-and-completion prognosis is included in *Appendix F-2*.

4.2.5 Snapper North INJ 2 Detailed Discussion of Injection Well Design

Operator plans to inject a volume of [redacted] MTPA of CO_2 into the proposed well. As previously discussed, Operator recognizes that both planned and unplanned downtime will be encountered, and a sensitivity model was run to ensure that a maximum system injection rate [redacted] can be maintained [redacted] The maximum injection rate allocated to the Snapper North INJ 2 during this sensitivity model was [redacted] MTPA. [redacted] Reservoir modeling was performed for this rate, taking into consideration 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. The Snapper North INJ 2 is designed to the necessary specifications suitable for the highest modeled injection rate for the well. The maximum injection rates [redacted] for the Snapper North INJ 2 are displayed in Table 4-17.

Table 4-17 – Snapper North INJ 2 maximum modeled injection rates.

[redacted]

Figure 4-7 – Snapper North INJ 2 Injection Pressure Plot

Model-generated well operating parameters [redacted] are detailed in Tables 4-18 and 4-19.

Table 4-18 – Model outputs for Snapper North INJ 2 [redacted]

[redacted]

Table 4-19 – Model outputs for Snapper North INJ 2 [redacted]

[redacted]

The model results indicate that [redacted] tubing is the appropriate size to inject the desired volumes of CO_2 into the well. Under expected operating conditions, the CO_2 will be in the dense phase (either liquid or supercritical) throughout the injection wellbore, and in the supercritical phase in the storage formation.

[redacted]

4.2.5.1 Conductor Pipe

Conductor pipe will be used to ensure that the hole integrity is maintained during the initial drilling of Snapper North INJ 2. [redacted]

The conductor pipe specifications were chosen to support the desired bit-size requirement for drilling the surface casing. [redacted] Once the conductor pipe is installed, the pipe will be flushed out and cleaned, and drilling will commence.

4.2.5.2 Surface Casing

The surface hole will be drilled to [redacted] A string of [redacted] casing will be run and cemented with the casing centered, using centralizers in the open hole. Cement will be circulated to surface. [redacted]

Summaries of engineering calculations for the surface casing are displayed in Table 4-20. The engineering calculations for all six Project injection wells were performed assuming identical wellbore conditions and setting depth for surface casing. Snapper North INJ 2 surface casing annular geometries are displayed in Table 4-21 and surface casing volume calculations are displayed in Table 4-22.

Table 4-20 – Snapper North INJ 2 surface casing engineering calculations.

[redacted]

Table 4-21 – Snapper North INJ 2 surface casing annular geometries

[redacted]

Table 4-22 – Snapper North INJ 2 surface casing volume calculations.

[redacted]

[redacted]

4.2.5.3 Long String Casing

The long string casing will be run to TD and cemented from the casing-shoe setting depth back to surface utilizing conventional cementing.

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

[redacted]

A metallurgical analysis was performed considering the chemical composition of the injectate and the downhole conditions previously detailed (Table 4-3). [redacted]

The long string casing will be cemented with CO_2-resistant cement [redacted] This will provide a sufficient barrier to prevent CO_2 movement out of the injection interval. [redacted]

The engineering and design parameters for the long string casing are summarized in Tables 4-23 through 4-25.

Table 4-23 – Snapper North INJ 2 long string casing engineering calculations.

[redacted]

Table 4-24 – Snapper North INJ 2 long string casing annular geometries.

[redacted]

Table 4-25 – Snapper North INJ 2 long string casing volume calculations.

[redacted]

4.2.5.4 Centralizers

Bow spring centralizers will be utilized in the [redacted] surface casing to ensure that a continuous column of cement is present [redacted] The recommended locations are as follows:

[redacted]

Bow spring centralizers will also be utilized [redacted] to ensure that a continuous column of cement is present throughout the annulus. The recommended locations are as follows:

[redacted]

4.2.5.5 Injection Tubing

The [redacted] injection tubing [redacted] selected based on modeling results from planned injection volumes, rates, and injectate composition. [redacted] A complete summary of the metallurgical analysis is included in *Appendix G-1*. Table 4-26 provides the tubing engineering design calculations for the Snapper North INJ 2 injection well.

Table 4-26 – Tubing engineering design calculations – Snapper North INJ 2.

[redacted]

4.2.5.6 Packer Discussion

[redacted] Once the packer and tubing are installed, the tubing/long string casing annulus will be pressure-tested for verification.

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.

Figure 4-3 (*Section 4.2.2.6*) provides an example schematic of the planned packer assembly.

4.2.5.7 Subsurface Injection Valve

In accordance with 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted]-80 tubing above the packer.

Figure 4-4 (*Section 4.2.2.7*) provides an example schematic of the planned SSIV assembly.

4.2.5.8 [redacted]

4.2.5.9 Wellhead Discussion

The wellhead is designed to control working pressures and corrosion complications. [redacted]

[redacted] The final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as illustrated in Figure 4-5 (*Section 4.2.2.9*). The wellhead design and manufacturer shown may change based on well and commercial factors determined before drilling.

4.2.6 Snapper North INJ 2 Completion/Stimulation Plans

The proposed Snapper North INJ 2 injection well may be stimulated during completion operations, to clean up the well after drilling and/or to improve injection performance. Stimulation may include but is not limited to flowing fluids into or out of the well, increasing or connecting pore spaces throughout the injection formation, or other activities intended to allow the injectate to move more readily into the injection zone. Final stimulation designs will be determined based on the conditions met during drilling. Operator will submit proposed stimulation procedures to the EPA or the UIC Director at least 30 days prior to beginning such operations, per 40 CFR **§146.91(d)(2)**. Such procedures may include the following standard industry stimulation:

- Wellbore clean up [redacted]
- Wellbore Stimulation [redacted]

4.2.7 Snapper North INJ 3 Engineering Design

The CO_2 stream in the Snapper North INJ 3 well will be injected into the [redacted] and contained by impermeable shale layers to ensure long-term storage. The injection interval sands are located from approximately [redacted] TVD gross. The sand formations are porous and permeable, making them favorable for CO_2 injection and storage.

[redacted] The CO_2 plume will be monitored during and after injection and compared to the modeled expectations; adjustments to the operation plan will be made as necessary.

Table 4-27 – Snapper North INJ 3 operational strategy.

[redacted]

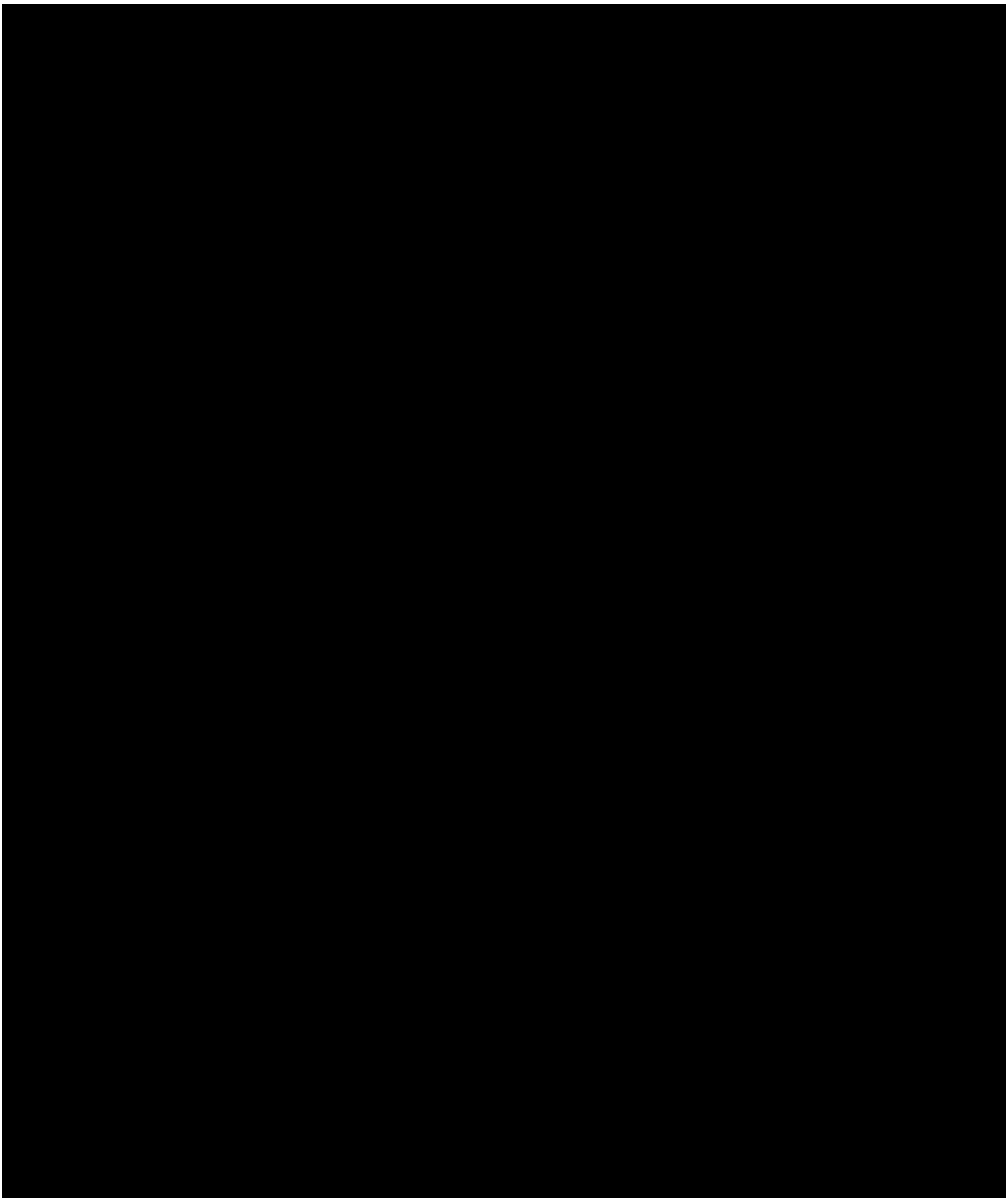
[redacted]

[redacted] These monitoring strategies will ensure that wellbore and mechanical integrity are maintained throughout the life of the Project.

Figure 4-8 (*Appendix F-1*) shows the proposed injection well design for the Snapper North INJ 3.

Figure 4-8 – Snapper North INJ 3 wellbore diagram.

The drilling and completion design for Snapper North INJ 3 is as follows:



A detailed drilling-and-completion prognosis is included in *Appendix F-2*.

4.2.8 Snapper North INJ 3 Detailed Discussion of Injection Well Design

Operator plans to inject a volume of up to [redacted] MTPA of CO_2 into the proposed well (Stage 1, Rate 2). As previously discussed, Operator recognizes that both planned and unplanned downtime will be encountered, and a sensitivity model was run to ensure that a maximum system injection rate [redacted] can be maintained if one well is shut in. The maximum injection rate allocated to the Snapper North INJ 3 during this sensitivity model was [redacted] MTPA. [redacted] Reservoir modeling was performed for this rate, taking into consideration 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. The Snapper North INJ 3 is designed to the necessary specifications suitable for the highest modelled injection rate for the well. The maximum injection rates [redacted] for the Snapper North INJ 3 are displayed in Table 4-28.

Table 4-28 – Snapper North INJ 3 maximum modeled injection rates.

[redacted]

Figure 4-9 – Injection pressure plot for Snapper North INJ 3.

Model-generated well operating parameters [redacted] are detailed in Tables 4-29 and 4-30.

Table 4-29 – Model outputs for Snapper North INJ 3 [redacted]

Table 4-30 – Model outputs for Snapper North INJ 3 [redacted]

The model results indicate that [redacted] tubing is the appropriate size to inject the desired volumes of CO_2 into each well. Under expected operating conditions, the CO_2 will be in the dense phase (either liquid or supercritical) throughout the injection wellbore, and in the supercritical phase in the storage formation.

[redacted]

[redacted]

4.2.8.1 Conductor Pipe

Conductor pipe will be used to ensure that the hole integrity is maintained during the initial drilling of Snapper North INJ 3. [redacted]

The conductor pipe specifications were chosen to support the desired bit-size requirement for drilling the surface casing. [redacted] Once the conductor pipe is installed, the pipe will be flushed out and cleaned, and drilling will commence.

4.2.8.2 Surface Casing

The surface hole will be drilled to [redacted] A string of [redacted] casing will be run and cemented with the casing centered using centralizers in the open hole. Cement will be circulated to surface. [redacted]

Summaries of engineering calculations for the surface casing are displayed in Table 4-31. The engineering calculations for all six Project injection wells were performed assuming identical wellbore conditions and setting depth for surface casing. Snapper North INJ 3 surface casing annular geometries are displayed in Table 4-32 and surface casing volume calculations are displayed in Table 4-33.

Table 4-31 – Snapper North INJ 3 surface casing engineering calculations.

[redacted]

Table 4-32 – Snapper North INJ 3 surface casing annular geometries.

[redacted]

Table 4-33 – Snapper North INJ 3 surface casing volume calculations.

[redacted]

4.2.8.3 Long String Casing

The long string casing will be run to TD and cemented from the casing-shoe setting depth back to surface utilizing conventional cementing.

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

[redacted]

A metallurgical analysis was performed considering the chemical composition of the injectate and the downhole conditions previously detailed (Table 4-3). [redacted]

The long string casing will be cemented with CO_2-resistant cement from [redacted] This will provide a sufficient barrier to prevent CO_2 movement out of the injection interval. [redacted]

The engineering and design parameters for the long string casing are summarized in Tables 4-34 through 4-36.

Table 4-34 – Snapper North INJ 3 long string casing engineering calculations.

Table 4-35 – Snapper North INJ 3 long string casing annular geometries.

Table 4-36 – Snapper North INJ 3 long string casing volume calculations.

4.2.8.4 Centralizers

Bow spring centralizers will be utilized in the [redacted] surface casing to ensure that a continuous column of cement is present [redacted] The recommended locations are as follows:

[redacted]

Bow spring centralizers will also be utilized [redacted] to ensure that a continuous column of cement is present throughout the annulus. The recommended locations are as follows:

[redacted]

4.2.8.5 Injection Tubing

The [redacted] injection tubing [redacted] were selected based on modeling results from planned injection volumes, rates, and injectate composition. [redacted] A complete summary of the metallurgical analysis is included in *Appendix G-1*. Table 4-37 provides the tubing engineering design calculations for the Snapper North INJ 3 injection well.

Table 4-37 – Tubing engineering design calculations – Snapper North INJ 3.

[redacted]

4.2.8.6 Packer Discussion

[redacted] Once the packer and tubing are installed, the tubing/long string casing annulus will be pressure tested for verification.

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.

Figure 4-3 (*Section 4.2.2.6*) provides an example schematic of the planned packer assembly.

4.2.8.7 Subsurface Injection Valve

In accordance with 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted] tubing above the packer.

Figure 4-4 (*Section 4.2.2.7*) provides an example schematic of the planned SSIV assembly.

4.2.8.8 [redacted]

4.2.8.9 Wellhead Discussion

The wellhead is designed to control working pressures and corrosion complications. [redacted] The final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as illustrated in Figure 4-5 (*Section 4.2.2.9*). The wellhead design and manufacturer shown may change based on well and commercial factors determined before drilling.

4.2.9 Snapper North INJ 3 Completion/Stimulation Plans

The proposed Snapper North INJ 3 injection well may be stimulated during completion operations, to clean up the well after drilling and/or to improve injection performance. Stimulation may include, but is not limited to, flowing fluids into or out of the well, increasing or connecting pore spaces throughout the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection zone. Final stimulation designs will be determined based on the conditions met during drilling. Operator will submit proposed stimulation procedures to the EPA or the UIC Director at least 30 days prior to beginning such operations, per 40 CFR **§146.91(d)(2)**. Such procedures may include the following standard industry stimulation:

- Wellbore clean up [redacted]
- Wellbore Stimulation

[redacted]

4.2.10 Snapper South INJ 1 Engineering Design

The CO_2 stream in the Snapper South INJ 1 well will be injected into the [redacted] and contained by impermeable shale layers to ensure long-term storage. Shale layers throughout the formation will be employed to separate the injection into discrete injection stages. The shale layers will act as vertical barriers allowing greater control of the available pore space. This completion design will minimize CO_2 plume migration while maximizing the use of available pore space. The injection interval sands are located from approximately [redacted] TVD. The sand formations are porous and permeable, making them favorable for CO_2 injection and storage.

[redacted] The CO_2 plume will be monitored during and after injection and compared to the modeled expectations; adjustments to the operation plan will be made as necessary.

Table 4-38 – Snapper South INJ 1 operational strategy.

[redacted]

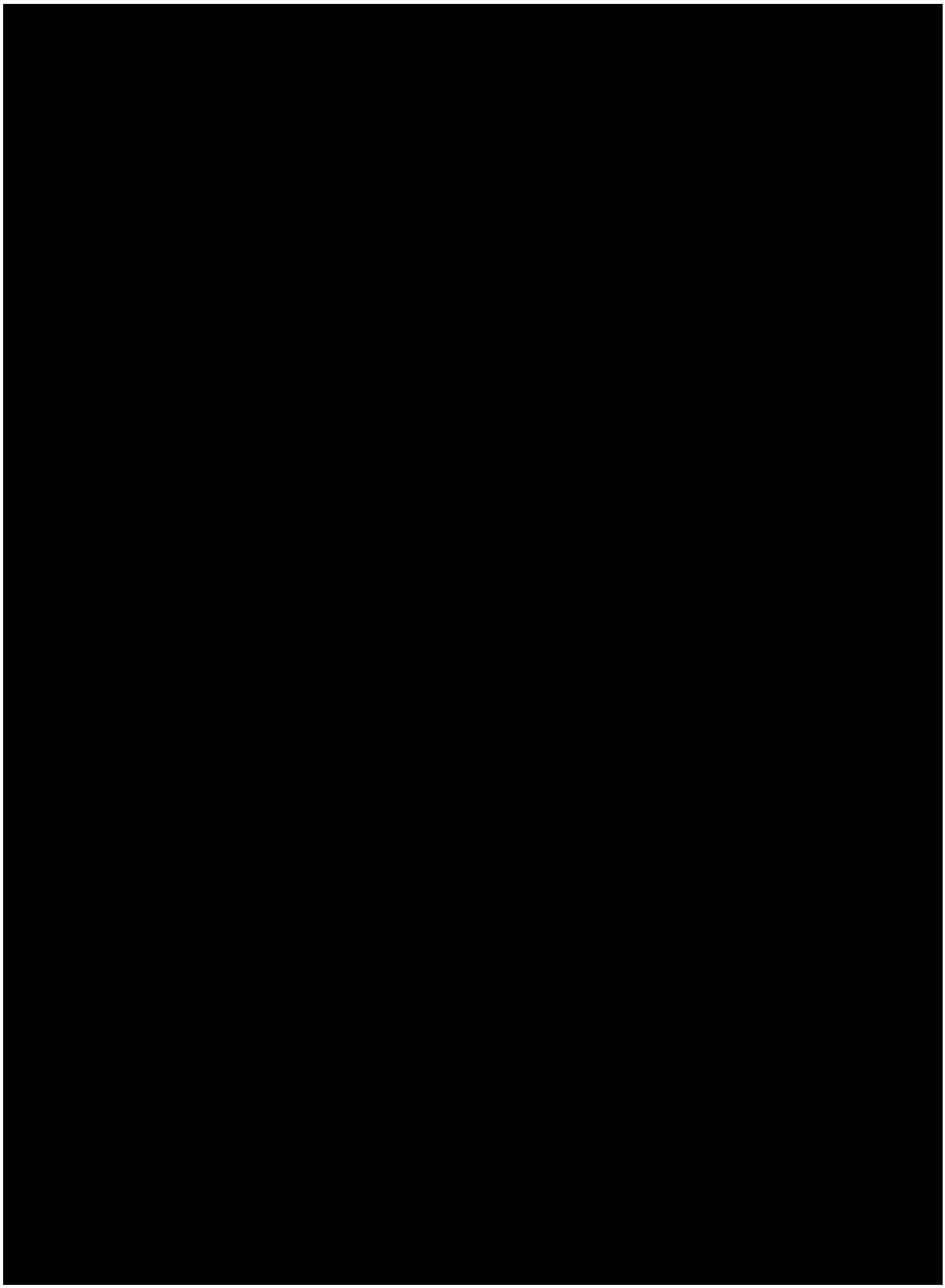
[redacted] These monitoring strategies will ensure that wellbore and mechanical integrity are maintained throughout the life of the project.

Figure 4-10 (*Appendix F-1*) shows the proposed injection well design for the Snapper South INJ 1.

Figure 4-10 – Snapper South INJ 1 wellbore diagram.

The drilling and completion design for Snapper South INJ 1 is as follows:

[redacted]



A detailed drilling-and-completion prognosis is included in *Appendix F-2*.

4.2.11 Snapper South INJ 1 Detailed Discussion of Injection Well Design

Operator plans to inject a volume of [redacted] MTPA of CO_2 into the proposed well. As previously discussed, Operator recognizes that both planned and unplanned downtime will be encountered, and a sensitivity model was run to ensure that a maximum system injection rate [redacted] can be maintained if one well is shut in. The maximum injection rate allocated to the Snapper South INJ 1 during this sensitivity model was [redacted] MTPA. [redacted] Reservoir modeling was performed for this rate, taking into consideration 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. The Snapper South INJ 1 is designed to the necessary specifications suitable for the highest modeled injection rate for the well. The maximum injection rates [redacted] for the Snapper South INJ 1 are displayed in Table 4-39.

Table 4-39 – Snapper South INJ 1 maximum modeled injection rates.

[redacted]

Figure 4-11 – Snapper South INJ 1 injection pressure plot.

Model-generated well operating parameters [redacted] are detailed in Tables 4-40 and 4-41.

Table 4-40 – Model outputs for Snapper South INJ 1 [redacted]

Table 4-41 – Model outputs for Snapper South INJ 1 [redacted]

The model results indicate that [redacted] tubing is the appropriate size to inject the desired volumes of CO_2 into each well. Under expected operating conditions, the CO_2 will be in the dense phase (either liquid or supercritical) throughout the injection wellbore, and in the supercritical phase in the storage formation.

[redacted]

[redacted]

Conductor Pipe

Conductor pipe will be used to ensure that the hole integrity is maintained during the initial drilling of Snapper South INJ 1. [redacted]

The conductor pipe specifications were chosen to support the desired bit size requirement for drilling the surface casing. [redacted] Once the conductor pipe is installed, the pipe will be flushed out and cleaned, and drilling will commence.

Surface Casing

The surface hole will be drilled to [redacted] A string of [redacted] casing will be run and cemented with the casing centered using centralizers in the open hole. Cement will be circulated to surface. [redacted]

Summaries of engineering calculations for the surface casing are displayed in Table 4-42. The engineering calculations for all six Project injection wells were performed assuming identical wellbore conditions and setting depth for surface casing. Snapper South INJ 1 surface casing annular geometries are displayed in Table 4-43 and surface casing volume calculations are displayed in Table 4-44.

Table 4-42– Snapper South INJ 1 surface casing engineering calculations.

[redacted]

*bbl – barrels | W/m – watts per meter

Table 4-43 – Snapper South INJ 1 surface casing annular geometries.

[redacted]

Table 4-44 – Snapper South INJ 1 surface casing volume calculations.

[redacted]

Long String Casing

The long string casing will be run to TD and cemented from the casing-shoe setting depth back to surface utilizing conventional cementing.

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

[redacted]

A metallurgical analysis was performed considering the chemical composition of the injectate and the downhole conditions previously detailed (Table 4-3). [redacted]

The long string casing will be cemented with CO_2-resistant cement from [redacted] This will provide a sufficient barrier to prevent CO_2 movement out of the injection interval. [redacted]

The engineering and design parameters for the long string casing are summarized in Tables 4-45 through 4-47.

Table 4-45 – Snapper South INJ 1 long string casing engineering calculations.

[redacted]

Table 4-46 – Snapper South INJ 1 long string casing annular geometries.

[redacted]

Table 4-47 – Snapper South INJ 1 long string casing volume calculations.

[redacted]

Centralizers

Bow spring centralizers will be utilized in the [redacted] surface casing to ensure a continuous column of cement is present [redacted] The recommended locations are as follows:

[redacted]

Bow spring centralizers will also be utilized [redacted] to ensure that a continuous column of cement is present throughout the annulus. [redacted]

[redacted]

Injection Tubing

The [redacted] injection tubing [redacted] were selected based on modeling results from planned injection volumes, rates, and injectate composition. [redacted] A complete summary of the metallurgical analysis is included in *Appendix G-1*. Table 4-48 provides the tubing engineering design calculations for the Snapper South INJ 1 injection well.

Table 4-48 – Tubing engineering design calculations – Snapper South INJ 1.

[redacted]

Packer Discussion

[redacted] Once the packer and tubing are installed, the tubing/long string casing annulus will be pressure-tested for verification.

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.

Figure 4-3 (*Section 4.2.2.6*) provides an example schematic of the planned packer assembly.

Subsurface Injection Valve

In accordance with 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted] tubing above the packer.

Figure 4-4 (*Section 4.2.2.7*) provides an example schematic of the planned SSIV assembly.

[redacted]

Wellhead Discussion

The wellhead is designed to control working pressures and corrosion complications. [redacted] The final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as illustrated above in Figure 4-5 (*Section 4.2.2.9*). The wellhead design and manufacturer shown may change based on well and commercial factors determined before drilling.

4.2.12 Snapper South INJ 1 Completion/Stimulation Plans

The proposed Snapper South INJ 1 injection well may be stimulated during completion operations, to clean up the well after drilling and/or to improve injection performance. Stimulation may include, but is not limited to, flowing fluids into or out of the well, increasing or connecting pore spaces throughout the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection zone. Final stimulation designs will be determined based on the conditions met during drilling. Operator will submit proposed stimulation procedures to the EPA or the UIC Director at least 30 days prior to beginning such operations, per 40 CFR **§146.91(d)(2)**. Such procedures may include the following standard industry stimulation:

- Wellbore clean up

[redacted]

- Wellbore Stimulation

[redacted]

4.2.13 Snapper South INJ 2 Engineering Design

The CO_2 stream in the Snapper South INJ 2 well will be injected into the [redacted] and contained by impermeable shale layers to ensure long-term storage. Shale layers throughout the formation will be employed to separate the injection into discrete injection stages. The shale layers will act as vertical barriers allowing greater control of the available pore space. This completion design will minimize CO_2 plume migration while maximizing the use of available pore space. The injection interval sands are located from approximately [redacted] TVD. The sand formations are porous and permeable, making them favorable for CO_2 injection and storage.

[redacted] The CO_2 plume will be monitored during and after injection and compared to the modeled expectations; adjustments to the operation plan will be made as necessary.

Table 4-49 – Snapper South INJ 2 operational strategy.

[redacted]

[redacted] These monitoring strategies will ensure that wellbore and mechanical integrity are maintained throughout the life of the project.

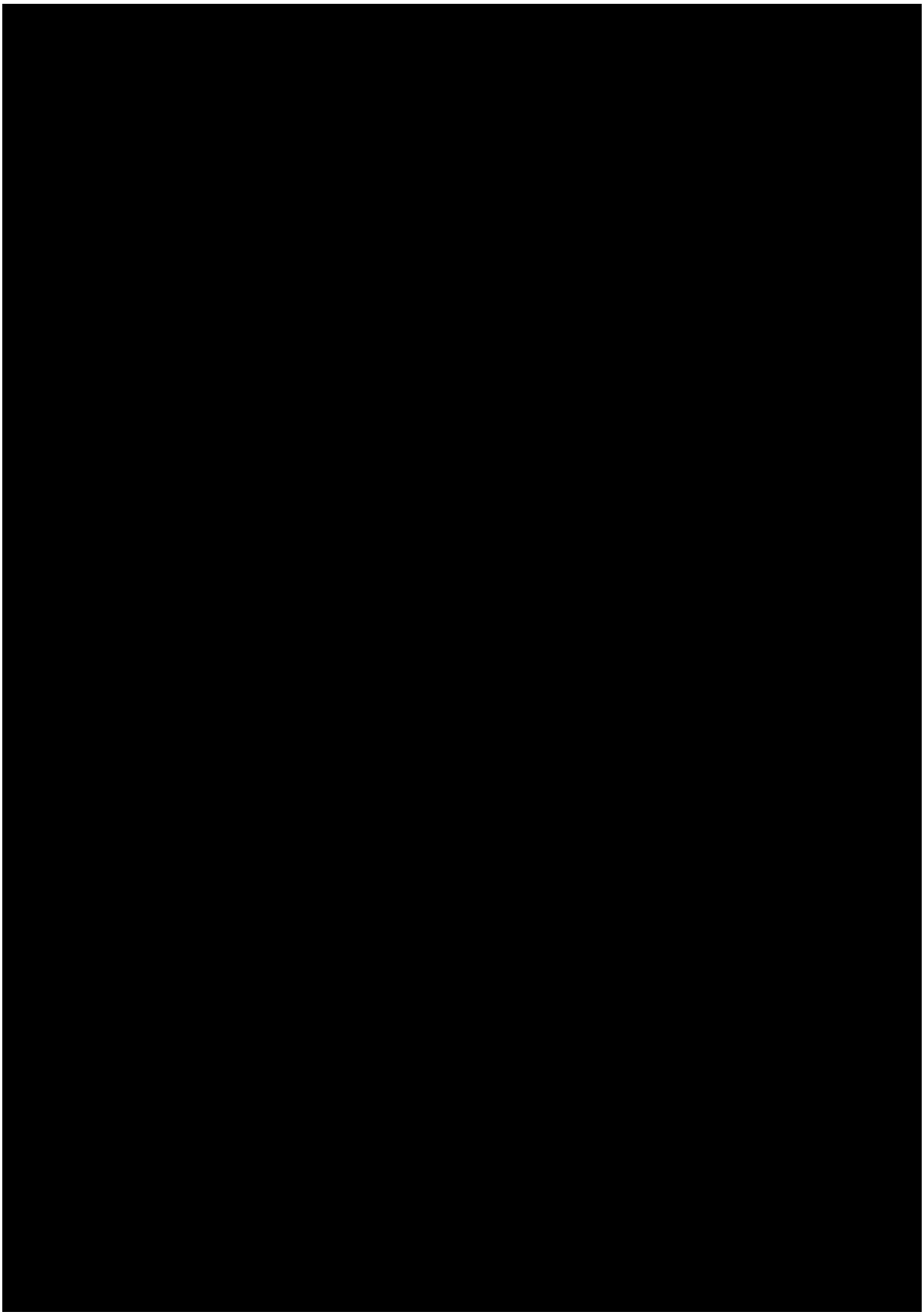
Figure 4-12 (*Appendix F-1*) shows the proposed injection well design for the Snapper South INJ 2.

[redacted]

Figure 4-12 – Snapper South INJ 2 wellbore diagram.

The drilling and completion design for Snapper South INJ 2 is as follows:

[redacted]



[redacted]

A detailed drilling-and-completion prognosis is included in *Appendix F-2*.

4.2.14 Snapper South INJ 2 Detailed Discussion of Injection Well Design

Operator plans to inject a volume of [redacted] MTPA of CO_2 into the proposed well. As previously discussed, Operator recognizes that both planned and unplanned downtime will be encountered, and a sensitivity model was run to ensure that a maximum system injection rate [redacted] can be maintained if one well is shut in. The maximum injection rate allocated to the Snapper South INJ 2 during this sensitivity model was [redacted] MTPA. [redacted] Reservoir modeling was performed for this rate, taking into consideration 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. The Snapper South INJ 2 is designed to the necessary specifications suitable for the highest modeled injection rate for the well. The maximum injection rates [redacted] for the Snapper South INJ 2 is displayed in Table 4-50.

Table 4-50 – Snapper South INJ 2 maximum modeled injection rates.

[redacted]

Figure 4-13 – Injection pressure plot for Snapper South INJ 2.

Model-generated well operating parameters [redacted] are detailed in Tables 4-51 and 4-52.

Table 4-51 – Model outputs for Snapper South INJ 2 [redacted]

Table 4-52 – Model outputs for Snapper South INJ 2 [redacted]

The model results indicate that [redacted] tubing is the appropriate size to inject the desired volumes of CO_2 into each well. Under expected operating conditions, the CO_2 will be in the dense

phase (either liquid or supercritical) throughout the injection wellbore, and in the supercritical phase in the storage formation.

[redacted]

[redacted]

4.2.14.1 Conductor Pipe

Conductor pipe will be used to ensure that the hole integrity is maintained during the initial drilling of Snapper South INJ 2. [redacted]

The conductor pipe specifications were chosen to support the desired bit size requirement for drilling the surface casing. [redacted] Once the conductor pipe is installed, the pipe will be flushed out and cleaned, and drilling will commence.

4.2.14.2 Surface Casing

The surface hole will be drilled to [redacted] A string of [redacted] casing will be run and cemented with the casing centered using centralizers in the open hole. Cement will be circulated to surface. [redacted]

Summaries of engineering calculations for the surface casing are displayed in Table 4-53. The engineering calculations for all six Project injection wells were performed assuming identical wellbore conditions and setting depth for surface casing. Snapper South INJ 2 surface casing annular geometries are displayed in Table 4-54 and surface casing volume calculations are displayed in Table 4-55.

Table 4-53 – Snapper South INJ 2 surface casing engineering calculations.

[redacted]

Table 4-54 – Snapper South INJ 2 surface casing annular geometries.

[redacted]

Table 4-55 – Snapper South INJ 2 surface casing volume calculations.

[redacted]

4.2.14.3 Long String Casing

The long string casing will be run to TD and cemented from the casing-shoe setting depth back to surface utilizing conventional cementing.

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

[redacted]

A metallurgical analysis was performed considering the chemical composition of the injectate and the downhole conditions previously detailed (Table 4-3). [redacted]

The long string casing will be cemented with CO_2-resistant cement from [redacted] This will provide a sufficient barrier to prevent CO_2 movement out of the injection interval. [redacted]

The engineering and design parameters for the long string casing are summarized in Tables 4-56 through 4-58.

Table 4-56 – Snapper South INJ 2 long string casing engineering calculations.

[redacted]

Table 4-57 – Snapper South INJ 2 long string casing annular geometries.

[redacted]

Table 4-58 – Snapper South INJ 2 long string casing volume calculations.

[redacted]

4.2.14.4 Centralizers

Bow spring centralizers will be utilized in the [redacted] surface casing to ensure that a continuous column of cement is present [redacted] The recommended locations are as follows:

[redacted]

Bow spring centralizers will also be utilized [redacted] to ensure that a continuous column of cement is present throughout the annulus. The recommended locations are as follows:

[redacted]

4.2.14.5 Injection Tubing

The [redacted] injection tubing [redacted] were selected based on modeling results from planned injection volumes, rates, and injectate composition. [redacted] A complete summary of the metallurgical analysis is included in *Appendix G-1*. Table 4-59 provides the tubing engineering design calculations for the Snapper South INJ 2 injection well.

Table 4-59 – Snapper South INJ 2 tubing engineering design calculations.

[redacted]

4.2.14.6 Packer Discussion

[redacted] Once the packer and tubing are installed, the tubing/long string casing annulus will be pressure tested for verification.

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.

Figure 4-3 (*Section 4.2.2.6*) provides an example schematic of the planned packer assembly.

4.2.14.7 Subsurface Injection Valve

In accordance with 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted] tubing above the packer.

Figure 4-4 (*Section 4.2.2.7*) provides an example schematic of the planned SSIV assembly.

4.2.14.8 [redacted]

4.2.14.9 Wellhead Discussion

The wellhead is designed to control working pressures and corrosion complications. [redacted] The final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as illustrated in Figure 4-5 (*Section 4.2.2.9*). The wellhead design and manufacturer shown may change based on well and commercial factors determined before drilling.

4.2.15 Snapper South INJ 2 Completion/Stimulation Plans

The proposed Snapper South INJ 2 injection well may be stimulated during completion operations, to clean up the well after drilling and/or to improve injection performance. Stimulation may include, but is not limited to, flowing fluids into or out of the well, increasing or connecting pore spaces throughout the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection zone. Final stimulation designs will be determined based on the conditions met during drilling. Operator will submit proposed stimulation procedures to the EPA or the UIC Director at least 30 days prior to beginning such operations, per 40 CFR **§146.91(d)(2)**. Such procedures may include the following standard industry stimulation:

- Wellbore clean up [redacted]
- Wellbore stimulation [redacted]

4.2.16 Snapper South INJ 3 Engineering Design

The CO_2 stream in the Snapper South INJ 3 well will be injected into the [redacted] and contained by impermeable shale layers to ensure long-term storage. Shale layers throughout the formation will be employed to separate the injection into discrete injection stages. The shale layers will act as vertical barriers allowing greater control of the available pore space. This completion design will minimize CO_2 plume migration while maximizing the use of available pore space. The injection interval sands are located from approximately [redacted] TVD. The sand formations are porous and permeable, making them favorable for CO_2 injection and storage.

[redacted] The CO_2 plume will be monitored during and after injection and compared to the modeled expectations; adjustments to the operation plan will be made as necessary.

Table 4-60 – Snapper South INJ 3 operational strategy.

[redacted] These monitoring strategies will ensure that wellbore and mechanical integrity are maintained throughout the life of the project.

Figure 4-14 (*Appendix F-1*) shows the proposed injection well design for the Snapper South INJ 3.

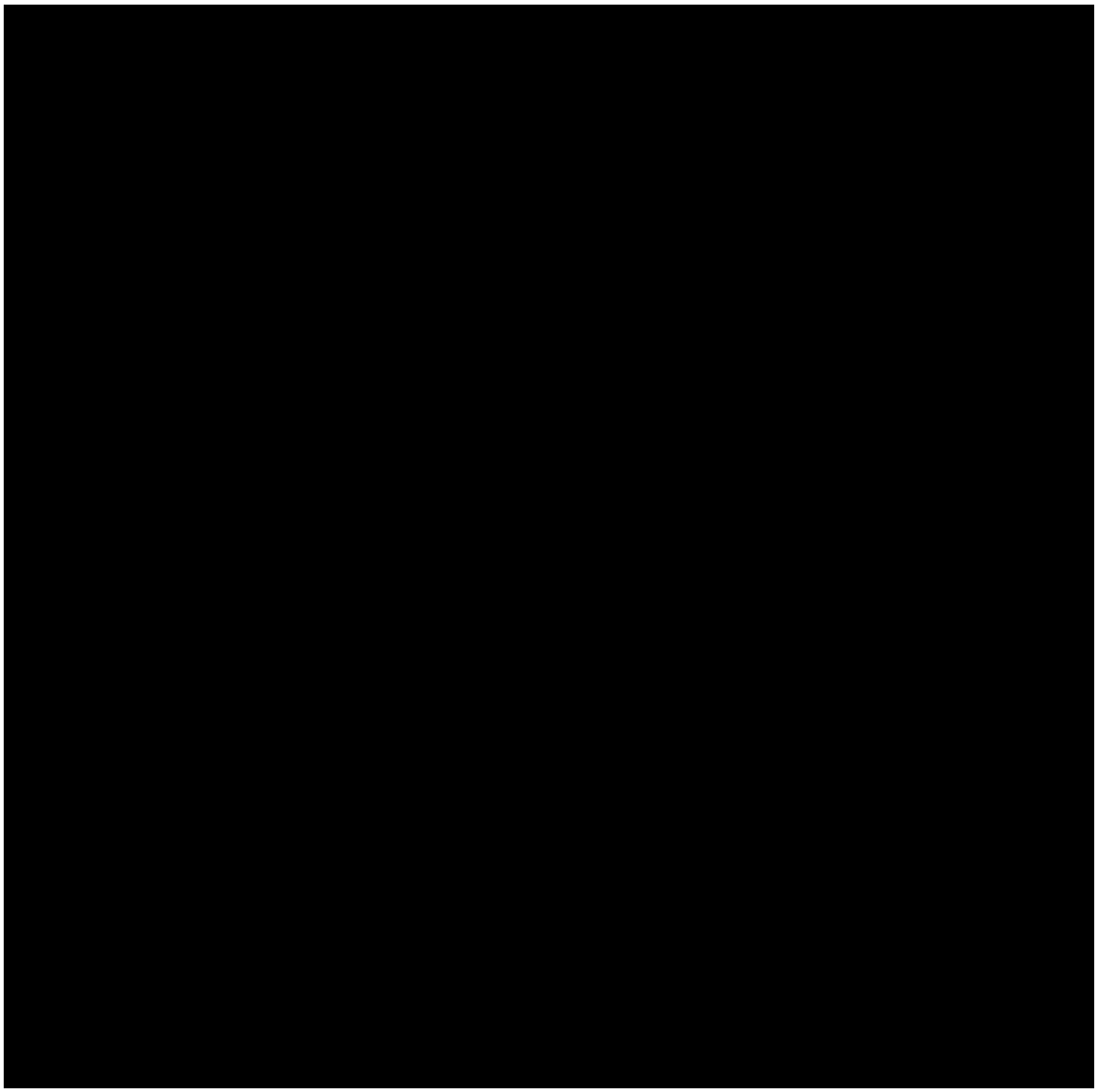
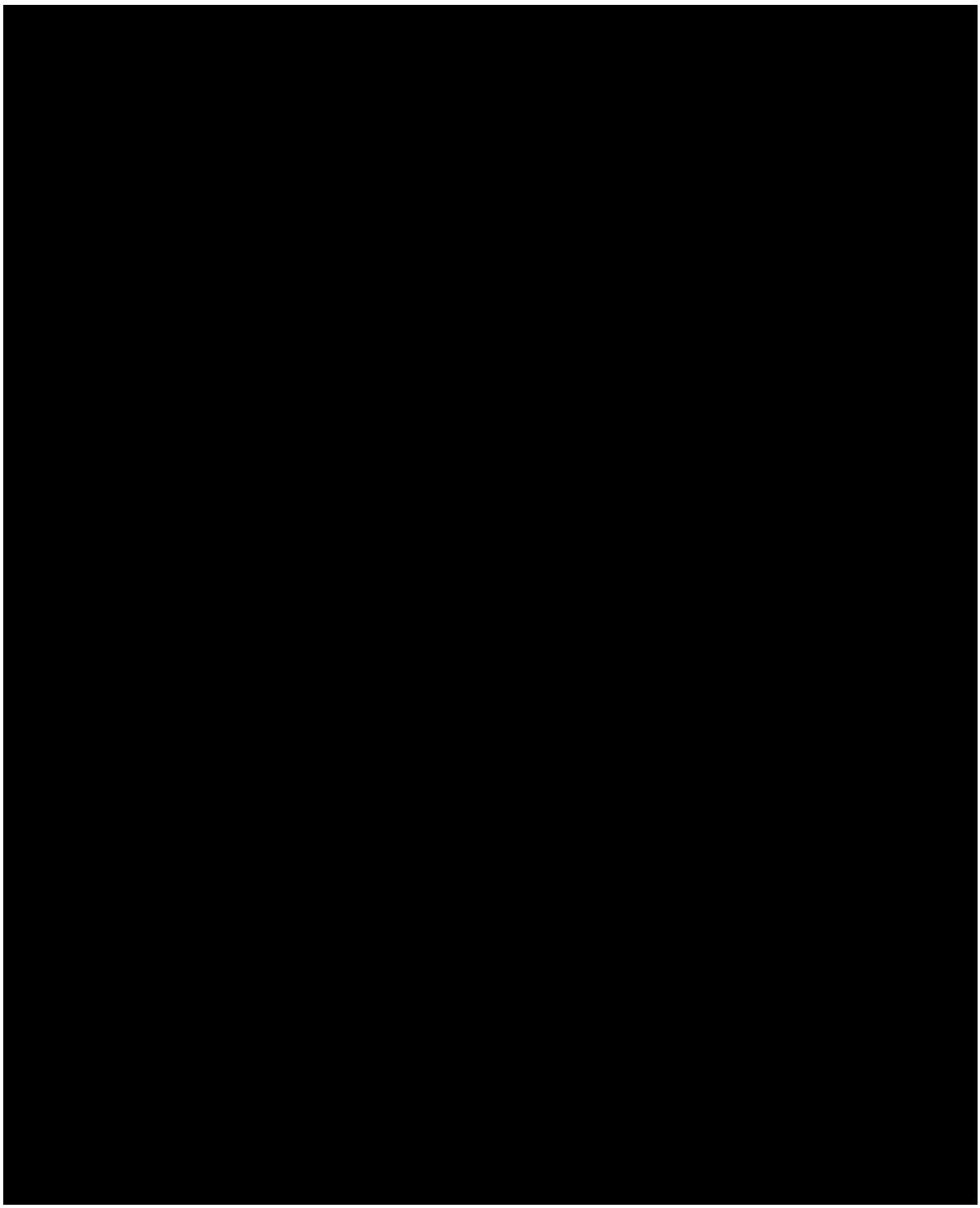


Figure 4-14 – Snapper South INJ 3 wellbore diagram.

The drilling and completion design for Snapper South INJ 3 is as follows:



A detailed drilling-and-completion prognosis is included in *Appendix F-2*.

4.2.17 Snapper South INJ 3 Detailed Discussion of Injection Well Design

Operator plans to inject a volume of [redacted] MTPA of CO_2 into the proposed well. As previously discussed, Operator recognizes that both planned and unplanned downtime will be encountered, and a sensitivity model was run to ensure that a maximum system injection rate [redacted] can be maintained if one well is shut in. The maximum injection rate allocated to the Snapper South INJ 3 during this sensitivity model was [redacted] MTPA. [redacted] Reservoir modeling was performed for this rate taking into consideration 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. The Snapper South INJ 3 is designed to the necessary specifications suitable for the highest modeled injection rate for the well. The maximum injection rates [redacted] for the Snapper South INJ 3 can be seen in Table 4-61.

Table 4-61 – Snapper South INJ 3 maximum modeled injection rates.

[redacted]

Figure 4-15 – Injection pressure plot for Snapper South INJ 3.

Model-generated well operating parameters [redacted] are detailed in Table 4-62 and Table 4-63.

Table 4-62 – Model outputs for Snapper South INJ 3 [redacted]

Table 4-63 – Model outputs for Snapper South INJ 3 [redacted]

The model results indicate that [redacted] tubing is the appropriate size to inject the desired volumes of CO_2 into each well. Under expected operating conditions, the CO_2 will be in the dense phase (either liquid or supercritical) throughout the injection wellbore, and in the supercritical phase in the storage formation.

[redacted]

[redacted]

Conductor Pipe

Conductor pipe will be used to ensure that the hole integrity is maintained during the initial drilling of Snapper South INJ 3. [redacted]

The conductor pipe specifications were chosen to support the desired bit-size requirement for drilling the surface casing. [redacted] Once the conductor pipe is installed, the pipe will be flushed out and cleaned, and drilling will commence.

Surface Casing

The surface hole will be drilled to [redacted] A string of [redacted] casing will be run and cemented with the casing centered using centralizers in the open hole. Cement will be circulated to surface. [redacted]

Summaries of engineering calculations for the surface casing are displayed in Table 4-64. The engineering calculations for all six Project injection wells were performed assuming identical wellbore conditions and setting depth for surface casing. Snapper South INJ 3 surface casing annular geometries are displayed in Table 4-65 and surface casing volume calculations are displayed in Table 4-66.

Table 4-64 – Snapper South INJ 3 surface casing engineering calculations.

[redacted]

Table 4-65 – Snapper South INJ 3 surface casing annular geometries.

[redacted]

Table 4-66 – Snapper South INJ 3 surface casing volume calculations.

[redacted]

Long String Casing

The long string casing will be run to TD and cemented from the casing-shoe setting depth back to surface utilizing conventional cementing.

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

[redacted]

A metallurgical analysis was performed considering the chemical composition of the injectate and the downhole conditions previously detailed (Table 4-3). [redacted]

The long string casing will be cemented with CO_2-resistant cement from [redacted] This will provide a sufficient barrier to prevent CO_2 movement out of the injection interval. [redacted]

The engineering and design parameters for the long string casing are summarized in Tables 4-67 through 4-69.

Table 4-67 – Snapper South INJ 3 long string casing engineering calculations.

[redacted]

Table 4-68 – Snapper South INJ 3 long string casing annular geometries.

[redacted]

Table 4-69 – Snapper South INJ 3 long string casing volume calculations.

[redacted]

Centralizers

Bow spring centralizers will be utilized in the [redacted] surface casing to ensure that a continuous column of cement is present [redacted] The recommended locations are as follows:

[redacted]

Bow spring centralizers will also be utilized [redacted] to ensure that a continuous column of cement is present throughout the annulus. The recommended locations are as follows:

[redacted]

Injection Tubing

The [redacted] injection tubing [redacted] were selected based on modeling results from planned injection volumes, rates, and injectate composition. [redacted] A complete summary of the metallurgical analysis is included in *Appendix G-1*. Table 4-70 provides the tubing engineering design calculations for the Snapper South INJ 3 injection well.

Table 4-70 – Tubing engineering design calculations – Snapper South INJ 3.

[redacted]

Packer Discussion

[redacted] Once the packer and tubing are installed, the tubing/long string casing annulus will be pressure-tested for verification.

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.

Figure 4-3 (*Section 4.2.2.6*) provides an example schematic of the planned packer assembly.

Subsurface Injection Valve

In accordance with 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted] tubing above the packer.

Figure 4-4 (*Section 4.2.2.7*) provides an example schematic of the planned SSIV assembly.

[redacted]

Wellhead Discussion

The wellhead is designed to control working pressures and corrosion complications. [redacted] The final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as illustrated above in Figure 4-5 (*Section 4.2.2.9*). The wellhead design and manufacturer shown may change based on well and commercial factors determined before drilling.

4.2.18 Snapper South INJ 3 Completion/Stimulation Plans

Operator's proposed Snapper South INJ 3 injection well may be stimulated during completion operations, to clean up the well after drilling and/or to improve injection performance. Stimulation may include, but is not limited to, flowing fluids into or out of the well, increasing or connecting pore spaces throughout the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection zone. Final stimulation designs will be determined based on the conditions met during drilling. Operator will submit proposed stimulation procedures to the EPA or the UIC Director at least 30 days prior to beginning such operations, per 40 CFR **§146.91(d)(2)**. Such procedures may include the following standard industry stimulation:

- Wellbore clean up [redacted]
- Wellbore Stimulation

[redacted]

4.3 Testing and Logging during Drilling and Completion Operations

In accordance with 16 TAC **§5.206(i)** [40 CFR **§146.87(f)**], Operator 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. Operator will submit notice at least 48 hours in advance of any actual activity.

4.3.1 Coring Plan

Whole core will be collected in the UCZ, injection intervals, and lower confining zone (LCZ) from the planned stratigraphic test wells in the Project area. To supplement the data, additional sidewall cores may be taken during the drilling of the injection wells. [redacted]

4.3.2 Logging Plan

A suite of electric logs will be run in both the openhole and cased-hole sections of the Snapper North INJ 1, 2, and 3 and Snapper South INJ 1, 2, and 3 to confirm the properties. [redacted]

The openhole logging plan is detailed in Table 4-71. The cased-hole logging plan is detailed in Table 4-72.

Table 4-71 – Openhole logging plan.

[redacted]

Table 4-72 – Cased-hole logging plan.

[redacted]

4.3.3 Formation Fluid Testing

Samples of formation fluid will be obtained from multiple depths in the planned stratigraphic test wells. Additional samples can be obtained from the injection wells as needed [redacted]

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)**].

4.3.3.1 Step-Rate Test

Prior to the commencement of CO_2 injection, Operator 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)**]. Initial bottomhole pressure and temperature will be recorded prior to injection.

[redacted]

4.3.3.2 Testing Method

Specific wellbore and injection zone properties will define the final test parameters. The following test methods outline the expected test injection rates and times for each of the six injection wells. [redacted]

Table 4-73 – Proposed step-rate injection test (Snapper North INJ 1).

Table 4-74 – Proposed step-rate injection test (Snapper North INJ 2).

Table 4-75 – Proposed step-rate injection test (Snapper North INJ 3).

Table 4-76 – Proposed step-rate injection test (Snapper South INJ 1).

Table 4-77 – Proposed step-rate injection test (Snapper South INJ 2).

[redacted]

Table 4-78 – Proposed step-rate injection test (Snapper South INJ 3).

[redacted]

4.3.4 Injection Well Operating Strategy

The currently modeled completion and operational strategy [redacted] is shown on Table 4-79—displaying the injection rates for each injection well vs. time [redacted]

Table 4-79 – Injection well completion and operating strategy [redacted]

[redacted]

4.3.5 Snapper North INJ 1 Operating Strategy

[redacted]

[redacted]

Table 4-80 – Snapper North INJ 1 operating parameters.

[redacted]

Surface injection pressures will be limited so that the BHP does not exceed [redacted]% of the fracture pressure of the injection reservoir. The anticipated bottomhole fracture pressures and associated maximum-allowable injection bottomhole pressures for the well are shown in Table 4-81.

Table 4-81 – Snapper North INJ 1 bottomhole pressure summary.

[redacted]

[redacted] A summary of the planned injection strategy is listed in Table 4-82.

Table 4-82 – Snapper North INJ 1 planned injection strategy.

[redacted]

The operational strategy for the well was developed to optimize pore space utilization, plume expansion, and (composite) pressure front maximum extent. [redacted]

[redacted]

4.3.6 Snapper North INJ 2 Operating Strategy

[redacted]

[redacted]

Table 4-83 – Snapper North INJ 2 operating parameters.

[redacted]

[redacted]

Surface injection pressures will be limited so that the BHP does not exceed [redacted]% of the fracture pressure of the injection reservoir. The anticipated bottomhole fracture pressures and associated maximum-allowable injection bottomhole pressures for the well are shown in Table 4-84.

Table 4-84 – Snapper North INJ 2 bottomhole pressure summary.

[redacted]

[redacted] A summary of the planned injection strategy is listed in Table 4-85.

Table 4-85 – Snapper North INJ 2 planned injection strategy.

[redacted]

The operational strategy for the well was developed to optimize pore space utilization, plume expansion, and (composite) pressure front maximum extent. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.3.7 Snapper North INJ 3 Operating Strategy

[redacted]

[redacted]

[redacted]

Table 4-86 – Snapper North INJ 3 operating parameters.

[redacted]

Surface injection pressures will be limited so that the BHP does not exceed [redacted]% of the fracture pressure of the injection reservoir. The anticipated bottomhole fracture pressures and associated maximum-allowable injection bottomhole pressures for the well are shown in Table 4-87.

Table 4-87 – Snapper North INJ 3 bottomhole pressure summary.

[redacted]

[redacted] A summary of the planned injection strategy is listed in Table 4-88.

Table 4-88 – Snapper North INJ 3 planned injection strategy.

[redacted]

The operational strategy for the well was developed to optimize pore space utilization, plume expansion, and pressure front maximum extent. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.3.8 Snapper South INJ 1 Operating Strategy

[redacted]

[redacted]

Table 4-89 – Snapper South INJ 1 operating parameters.

[redacted]

Surface injection pressures will be limited so that the BHP does not exceed [redacted]% of the fracture pressure of the injection reservoir. The anticipated bottomhole fracture pressures and associated maximum-allowable injection bottomhole pressures for the well are shown in Table 4-90.

Table 4-90 – Snapper South INJ 1 bottomhole pressure summary.

[redacted]

[redacted] A summary of the planned injection strategy is listed in Table 4-91.

Table 4-91 – Snapper South INJ 1 planned injection strategy.

[redacted]

The operational strategy for the well was developed to optimize pore space utilization, plume

expansion, and (composite) pressure front maximum extent. [redacted]

[redacted]

[redacted]

[redacted]

4.3.9 Snapper South INJ 2 Operating Strategy

[redacted]

[redacted]

Table 4-92 – Snapper South INJ 2 operating parameters.

[redacted]

Surface injection pressures will be limited so that the BHP does not exceed [redacted]% of the fracture pressure of the injection reservoir. The anticipated bottomhole fracture pressures and associated maximum-allowable injection bottomhole pressures for the well are shown in Table 4-93.

Table 4-93 – Snapper South INJ 2 bottomhole pressure summary.

[redacted]

[redacted] A summary of the planned injection strategy is listed in Table 4-94.

Table 4-94 – Snapper South INJ 2 planned injection strategy.

[redacted]

The operational strategy for the well was developed to optimize pore space utilization, plume expansion, and (composite) pressure front maximum extent. [redacted]

[redacted]

4.3.10 Snapper South INJ 3 Operating Strategy

[redacted]

[redacted]

Table 4-95 – Snapper South INJ 3 operating parameters.

[redacted]

Surface injection pressures will be limited so that the BHP does not exceed [redacted]% of the fracture pressure of the injection reservoir. The anticipated bottomhole fracture pressures and associated maximum-allowable injection bottomhole pressures for the well are shown in Table 4-96.

Table 4-96 – Snapper South INJ 3 bottomhole pressure summary.

[redacted]

[redacted] A summary of the planned injection strategy is listed in Table 4-97.

Table 4-97 – Snapper South INJ 3 planned injection strategy.

[redacted]

The operational strategy for the well was developed to optimize pore space utilization, plume expansion, and (composite) pressure front maximum extent. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.4 Injection Well Construction and Operation Summary

The well designs for the six proposed injection wells are engineered to address all potential hazards and risks associated with injecting CO_2 into a Class VI well, with emphasis on protecting the USDW. The requirements for casing setting depth, material, and cement all meet or exceed the requirements for Class VI injection wells. In addition, the operational considerations given to downtime ensure that these wells are designed to the specifications necessary to support the planned total Project injection rate of [redacted] MTPA.

[redacted]

The completion and operating strategies of these wells allow for the injection of [redacted]

4.5 Engineering Design and Operations Summary

The Project site is ideally suited for permanent CO_2 storage and associated monitoring activities. By combining the best engineering practices in each well design with a state-of-the-art monitoring system and robust reservoir management strategy, the proposed injection wells will safely and permanently store CO_2.

Detailed drilling and completion procedures are provided in *Appendix F-2.* Cement programs and an example mud program are included in *Appendix F-3*.

Appendix F – Well Construction Schematics and Procedures:

- Appendix F-1 Injection Wellbore Schematics
- Appendix F-2 Injection Well Drilling and Completion Prognoses
- Appendix F-3 Supporting Well Construction Programs
- Appendix F-4 Preliminary Wellhead Design

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 5 – TESTING AND MONITORING PLAN

July 2024

SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

The operating plans for the proposed ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) project (Project) injection wells include robust testing and monitoring programs designed to satisfy the requirements of 16 Texas Administrative Code (16 TAC) ***§*5.203(j)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**]. Monitoring strategies are designed to ensure and verify the protection of the Underground Source of Drinking Water (USDW). 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 designs of all monitoring wells are included in this section, as well as the data that ConocoPhillips Texas Gulf Coast CCS LLC (Operator) plans to gather at each location. In addition to direct monitoring techniques, a summary of indirect methodologies and technologies has been provided. A combination of direct and indirect monitoring techniques provides Operator the ability to calibrate plume growth models and ensure the containment of CO_2.

These testing and monitoring programs will begin prior to CO_2 injection and extend 50 years post-injection or as prescribed by the Underground Injection Control program director (UIC Director) or other governmental authority with jurisdiction. More detailed information on post-injection monitoring plans is included in *Section 7 – Post Injection Site Care (PISC) and Site Closure*. The monitoring activities will follow a predetermined timeline to verify that the observed CO_2 plume development aligns with modeling expectations, as well as demonstrate that the injected CO_2 does not endanger USDWs.

5.2 Reporting Requirements

To comply with 16 TAC **§5.207** [40 CFR **§146.91**], Operator will provide routine and incident reports to the UIC Director. The report contents and submittal frequencies are as follows (Table 5-1):

Table 5-1 – Incident and routine well intervention reporting requirements.

Reporting Reason	Reporting Method	Reporting Timing
Incident Reporting		
Any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between USDWs	Verbal	Within 24 hours[1]
	Written	Within 5 business days[1]
Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW	Verbal	Within 24 hours[1]
	Written	Within 5 business days[1]
Any failure to maintain mechanical integrity	Verbal	Within 24 hours[1]
	Written	Within 5 business days[1]
Any significant data that indicate the presence of leaks in the well or lack of confinement to the storage reservoir	Verbal	Within 24 hours[1]
	Written	Within 5 business days[1]
Description of any event that exceeds operating parameters for annulus pressure or injection pressure, as specified in the permit	Verbal	Within 24 hours[1]
	Written	Within 72 hours[1]
Description of any unplanned event that triggers a shutoff device either downhole or at the surface and the response taken	Verbal	Within 24 hours[1]
	Written	Within 72 hours[1]
Routine Well Intervention Reporting		
Description of any well workover, including injection and monitoring wells	Written	30 days following the activity
Any additional testing of wells, as required by the UIC Director	Written	30 days following the activity
Periodic mechanical integrity tests (MITs)	Written	30 days following the activity
Description of a planned workover	Written	30 days prior to the planned activity
Description of planned stimulation activity	Written	30 days prior to the planned activity
Description of planned well tests	Written	30 days prior to the planned activity

[1] Incident reporting time frames are initiated upon discovery/identification of the incident/event.

Operator will provide a **semiannual** report containing the following information:

- A summary of the wellhead pressure monitoring.
- Any changes to the source of the CO_2 stream.
- Submission of the average injection characteristics from the prior 6 months, noting 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 operating 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.
- Description of any unplanned event that triggers a shutdown and the response taken.
- Results of any monitoring, as described in this section.

Operator will provide an **annual** report containing the following information:

- Any corrective action performed.
- Recalculated AOR or an affirmation statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR on file with the governing commission(s).
- Proof of good faith claim to sufficient property rights for geologic storage facility operation.
- Volume of CO_2 injected.
- Any new wells installed and the type, location, number, and other information required in 16 TAC **§5.203(e)**.

Operator will submit all reports, notifications, and other required materials to the EPA and Railroad Commission of Texas (TRRC) and ensure that all 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 at least 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 at least 10 years post-collection, while well-plugging reports, PISC data, and the site closure report will be retained for at least 10 years after site closure.

5.3 Testing and Monitoring Plan Review and Updates

Per 16 TAC **§5.207(a)(3)** [40 CFR **§146.90(j)**], Operator will review and revise the Testing and Monitoring Plan as necessary, at least every 5 years. The review process will incorporate collected monitoring data, inclusive of updated plume modeling to be calibrated with said data.

Any amendments to the Testing and Monitoring Plan will be submitted within 1 year of an AOR reevaluation, following significant changes within the AOR or as required by the UIC Director.

5.4 Testing Strategies

5.4.1 Mechanical Integrity Testing

In accordance with 16 TAC **§5.203(h)(1)(C)** [40 CFR **§146.89(b)**], Operator will ensure the mechanical integrity of all injection wells by performing annulus pressure tests (1) after the wells have been completed, (2) prior to injection, and (3) at least once every 5 years thereafter. This annular pressure test specifically verifies the integrity of the annulus between the casing and tubing above the packer. During well construction, prior to completion, the casing will also be pressure tested to the maximum anticipated annulus 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. In accordance with 16 TAC **§3.9.12**, the annulus will be pressured to a minimum of 500 pounds per square inch (psi) fluid pressure. Once the test has begun, a block valve will be used to isolate the test pressure source from the test pressure gauge. All ports into the casing annulus—other than the one monitored by the test pressure gauge—will be closed. [redacted]

All annulus pressure test results will be submitted to the EPA and TRRC on Form H-5 within 30 days of log run completion.

5.4.2 External Mechanical Integrity Testing

Operator will perform external MITs annually to meet the requirements of 16 TAC **§5.203(h)(1)(D)** [40 CFR **§146.90(e)**], by running a temperature [redacted] log [redacted] of each injection well. Temperature [redacted] logs will be run prior to beginning injection operations and will establish the baseline to compare against future logs. Satisfactory mechanical integrity is demonstrated by the proper correlation between the baseline and subsequent logs. [redacted]

5.4.2.1 Temperature [redacted] Log Procedure

Prior to injection, the injection wells will be shut in to stabilize temperatures, and temperature [redacted] logs will be run to establish baseline surveys. [redacted]

[redacted] these baseline surveys will be compared against annual temperature [redacted] surveys to determine fluid flow outside the casing. In all future temperature [redacted] logs, the same stabilization period is required to accurately compare any differences in the log.

When conducting a temperature [redacted] survey via wireline, the tools will log from surface to the total depth (TD) of the wells. No logging runs should precede the log(s) to ensure static conditions in the wellbore. Best-practice logging speeds will be utilized, and all depths should be zeroed to the bradenhead flange. The following list highlights the general procedure for the wireline logging operations for the proposed injection wells:

1. Allow the well to stabilize.
2. Rig up wireline unit to the wellhead and make up the logging tool (temperature [redacted] 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. Correlate collar depths to CCL.
5. Pull out of hole and rig down wireline unit.

Once the temperature [redacted] log is processed, collected data will be compared to baseline temperature [redacted] log(s) to identify any anomalies. [redacted] All temperature [redacted] logs will be reported to the UIC Director within 30 days of the log run. As needed, the new log and the baseline log will both be included in a report for measurement-difference calculations.

5.4.3 Pressure Falloff Testing

Operator will perform a required pressure falloff test on each of the six Project injection wells 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 (i.e., permeability, reservoir pressure, etc.) and monitor for near-wellbore environmental changes (e.g., skin), 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 refinement of reservoir properties and indications of fluid leakage during the test.

5.4.3.1 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 the tubing encapsulated conductor (TEC) deployed pressure gauge installed downhole on the tubing. The falloff period will end once the plotted pressure-decay data indicates that radial-flow conditions have been reached.

Detailed Pressure Falloff Test Procedure

1. Prior to testing, keep the injection rate and pressure as constant and continuous as possible.
[redacted]
2. Stop injection and shut in the well completely.
[redacted]
3. During the shut-in period, continue to record temperatures and pressures at the highest obtainable frequency. The shut-in period should be sufficiently long to establish a radial flow regime using pressure-transient analysis techniques, such as a log-log diagnostic plot and/or establishment of the semi-log straight line response. Pressure decay response during the radial flow period is the basis for the calculation of key reservoir properties such as permeability, skin, and reservoir pressure. 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.

5.4.3.2 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 to later tests. When comparing multiple pressure falloff tests, effects due to changing saturations (i.e., CO_2 and water) and relative permeabilities will be taken into consideration. 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.

5.4.3.3 Quality Assurance/Quality Control (QA/QC)

All surface field equipment utilized during the pressure falloff test will undergo inspection and testing prior to operation. The pressure gauges used in the falloff test will be calibrated according to the manufacturer's instructions. Documentation certifying proper calibration will also be enclosed with the test results.

5.4.4 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 may include [redacted]

[redacted] casing inspection logs to establish baseline logs—as well as the initial condition of the long string casing. These surveys will characterize the original state of the wellbore materials.

Casing inspection logs will be run whenever tubing is removed for workover operations, or at least once every 5 years. The following tools will be run at that time:

- Casing Inspection Logs:
  - [redacted]
  - [redacted]

Operator will provide a schedule of all logging plans to the UIC Director at least 30 days before conducting the first test.

5.4.4.1 Logging and Testing Reporting

A report that includes log and test results obtained during the drilling and construction of each Project injection well—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

Operator has designed a robust monitoring plan to satisfy requirements set forth in 16 TAC ***§*5.203(j)** [40 CFR **§146.90**]. The plan begins prior to first CO_2 injection to establish monitoring baselines, continues throughout active injection operations, and extends 50 years post-injection (unless otherwise approved by the UIC Director) to ensure and demonstrate the protection of USDWs.

As shown in Figure 5-1, the Project utilizes development sites clustered in the north and south ends of the Project area to optimize utilization of the storage reservoir (Frio and Miocene Sands). The Project comprises six total injection wells, [redacted]. Monitoring programs built around these development sites will include the following:

- Injection stream monitoring
  - Physical (pressure, temperature, and rate)
  - Composition
- Corrosion coupon monitoring
- USDW-quality monitoring through [redacted] USDW monitoring wells
- Above-zone monitoring through [redacted] above-zone monitoring (AZM) wells
  - [redacted]
- Direct in-zone monitoring through [redacted] dedicated in-zone monitoring (IZM) wells
  - [redacted]
- Direct in-zone monitoring in each Project injection well
  - [redacted]
- Indirect in-zone monitoring through repeated 2D seismic surveys
  - [redacted]

Injection wells and monitoring well locations, [redacted] are displayed in Figure 5-1 and Table 5-2. The monitoring programs making up this plan are summarized in Table 5-3 and discussed in detail in the subsequent sections.

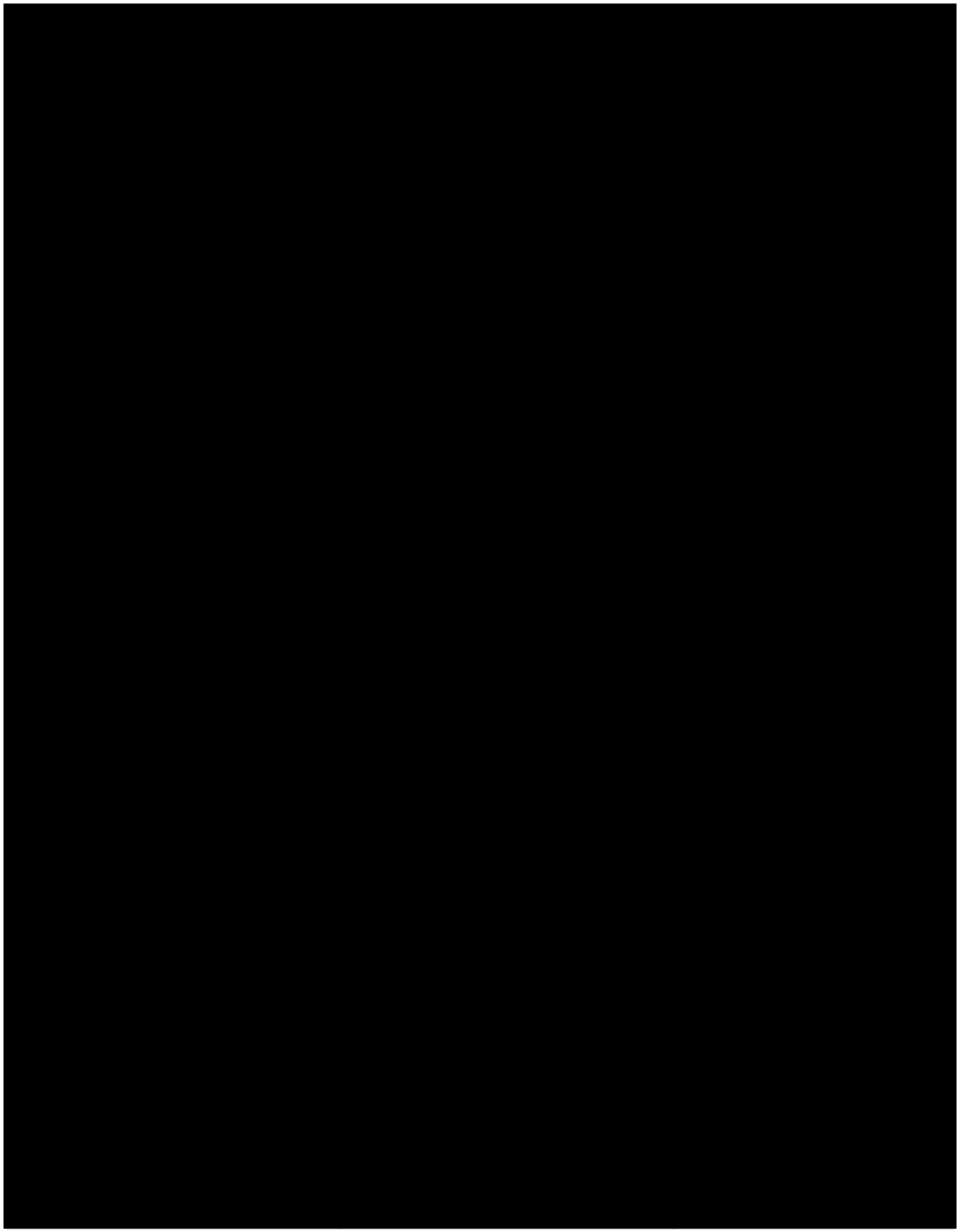


Figure 5-1 – Development and monitoring plan map.

Table 5-2 – Development pads and associated wells.

[redacted]

[redacted]

Table 5-3 – Testing and monitoring program and frequency.

Monitoring Type	Monitoring Program	Location	Frequency
CO_2 injection stream composition	[redacted]		
Corrosion monitoring			
Continuous recording of injection pressure, rate, and volume			
Well annulus pressure between tubing and casing			
USDW monitoring			
Above-zone monitoring			
Direct reservoir monitoring (IZM)			
Direct reservoir monitoring (injection wells)			

Monitoring Type	Monitoring Program	Location	Frequency
	[redacted]		
Indirect reservoir monitoring			
Internal mechanical integrity			
Hydrogeologic testing			
External mechanical integrity			

5.5.1 Continuous Injection Stream Physical Monitoring

In compliance with 16 TAC **§5.203(j)(2)(B**) [40 CFR **§146.90(b)**], Operator will ensure the continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure. Digital pressure and temperature transmitters will provide continuous monitoring of the CO_2 stream at the well facility and wellhead. A Coriolis mass flow rate meter will be installed at the well facility to provide continuous monitoring of the rates and volumes of the injected CO_2 stream. All digital devices will be linked to a Supervisory Control and Data Acquisition (SCADA) system that will collect the data for operational and monitoring purposes. Alarms and automatic shutdown valves will be installed to alert operations and stop injection if the stream is not within safe normal operating conditions.

To meet the requirements of 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2**)], automatic shutoff systems and alarms will be installed to alert 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 in the annular pressure outside of standard operating conditions during injection operations will result in a shutdown event. Figure 5-2 provides a schematic of a typical well and injection skid flow.

Figure 5-2 – Typical injection well and injection skid flow schematic.

5.5.1.1 Analytical Methods

Operator will continuously interpret parameters to validate that they are within permitted limits. The data review will also be used to diagnose equipment maintenance or calibration requirements. Reporting of the monitoring data will be submitted as required.

5.5.1.2 CO_2 Mass Rate to Volumetric Injection Rate – Calculation Methodology

The CO_2 mass flow rates observed during CO_2 injection can be converted to a volumetric flow rate at a specific condition. The pressure, temperature, and fluid composition are required to calculate density at specific conditions (i.e., the bottomhole condition referencing the equations below). The National Institute of Standards and Technology (NIST) Reference Fluid Thermodynamic and Transport Properties Database (REFPROP, Version 10.0) or a similar fluid-property calculation software may be used to determine the density.

Variables Defined:

Q_m = Mass Flow Rate (lb/day)
T_{bh} = Temperature at Bottomhole
P_{bh} = Pressure at Bottomhole
ρ_{bh} = CO_2 Density at Bottomhole Conditions (pounds per cubic foot (lb/ft^3))
Q_{vb} = Flow Rate at Bottomhole Conditions (cubic feet per day (ft^3/day))

Equations:

(1) $\rho_{bh} = f(T_{BH}, P_{BH}, Fluid\ Composition) \leftarrow REFPROP\ software$

(2) $Q_{vbh} = \frac{Q_m}{\rho_{bh}}$

5.5.2 Injection Stream Composition Monitoring

In accordance with 16 TAC **§5.203(j)(2)(A)** [40 CFR **§146.90(a)**] requirements, Operator will monitor the injection stream composition quarterly, and continuously monitor pressure, temperature, and flowrate, at the custody transfer meter upstream of injection. Alarms and automatic shutdown valves will be installed to alert operations and/or shut in when operating parameters diverge from allowable ranges.

5.5.2.1 Sampling Methods

The sampling method will be defined as the Project continues to evolve—and will meet the requirements set forth in 40 CFR **§146.90(a)**].

5.5.2.2 Parameters to Be Measured

The injectate parameters and their measurement frequencies are provided in Table 5-4.

Table 5-4 – Injectate parameters measured and measurement frequency.

Parameter/Analyte	Frequency
Pressure	Continuously
Temperature	Continuously
Mass Flow Rate	Continuously
CO_2 Composition	Quarterly

5.5.3 Corrosion Coupon Monitoring

Corrosion monitoring of the tubing and casing materials in the injection wells will be conducted in adherence to 16 TAC ***§*5.203(j)(2)(C)** [40 CFR ***§*146.90(c)**]. Corrosion monitoring for the well materials in contact with the CO_2 will be completed on a quarterly basis. This evaluation will provide assurance that the tubing components meet the standards for material strength and performance.

5.5.3.1 Sampling Methods

Corrosion coupon holder(s) rated to exceed the maximum allowable operating pressure of the flowline will be installed prior to startup. Post-startup a corrosion coupon, [redacted], will be installed. The coupons, once removed, will be visually inspected for signs of corrosion, including pitting, and measured for weight each time they are removed. [redacted]

5.5.4 Groundwater/USDW Quality Monitoring

To meet 16 TAC **§5.203 (j)(2)(C)** [40 CFR **§146.90(d)**] requirements, groundwater quality and geochemical monitoring in the lowermost USDW formation above the upper confining zone (UCZ) will be conducted.

For the Project, Operator will utilize [redacted] USDW monitoring wells, [redacted], as shown in Figure 5-3 and listed in Table 5-5. [redacted] During the final planning of the monitoring wells, the locations of the USDW monitoring wells may change slightly. The USDW monitoring well locations and estimated depth of the base of the USDW formation (based on geological evaluation and mapping) are provided in Table 5-5. Well construction and drilling details, along with schematics, are included in *Appendix H*.

In each USDW monitoring well, baseline samples will be collected and tested prior to injection. Parameters to be measured and frequency of sampling and analysis are provided in Table 5-6.

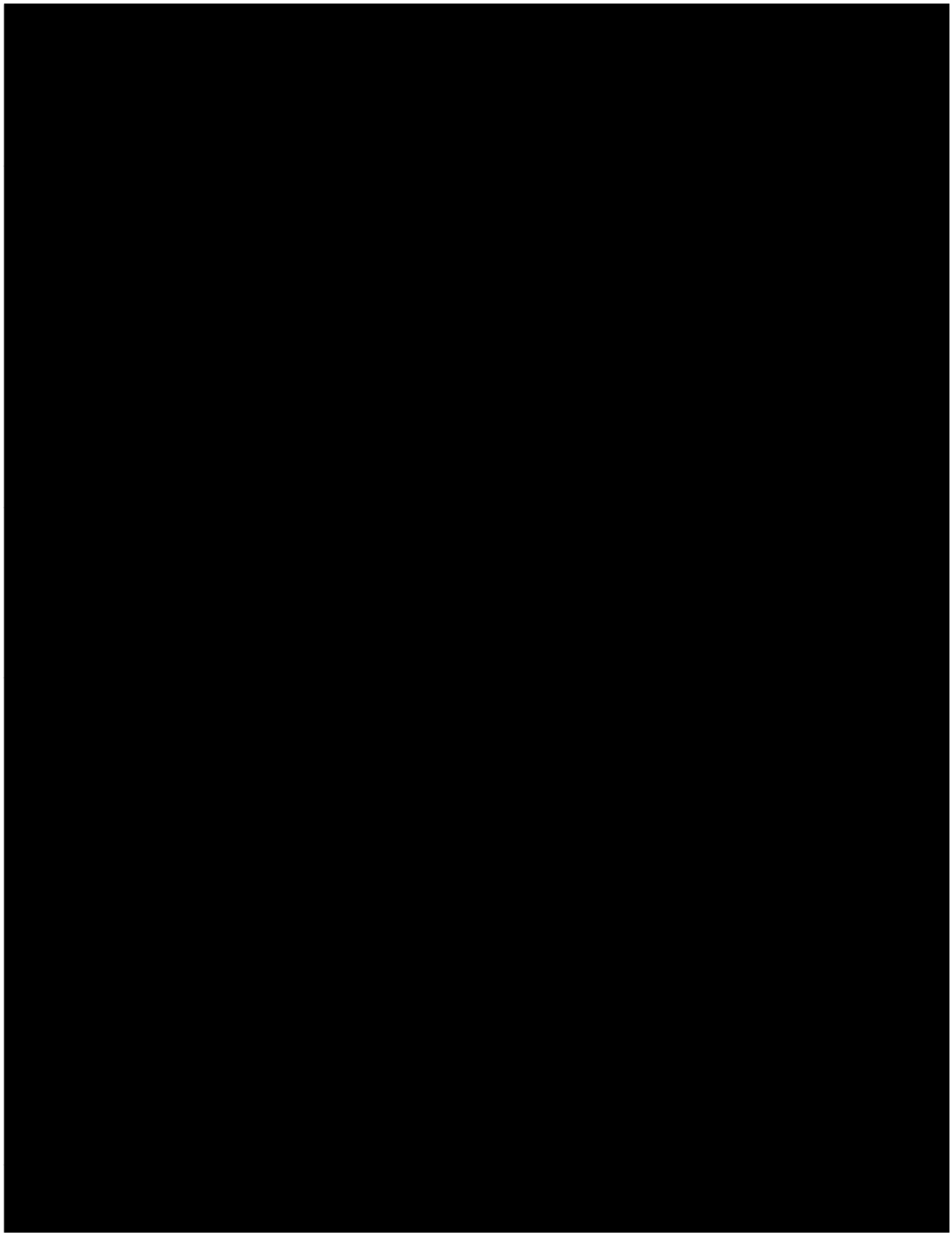


Figure 5-3 – USDW monitoring wells map.

Table 5-5 – USDW monitoring well locations.

[redacted]

A detailed wellbore schematic [redacted] is displayed in Figure 5-4 as a representative example of such wells to be utilized for USDW monitoring. [redacted]

Figure 5-4 – [redacted] wellbore schematic.

5.5.4.1 Parameters Measured

Table 5-6 shows analytical parameters, analytical method, and frequency of samples to be collected from the USDW monitoring wells.

Table 5-6 – USDW groundwater quality parameters measured and measurement frequency.

[redacted]

5.5.4.2 Sampling Methods

[redacted]

5.5.4.3 Analytical Methods

Groundwater samples will be analyzed, and results maintained for the parameters listed in Table 5-5. [redacted] Results from the samples will be maintained in an electronic database.

Analytical methods for detection were listed in Table 5-6. Final laboratory selection has not been made at this time, and such laboratory-specific standard operating procedures (SOPs) utilized by the laboratory will be determined after a contract laboratory has been selected. Analytical SOPs will be made available to the agency upon request.

5.5.4.4 Laboratory to Be Used/Chain of Custody Procedures

Groundwater samples will be sent to an EPA-approved laboratory, and EPA-approved sample management and chain-of-custody procedures will be utilized during all groundwater sampling events. Standardized chain-of-custody procedures will be followed, and records maintained, to allow for the full documentation of how samples were collected, stored, and transported. Field notes will be collected for all groundwater samples collected. These forms will be retained and archived as reference.

All sample bottles will have waterproof labels with information denoting the Project, the sampling date, sampling location/well, sample identification number, sample type (freshwater or brine), analyte, volume, filtration used (if any), and preservative used (if any). For groundwater samples, the chain of custody will be documented using a standardized form provided by the laboratory that is selected to complete analysis of the samples.

As noted above, final laboratory selection has not been made at this time, therefore such laboratory-specific chain-of-custody procedures are yet to be developed.

5.5.4.5 Quality Assurance and Surveillance Measures

To ensure that groundwater samples are representative of in situ groundwater conditions and to identify potential sources of variability during sample collection and handling, QA/QC measures will be implemented as a component of the approved sampling plan. Duplicate samples and trip blanks for QA/QC purposes, as well as calibration methods, will be implemented as follows:

Duplicates

For each groundwater sampling event, duplicate groundwater samples will be collected from one of the USDW monitoring wells. Duplicate samples are collected from the same source—immediately after the original sample—in different sample containers and processed identically to the other samples. Duplicate samples are used to assess sample heterogeneity and analytical precision.

Blanks

For each groundwater sampling event, a field blank will be collected and then accompany the groundwater samples at all times. Field blanks will be exposed to the same field and transport conditions as the groundwater samples. Field blanks will also be used to detect contamination resulting from the collection and transportation process.

Calibration and Frequency of Calibration

Portable field meters or multiprobes used to determine field parameters (e.g., pH, temperature, specific conductance, dissolved oxygen) will be calibrated, according to manufacturer recommendations and equipment manuals, each day before sample collection begins. Recalibration will be performed if any components yield atypical values or fail to stabilize during sampling. Calibration values will be recorded in sampling records and any errors in calibration will be noted. For parameters where calibration is not acceptable, redundant equipment may be used to minimize loss of data.

5.5.4.6 Plan for Guaranteeing Access to All Monitoring Locations

All groundwater monitoring wells are located on property where access permissions have already been granted to Operator. No site-inaccessibility concerns are anticipated that would impact sampling or well maintenance. In cases where inclement weather or otherwise uncontrollable events are encountered that limit access to monitoring locations, sampling schedules will be reviewed, and alternative dates may be selected with the intent to meet permit conditions.

5.5.5 Above-Zone Monitoring

In addition to the [redacted] USDW monitoring wells, AZM wells will be drilled [redacted] Each AZM well will be drilled to a depth to allow monitoring of the first permeable formation above the [redacted] UCZ. [redacted]

The AZM well locations are shown in Figure 5-5 and listed in Table 5-7. During the final planning of the monitoring wells, the locations of the AZM wells may change slightly. The AZM well design is displayed in Figure 5-7. Well construction and drilling details, along with schematics, are included in *Appendix H*.

[redacted] Reservoir pressure will be monitored continuously starting prior to injection operations. Additionally, baseline fluid samples will be obtained and tested prior to injection operations.

[redacted]

Pressures, temperature, [redacted] will be used to identify potential leakage through the top seal. If necessary, fluid samples can be obtained and compared against the baseline samples.

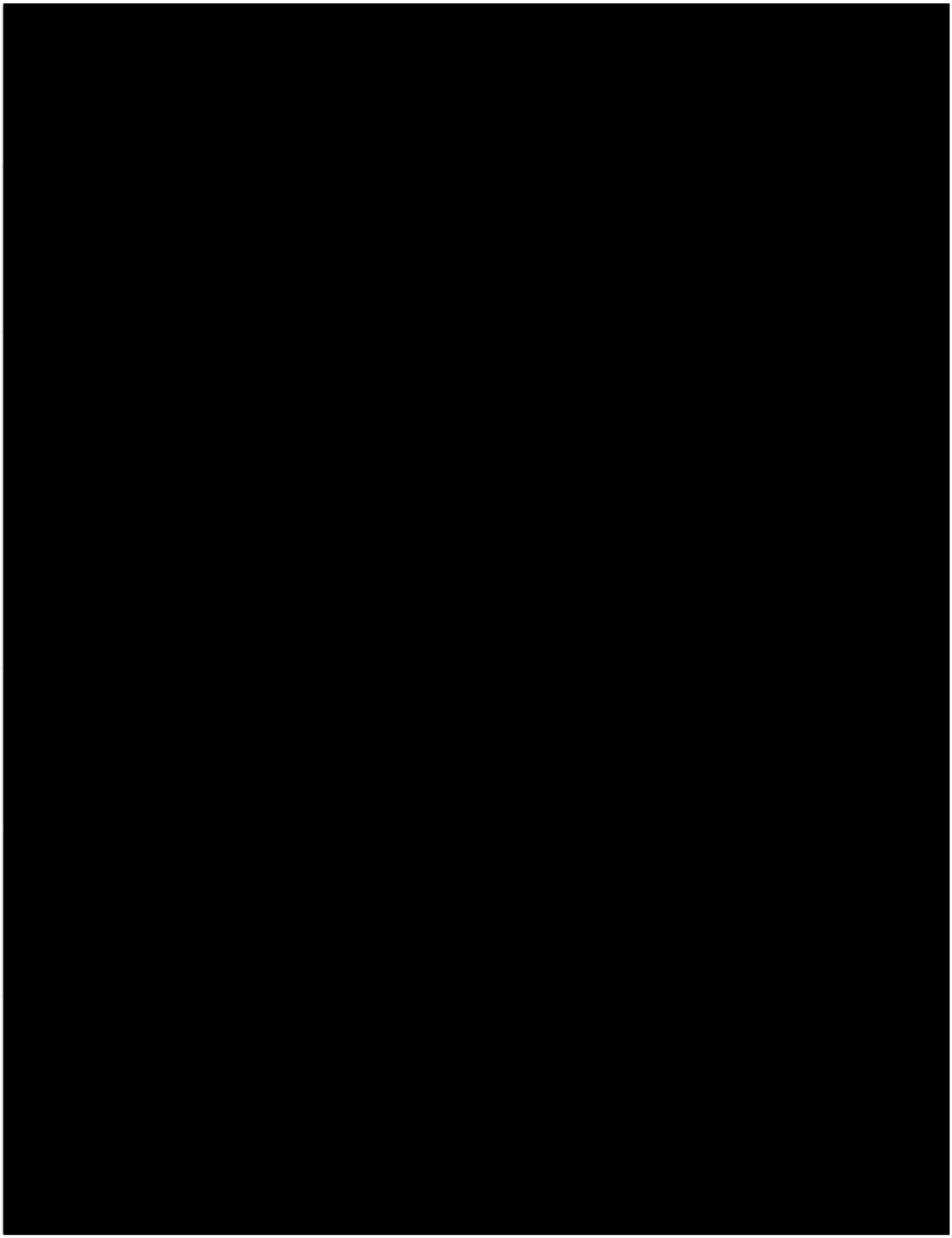


Figure 5-5 – Above-zone monitoring wells map.

Table 5-7 – Above-zone monitoring well locations.

[redacted]

5.5.5.1 Pressure and Temperature Monitoring

[redacted] Figure 5-6 illustrates a conceptual design on the P/T gauge system, installation, and data measurement as discussed in *Section 5.5.6* (direct P/T measurement for in-zone monitoring).

Figure 5-6 – Example of P/T gauges ported into the tubing with an isolated packer for single perforation interval.

A detailed wellbore schematic [redacted] is displayed in Figure 5-7 as a representative example of such wells to be utilized for above-zone monitoring. [redacted]

Figure 5-7 – [redacted] wellbore schematic.

[redacted]

[redacted]

[redacted]

5.5.5.3 Fluid Sampling

While the main purpose of the AZM wells will be to continuously monitor the pressure of the first mappable sand identified above the UCZ, fluid samples can also be obtained from these wells, if necessary. Upon observation of a pressure deviation from baseline pressures within an AZM well, fluid samples may be collected to determine geochemical deviations from baseline using the bottomhole sampling methodology described below.

5.5.5.4 Parameters Measured

Table 5-8 shows the analytical parameters, analytical method, and frequency of samples to be collected from the AZM wells.

Table 5-8 – AZM groundwater quality parameters measured and measurement frequency

[redacted]

5.5.5.5 Sampling Methods

[redacted]

5.5.5.6 Analytical Methods

The AZM water samples will be analyzed, and results maintained for the parameters listed in Table 5-8. [redacted] Results from the samples will be maintained in an electronic database.

Analytical methods for detection were also listed in Table 5-8. Final laboratory selection has not been made at this time, and such laboratory-specific SOPs utilized by the laboratory will be determined after a contract laboratory has been selected. Analytical SOPs will be made available to the agency upon request.

5.5.5.7 Laboratory to Be Used/Chain of Custody Procedures

The AZM water samples will be sent to an EPA-approved laboratory. The EPA-approved sample management and chain-of-custody procedures will be utilized during all AZM water sampling events. Standardized chain-of-custody procedures will be followed, and records maintained, to allow for full documentation of how samples were collected, stored, and transported. Field notes will be collected for all AZM water samples collected. These forms will be retained and archived as reference.

[redacted] For AZM water samples, the chain-of-custody will be documented using a standardized form provided by the laboratory that is selected to complete analysis of the samples.

Because, as noted, final laboratory selection has not been made at this time, such laboratory specific chain-of-custody procedures are yet to be developed.

5.5.5.8 Quality Assurance and Surveillance Measures

To ensure that AZM water samples are representative of in situ groundwater conditions and to identify potential sources of variability during sample collection and handling, QA/QC measures will be implemented as a component of the approved sampling plan. Duplicate samples and trip blanks for QA/QC purposes, as well as calibration methods will be implemented as follows:

Duplicates

For each AZM water sampling event, duplicate AZM water samples will be collected from one of the AZM monitoring wells. Duplicate samples are collected from the same source—immediately after the original sample—in different sample containers and processed identically to other samples. Duplicate samples are used to assess sample heterogeneity and analytical precision.

Blanks

For each AZM water sampling event, a field blank will be collected and then accompany the AZM water samples at all times. Field blanks will be exposed to the same field and transport conditions as the AZM water samples. Field blanks will be used to detect contamination resulting from the collection and transportation process.

5.5.5.9 Plan for Ensuring Access to All Monitoring Locations

All AZM wells are located on property where access permissions have already been granted to Operator. No site-inaccessibility concerns are anticipated. In cases where inclement weather or otherwise uncontrollable events are encountered that limit access to monitoring locations, sampling schedules will be reviewed, and alternative dates may be selected with the intent to meet permit conditions.

[redacted]

5.5.6 In-Zone Monitoring

Operator proposes a two-tiered system–both direct and indirect methods–for plume and pressure-front tracking per the operational monitoring requirements of 16 TAC **§5.203(j(2(E** [40 CFR **§146.90(g**]. Continuous P/T monitoring will be used to directly monitor the plume and pressure fronts through ongoing analysis of injection data and reservoir modeling using calibrated dynamic simulation models. [redacted]

Direct pressure and temperature monitoring will be primarily accomplished through the IZM wells displayed in Figure 5-8 and further described in Table 5-9. [redacted]

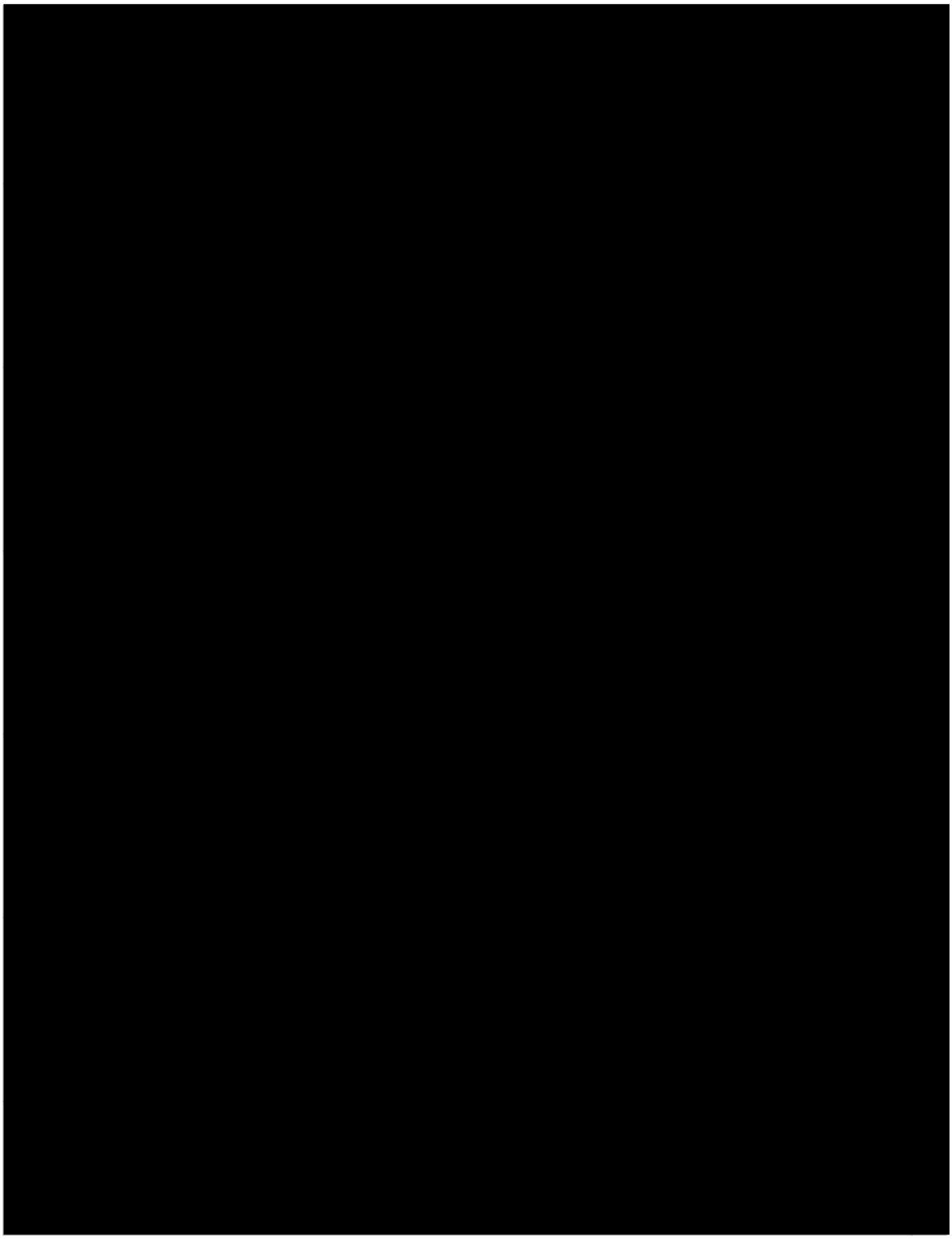


Figure 5-8 – In-zone monitoring wells map.

Table 5-9 – In-zone monitoring well locations.

[redacted]

A detailed wellbore schematic [redacted] is displayed in Figure 5-9 as a representative example of such wells to be utilized for in-zone monitoring. [redacted]

Figure 5-9 – [redacted] wellbore schematic.

5.5.6.1 Direct Monitoring – IZM Wells

As required by 40 CFR **§146.90(g)(1)**, direct monitoring in the injection intervals will be accomplished with [redacted] IZM wells shown in Figure 5-10. Additionally, pressure, temperature, and injection rate data will be gathered from the injection wells. [redacted]

[redacted]

[redacted]

Figure 5-10 – [redacted]

[redacted]

[redacted]

5.5.6.2 Direct Monitoring – Injection Wells

Data gathered from the injection intervals in the IZM wells will be supplemented with pressure, temperature, and injection rate data continuously gathered from the injection wells. The injection wells will be equipped with a similar setup to the AZM wells for P/T data gathering and monitoring in the active injection interval. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Operator will [redacted] 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.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Baseline 2D seismic surveys will be acquired prior to injection. [redacted]

[redacted]

[redacted]

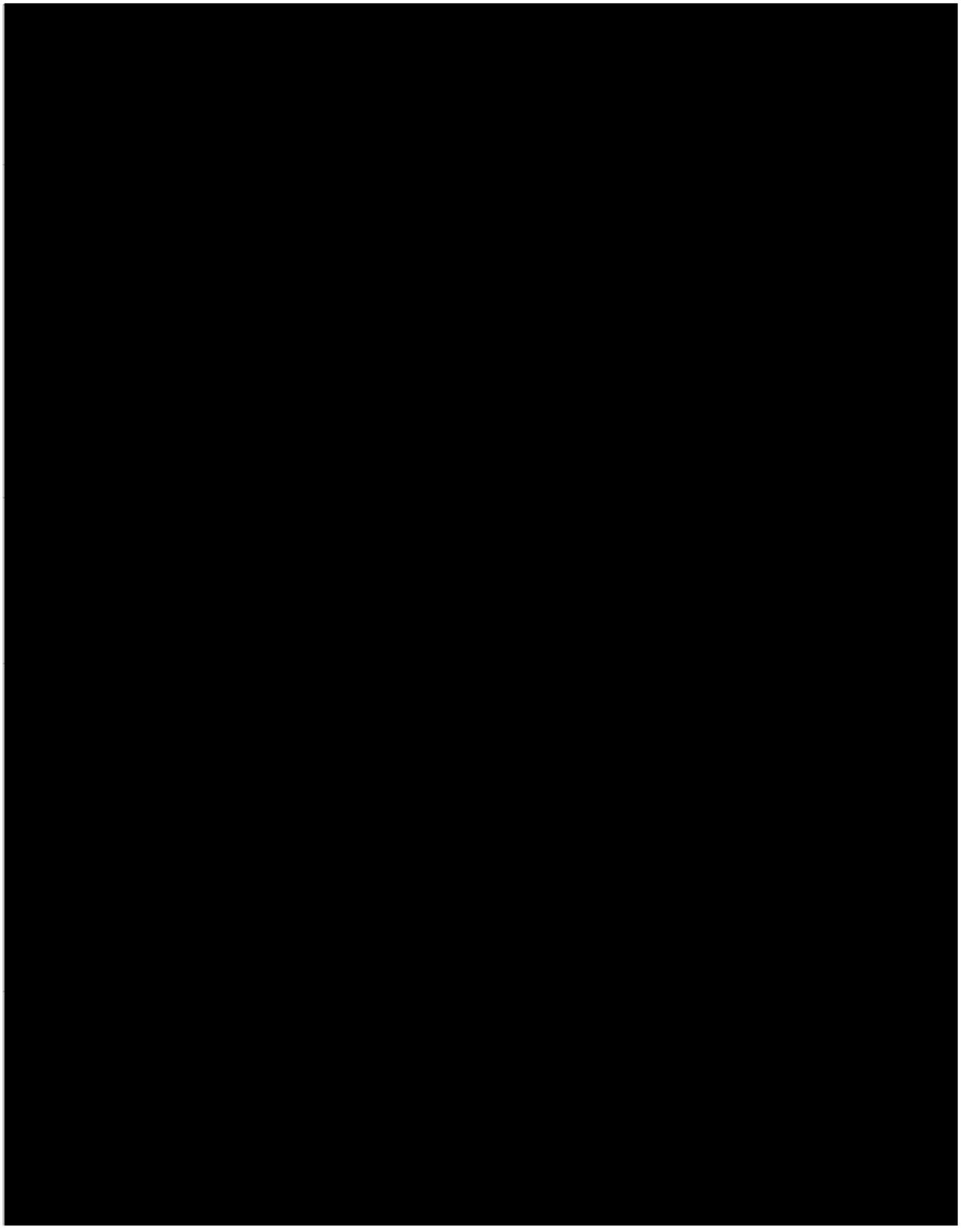


Figure 5-11 – [redacted]

5.5.6.5.1 2D Surface Seismic Surveying

In a 2D surface seismic survey, sources and receivers are deployed along a line at the surface, whereas in 3D surveys multiple lines of sources and receivers are deployed over an area. The 2D surveys can be acquired relatively quickly and with minimal environmental impact because they require access to fewer surface locations than 3D surveys. When the structural complexity is moderate and the dips of the bedding planes are small, as is the case for the Project site, then 2D seismic surveying is an efficient and effective indirect monitoring method.

[redacted]

[redacted]

Figure 5-12 – [redacted]

[redacted]

Figure 5-13 –

5.5.6.5.3 Time-Lapse Seismic Surveying

Reservoir monitoring using time-lapse seismic surveying has been used extensively in waterflood, and enhanced oil-and-gas recovery. ConocoPhillips Company has operated two seismic monitoring programs at Surmont in Canada and Ekofisk in Norway for more than a decade (Byerley et al., 2009; Folstad et al., 2021). The methodology has also undergone thorough testing to monitor CO_2 storage in saline aquifers (e.g., at the Sleipner storage project in Norway (Furre et al., 2017)). The time-lapse effect detected in a seismic image is primarily driven by the change in acoustic impedance resulting from changes in compressional velocity between high CO_2 concentrations and formation gases/fluids. As formation fluids are displaced by CO_2, the change in acoustic impedance during plume growth can be analyzed.

The steps involved in a time-lapse seismic monitoring program include the following:

1. Rock Physics Model
2. CO_2 Substitution and Feasibility Study
3. Baseline Surveys
4. Monitor Surveys
    a. Seismic Survey Acquisition
5. Data Processing, Analysis, and Interpretation

5.5.6.5.4 Rock Physics Model

A rock physics model is critical to the time-lapse interpretation. This model establishes a relationship between fluid substitution and the change in acoustic impedance, and it can be produced with a high degree of 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 whether 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 prior to any saturation modeling. The model accounts for the formation properties below:

- Total and effective porosity fluid saturations
- Brine salinity
- Mineral types and content
- Mineral moduli
- Fluid and mineral mixing patterns
- Temperature and pressure

5.5.6.5.5 CO_2 Substitution and Feasibility Study

The rock physics model will be used to generate a dry rock physics model, which is then used to establish a saturated rock physics model by perturbing the elastic parameters for varying degrees of gas or fluid saturations.

Figure 5-14 shows the locations of existing wells used for a preliminary rock physics modeling feasibility study.

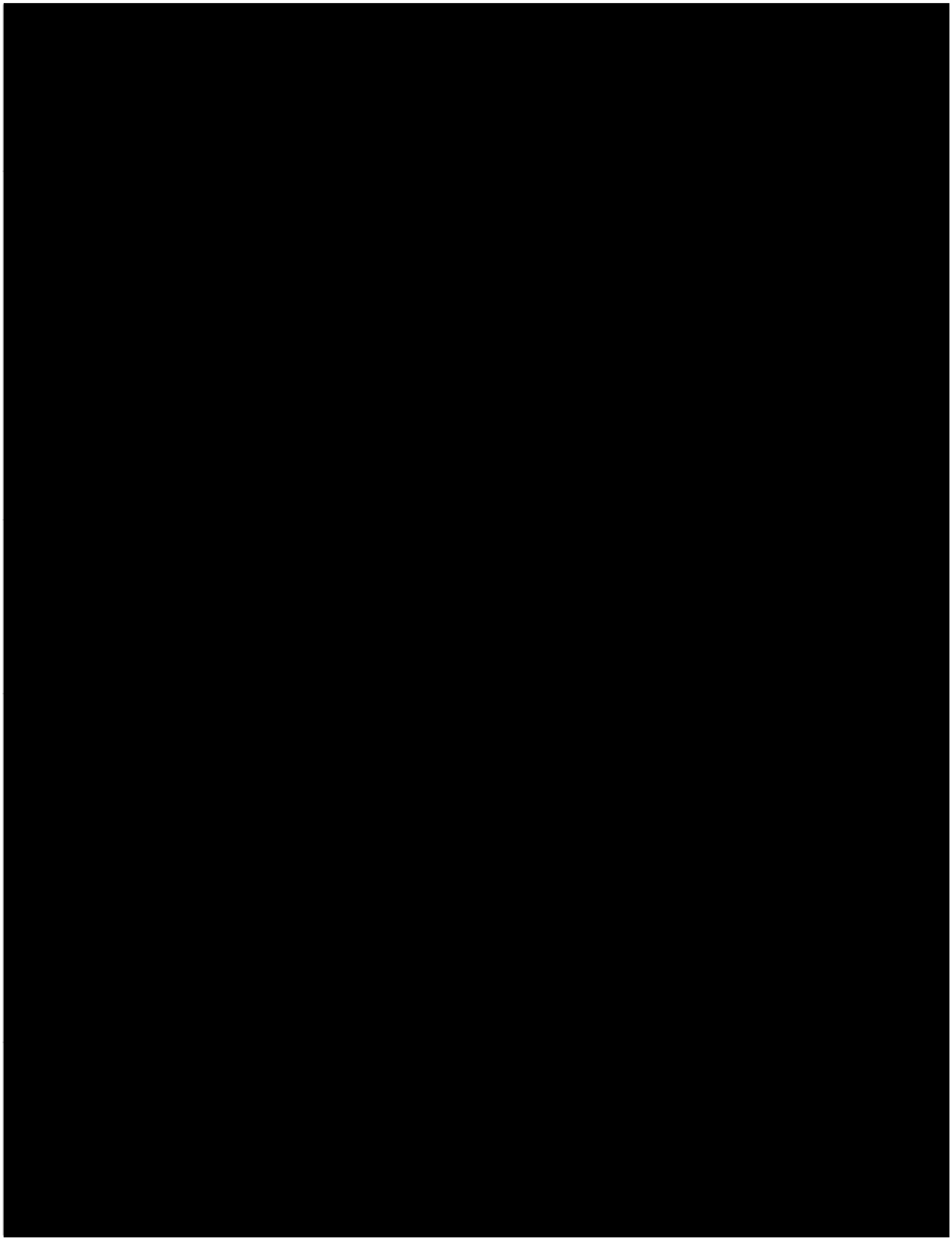


Figure 5-14 – Existing wells for rock physics modeling.

An example of typical in situ rock physics properties for [redacted] is shown in Figure 5-15. [redacted]

Rock property contrasts at the boundaries of [redacted] Figure 5-15. [redacted]

Figure 5-15 – [redacted]

Seismic-well tie is a process required to convert well data from depth domain to time domain before conducting any analysis of amplitude variation along angle/offset (AVA/AVO) for fluid substitution and feasibility study. Figure 5-16 displays an example of seismic-well tie in [redacted] (API No. 42-391-33185). Synthetic data was created from density, checkshot-corrected sonic, and seismic wavelet data. Synthetic traces are displayed in blue while the seismic traces at the well location are displayed in red. Seismic statistical wavelet extracted from seismic data has zero phase. In general, the correlation between well synthetics and seismic data is good for the wells shown in Figure 5-14. [redacted] The output time-depth relationship from the seismic well is used to convert well data to time, for seismic-horizon picking and velocity-model building.

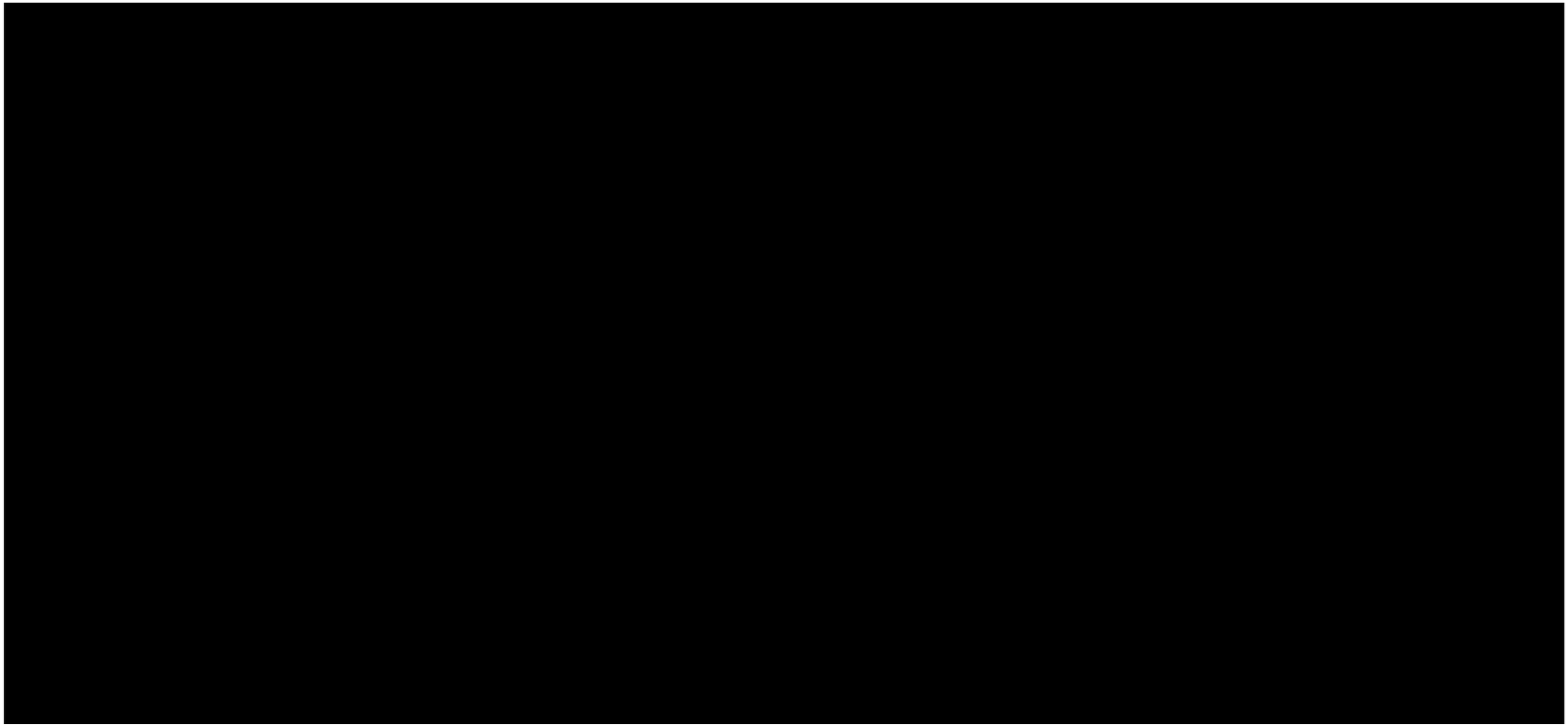


Figure 5-16 –

Once a rock physics model with dry and saturated moduli at reservoir conditions is obtained, CO_2 substitution can be performed. In this process, formation fluid (brine water) will be replaced by CO_2. When this happens, the density and velocity of the rock will change, which results in changing seismic reflectivity and amplitude.

[redacted]

[redacted]

[redacted]

Preliminary forward modeling results from CO_2 substitution work indicate that the indirect monitoring methods for CO_2 plume prediction [redacted] could be successfully used.

Figure 5-17 – [redacted]

Operator plans to update the rock physics models with new data from appraisal wells and future injection/AZM/IZM wells to improve the qualitative and quantitative predictability of injected CO_2 in the AOR.

[redacted]

5.5.6.5.6 Baseline Surveys

A baseline survey is acquired before injection and yields a data set that is used as a reference to compare with data sets from future monitor surveys. The baseline survey is the only opportunity to capture an image of the reservoir prior to being impacted by injection operations or offset activity, whether natural or man-made. Without a baseline survey, the future interpretation of formation changes can be challenging.

[redacted]

To get the clearest time-lapse images, every effort is made to acquire the baseline survey in a way that is repeatable in future monitor surveys. Source and receiver positions are accurately recorded, and instrumentation settings and other acquisition parameters are conserved.

[redacted]

5.5.6.5.7 Monitor Surveys

Monitor surveys are acquired in as repeatable a manner as possible with respect to the baseline survey. This means that, where possible, source and receiver positions are reoccupied, and the same, or similar, types of source and receivers are utilized. Differences in the way surveys are acquired will result in time-lapse noise, which must be mitigated during data processing.

[redacted]

5.5.6.5.8 Seismic Survey Acquisition

The 2D seismic baseline and monitor surveys—[redacted] will employ a controlled seismic source at the surface. Where the ground is firm enough to support them, vibrator trucks will be used to generate the seismic waves that are transmitted through the Earth. Figure 5-18 shows an example of a vibrator truck that weighs approximately 80,000 lbs and is capable of sweeping frequencies up to 250 Hz. If the ground cannot support the weight of a vibrator truck, or large vehicles cannot reach the intended location, then small explosive charges can be deployed inside shallow shot holes drilled a minimum of 10 ft below ground.

Figure 5-18 – A vibrator truck that, in position, lowers its baseplate to the ground and then vibrates it for several seconds through a range of frequencies.

The [redacted] baseline 2D seismic surveys will utilize modern seismic sensors deployed at the surface for the duration of the survey. These are autonomous nodal systems each with their own battery power source and recorder, so there are no cables between receiver stations—significantly reducing both the amount of equipment needed and the time required to deploy and retrieve them.

Figure 5-19 – Geophones planted in the ground for [redacted] seismic surveying.

[redacted]

[redacted]

5.5.6.5.9 Data Processing, Analysis, and Interpretation

Time-lapse seismic processing involves a number of specialized processing steps aimed at correcting for any known differences between baseline and monitor surveys with respect to the acquisition geometry, equipment, or weathering layer—while preserving differences resulting from changes in the subsurface. For example, if different equipment has been used, then the instrument responses are digitally matched and corrected for. Seismic traces are binned based on their constituent source and receiver location, so that baseline and monitor surveys share the same number of unique traces. Ultimately, the results of time-lapse processing are seismic images that can be subtracted to yield the location in the subsurface occupied by the CO_2 plume.

Further analysis of the processed time-lapse seismic data will be conducted with knowledge of the rock properties. The interpreted location will be compared to the dynamic plume modeling further discussed in *Section 2 – Plume Model*, which will then be updated if necessary.

5.5.7 Injection Wellbore Overview

The proposed wellbore design for all six injection wells consists of surface casing run below the USDW, to be cemented in place per EPA Class VI standards. [redacted] A detailed overview of all six wells follows (Table 5-10).

Table 5-10 – Injection wellbores overview.

Well Name	Surface Casing	Long-String Casing	Tubing
Snapper North INJ 1	[redacted]	[redacted]	[redacted]
Snapper North INJ 2	[redacted]	[redacted]	[redacted]
Snapper North INJ 3	[redacted]	[redacted]	[redacted]
Snapper South INJ 1	[redacted]	[redacted]	[redacted]
Snapper South INJ 2	[redacted]	[redacted]	[redacted]
Snapper South INJ 3	[redacted]	[redacted]	[redacted]

[redacted]

Wellbore schematics depicting the initial completion of each of the six injection wells are included in Figures 5-20 through 5-25.

Figure 5-20 – Snapper North INJ 1 wellbore schematic.

Figure 5-21 – Snapper North INJ 2 wellbore schematic.

Figure 5-22 – Snapper North INJ 3 wellbore schematic.

Figure 5-23 – Snapper South INJ 1 wellbore schematic.

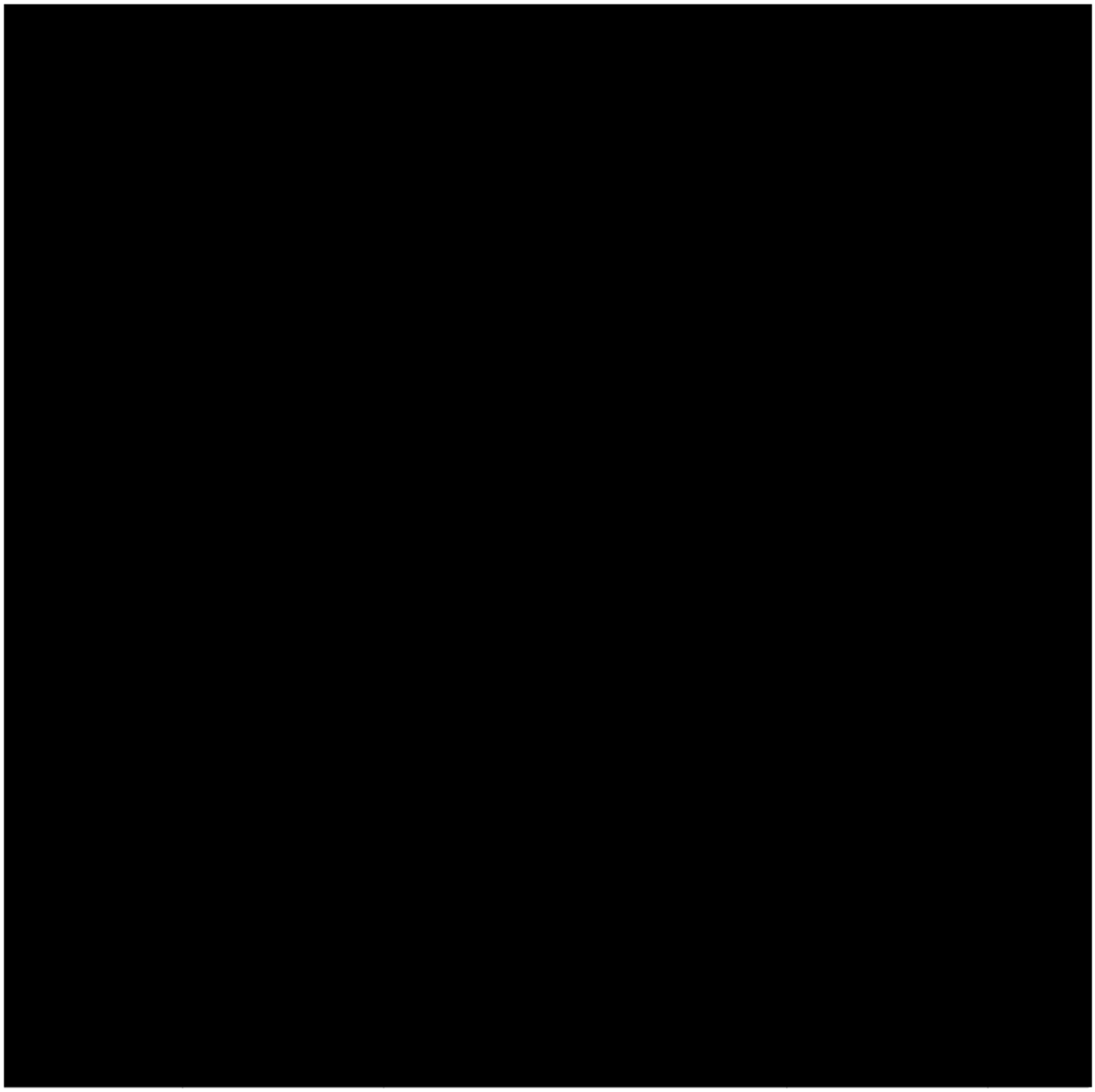


Figure 5-24 – Snapper South INJ 2 wellbore schematic.

Figure 5-25 – Snapper South INJ 3 wellbore schematic.

5.5.8

[redacted]

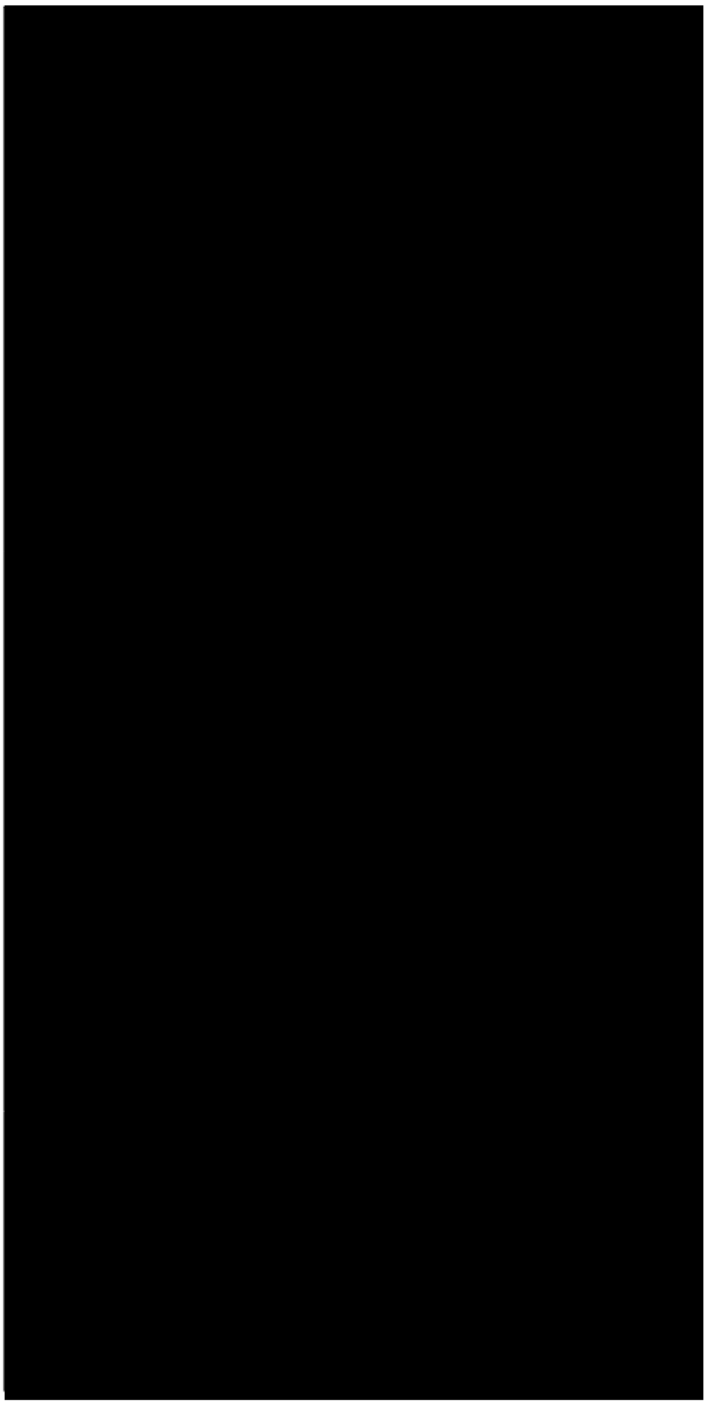
Figure 5-26 – [redacted]

[redacted]

Table 5-11 – [redacted]

[redacted]

Table 5-12 – [redacted]



[redacted]

Table 5-13 – [redacted]

[redacted]

[redacted]

Figure 5-27 – [redacted]

[redacted]

Figure 5-28 –

Table 5-14 – [redacted]

[redacted]

[redacted]

[redacted]

Figure 5-29 – [redacted]

[redacted]

[redacted]

Figure 5-30 –

Table 5-15 – [redacted]

[redacted]

[redacted]

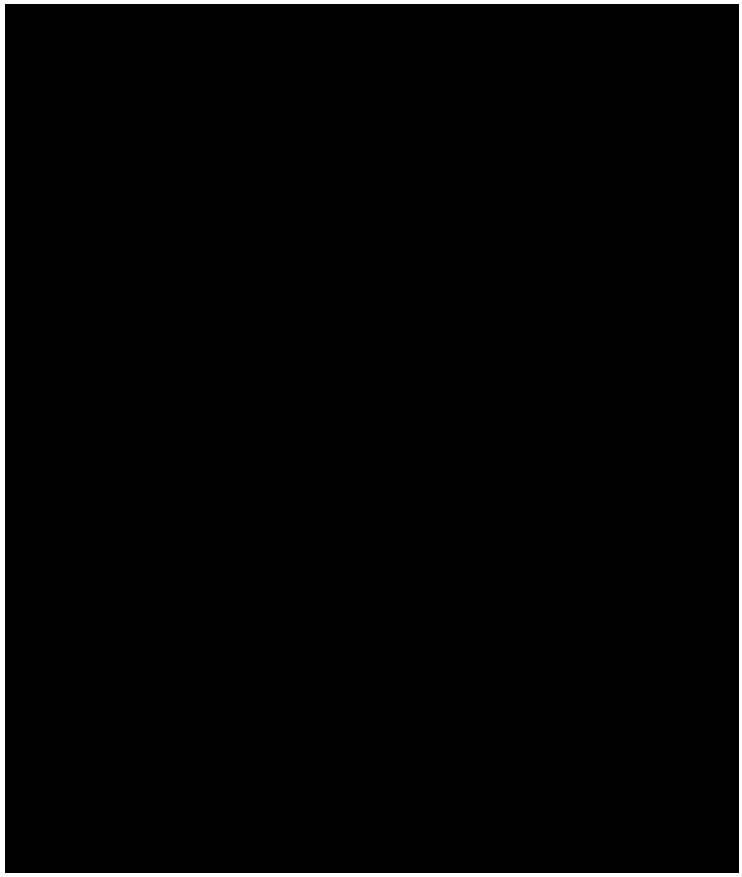


Figure 5-31 – [redacted]

[redacted]

5.5.9 Monitoring Conclusion

As discussed in detail above, the operating plans for the proposed Project include robust testing and monitoring programs in accordance with promulgated regulations, designed to satisfy all necessary requirements of 16 TAC ***§*5.203(j)** [40 CFR **§146.90**]. This plan begins before CO_2 injection commences and will extend 50 years post-injection—or as otherwise prescribed by the UIC Director through the submittal of site-specific data as discussed in detail in *Section 7*.

Testing and monitoring strategies discussed above are designed to ensure and verify protection of the USDWs. Testing programs for the Project will ensure wellbore and reservoir integrity. Monitoring strategies include monitoring and/or testing the injection-stream composition, corrosion of injection-well metallurgies, USDW quality, above-zone conditions, and plume and pressure front growth. Monitoring will be accomplished with direct measurement—using data acquired from injection and monitoring wells (USDW, AZM, and IZM wells)—or indirectly [redacted]. Furthermore, monitoring data will be utilized to refine dynamic reservoir models to better predict plume migration and critical pressure front extent.

Operator is committed to ensuring that appropriate testing and monitoring practices are employed throughout the life cycle of the Project.

Appendix H: Testing and Monitoring

- Appendix H-1 Development and Monitoring Plan Map
- Appendix H-2 USDW Monitoring Wells Map
- Appendix H-3 USDW Monitoring Wellbore Schematics
- Appendix H-4 Above-Zone Monitoring Wells Map
- Appendix H-5 Above-Zone Monitoring Wellbore Schematics
- Appendix H-6 In-Zone Monitoring well map
- Appendix H-7 In-Zone Monitoring Wellbore Schematics
- Appendix H-8 [redacted]

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Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 6 – WELL PLUGGING PLAN

July 2024

SECTION 6 – WELL PLUGGING PLAN

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Table 6-6 – Snapper South INJ 2 plugging details. 15
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6.1 Introduction

Plugging plans for the proposed ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) project (Project) injection and monitoring wells were prepared in accordance with the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(k)** and 16 TAC **§3.14** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.92**]. This section provides a general overview of the operational strategies that ConocoPhillips Texas Gulf Coast CCS LLC (Operator) will implement during the plugging and abandonment (P&A) of the Project wells. For injection wells, this plan includes the proposed stages of well development through final P&A. Monitoring well P&A plans are also included in this section. Complete P&A prognoses for all Project wells are included in *Appendix J*.

6.2 Injection Well Zonal Isolation and Final Plugging and Abandonment

Each injection well will be completed to include multiple injection intervals within the gross injection zone. Injection into each injection interval will occur for a set period of time, detailed in Operator's injection model. At the end of each injection period, the current injection interval will be isolated and abandoned, ceasing injection into that interval and preventing communication between injection intervals. The next injection interval will then be completed and injection into the next interval will begin. This procedure will continue until the final injection interval is isolated. After the uppermost plug is set in the injection zone, post-injection monitoring operations will begin and continue for 50 years post-injection, or until the UIC Director or other governmental authority with jurisdiction concurs that the Project no longer poses an endangerment to the USDW—as described in *Section 7.6*—or Operator transfers the monitoring obligation to a governmental authority. The injection wells will then 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).

Based on currently available geologic data and evaluation of the project area, potential superior quality water zones are not clearly defined. Any superior quality water zones identified will be properly isolated during final P&A of all wells associated with the project.

This section outlines the procedures for both types of plugging operations—described as follows—to be carried out in the injection wells:

- Isolation of the injection intervals via recompletion operations
- Final P&A of the wellbore

6.2.1 Zonal Isolation of Injection Zone/Intermediate Plugback Plan

[redacted]

[redacted]

[redacted]

[redacted]

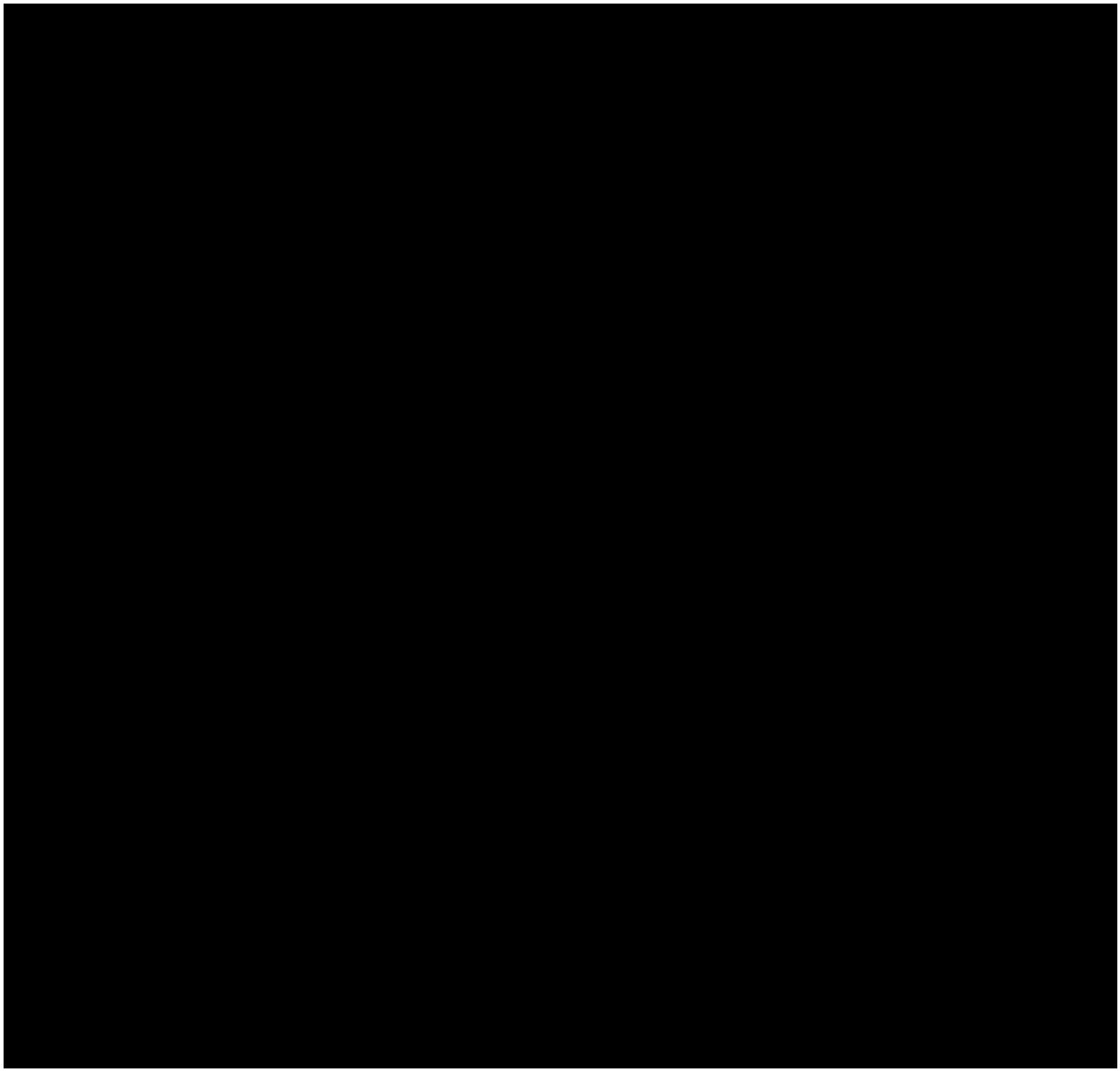

Figure 6-1 –

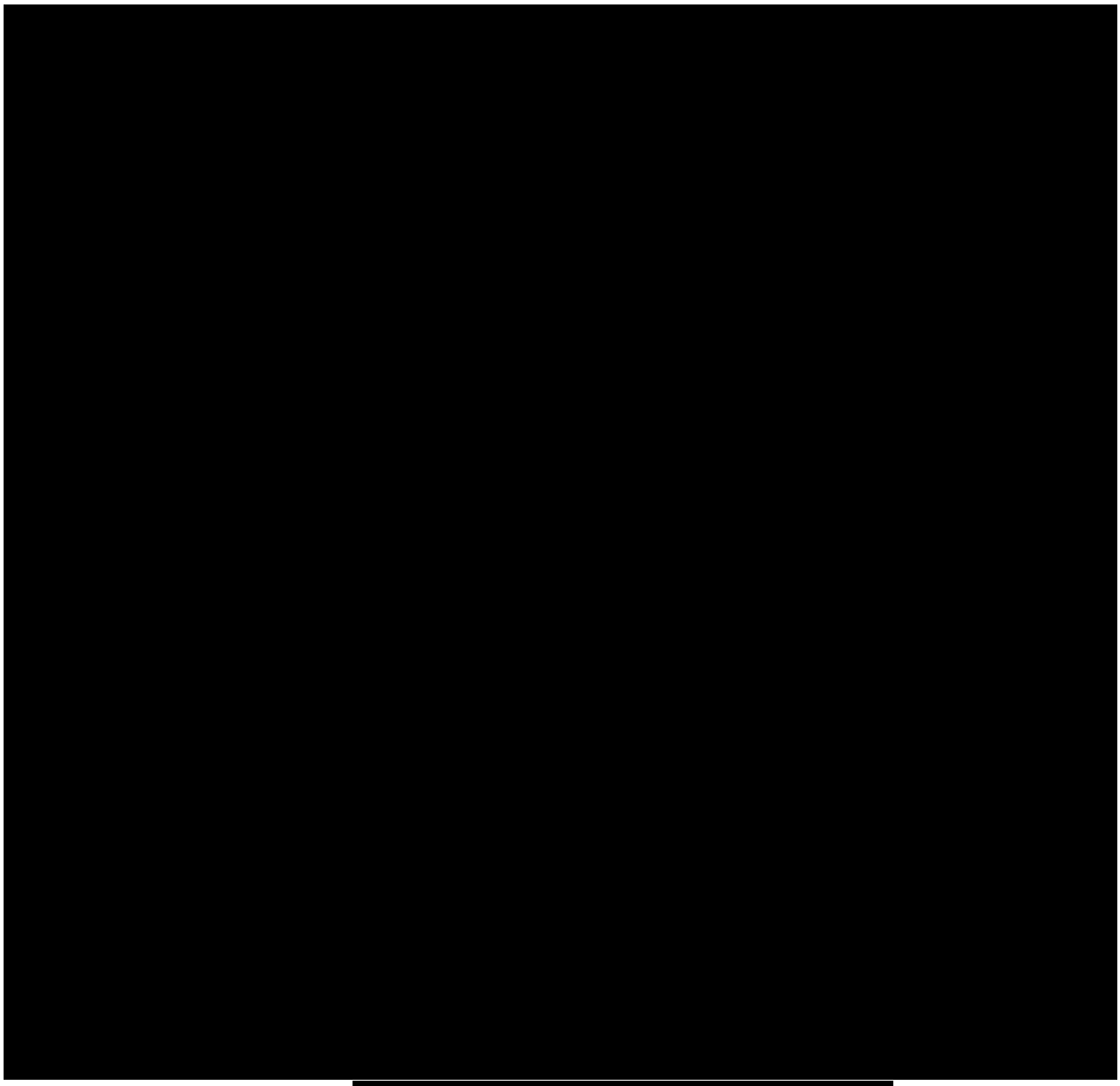

Figure 6-2 –

Figure 6-3 –

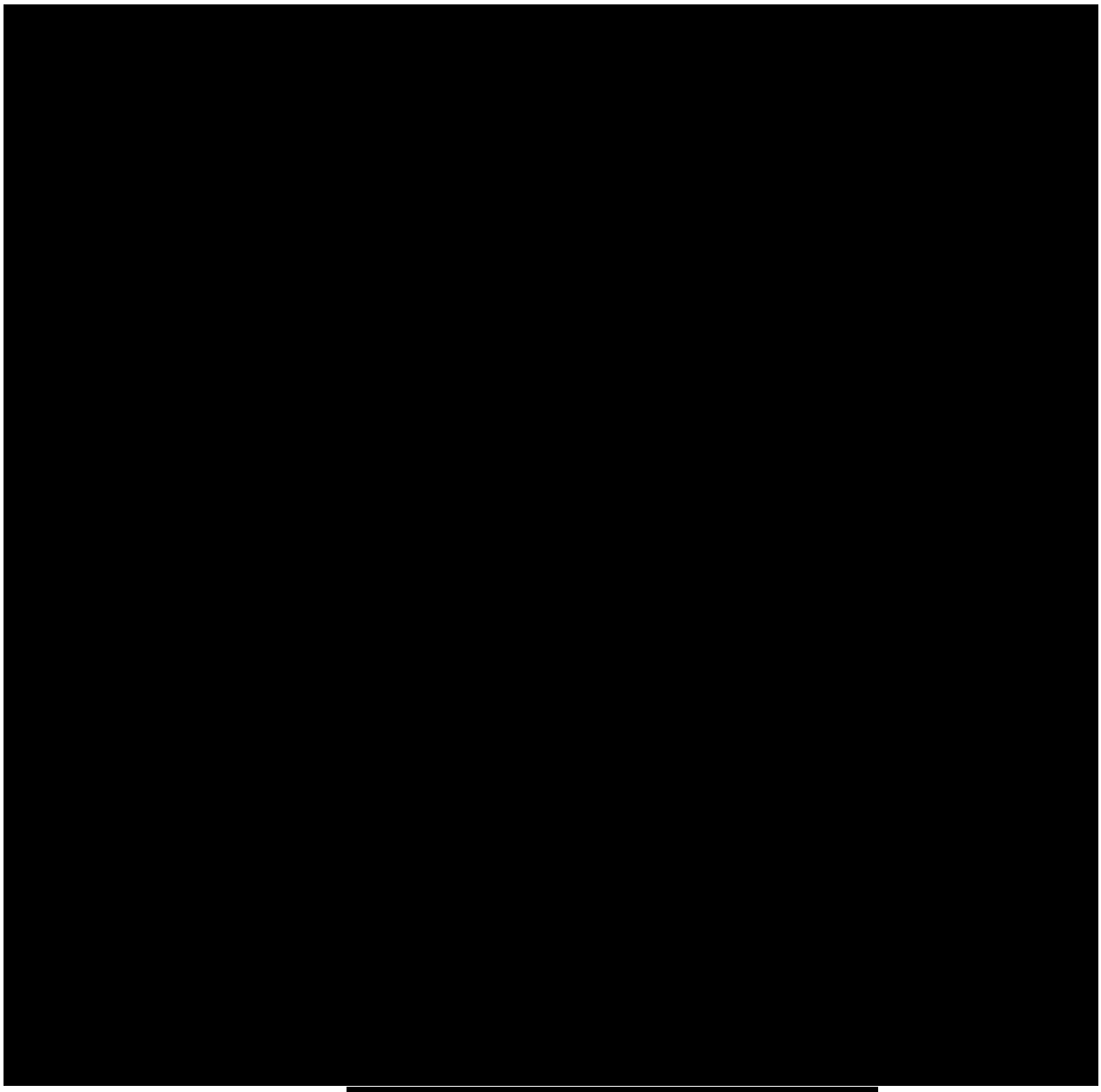

Figure 6-4 – [redacted]

Figure 6-5 –

6.2.1.2 Zonal Isolation Activities

6.2.2 Final Plugging and Abandonment

Post-injection monitoring will begin after injection into the final zone is complete. After post-injection monitoring is complete, the injection wells will be prepared for final P&A. General P&A procedures for the injection wells include the following:

6.2.2.1 Pre-plugging Activities

1. Operator will comply with all reporting and notification provisions.
    a. Operator 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)**)

[redacted]

3. External mechanical integrity will be demonstrated through approved monitoring methods described in *Section 5 – Testing and Monitoring Plan*. (16 TAC **§5.203(k)(2)(C)** [40 CFR ***§*146.92(a)**])
4. Casing inspection and cement bond logs will be performed before plugging.

6.2.2.2 Plugging Procedure for all Project Injection Wells

[redacted]

[redacted]

Detailed plugging procedures for each Project injection well are included in *Appendix J-2.* [redacted]

Table 6-1 – Description of casing, tubing, and other well construction materials to be removed.

[redacted]

6.2.2.3 Plugging Details

Tables 6-2 to 6-7 provide plugging details for the six Project injection wells.

Table 6-2 – Snapper North INJ 1 plugging details.

Table 6-3 – Snapper North INJ 2 plugging details.

Table 6-4 – Snapper North INJ 3 plugging details.

Table 6-5 – Snapper South INJ 1 plugging details.

Table 6-6 – Snapper South INJ 2 plugging details.

Table 6-7 – Snapper South INJ 3 plugging details.

Figures 6-6 through 6 -11 (*Appendix J-3)* show the final plugged schematics for the Snapper North INJ 1, 2, and 3, and Snapper South INJ 1, 2, and 3 injection wells.

Figure 6-6 – Snapper North INJ 1 final plugging schematic.

Figure 6-7 – Snapper North INJ 2 final plugging schematic.

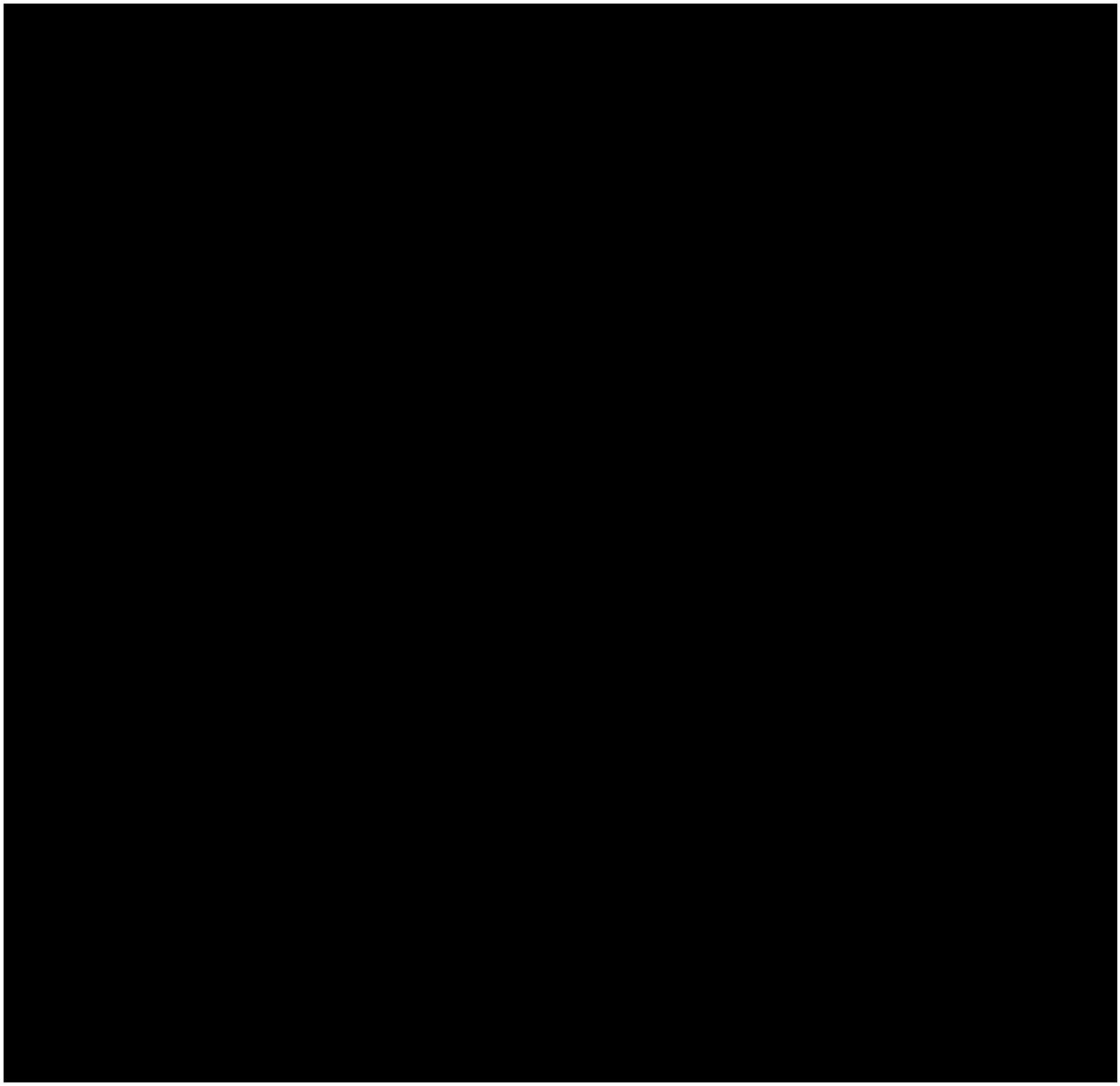

Figure 6-8 – Snapper North INJ 3 final plugging schematic.

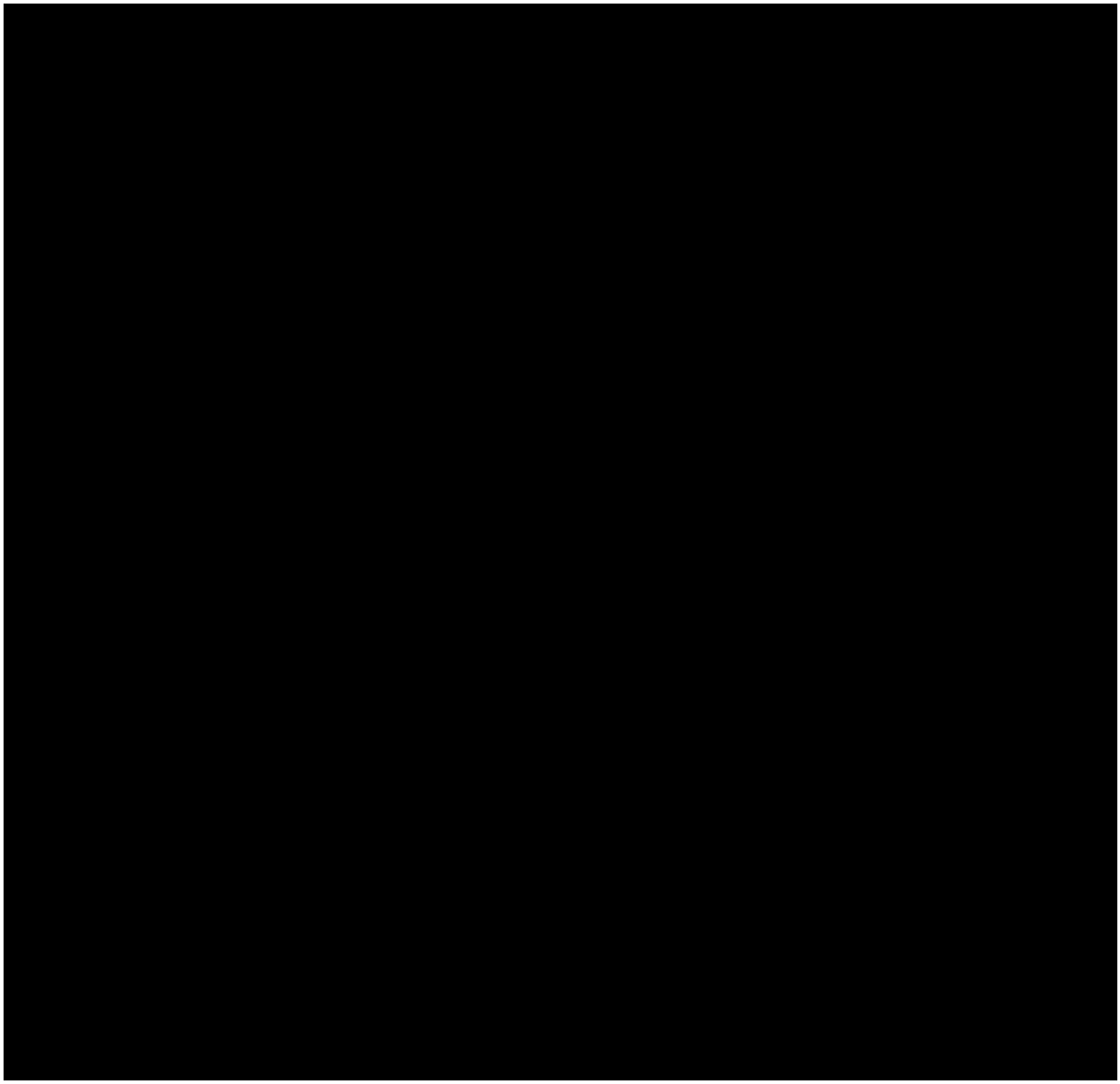

Figure 6-9 – Snapper South INJ 1 final plugging schematic.

Figure 6-10 – Snapper South INJ 2 final plugging schematic.

Figure 6-11 – Snapper South INJ 3 final plugging schematic.

6.3 Monitoring Wells Plugging and Abandonment

The following sections outline the plan for the P&A of monitoring wells associated with the Project injection wells.

6.3.1 Pre-Plugging Activities

1. Operator will comply with all reporting and notification provisions.
    a. Operator 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)**)

[redacted]

3. External mechanical integrity will be demonstrated through approved monitoring methods described in *Section 5 – Testing and Monitoring Plan*. (16 TAC **§5.203(k)(2)(C)** [40 CFR ***§*146.92(a)**])

6.3.2 Plugging Procedure (USDW Monitoring Wells)

Prior to plugging the Project USDW monitoring wells, Operator will pull packers and tubing out of the wellbores. The following is the general plugging procedure for all Project USDW monitoring wells:

[redacted]

A detailed plugging procedure for all Project USDW monitoring wells is included in *Appendix J-4*. All USDW monitoring well plugging schematics are included in *Appendix J-5*. Figure 6-12 shows the [redacted] plugging schematic as an example.

Figure 6-12 – Final plugging schematic for Project USDW monitoring wells [redacted]

6.3.3 Plugging Procedure (Above-Zone Monitoring Wells)

The following is the general plugging procedure for all Project above-zone monitoring (AZM) wells:

[redacted]

A detailed plugging procedure for all Project AZM wells is included in *Appendix J-6.* All AZM well plugging schematics are included in *Appendix J-7*. Figure 6-13 shows the [redacted] plugging schematic as an example.

Figure 6-13 – Final plugging schematic for Project AZM wells [redacted]

6.3.4 Plugging Procedure (In-Zone Monitoring Wells)

Prior to plugging the Project in-zone monitoring (IZM) wells, Operator will pull packers, sleeves, and tubing out of the wellbores. The following is the general plugging procedure for all Project IZM wells:

[redacted]

A detailed plugging procedure for all Project IZM wells is included in *Appendix J-8.* All IZM well plugging schematics are included in *Appendix J-9*. Figure 6-14 shows the [redacted] plugging schematic as an example.

Figure 6-14 – Final plugging schematic for Project IZM wells [redacted]

For each Project injection and monitoring well, 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. Within 30 days after plugging each well, Operator will file a complete well plugging record (Form W-3) with the TRRC district office.

The detailed plugging schematics and procedures in *Appendix J* include the following:

- Appendix J-1 [redacted]
- Appendix J-2 Injection Well Detailed Plugging Procedure
- Appendix J-3 Injection Well Final Plugging Schematics
- Appendix J-4 USDW Monitoring Well Detailed Plugging Procedure
- Appendix J-5 USDW Monitoring Well Final Plugging Schematics
- Appendix J-6 AZM Well Detailed Plugging Procedure
- Appendix J-7 AZM Well Final Plugging Schematics
- Appendix J-8 IZM Well Detailed Plugging Procedure
- Appendix J-9 IZM Well Final Plugging Schematics

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 7 – POST INJECTION SITE CARE AND SITE CLOSURE PLAN

July 2024

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

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7.1 Introduction

The Post-Injection Site Care (PISC) and Site Closure Plan for the ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) project (Project) was prepared in accordance with the regulatory requirements outlined in Title 16, Texas Administrative Code (16 TAC) **§5.203(m)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93**]. This plan outlines the activities for cessation of injection, ongoing monitoring, and final site closure. ConocoPhillips Texas Gulf Coast CCS LLC (Operator) will monitor groundwater quality and track the carbon dioxide plume and pressure front positions for 50 years post-injection—or as prescribed by the Underground Injection Control program director (UIC Director) or other governmental authority with jurisdiction. Site closure will occur upon plume stabilization and UIC Director concurrence that the Project no longer poses an endangerment to the Underground Source of Drinking Water (USDW).

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)**], Table 7-1 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*, for each injection well.

Table 7-1 – Maximum pressure differential by year.

*psi – pounds per square inch

Table 7-2 summarizes the highest expected pressure differential, the year it will occur, the completion stage, and the maximum pressure differential (psi) for each injection well.

Table 7-2 – Highest maximum pressure differential per injection well.

Figures 7-1 to 7-6 present graphical representations of the data in Table 7-1, showing the pressure differential over the life of the injection wells.

Figure 7-1 – Maximum pressure differential over time for Snapper North INJ 1.

Figure 7-2 – Maximum pressure differential over time for Snapper North INJ 2.

Figure 7-3 – Maximum pressure differential over time for Snapper North INJ 3.

Figure 7-4 – Maximum pressure differential over time for Snapper South INJ 1.

Figure 7-5 – Maximum pressure differential over time for Snapper South INJ 2.

Figure 7-6 – Maximum pressure differential over time for Snapper South INJ 3.

7.3 CO_2 Plume and Pressure Front Positions at End of Injection

The area of review (AOR) consists of both the CO_2 plume and critical pressure maximum extent as derived from the combined extents from each completion stage in all six injection wells. Figure 7-7 shows the AOR and its subcomponents at the end of injection.

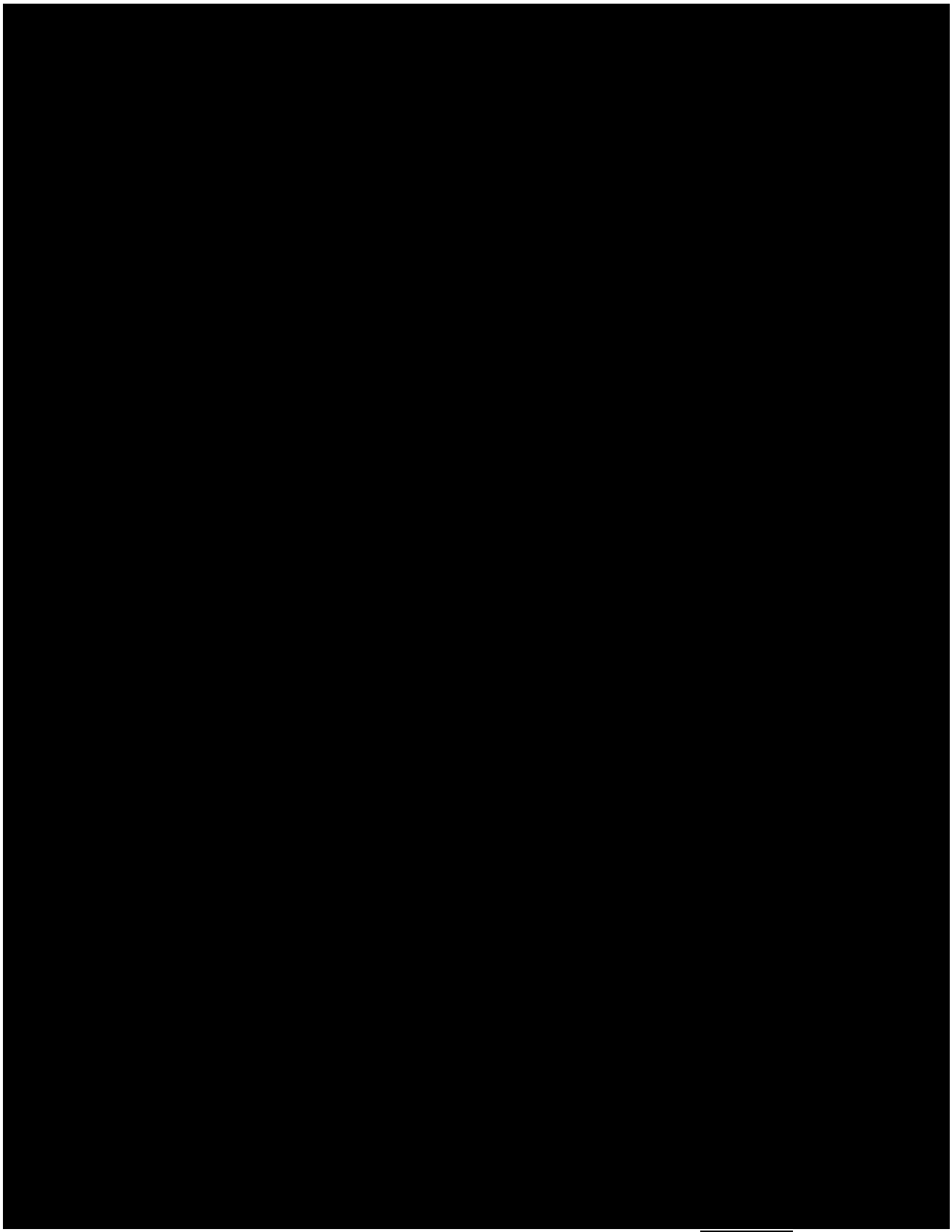

Figure 7-7 – CO_2 plume and pressure front at the end of injection [redacted]

7.4 CO_2 Plume and Pressure Front Positions at Site Closure

Figure 7-8 shows the CO_2 plumes at site closure, 50 years post-injection. [redacted] Figures 7-9 to 7-14 show cross-sectional views of the Project injection wells and corresponding CO_2 plumes at site closure (50 years post-injection).

[redacted] Figures 7-15 to 7-20 show cross-sectional views of the Project injection wells and the maximum pressure radii of influence.

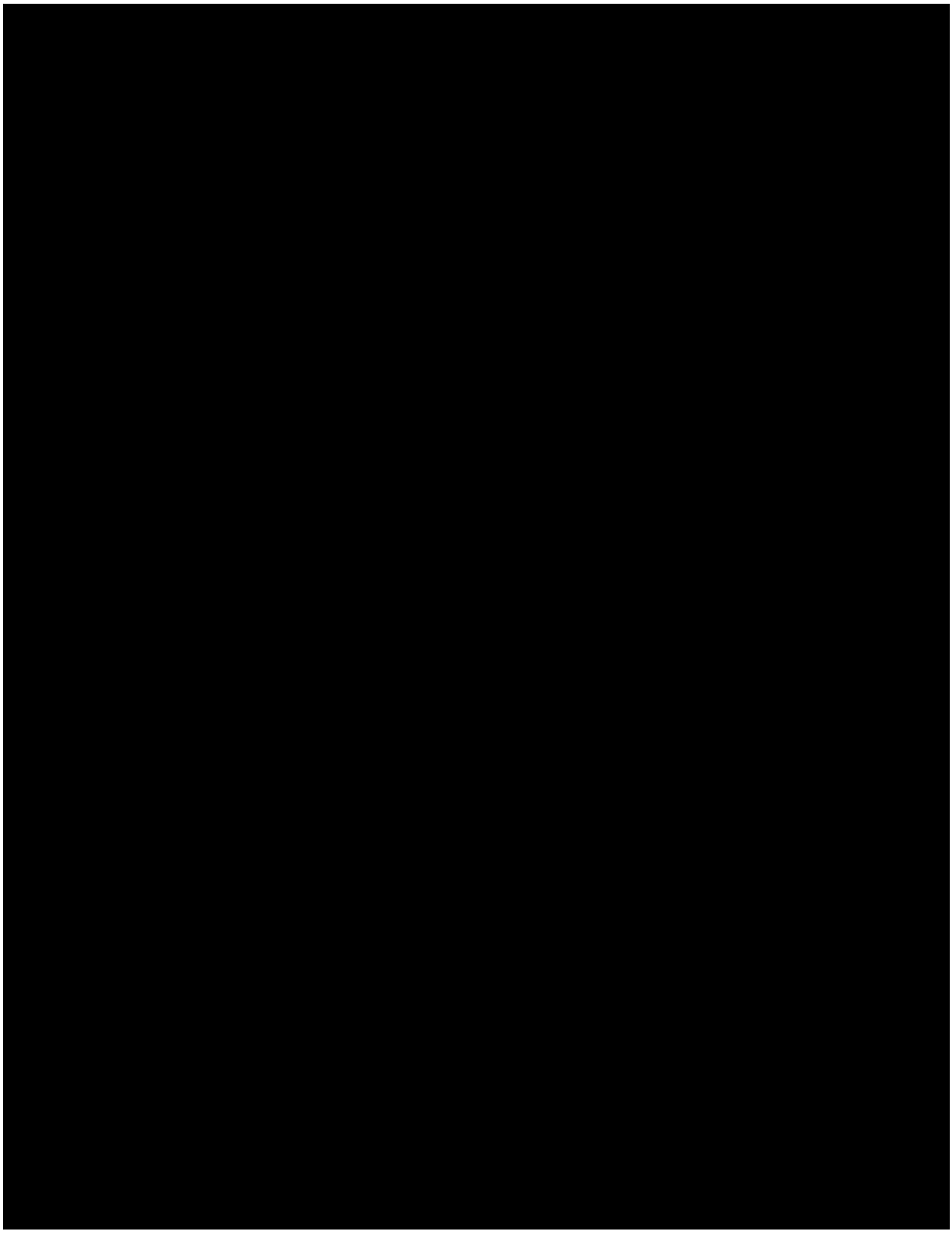

Figure 7-8 – CO_2 plume at site closure
(50 years post-injection).

Figure 7-9 – Cross-sectional views of Snapper North INJ 1 showing CO_2 plume at site closure (50 years post-injection).

Figure 7-10 – Cross-sectional views of Snapper North INJ 2 showing CO_2 plume at site closure (50 years post-injection).

Figure 7-11 – Cross-sectional views of Snapper North INJ 3 showing CO_2 plume at site closure (50 years post-injection).

Figure 7-12 – Cross-sectional views of Snapper South INJ 1 showing CO_2 plume at site closure (50 years post-injection).

Figure 7-13 – Cross-sectional views of Snapper South INJ 2 showing CO_2 plume at site closure (50 years post-injection).

Figure 7-14 – Cross-sectional views of Snapper South INJ 3 showing CO_2 plume at site closure (50 years post-injection).

Figure 7-15 – Cross-sectional views of Snapper North INJ 1 showing maximum pressure radius.

Figure 7-16 – Cross-sectional views of Snapper North INJ 2
showing maximum pressure radius of influence.

Figure 7-17 – Cross-sectional views of Snapper North INJ 3 showing maximum pressure radius of influence.

Figure 7-18 – Cross-sectional views of Snapper South INJ 1
showing maximum pressure radius of influence.

Figure 7-19 – Cross-sectional views of Snapper South INJ 2 showing maximum pressure radius of influence.

Figure 7-20 – Cross-sectional views of Snapper South INJ 3
showing maximum pressure radius of influence.

7.5 Post-Injection Monitoring Plan

As required by 16 TAC **§5.206(k)(2)** [40 CFR **§146.93(b)**], Operator will monitor the site for 50 years post-injection, or until the UIC Director or other governmental authority with jurisdiction concurs that the Project no longer poses an endangerment to the USDW—as described in *Section 7.6*—or Operator transfers the monitoring obligation to a governmental authority. The monitoring program will track the CO_2 plume migration and changes in the pressure front. Monitoring observations will be incorporated into the reservoir model throughout the Project to predict future plume growth and drift—and to accurately estimate plume stabilization. Based on the updated reservoir model, an amended PISC plan may be submitted to the UIC Director upon cessation of injection if necessary. [redacted] Post-injection monitoring activities will be an extension of the monitoring plan in *Section 5 – Testing and Monitoring Plan*. Injection wells and monitoring well locations [redacted] are displayed in Figure 7-21 and Table 7-3. Post-injection monitoring and reporting frequency are detailed in Table 7-4, and overview of Operator's plan is as follows:

- **Post-Injection Direct Monitoring:**

[redacted]

[redacted]

- **Post-Injection Indirect Monitoring:** [redacted]

- **Subsurface and Reservoir Modeling:** [redacted]

- **Monitoring Activity and Reporting Frequency:** Post-injection monitoring activity and reporting frequencies are discussed in *Section 7.6*.

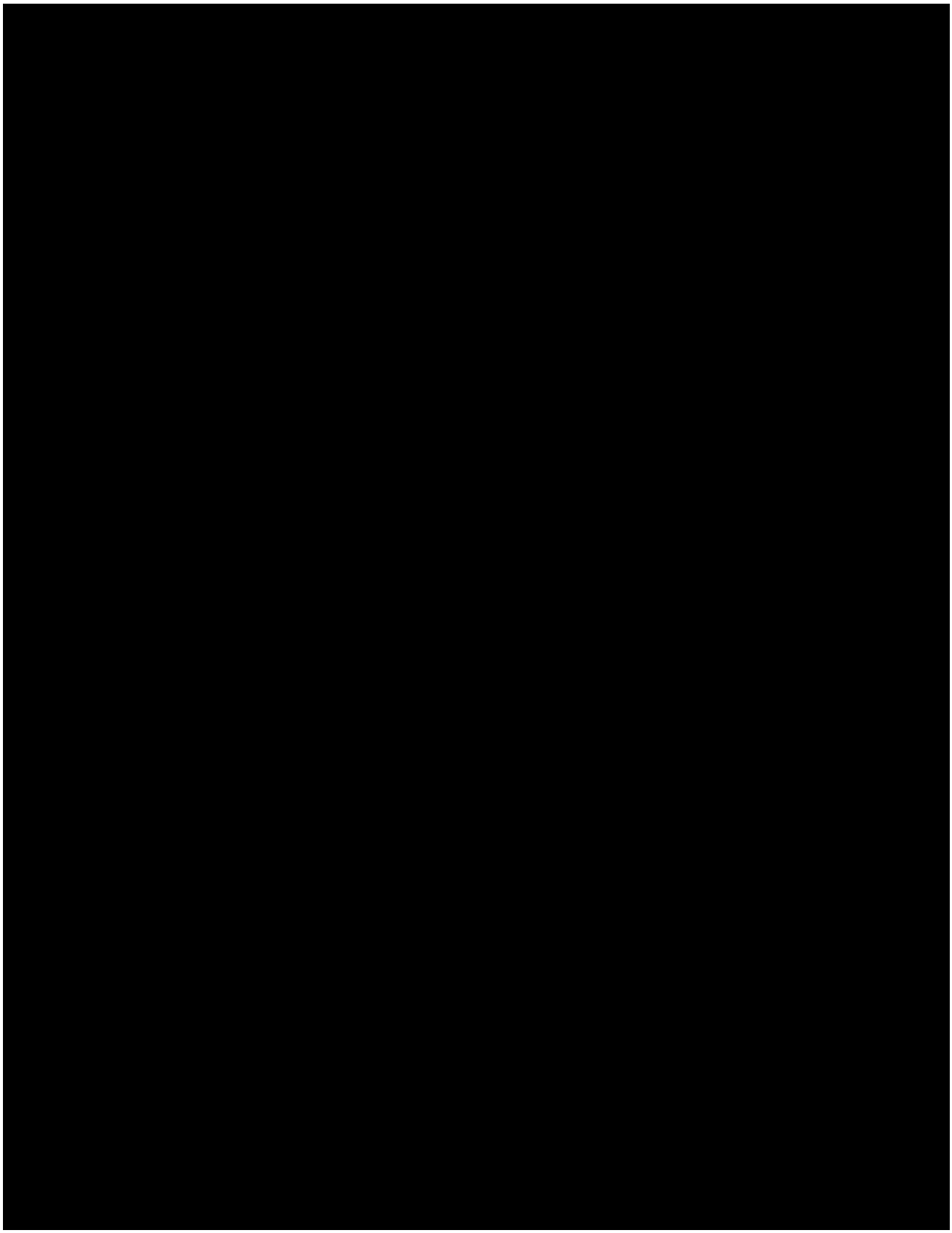

Figure 7-21 – Development and monitoring plan.

Table 7-3 – Development pads and associated wells.

7.6 Post-Injection Monitoring Activities

During the post-injection monitoring period, the testing and monitoring activities, as described in more detail in *Section 5 – Testing and Monitoring Plan,* will be performed and reported at the frequencies shown in Table 7-4. Monitoring reports will be prepared and submitted annually within 60 days of the anniversary date of injection cessation (or in accordance with any alternative timeline prescribed by the UIC Director) to the EPA Region 6 UIC branch office—and will summarize the methodology and monitoring results.

Table 7-4 – Post-injection monitoring and reporting frequency.

[redacted]

[redacted] An example wellbore schematic of a final completion stage is included in Figure 7-22, showing the post-injection monitoring configuration of the wellbore. Wellbore schematics of the final completion stage showing the anticipated post-injection monitoring configuration for all injection wellbores are located in *Appendices F-1*.

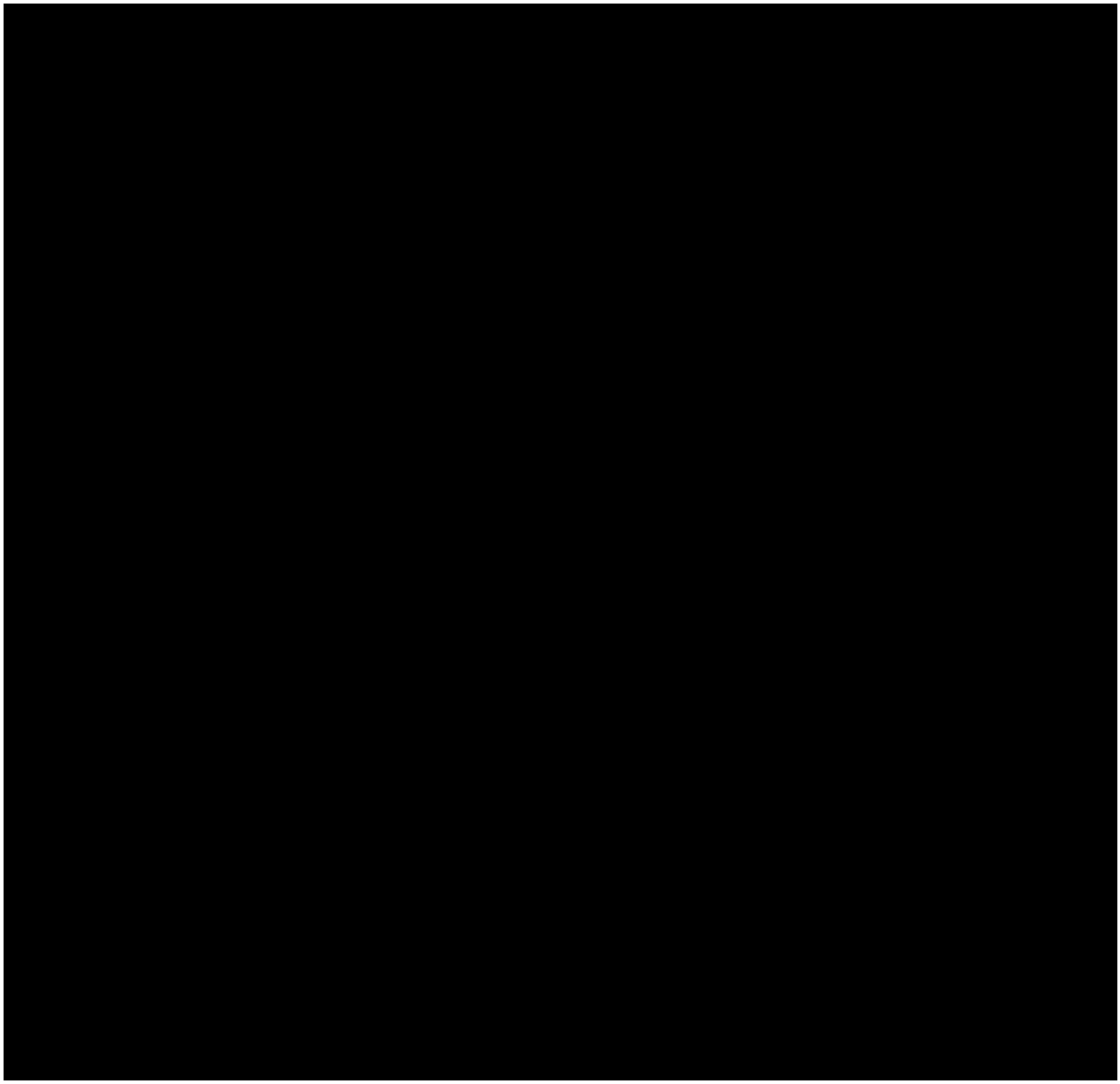

Figure 7-22 – Post-injection monitoring wellbore configuration.

7.7 Demonstration of Non-endangerment of USDW

As required by 16 TAC **§5.206(k)(3)** [40 CFR **§146.93(c)**], Operator will provide documentation that the USDW is not at risk of further endangerment from the CO_2 plume and critical pressure front before authorization of site-closure activities. Documentation will include a site/Project-specific report submitted to the UIC Director demonstrating the non-endangerment of the USDW—including monitoring data and other site-specific conditions, an updated plume model, predicted pressure decline within the injection zone, and any updates to the underlying geological assumptions used in the original model.

7.8 Site Closure Plan

Site closure can take place when monitoring indicates that the plume and formation pressure are stable and no danger to the USDWs exists. To meet the requirements of [40 CFR **§146.93(e)**], the following site closure activities will be performed, including the removal of surface equipment, plugging of all remaining Project wells, site restoration/remediation, and submittal of final site-closure reports.

7.8.1 Pre-Closure

Notice of intent to close the Project site will be submitted to the UIC Director at least 120 days prior to site-closure operations. At this time, any proposed changes to the original PISC and Site Closure Plan will be submitted as part of a revised plan for approval. Relevant notifications and applications, such as plugging requests, will be submitted for approval by the appropriate agency before starting such activities.

7.8.2 Plugging Activities

The subject injection wells, groundwater monitoring wells, and monitoring wells for the Project will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*. The plugging and abandonment procedures for the injection wells ensure that USDWs will not be endangered through movement of injection or formation fluids. Prior to plugging the injection wells, the mechanical integrity of the wells will be determined by an annulus pressure test, casing inspection log, radial cement bond log, and temperature log as described in *Section 6*. Detailed plugging schematics (and procedures are provided in *Appendices J-4* and *J-3*, respectively.

7.8.3 Site Restoration

Once the injection wells and monitoring wells are plugged and capped below grade, surface impacts will be restored as follows:

- All waste derived from plugging and abandonment activities will be removed from the Project site and properly disposed in an appropriate offsite disposal location.
- All drilling and production equipment, machinery, and equipment debris will be removed

from the Project site.

- All injection-related surface infrastructure, including well heads, shelters, pumps, and other wellsite surface features, will be removed from the site.
- Casing will be cut off below the surrounding surface elevation, and a steel marker plate welded on the casing.
- Any known or discovered contamination associated with activities at the well sites will be removed and remediated as applicable.
- The access roads and well pads will be removed or remediated to the reasonable satisfaction of the landowners [redacted]
- Any disturbances outside of the road and pad footprints, as well as areas where gravel infrastructure has been removed, will be contoured to match the surrounding grade and reseeded with an appropriate native seed mix.

7.8.4 Documentation of Site Closure

Within 90 days of site closure, a final report must be submitted to the UIC Director, per the requirements of 16 TAC **§5.206(k)(6)** [40 CFR **§146.93(f)**], to include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats and proper notification information
- Documentation of all Project-related well-plugging reports to the Railroad Commission of Texas (TRRC)
- Documentation of appropriate notification and information to the TRRC to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s)
- Records of the nature, composition, and volume of the CO_2 stream over the injection period

Operator will provide a document of record in the Official Records of Refugio County, Texas and Official Public Records of Aransas County, Texas to provide, in perpetuity, any potential purchaser of the property the following information:

- A complete legal description of the affected property
- The land used to permanently store CO_2
- The survey plat filed with the TRRC and the EPA
- The address of the office of the EPA, to which the operator sent a copy of the survey plat
- The total volume of fluid injected, the injection zones into which it was injected, and the period over which injection occurred

Operator will retain all records collected during the PISC period for at least 10 years following site closure. At the end of the retention period, Operator will deliver to the UIC Director all records, which will thereafter be retained at a location that the UIC Director designates for that purpose.

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

July 2024

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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8.1 Project Information

Project Name: ConocoPhillips Texas Gulf Coast CCS (Project)

Operator Name: ConocoPhillips Texas Gulf Coast CCS LLC (Operator)
925 North Eldridge Parkway
Houston, TX 77079

Project Contact: [redacted]

Project Location:

- Refugio and Aransas Counties, Texas
- Area of review (AOR) centered at [redacted]
  - [redacted]
- [redacted]

Well Locations:

Table 8-1 – Injection well coordinates

Well Name	County	Latitude (NAD 83)	Longitude (NAD 83)
Snapper North INJ 1	[redacted]		
Snapper North INJ 2			
Snapper North INJ 3			
Snapper South INJ 1			
Snapper South INJ 2			
Snapper South INJ 3			

Table 8-2 – Above-zone monitoring (AZM) well coordinates

[redacted]

Table 8-3 – USDW monitoring well coordinates

[redacted]

Table 8-4 – In-zone monitoring well coordinates

[redacted]

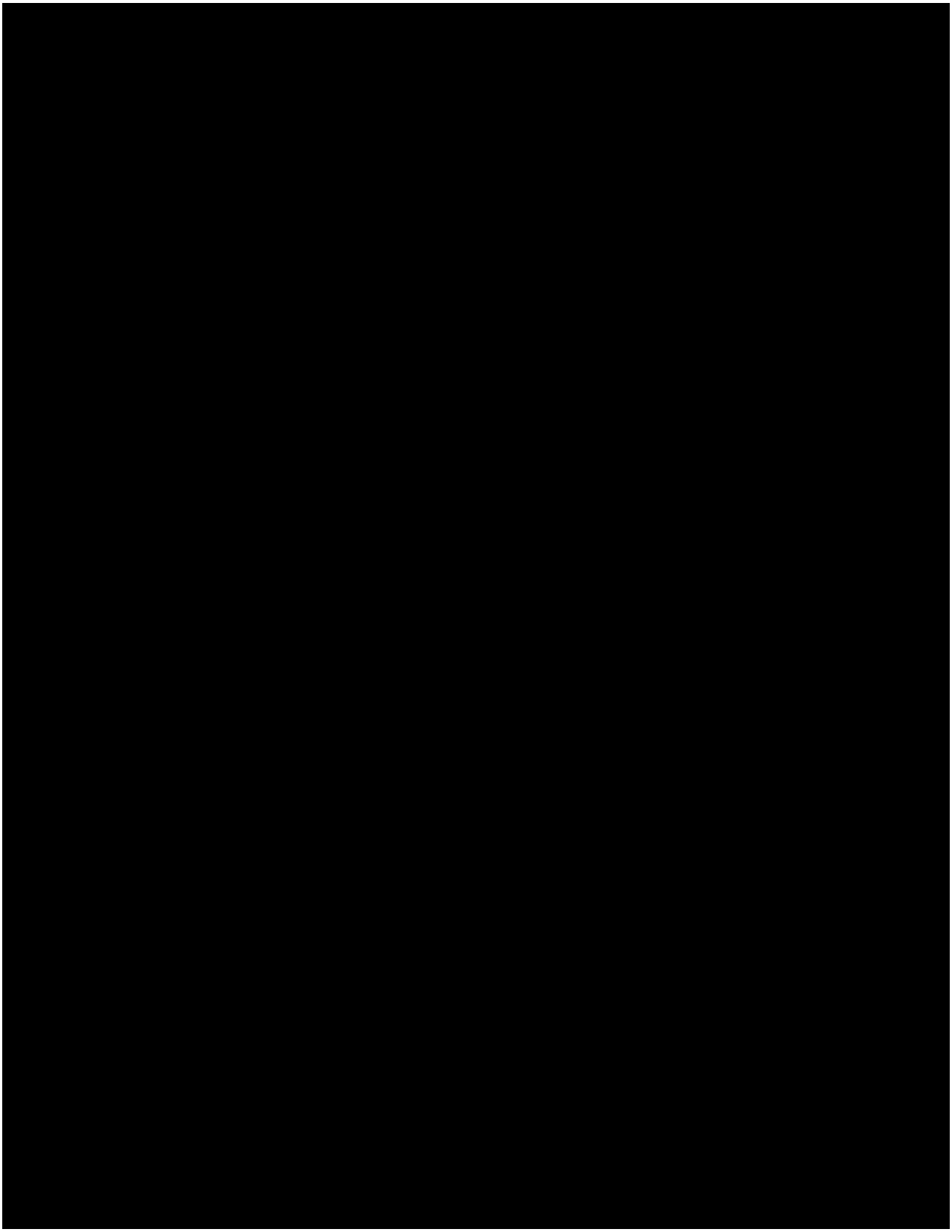

Figure 8-1 – Injection well locations map.

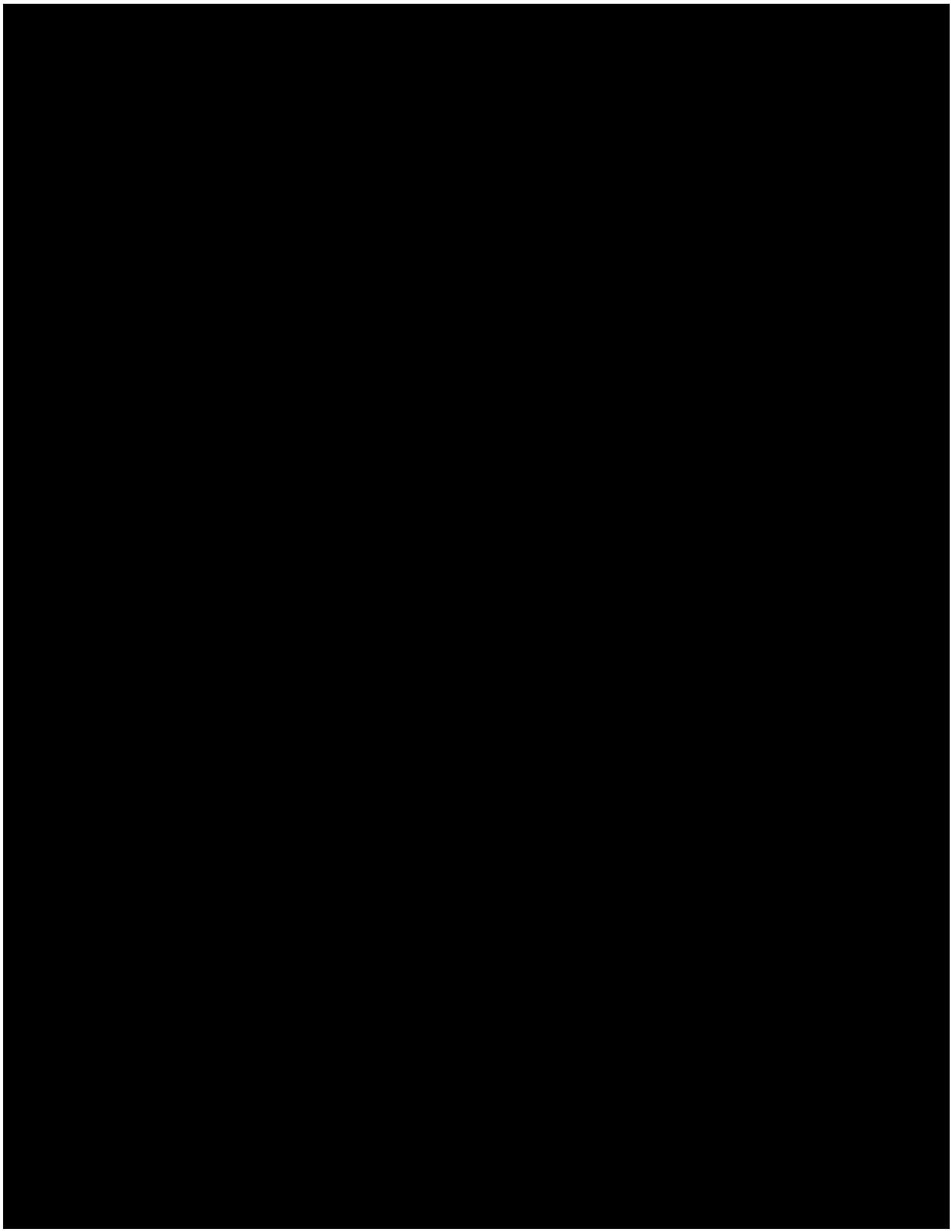

Figure 8-2 – Above-zone monitoring well locations map.

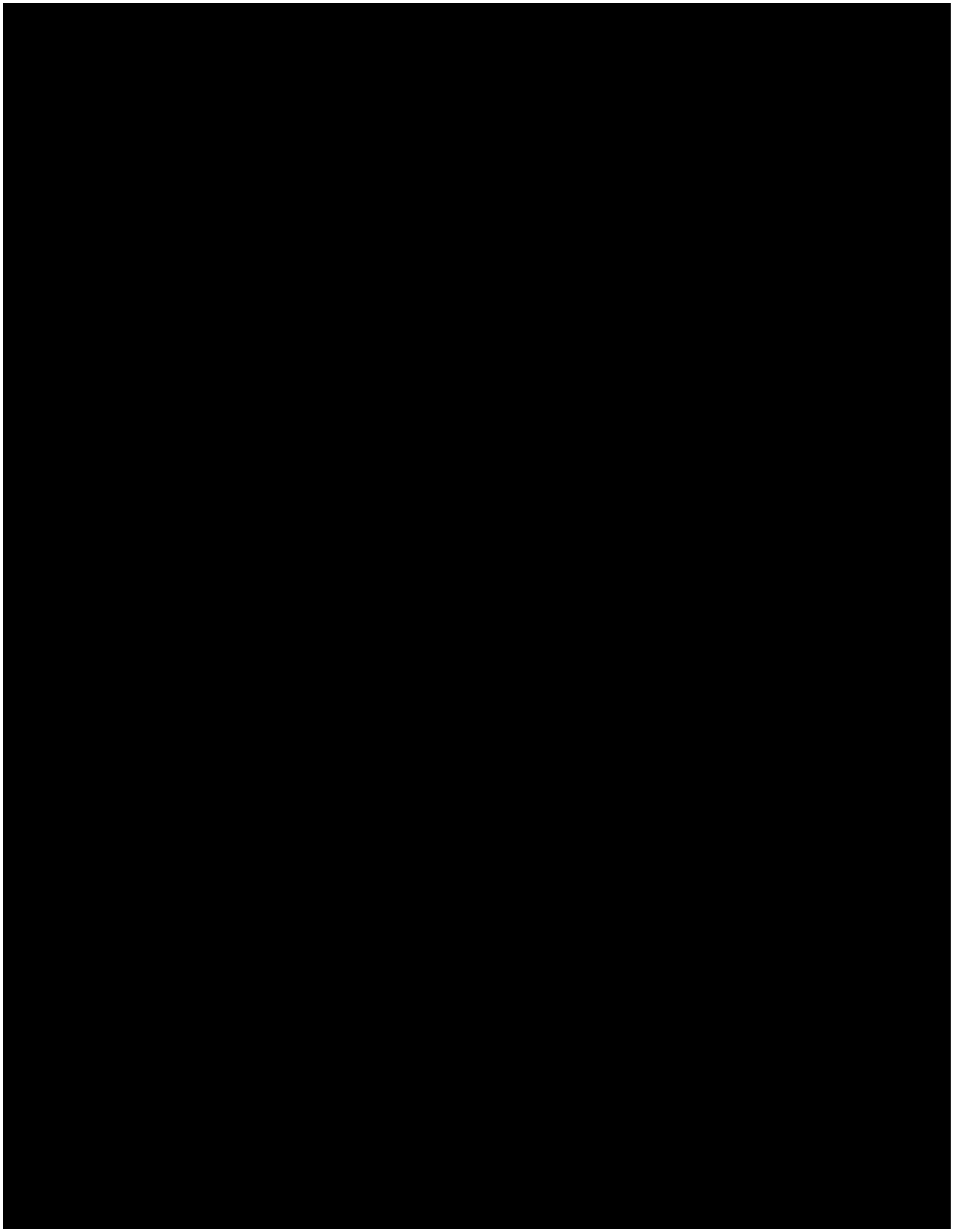

Figure 8-3 – USDW monitoring well locations map.

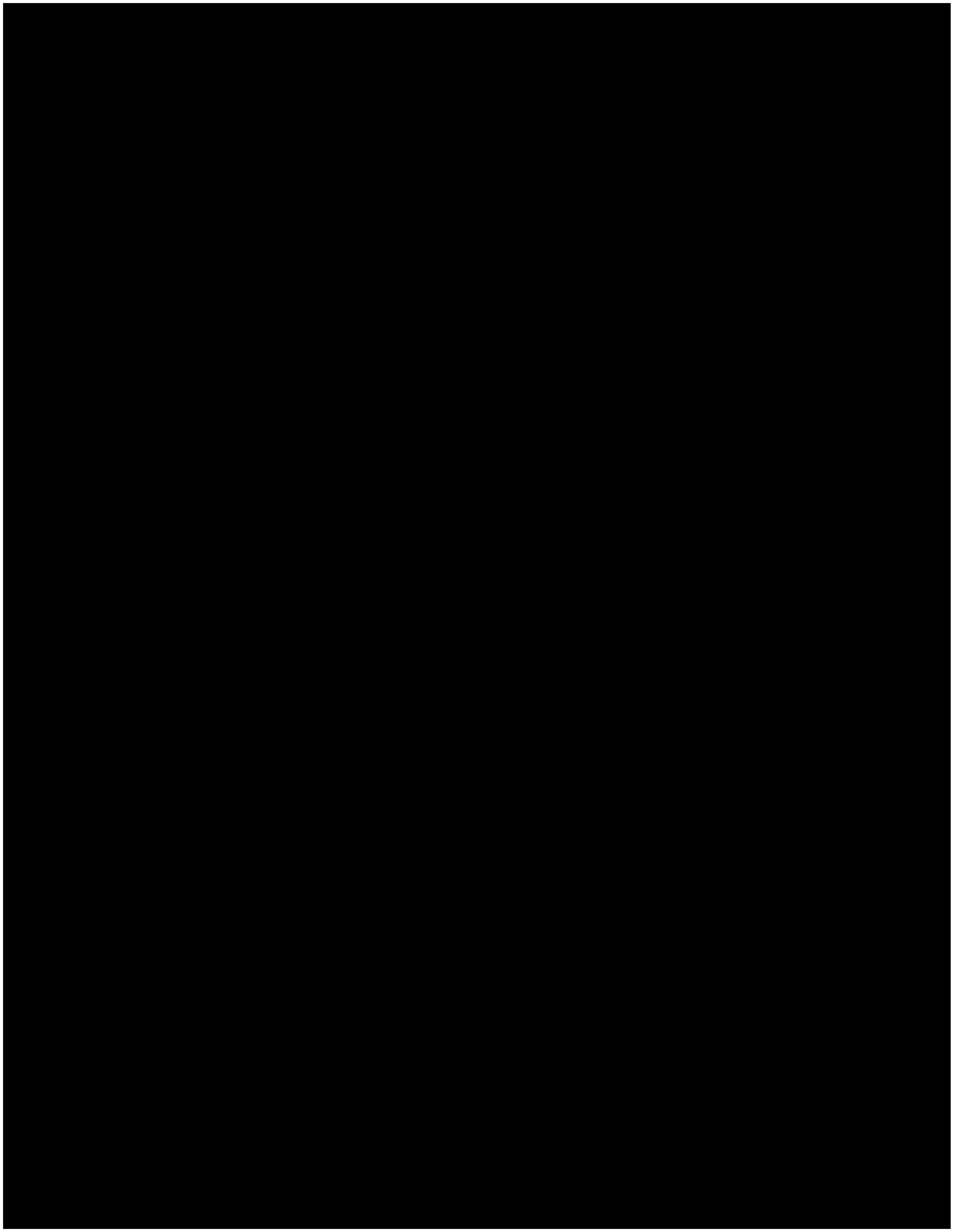

Figure 8-4 – In-zone monitoring well locations map.

8.2 Emergency Response Overview

ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) LLC (Operator) places strong emphasis on emergency preparedness to ensure the safety, health, and responsible operations for various stakeholders, including employees, contractors, customers, neighbors, communities, and shareholders.

[redacted]

This Emergency and Remedial Response Plan (ERRP) 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 ERRP solely focuses on preparedness and responses to emergencies related to risk scenarios that could potentially either impact the quality of the Underground Source of Drinking Water (USDW) or result in a release of CO_2 at the surface. This plan will be reviewed and updated annually, or as required by the Underground Injection Control program director (UIC Director). Any change in key personnel will also cause the ERRP to be updated immediately.

In addition to this ERRP, Operator is developing additional site-specific guidance and response protocols for all potential emergency scenarios. This additional guidance will be codified in Operator's Tier 1 Emergency Response Plan, which will be reviewed with local responders before drilling operations. A copy of this supplemental Tier 1 Emergency Response Plan will be available to the UIC Director [redacted]

8.3 Resources/Infrastructure in Area of Review

The Project's AOR is approximately [redacted] square miles (sq mi), and covers acreage in Refugio and Aransas Counties, Texas. [redacted]

Lists of known artificial penetrations existing within the AOR are included in *Section 3 – AOR and Corrective Action*. If an undocumented artificial penetration is found, the well will be remediated to ensure protection against any possible migration of CO_2. Additionally, the testing and monitoring programs described in *Section 5 – Testing and Monitoring* were designed to ensure and verify the protection of the USDW.

The base of the lowermost USDW in the AOR is estimated to be about [redacted] feet (ft) total vertical depth subsea (TVDss) deep in this area. The Groundwater Advisory Unit (GAU) at the Railroad Commission of Texas (TRRC) will provide groundwater determination letters to confirm both the base of usable quality water and the base of the USDW for the specific injection well locations, prior to finalizing well designs and commencing drilling operations. Figure 8-5 (*Appendix I-5*) shows the locations of nearby groundwater and water wells in relation to the Project.

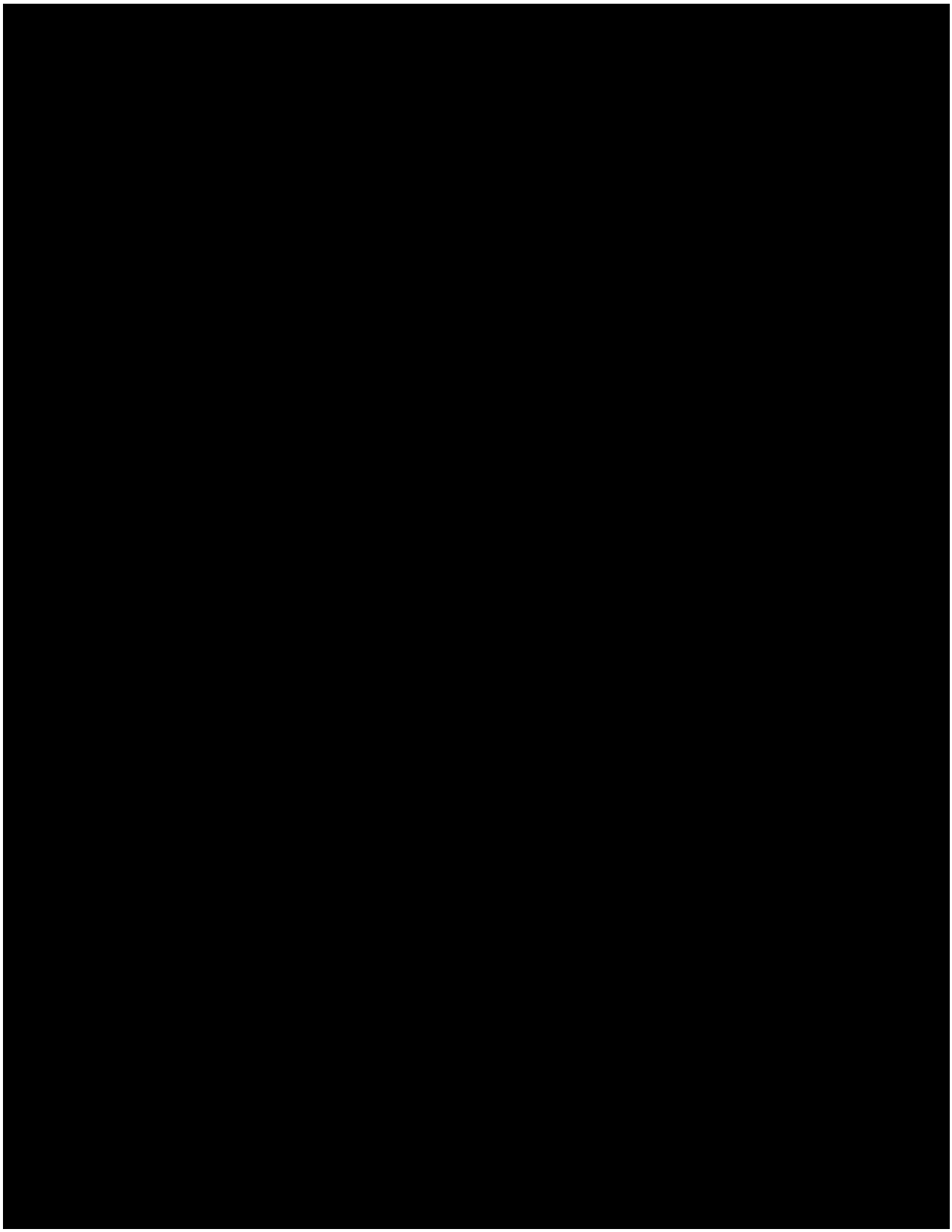

Figure 8-5 – AOR with groundwater wells map.

The closest hospital to the Project is the Refugio County Memorial Hospital (107 Swift Street, Refugio, Texas 78377) in the town of Refugio. The hospital is a Basic (Level IV) trauma facility with a 24-hour emergency room. Refugio County Memorial Hospital has 20 hospital beds and 3 emergency room beds, and also operates 4 rural health clinics throughout Refugio County.

Corpus Christi has six designated trauma facilities, listed in Table 8-5.

Table 8-5 – Corpus Christi[1] designated trauma facilities.

Corpus Christi Hospital	Trauma Designation
CHRISTUS Spohn Hospital Corpus Christi Shoreline	Major (Level II)
Corpus Christi Medical Center – Bay Area	Major (Level II)
Driscoll Children's Hospital	Advanced (Level III)
CHRISTUS Spohn Hospital Corpus Christi South	Basic (Level IV)
Corpus Christi Medical Center – Doctors Regional	Basic (Level IV)
Corpus Christi Medical Center – Northwest	Basic (Level IV)

The nearby communities are serviced by volunteer fire departments. The Refugio Volunteer Fire Department provides fire and rescue services for citizens of the town of Refugio and Refugio County, Texas. Aransas and Refugio counties are also serviced by the Coastal Plain Local Emergency Planning Committee (CPLEPC). The CPLEPC organization actively works to meet the requirements of the federal Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986. This work is performed strictly on a volunteer basis with industry and the county government working together. The CPLEPC coordinates projects in the Aransas and Refugio County school districts, a shelter-in-place emergency preparedness campaign, and a "take-shelter and all-clear" emergency alert system—and also provides emergency information pamphlets and additional education materials.

Refugio and Aransas Fire Departments coordinate between counties and regularly conduct fire drills together. [redacted] Area law enforcement resources include the Refugio Police Department, the Refugio County Sheriff's Office, and the Aransas County Sherriff's department.

Aransas and Refugio counties utilize Code Red, an emergency notification system that sends voice or text messages to residents about issues of public concern. There is also an emergency notification radio station, 1610 AM, which broadcasts community emergency messages.

Operator continues to evaluate local emergency response capacity and supplemental, third-party options to ensure appropriate resources are available. Figure 8-6 (*Appendix I-6*) shows the locations of nearby emergency response resources.

[1] https://www.dshs.texas.gov/dshs-ems-trauma-systems/trauma-system-development/texas-trauma-facilities

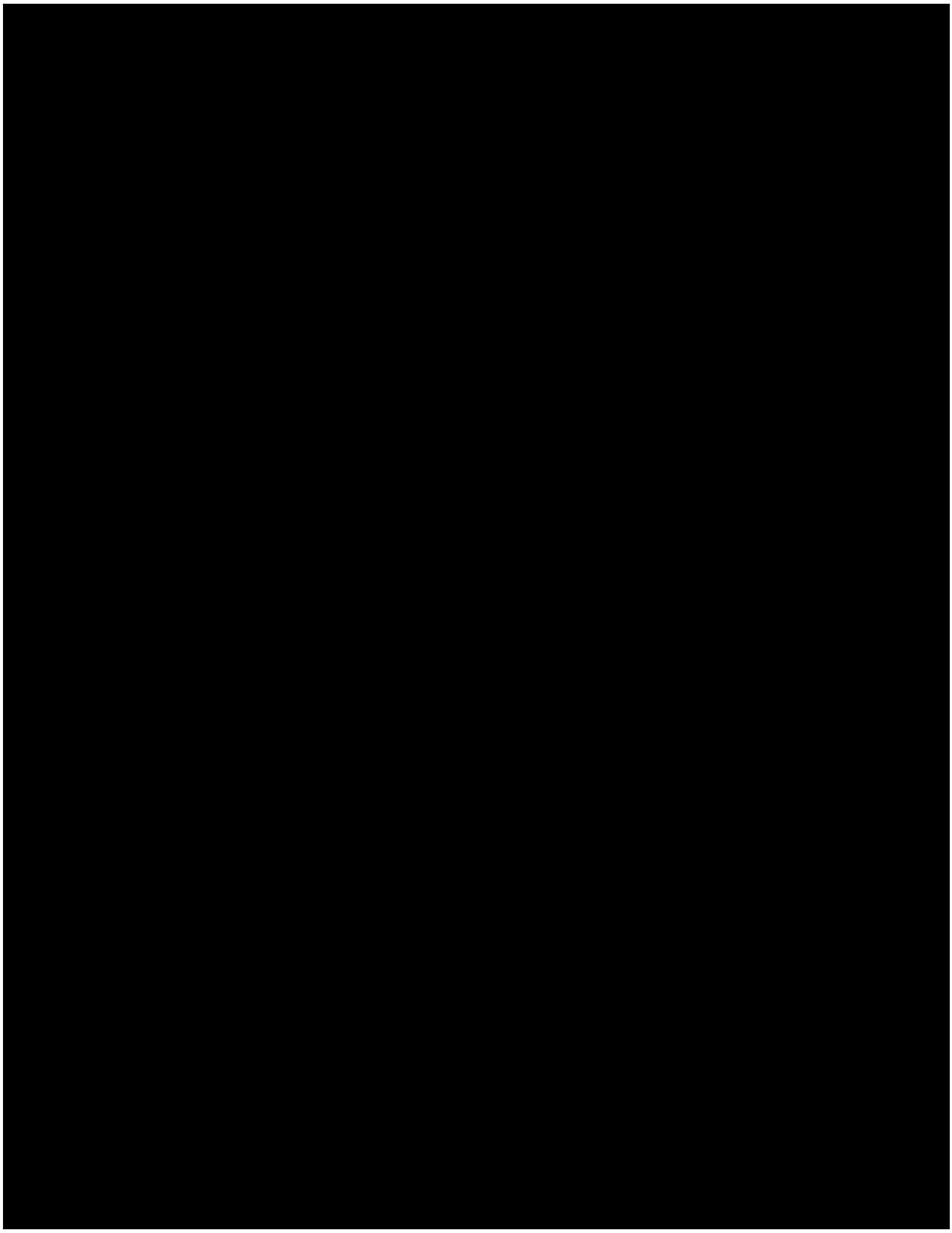

Figure 8-6 – Emergency response capacity map.

8.4 Alarms, Automatic Shutdown Systems, and Security Measures

In compliance with 16 TAC **§5.203(j)(2)(B)** [40 CFR **§146.90(b)**], Operator will ensure continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure. Digital pressure and temperature transmitters will provide continuous monitoring of the CO_2 stream at the well facility and wellhead. A mass-flow rate meter will be installed at the well facilities to provide continuous monitoring of rates and volumes of the injected CO_2 stream. All digital devices will be linked to a Supervisory Control and Data Acquisition (SCADA) system that will collect the data for operational and monitoring purposes. Alarms and automatic shutdown valves will be installed to alert operations and stop injection if the CO_2 stream is not within safe operating conditions.

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 (e.g., annulus pressure, injection rate, or other parameters) diverge from permitted ranges or gradients. A change in the annular pressure outside of standard operating conditions during injection operations will result in a shutdown event.

In compliance with 16 TAC **§5.203(i)(2)(B)**, Operator will implement general security measures to monitor the injection wells and associated facilities. [redacted]

8.5 Flood Risk

The Texas Coastal Bend Region is prone to hurricanes and flooding. In August 2017, Hurricane Harvey made landfall in the area, causing extensive damage in Aransas County, Nueces County, Refugio County, and the eastern part of San Patricio County. As the Texas Coastal Bend Region and these communities continue to rebuild, Operator acknowledges the sensitivity of this recovery. Operator's Tier 1 Emergency Response Plan includes comprehensive hurricane and flooding response procedures.

The principal type of flood posing the greatest risk in terms of potential impacts to the Project area, due to geographic location and topography, is coastal flooding. Coastal flooding refers to irregular tidal water and wave action that temporarily inundates areas near land-ocean boundaries. The Project wells are in the 500-year floodplain. The 500-year floodplains are moderate flood hazard areas known to have a 0.2% annual chance of flooding. These areas are known to flood, only at a much less frequent rate than the 100-year floodplains.

[redacted]

Table 8-6 – [redacted]

[redacted]

Table 8-7 – [redacted]

[redacted]

8.6 Potential Risk Scenarios

Operator's Project facilities, monitoring systems, and prevention mechanisms are designed in accordance with regulatory standards, in alignment with its longstanding commitment to safety, and to protect the USDWs. While Operator's goal is to minimize risk utilizing thoughtful design and thorough monitoring processes, the following sections detail events that could potentially result in emergency response due to:

1. Impact to USDW quality
2. Release of CO_2 at surface

8.6.1 Impact to USDW Quality

Risk scenarios associated with potential impacts to the USDW include the following:

1. Loss of seal integrity contaminates the USDW with CO_2.
2. Leakage of CO_2 via fault/fracture contaminates the USDW.
3. Cement failure on injection or in-zone monitoring well allows leakage of CO_2 into USDW.
4. Casing failure on injection or in-zone monitoring well allows CO_2 to contaminate USDW.
5. Well integrity failure of adjacent well(s) allows CO_2 to contaminate the USDW (e.g., corrective action wells).
6. Orphan well failure (e.g., well not identified prior to injection) allows CO_2 to contaminate the USDW.
7. Seismicity event (induced or natural) allows CO_2 to contaminate the USDW.

Potential Risk No. 1: Loss of seal integrity contaminates the USDW with CO_2	
Location(s)	• Upper confining zone (UCZ)
Potential Cause(s)	• Seal geochemistry that would weaken when exposed to CO_2 • Exceeded maximum operating formation fracture pressure
Mitigation(s)	• Geochemistry between the UCZ and CO_2 has been evaluated and no areas of concern have been identified • Shutdown valves/safety relief devices will be installed on surface to keep injection pressure below 90% of the formation fracture pressure
Mitigated Risk Level	[redacted]
Detection	• Surface and downhole sensors/gauges set within the in-zone and AZM wells • Mechanical integrity testing • Deviation from reservoir/overburden model predictions
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Perform seismic survey to identify leak pathway • Recomplete injection well • Abandon injection well
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 2: Leakage of CO_2 via fault/fracture contaminates the USDW	
Location(s)	• Any fault or system of faults that extends from an injection zone to USDW
Potential Cause(s)	• Pore pressure increase in the vicinity of the fault above its activation limit • Faults or fractures that are below seismic resolution • Exceeding maximum operating pressure • Seismic activity near fault/fissure (induced or natural)
Mitigation(s)	• Subsurface mapping of 3D reflection seismic data indicates sufficient distance from nearby faults that could act as a conduit • Fault stability analysis completed to identify any high-risk areas—predicted injection-zone pore pressure increases will not be high enough to reactivate faults • No historic seismicity has been recorded within the AOR • Maximum operating pressure will not exceed 90% of the formation fracture pressure • Periodic review of the U.S. Geological Survey (USGS) Earthquake Hazards Program; nearby activity will be compared with the Project's operating parameters
Mitigated Risk Level	[redacted]
Detection	• Above-zone and groundwater monitoring wells • Seismic surveys indicating plume migration along a fault vertically • Deviation from reservoir/overburden model predictions
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Perform seismic survey to identify leak pathway • Recomplete injection well uphole
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 3: Cement failure on injection or in-zone monitoring well allows leakage of CO_2 into the USDW	
Location(s)	• Any injection well or in-zone monitoring well
Potential Cause(s)	• Micro-annular channels could be present within the well's cement
Mitigation(s)	• Best practices for cementing will be utilized to minimize the risk of an inadequate cement job, including the use of CO_2-resistant cement • Automatic alarm and automatic shutoff systems will be designed and installed to sound if the injection well loses integrity during operation per 40 CFR **146.88(e)(2)** • Run a cement bond log post-cement job to ensure cement quality • Regular mechanical integrity testing • Above-zone monitoring wells to detect if an early leak were to occur
Mitigated Risk Level	[redacted]
Detection	• Cement bond logs following the cement job on all strings will confirm good cement quality or show where the cement job might need to be remediated • Groundwater sampling • Sampling from the USDW monitoring well • Pressure gauges installed in the AZM wells and USDW monitoring wells • Cased-hole logs run as part of mechanical integrity tests • Deviation from reservoir/overburden model predictions
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Run well diagnostics to determine point of leak(s) • Isolate leakage pathway • Demonstrate mechanical integrity • Recomplete injection well • Abandon injection well
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 4: Casing failure on injection or in-zone monitoring well allows CO_2 to contaminate the USDW	
Location(s)	• Casing of any injection well or in-zone monitoring well
Potential Cause(s)	• Corrosion of casing due to incompatible metallurgy • Leak in the surface casing, leak path in the surface casing cement, and channel in the injection zone • Mechanical deformation of the casing
Mitigation(s)	• Ensure appropriate metallurgies are used in the construction of the well • Annulus pressure tests (APTs) • Cement on long string to surface • Casing inspection and cement bond log post-cement job to ensure casing integrity and cement quality • Regular mechanical integrity tests (internal and external) • Automatic controls, equipment shutdowns, and pressure relief devices
Mitigated Risk Level	[redacted]
Detection	• Groundwater sampling • Deviation from reservoir/overburden model predictions
Available Response Action(s) and Equipment	• Shut-in injection program • Isolate leakage pathway • Abandon well • Monitor for contamination; ongoing as required • Provide clean drinking water source as required
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 5: Well integrity failure of adjacent well(s) allows CO_2 to contaminate the USDW (e.g., corrective action wells)	
Location(s)	• Any adjacent well
Potential Cause(s)	• Ineffective or inadequate plugging of adjacent wells
Mitigation(s)	• Proper corrective action on wells • Adequate review of existing wells and plugs • Regularly scheduled monitoring program updates to map plume location • Proper corrective action on all wells within the pressure front prior to pressure reaching the wellbore
Mitigated Risk Level	[redacted]
Detection	• Monitoring wells (in-zone, above-zone, and USDW) • Indirect monitoring through seismic surveys • Deviation from reservoir/overburden model predictions
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Isolate leakage pathway • Remediate leaky well
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responder • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 6: Orphan well failure (e.g., well not identified prior to injection) allows CO_2 to contaminate the USDW	
Location(s)	• Orphan wells
Potential Cause(s)	• Unknown/unidentified wellbore penetrations. • Inadequate corrective active
Mitigation(s)	• Magnetometer survey will be completed across the AOR to identify undocumented wellbore penetrations • Proper corrective action on identified wellbores • Extensive well records research conducted [redacted]
Mitigated Risk Level	[redacted]
Detection	• Monitoring wells (above-zone and USDW) • Deviation from reservoir/overburden model predictions
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Isolate leakage pathway • Remediate leaky well
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 7: Seismicity event (induced or natural) allows CO_2 to contaminate the USDW	
Location (s)	• Project area
Potential Cause(s)	• Fault activation (or reactivation) causes the plume to reach faults or fractures that cut through the primary seal
Mitigation(s)	• Seismically quiet Project location • Periodic review of USGS Earthquake Hazards Program • Detectable seismic events within a 4-mi radius of wellheads will be compared with operating parameters to understand potential correlation • Operating below formation fracture pressures
Mitigated Risk Level	[redacted]
Detection	• USGS Earthquake Hazards Program • Above-zone and USDW monitoring wells
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Perform site survey to assess potential surface damages to facilities • Perform seismic survey to identify leak pathway
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

8.6.2 CO_2 Release to or at the Surface

Potential hazardous events associated with potential for CO_2 release to or at the surface include the following:

1. Well control event occurs during drilling operations.
2. CO_2 migrates along fault/fracture to surface.
3. Casing failure on injection or in-zone monitoring well allows CO_2 to escape to surface.
4. Cement failure on injection or monitoring well allows CO_2 to escape to surface near wellbore.
5. Major mechanical failure of well flowlines allows CO_2 to escape to the atmosphere.
6. Well integrity failure of adjacent well(s) allows CO_2 to escape to surface (e.g., corrective action wells).
7. Orphan well (e.g., well not identified prior to injection) failure allows CO_2 to escape to surface.
8. Seismicity event (induced or natural) allows CO_2 to escape to surface.
9. Severe weather (i.e., hurricanes, flooding, strong winds, etc.) results in damage allowing CO_2 to escape to surface.

Potential Risk No. 1: Well control event occurs during drilling operations	
Location(s)	• Injection and monitoring wells
Potential Cause(s)	• Equipment/monitoring equipment failure • Imbalance encountered with subsurface pore pressure
Mitigation(s)	• Evaluation of formation pressures at different drilling stages • Comprehensive review of nearby wells and drilling hazards to guide execution plan • Monitoring during drilling for flow, pressure, take level, tripping displacement, and mud weight • Mud weight control will prevent movement of fluids or gases across zones to prevent kick or blowout • Well control equipment • Well control training • Blowout preventer (BOP) testing (per manufacturer specifications and state requirements)
Risk Level	[redacted]
Detection	• Unexpected changes to flow, pressure, take level, tripping displacement, and mud weight during drilling
Available Response Action(s) and Equipment	• Pause drilling operations and assess fluid levels in the wellbore • Close the BOP • Initiate well control procedures using well control equipment (e.g., blowout preventer) • Shut in the well • Surface cleanup and monitoring • Re-drill well with added casing string for wellbore integrity
Response Personnel	• Rig crew, driller, rig tool pusher, and company man • Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 2: CO_2 migrates along the fault/fracture to surface	
Location(s)	• Any fault/fracture that runs to surface
Potential Cause(s)	• Continuation from leak to USDW • Seismic activity near fault/fissure (induced or natural) • Pore pressure increase in the vicinity of the fault above its activation limit • Exceeding maximum operating pressure
Mitigation(s)	• No historical seismicity has been recorded within the AOR • Sufficient distance from nearby faults that could act as a conduit • Fault stability analysis completed to identify any high-risk areas—predicted injection-zone pore pressure increases will not be high enough to reactivate faults • Maximum operating pressure will not exceed 90% of the formation fracture pressure • Periodic review of the USGS Earthquake Hazards Program; nearby activity will be compared with the Project's operating parameters
Mitigated Risk Level	[redacted]
Detection	• Above-zone and USDW monitoring wells • Seismic surveys indicating plume migration along a fault vertically • Deviation from reservoir/overburden model predictions
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Perform seismic survey to identify leak pathway • Recomplete injection wells • Abandon injection wells • Surface cleanup and monitoring
Response Personnel	• Environmental services contractor • Local emergency responders • Local company operations • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 3: Casing failure on injection or in-zone monitoring well allows CO_2 to escape to surface	
Location(s)	• Injection wells and in-zone monitoring wells
Potential Cause(s)	• Corrosion of casing due to incompatible metallurgy • Mechanical deformation
Mitigation(s)	• Ensure appropriate metallurgies are used in the construction of the well • Run a casing inspection log post casing install to ensure quality • Automatic controls, equipment shutdowns, and pressure relief devices • Regular mechanical integrity testing (internal and external)
Mitigated Risk Level	[redacted]
Detection	• Safety shutdowns in the casing • CO_2 monitors on the pad site • USDW and above-zone monitoring wells
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Run well diagnostics to determine point of leak(s) • Use tubing and packers to find the leak point within the casing/cement job (equipment) • Isolate leakage pathway • Remediate leaky well • Recomplete injection well uphole • Abandon well
Response Personnel	• Local company operations • Emergency Response Team/IMT • Engineering and remediation specialists • Environmental services contractor
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 4: Cement failure on injection or monitoring well allows CO_2 to escape to surface near wellbore	
Location(s)	• Injection and monitoring wells
Potential Cause(s)	• Micro-annular channels could be present within the cement of the well • Potential continuation from a leak to USDW
Mitigation(s)	• Best practices for cementing will be utilized to minimize the risk of an inadequate cement job, including the use of CO_2-resistant cement • Automatic alarm and automatic shutoff systems will be designed and installed to sound if the injection well loses integrity during operation per 40 CFR **146.88(e)(2)** • Run a cement bond log post-cement job to ensure cement quality • Regular mechanical integrity testing
Mitigated Risk Level	[redacted]
Detection	• Safety shutdowns in the casing • CO_2 monitors on the pad site • USDW and above-zone monitoring wells
Available Response Action(s) and Equipment	• Shut-in injection program • Monitor for contamination; ongoing as required • Run well diagnostics to determine point of leak(s) • Use tubing and packers to find the leak point within the casing/cement job (equipment) • Isolate leakage pathway • Demonstrate mechanical integrity • Abandon well
Response Personnel	• Local company operations • Emergency Response Team/IMT • Engineering and remediation specialists • Environmental services contractor
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 5: Major mechanical failure of well flowlines allows CO_2 to escape to the atmosphere	
Location(s)	• Anywhere along the well flowlines
Potential Cause(s)	• Internal corrosion • External corrosion • Material failure • Operating beyond preventative maintenance (PM) schedules
Mitigation(s)	• Monitoring of injection pressure, temperature, rates, and composition at surface • Monitoring of corrosion rates • External pipe coating/cathodic protection for buried pipe • Automatic controls, equipment shutdowns, and pressure relief devices • PM schedules
Mitigated Risk Level	[redacted]
Detection	• Alarm systems for early detection and shut-in response, if necessary
Available Response Action(s) and Equipment	• Demonstrate mechanical integrity • Surface cleanup and monitoring • Shut in equipment and isolate • Remediate surface equipment • Valves to isolate piping • Proper equipment to remediate surface impacts and repair the piping
Response Personnel	• Environmental services contractor • Local emergency responders • Local company operations • Engineering and remediation specialists • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 6: Well integrity failure of adjacent well(s) allows CO_2 to escape to surface (e.g., corrective action wells)	
Location(s)	• Adjacent corrective action wells
Potential Cause(s)	• Inadequate well integrity • Inadequate corrective action
Mitigation(s)	• Investigated databases and historic TRRC maps to identify offset wells • Proper corrective action on all wells within the pressure front prior to pressure reaching wellbore • Magnetometer survey on AOR before starting injection to identify orphan wells • Adequate review of existing wells and plugs
Mitigated Risk Level	[redacted]
Detection	• USDW and above-zone monitoring wells • Indirect monitoring through seismic surveys • Deviation from reservoir/overburden model
Available Response Action(s) and Equipment	• Surface cleaning and monitoring • Properly plug the well • Workover rig and CO_2-resistant cement
Response Personnel	• Environmental services contractor • Local emergency responders • Local company operations • Engineering and remediation specialists • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 7: Orphan well failure (e.g., well not identified prior to injection) allows CO_2 to escape to surface	
Location (s)	• Orphan wells
Potential Cause(s)	• Unknown/unidentified wellbore penetrations • Inadequate corrective action
Mitigation(s)	• Magnetometer survey to be completed across AOR to identify undocumented wellbore penetrations • Proper corrective action on identified wellbores • Extensive well records research conducted [redacted]
Mitigated Risk Level	[redacted]
Detection	• USDW and above-zone monitoring wells • Indirect monitoring through seismic surveys • Deviation from reservoir/overburden model
Available Response Action(s) and Equipment	• Surface cleanup and monitoring • Properly plug the well • Workover rig and CO_2-resistant cement
Response Personnel	• Environmental services contractor • Local emergency responders • Local company operations • Engineering and remediation specialists • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 8: Seismicity event (induced or natural) allows CO_2 to escape to surface	
Location (s)	• Project area
Potential Cause(s)	• Fault activation or reactivation of faults that cut to surface due to local pore pressure increase above critical stress
Mitigation(s)	• Periodic review of USGS Earthquake Hazards Program • Detectable seismic events within a 4-mi radius of wellheads will be compared with operating parameters to understand potential correlation • Seismically quiet location selected • Above-zone monitoring wells and USDW wells monitoring pressure
Mitigated Risk Level	[redacted]
Detection	• USGS Earthquake Hazards Program • USDW and above-zone monitoring wells
Available Response Action(s) and Equipment	• Shut in injection program • Monitor for contamination; ongoing as required • Perform site survey to assess potential surface damages to facilities • Perform seismic survey to identify leak pathway
Response Personnel	• Environmental services contractor • Local company operations • Local emergency responders • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

Potential Risk No. 9: Severe Weather (i.e., hurricanes, flooding, strong winds, etc.) results in damage, allowing CO_2 to escape to surface	
Details	• Severe weather could potentially damage injection wells, monitoring wells, or flowlines
Location (s)	• Any Project location
Potential Cause(s)	• Global weather patterns
Mitigation(s)	• Weather monitoring, early response • Preemptive decision to shut in operations and isolate in anticipation of severe weather, if necessary • Buried flowlines • Pads and facilities designed to mitigate flood and storm impacts
Mitigated Risk Level	[redacted]
Detection	• National Weather Service[2] • Texas Division of Emergency Management (TDEM) Twitter Feed[3] • Centers for Disease Control (CDC) Emergency Twitter Feed[4] • FEMA Text Messages • Wireless Emergency Alerts • Alarm systems at Project site
Available Response Action(s) and Equipment	• Shut in injection program and isolate • Monitor for contamination; ongoing as required • Provide clean drinking water source as required • Demonstrate mechanical integrity • Evaluate accessibility to injection or monitoring well(s) and/or flowlines Operator's Tier 1 Emergency Response Plan details response actions to weather events that may or may not result in CO_2 escape to surface.
Response Personnel	• Local company operations • Environmental services contractor • Emergency Response Team/IMT
Notifications	• EPA Region 6 UIC Director and other pertinent agencies—within 24 hours of discovery and prior to resuming operations

[2] https://www.weather.gov/#typeLocation
[3] https://x.com/TDEM
[4] https://www.twitter.com/CDCemergency

8.7 Risk Assessment

The following sections outline Operator's risk assessment process during ERRP development. Table 8-8 was generated from FEMA's natural-hazard risk data and considered for flood risk (*Section 8.5*), natural seismic events (*Section 8.6.1*, Potential Risk No. 7, and *Section 8.6.2*, Potential Risk No. 8), and severe weather considerations (*Section 8.6.2*, Potential Risk No. 9). Detailed FEMA National Risk Index Reports for Aransas and Refugio Counties are included in *Appendices I-7* and *I-8*, respectively.

Table 8-8 – FEMA natural hazard risk ratings[5] – Aransas and Refugio Counties.

Event	Aransas County, Texas FEMA Risk Index and National Percentile	Refugio County, Texas FEMA Risk Index and National Percentile
Coastal Flooding	Relatively High (95.4)	Relatively Low (63.0)
Earthquake	Very Low (7.6)	Very Low (5.2)
Hurricane	Relatively Moderate (87.8)	Relatively Low (85.2)
Riverine Flooding	Relatively Moderate (77.9)	Relatively Low (60.2)
Strong Wind	Relatively Low (30.1)	Very Low (20.4)
Wildfire	Very Low (30.0)	Very Low (49.3)

The FEMA risk index scores are calculated using an equation that combines scores for expected annual loss due to natural hazards, social vulnerability, and community resilience. Figure 8-7 provides a more detailed breakdown of FEMA's risk index equation.

Figure 8-8 documents Operator's risk assessment scoring process utilized during ERRP development, and Figure 8-9 documents the risk-level threshold determinations for each potential risk, discussed in *Sections 8.6.1* and *8.6.2*, respectively, through a risk-matrix analysis process. The risk assessment results and corresponding financial assurance cost estimates are summarized in Table 8-9. The detailed risk assessment table is included in *Appendix I-9*.

[5] https://hazards.fema.gov/nri/map

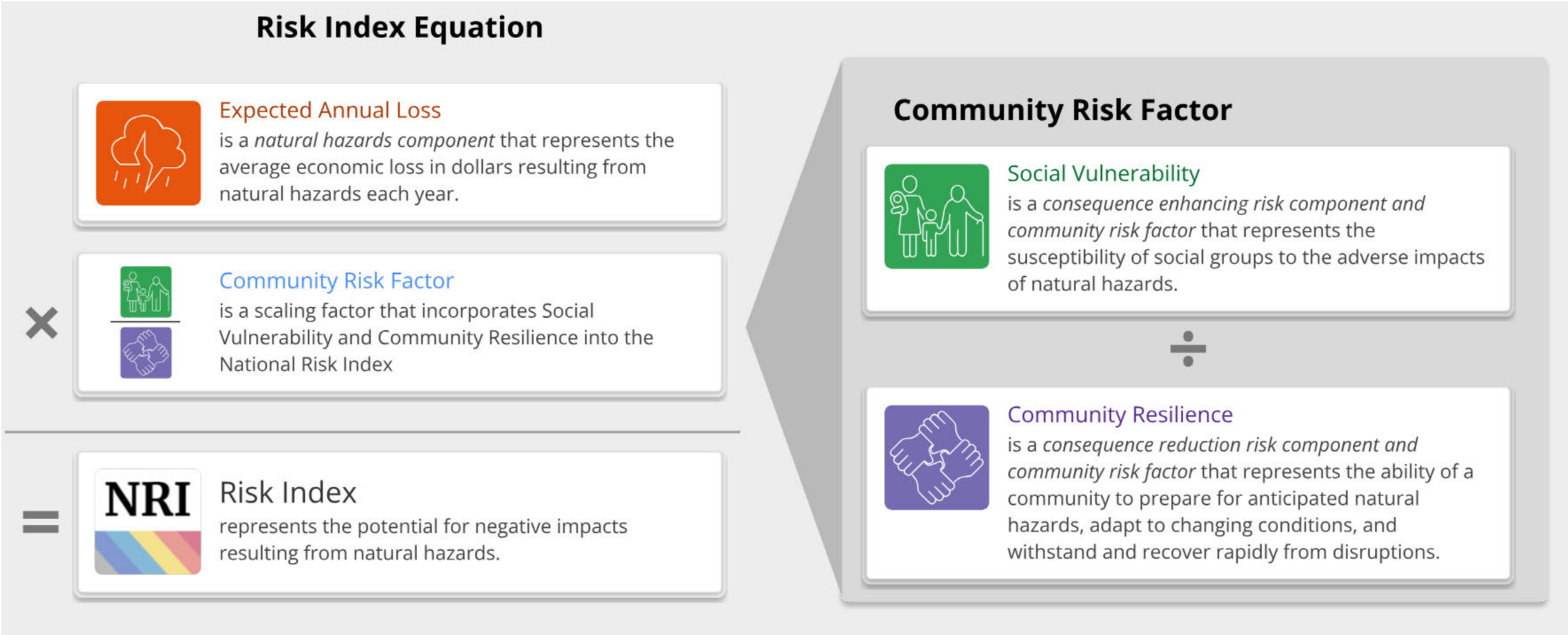

Figure 8-7 – FEMA risk index equation details[6].

[6] https://hazards.fema.gov/nri/determining-risk

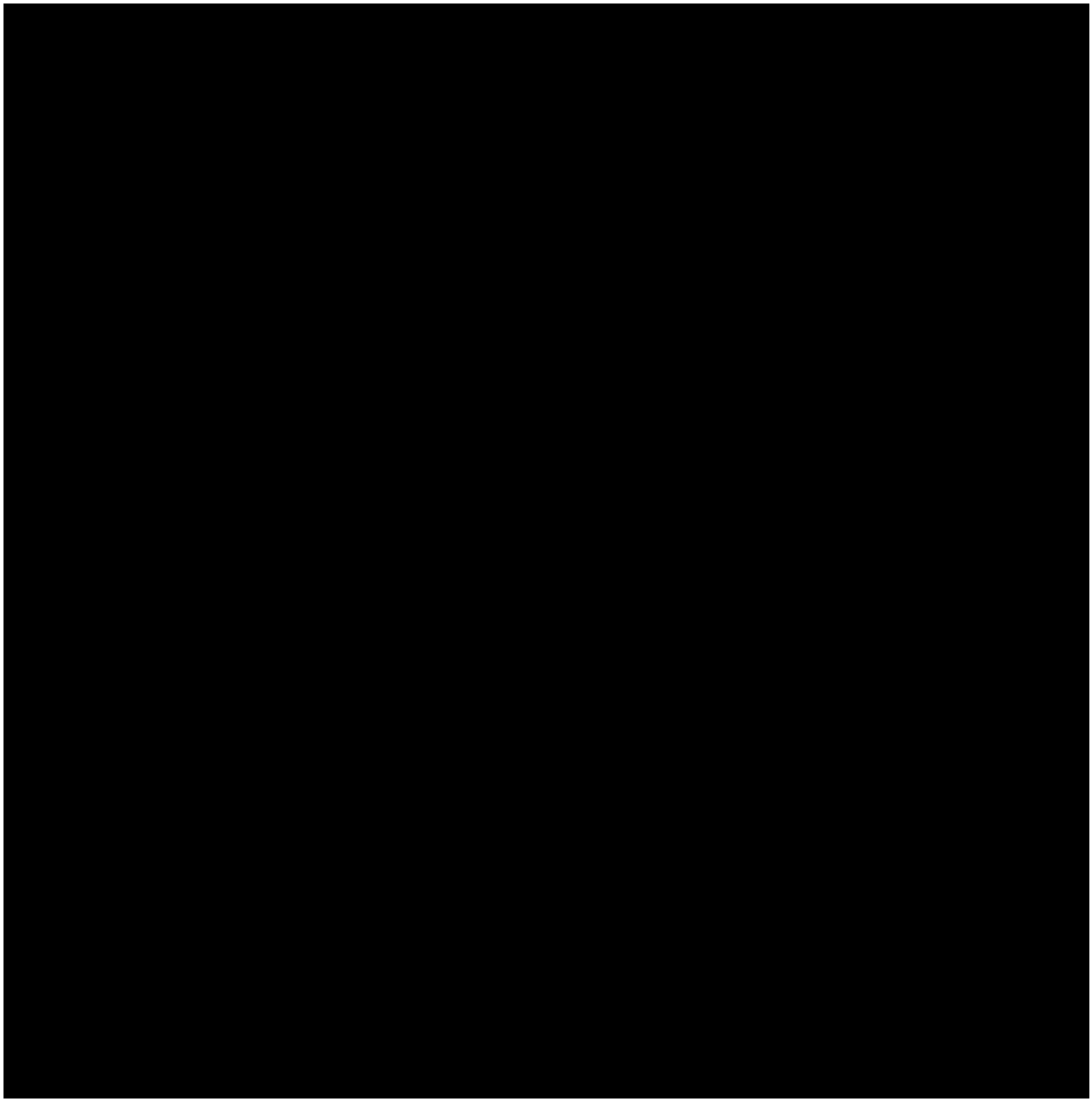

Figure 8-8 – Risk assessment scores.

Figure 8-9 – Risk scores, level, and mitigation classification.

Table 8-9 – Risk assessment summary table.

8.8 Staff Training and Exercise Procedures

An emergency training schedule will be developed and implemented by Operator's Health, Safety, and Environment (HSE) organization based on requirements in this ERRP and the supplemental Tier 1 Emergency Response Plan. The training program is developed to ensure that there are adequate competent personnel to provide continuous response capability—and that all designated personnel are effective and proficient in the principles and processes of their assigned incident management role.

8.9 Communications Plan and Emergency Notification Procedures

This emergency contact list will be updated and maintained throughout the Project life cycle and will be comprised of all applicable leadership and essential personnel that would be notified, activated, and/or deployed in the event of an emergency. Operator will provide an updated project contact list, including facility contacts, to appropriate parties (i.e., UIC Director and local first responders) prior to commencing drilling operations. The contact numbers are provided in Tables 8-10 through 8-12.

Table 8-10 – Operator contacts.

[redacted]

Table 8-11 – Emergency services – in the event of an emergency, **CALL 911**.

Agency	Telephone Number
Refugio County Volunteer Fire Department	911 or 361-526-2114
Refugio County Sheriff	911 or 361-526-2352
Town of Refugio Police Department	911 or 361-526-4533
Refugio County Memorial Hospital	911 or 361-526-2321
Refugio County Office of Emergency Management	361-526-2820
Aransas County Sheriff	911 or 361-729-2222
Aransas Pass Police Department	911 or 361-758-5224
Coastal Plain Local Emergency Planning Committee	361-587-3560
Texas Department of Public Safety	512-424-2000
EPA National Response Center	800-424-8802

Table 8-12 – Government agency notification.

Agency	Telephone Number
EPA Region 6	214-665-2102
EPA Region 6 UIC Class VI Contacts	214-665-7252 (Brandon Maples) 214-665-7435 (Arnold Bierschenk)
Texas Commission on Environmental Quality	512-239-6075
Railroad Commission of Texas UIC Contacts	512-463-3011 (Ivan Salas) 512-239-6075 (Bryan Smith)
EPA National Response Center (NRC)	800-424-8802
Texas General Land Office – Coastal Resources	512-475-0773
Texas Department of Public Safety	409-924-5466
Texas Fish and Wildlife Service	512-353-0011

8.10 Communication Strategy

Operator will provide the following information to adjacent landowners prior to the commencement of CO_2 injection operations:

- A summary of potential Project emergency response plans
- Project-specific emergency contact list

Operator will communicate with impacted surface owners and/or the public regarding events that require an emergency response, as appropriate. The amount of information, timing, and communications method(s) will be dependent on the specific event, its severity, whether impacts to drinking water or other environmental resources occurred, and impacts to nearby communities. Information to be provided may include the following:

- Description of the event that required emergency response
- Event severity
- Impacts to the environment or drinking water sources
- Description of how the event was investigated
- Actions taken or planned to mitigate the event
- Current status of Operator's response

Operator will also communicate with entities that may need to be informed about, or act in response to, the event. These entities include but are not limited to the local water systems' operator, pipeline operators, landowners, and regional response teams (as part of the National Response Team).

8.11 Plan Review Process

This ERRP will be reviewed as follows:

- At least once every 5 years following its approval by the permitting agency
- Within 1 year of any AOR reevaluation
- Within 1 year of either any significant changes to the injection process or the injection facility—or an emergency event
- As required by the permitting agency

If the review indicates that no amendments to the ERRP are necessary, Operator will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments will be made and submitted to the permitting agency within the time frame agreed to by affected parties (i.e., Operator, regulators, etc.).

The following attachments are located in *Appendix I*:

- Appendix I-1 Injection Well Locations Map
- Appendix I-2 Above-Zone Monitoring Well Map
- Appendix I-3 USDW Monitoring Well Locations Map
- Appendix I-4 In-Zone Monitoring Well Locations Map
- Appendix I-5 AOR with Groundwater Wells Map
- Appendix I-6 Emergency Response Capacity Map
- Appendix I-7 FEMA National Risk Index Report – Aransas County
- Appendix I-8 FEMA National Risk Index Report – Refugio County
- Appendix I-9 Risk Assessment Table

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 9 – FINANCIAL RESPONSIBILITY

July 2024

SECTION 9 – FINANCIAL RESPONSIBILITY

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9.1 Project Information

Project Site Name: ConocoPhillips Gulf Coast CCS (Project)

Project Operator: ConocoPhillips Texas Gulf Coast CCS LLC (Operator)

Project Contact: [redacted]

Project Location:

Table 9-1 – Injection well location coordinates.

Well Name	County	Latitude (NAD 83)	Longitude (NAD 83)
Snapper North INJ 1	[redacted]		
Snapper North INJ 2			
Snapper North INJ 3			
Snapper South INJ 1			
Snapper South INJ 2			
Snapper South INJ 3			

*NAD – North American Datum of 1983

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 capture and storage (CCS) wells are required to demonstrate financial responsibility for associated activities. Operator plans to construct six Class VI injection wells for the purpose of permanently storing [redacted] CO_2.

Consistent with these regulatory requirements, Operator prepared this document to demonstrate financial responsibility for the Project injection wells. The following sections summarize cost estimates, Project activities, and the qualifying financial instrument(s) Operator plans to use to demonstrate financial responsibility for the following Project elements:

1. Corrective Action
2. Injection Well Plugging
3. Post-Injection Site Care (PISC) and Site Closure, Including Monitoring Well Plugging
4. Emergency and Remedial Response

9.3 Financial Assurance Demonstration

[redacted]

9.3.1 Estimated Coverage Summary

The total current cost estimate for all storage activities necessitating financial assurance for the Project is [redacted] in 2024 dollars. Table 9-2 summarizes the estimated financial responsibility costs by activity, funding milestone, and Project phase.

Table 9-2 – Financial responsibility cost estimate summary and funding timing.

Financial Responsibility Element	Cost Estimate	Funding Timing	Project Phase
Corrective Action	[redacted]		
Injection Well Plugging			
Post-Injection Site Care Testing and Monitoring			
Monitoring Well Plugging			
Site Remediation/Closure			
Emergency and Remedial Response			
TOTAL			

The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the permit application process and were reviewed by a third party. The estimated 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.

[redacted]

[redacted]

9.4 Corrective Action

[redacted]

[redacted]

[redacted]

[redacted]

9.5 Injection Well Plugging

Plugging and abandonment (P&A) of the Project injection wells will meet the requirements of 16 TAC **§5.203(k)** [40 CFR **§146.92**] and be designed so that no movement of fluids occur from the injection interval to a non-injection interval. More detailed P&A plans are outlined in *Section 6 – Well Plugging Plan*.

[redacted]

[redacted]

Table 9-3 – Injection well plugging cost estimate summary.

[redacted]

9.6 Post-Injection Site Care and Site Closure

The PISC and Site Closure Plan was designed to meet the requirements of 16 TAC **§5.206(k)** [40 CFR **§146.93**]. The costs associated with the plan are highlighted in Tables 9-4 and 9-5, 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 7*, Operator will monitor the site for 50 years post-injection, or until the UIC Director or other governmental authority with jurisdiction concurs that the Project no longer poses an endangerment to the Underground Source of Drinking Water (USDW)—or Operator transfers the monitoring obligation to a governmental authority. Post-injection monitoring activities include direct and indirect CO_2 plume and pressure front monitoring as well as monitoring of above-zone conditions. [redacted]

Direct reservoir monitoring, both pressure and temperature, will occur through the injection wells until they are plugged and within the in-zone monitoring (IZM) wells. As it is currently planned, indirect monitoring through 2D seismic surveying will occur [redacted] to monitor plume drift. Operator will work with the UIC Director to determine frequency, method, and scope of post-injection seismic surveying efforts. At least every 5 years, the 3D subsurface models and reservoir simulations for pressure and CO_2 plume prediction will be updated and constrained with direct and indirect monitoring data during the post-injection period.

Additionally, USDW and above-zone fluid monitoring (fluid sampling and geochemical analysis) will occur [redacted] in each of the [redacted] USDW and above-zone monitoring (AZM) wells. Formation pressure and temperature will be continuously monitored via downhole gauges in each of the [redacted] AZM wells [redacted]

The costs detailed in Table 9-4 are provided to cover all post-injection monitoring costs.

Table 9-4 – Post-injection monitoring cost estimate summary.

[redacted]

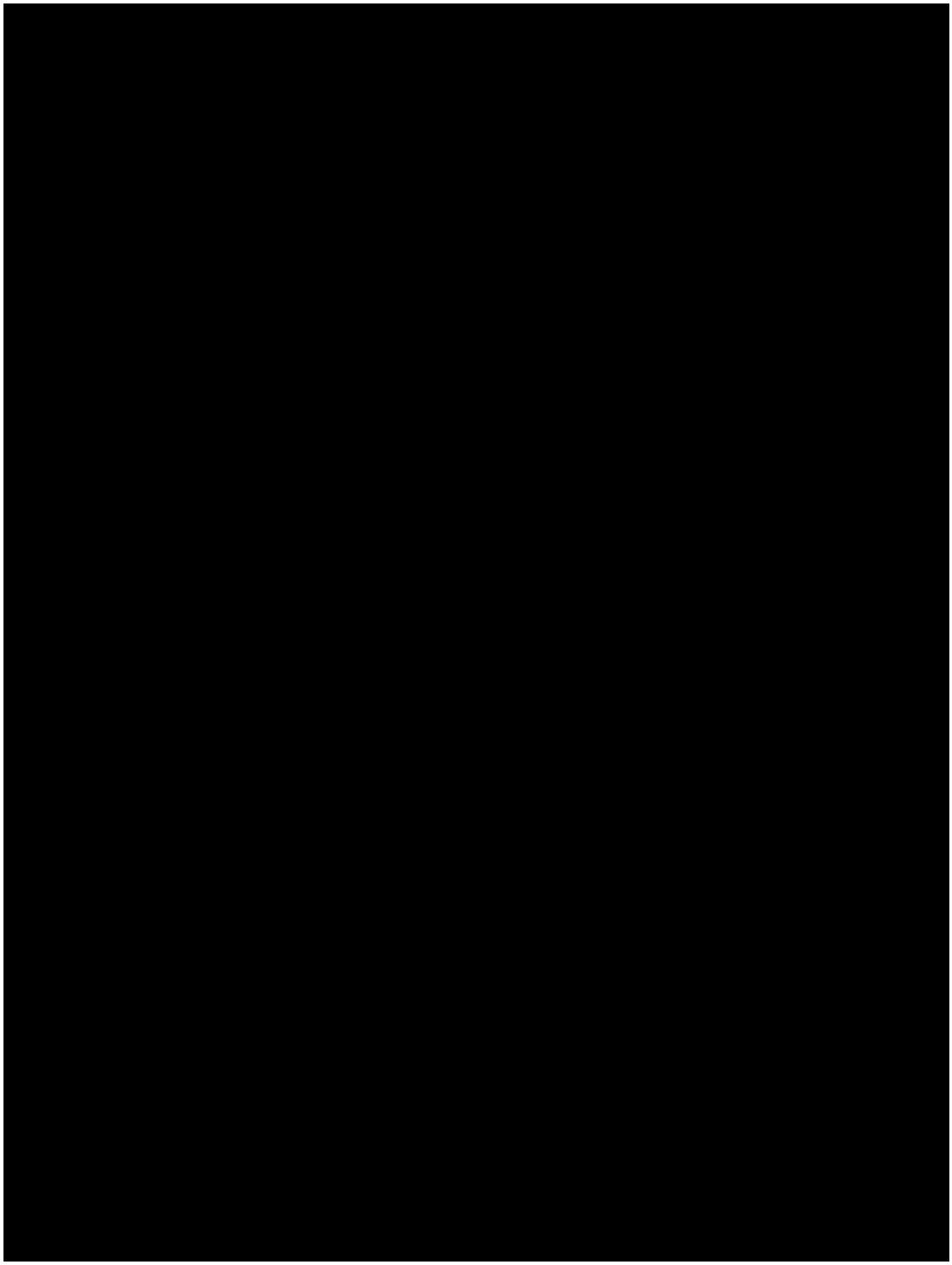
9.6.2 Monitoring Well Plugging

The P&A of the Project monitoring wells will also meet the requirements of 16 TAC **§5.203(k)** [40 CFR **§146.92**]. The P&A of these monitoring wells will be designed so that no movement of fluids will occur from the injection interval to a non-injection interval, and the USDWs will be protected. More detailed P&A plans are outlined in *Section 6 – Well Plugging Plan.*

[redacted]

[redacted]

Table 9-5 – Monitoring well plugging cost estimate summary.



9.6.3 Site Closure

Site closure will occur when the UIC Director releases Operator from all PISC duties. The costs estimated in Table 9-6 reflect the amount expected to decommission and close the site. [redacted]

[redacted]

Table 9-6 – Site closure cost estimate summary.

[redacted]

9.7 Emergency and Remedial Response

The Emergency and Remedial Response Plan discussed in *Section 8 – Emergency and Remedial Response Plan* is designed to comply with 16 TAC **§5.203(l)** [40 CFR **§146.94**].

The resultant estimated cost for emergency and remedial response is [redacted] in 2024 dollars. [redacted] Cost estimate details are explained in *Section 8*.

9.8 Financial Assurance Updates

In accordance with 16 TAC **§5.205(c)** [40 CFR **§146.85(c)**], Operator will adjust the cost estimate for inflation within 60 days prior to the anniversary date [redacted] and provide this adjustment to the UIC Director during the active life of the Project. Operator will also provide written updates of adjustments to the cost estimate within 60 days of any amendments to the Area of Review and Corrective Action Plan, the Injection Well Plugging Plan, the PISC and Site Closure Plan, and the Emergency and Remedial Response. [redacted]

In accordance with 16 TAC **§5.205(b)(1)**, Operator will provide annual evidence of financial responsibility satisfactory to the UIC Director or their designee for review and approval, including annual written updates of any increases or decreases to the cost estimates. In addition, Operator will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Director or their designee.

9.9 Conclusion

State and federal regulations require the owner and Operator of the six proposed Class VI wells to demonstrate financial responsibility for the Project. The information contained in this section details the instrument(s) Operator will utilize to prove its financial assurance to properly execute operations and uphold regulations throughout the life of the project. Operator will secure the appropriate financial assurance instrument(s) before the timing milestones outlined in Table 9-2—and maintain financial responsibility and resources until the UIC Director or designee receives and approves the completed PISC and Site Closure Plan, and approves final site closure.

These documents, in addition to the information contained in this section, fulfill Operator's responsibilities to ensure financial assurance.

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

SECTION 10 – ENVIRONMENTAL AND COMMUNITY IMPACT ANALYSIS

July 2024

SECTION 10 – ENVIRONMENTAL AND COMMUNITY IMPACT ANALYSIS

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10.1 Executive Summary

ConocoPhillips Texas Gulf Coast CCS (carbon capture and storage) LLC (Operator) selected the CO_2 storage project site in Refugio and Aransas Counties, Texas (Project) based on favorable geology for permanent storage. The monitoring program and wellbore construction plan are designed in accordance with regulatory standards intended to safeguard the Underground Source of Drinking Water (USDW). The Project has 6 planned injection wells and will inject up to [redacted] Operator will monitor the site following the cessation of injection operations to delineate the evolution of the CO_2 plume and pressure front for 50 years post-injection—or until the Underground Injection Control (UIC) program director (UIC Director) determines that the Project does not pose endangerment to USDWs based on monitoring and other site data, or until Operator transfers the monitoring obligation to a governmental authority. The planned injection wells will be located on private property, and the CO_2 will be injected and stored in subsurface pore space. The Project site was selected with consideration of critical factors such as surface and subsurface constraints, distance from communities and occupied structures, topography, and proximity to emission sources to minimize or mitigate potential environmental impacts.

Operator is committed to meaningful engagement with stakeholders to understand their unique values and interests. Operator strives to integrate community input into its Project plans and operations, reduce the impact of its operations as feasible, and seek opportunities to contribute to economic and community development. An open dialogue with stakeholders such as community members and organizations, government entities, academic institutions, and other community partners will be maintained throughout the life of the Project.

10.2 Project Location

As described in further detail in *Section 3 – AOR and Corrective Action Plan*, the Project's area of review (AOR) is based on the greater of two components: (1) the anticipated CO_2 plume (the extent underground, in 3D, of an injected CO_2 stream); and (2) the associated pressure front (the zone of elevated pressure created by the injection of CO_2 into the subsurface). The AOR totals [redacted] square miles (sq mi) and encompasses portions of southern Refugio County, Texas and northwestern Aransas County, Texas. The AOR is located within the Coastal Zone boundary, as defined by the Texas Coastal Management Plan. Figure 10-1 is an aerial reference map of the Project location, centered on the AOR.

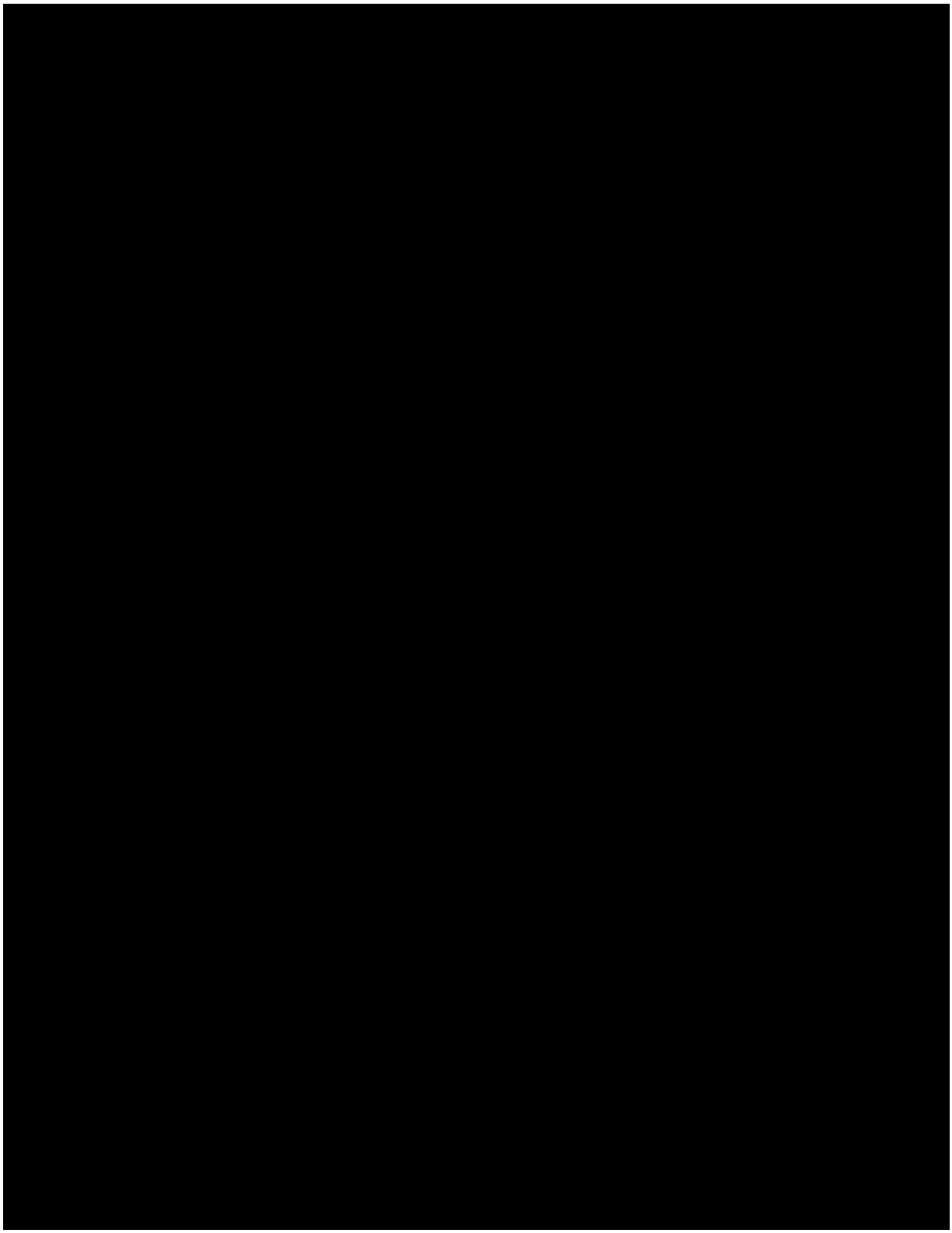


Figure 10-1 – Project location map.

The Project's anticipated CO_2 plume is contained beneath rural property owned by private landowners, who utilize the property primarily for hunting and cattle operations. [redacted]

The topography of the AOR is generally flat, undeveloped land covered with tall prairie grasses and scattered pockets of dense mesquite and brush. Wetlands are intermittently scattered throughout the AOR.

There are no permanent residents within the AOR. Buildings within the AOR are limited to structures such as barns or cattle enclosures, owned solely by the private landowners. [redacted]

Nearby communities include Holiday Beach [redacted] and the town of Refugio [redacted] *Section 10.4.1* provides additional details about these communities. Corpus Christi is approximately [redacted] southwest of the AOR.

[redacted] Figure 10-2 identifies the planned well locations and existing access roads.

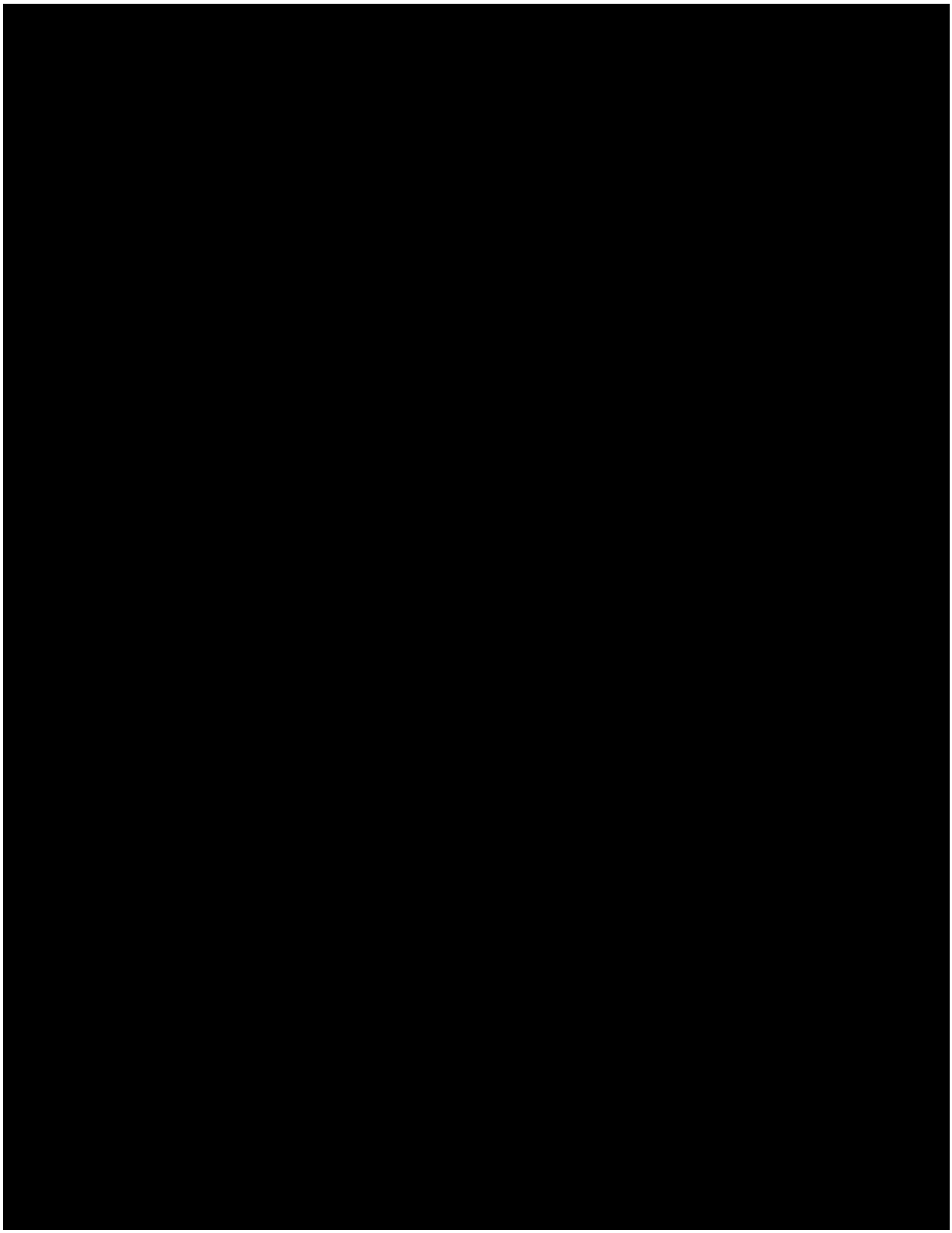


Figure 10-2 – Planned well locations and existing access roads.

10.3 Environmental Justice

The EPA defines environmental justice (EJ) as the "just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, tribal affiliation, or disability, in agency decision-making and other federal activities that affect human health and the environment so that people:

- are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards, including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers; and

- have equitable access to a healthy, sustainable, and resilient environment in which to live, play, work, learn, grow, worship, and engage in cultural and subsistence practices."[1]

Identified EJ communities include populations of color, low-income populations, Native American Tribes, and/or indigenous communities.

The Project location was selected in part due to its rural location and limited, dispersed population. As discussed in *Section 10.2*, there are no permanent residents, and therefore no affected communities with potential EJ concerns, within the AOR.

10.3.1 EJScreen Summary

In accordance with EPA guidance, Operator utilized the EPA's EJScreen tool (version 2.3) to evaluate the AOR for possible adverse impacts to potential EJ communities. The standard unit of analysis in EJScreen is the census block group. Using EPA's EJScreen tool, screening buffers "aggregate appropriate portions of the intersecting block groups, weighted by population, to create a representative set of data for the entire [EJScreen buffer] area, honoring variation and dispersion of the population in the block groups within it. For each indicator, the result is a population-weighted average, which equals the block group indicator values averaged over all residents who are estimated to be inside the buffer."[2]

Per the EPA's *Environmental Justice Guidance for UIC Class VI Permitting and Primacy* (Aug. 17, 2023) memorandum on selecting an appropriate EJScreen buffer, Operator applied the EJScreen to the Project's AOR. However, because no permanent residents live within the AOR, the EJScreen tool issued an error message, as shown in Figure 10-3.

[1] Executive Order 14096 (88 FR 25251, April 21, 2023) https://www.epa.gov/environmentaljustice
[2] https://www.epa.gov/ejscreen/how-interpret-ejscreen-data

Figure 10-3 – AOR EJScreen error message.
(July 11, 2024)

While the results of the EJScreen were indicative of the rural setting of the AOR, to implement the purpose and thought behind the EPA's guidance, Operator conservatively elected to expand the EJScreen to screen for potential vulnerabilities of and baseline environmental exposures for people living nearby. [redacted] The expansion of Operator's EJScreen area demonstrates a conservative and good faith effort to incorporate adjacent populations and ensure EJ communities are adequately identified for consideration.

The final Expanded EJScreen Area covers [redacted] in Refugio and Aransas counties [redacted] and identified a population of [redacted] people inside the buffer. The Expanded EJScreen Area is shown in comparison to the AOR on Figure 10-4, and the entire EJScreen Report is attached as *Appendix L-1*.

[redacted]

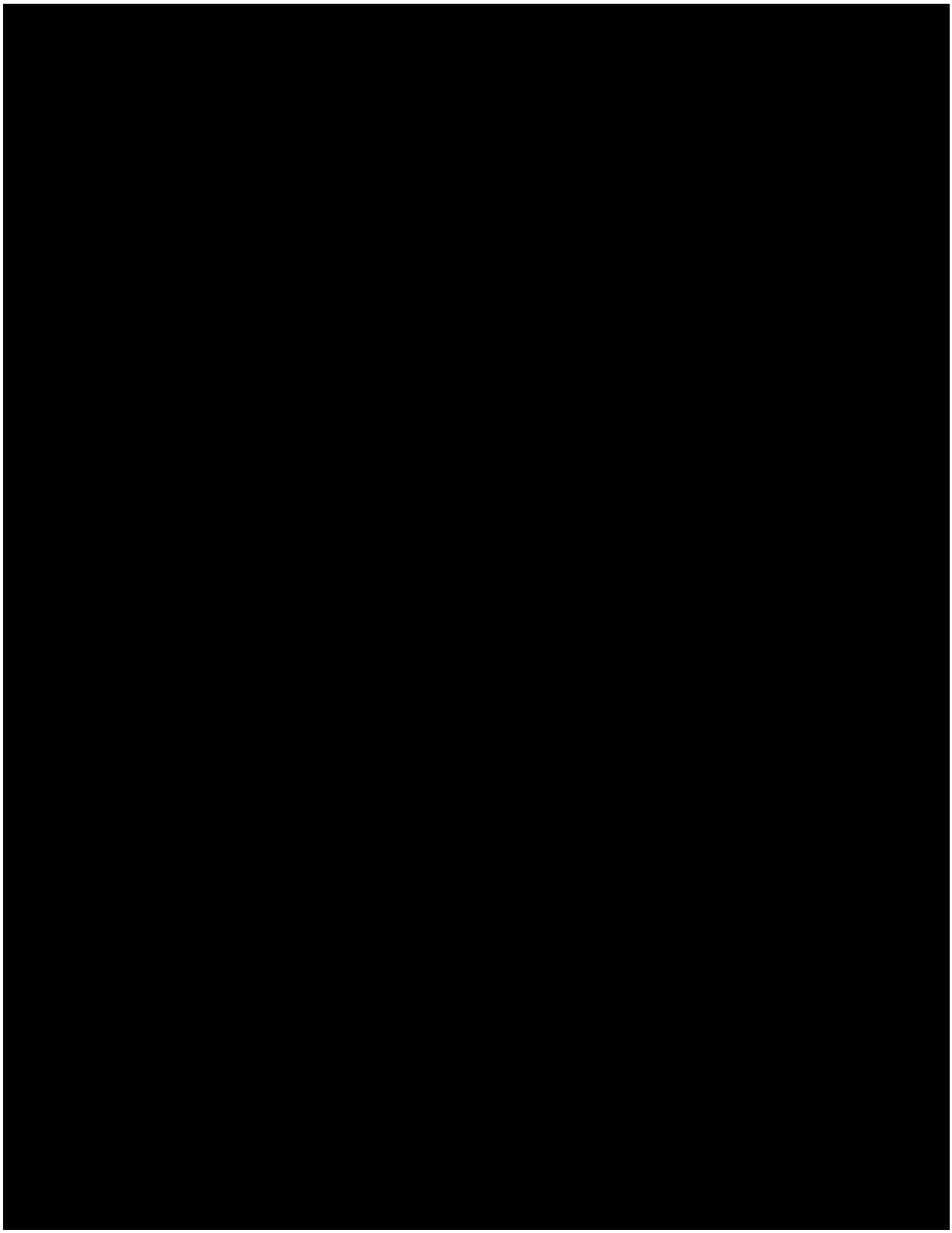


Figure 10-4 – Map of Expanded EJScreen Area with AOR.

10.3.2 EJ Indices

The EPA's EJScreen tool employs a framework of 13 EJ demographic 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 two socioeconomic indicators, low-income and minority populations, with corresponding environmental indicators.

Unlike a cumulative scoring approach, each EJ Index is derived through the multiplication of the percentile rank of an environmental indicator with the standard demographic index. The standard demographic index represents the mean percentile ranks of low-income and minority 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.

The percentiles detail the percent of the Texas and U.S. populations that *have equal or lower values*, meaning less potential for exposure, risk, or proximity to certain facilities, or a lower-percent minority.

The EJScreen provides screening-level indicators, not a determination of the existence or absence of EJ concerns.[4] Per the EPA's "How to Interpret EJScreen Data" website[5], an initial screening point for EJ indices has been established at the 80th percentile relative to state and national averages (i.e., an area with any of the 13 EJ Indexes at or above the 80th percentile nationally should be considered as a potential candidate for further review). The 80th percentile threshold is not intended to formally designate EJ communities.

The EJ Index results from the EJScreen are provided in Table 10-1.

[4] The EPA cautions that EJScreen should not be used as a means to identify or label an area as an "EJ community," to quantify specific risk values for a selected area, to measure cumulative impacts of multiple environmental factors, or as the sole basis for making a determination regarding the existence or absence of EJ concerns. https://www.epa.gov/ejscreen/how-does-epa-use-ejscreen.

[5] https://www.epa.gov/ejscreen/how-interpret-ejscreen-data#:~:text=In%20EJScreen%2C%20if%20your%20results,of%20the%20US%20population%20lives.

Table 10-1 – EJ Index measurements (Expanded EJ Screen Area).

EJ Index	State Percentile	U.S. Percentile
Particulate Matter (2.5)		
Ozone		
Nitrogen Dioxide (NO_2)		
Diesel Particulate Matter		
Toxic Releases to Air		
Traffic Proximity		
Lead Paint		
Superfund Proximity		
Risk Management Plan (RMP) Facility Proximity		
Hazardous Waste Proximity		
Underground Storage Tanks		
Wastewater Discharge		
Drinking Water Non-Compliance		

In the Expanded EJScreen Area, none of the thirteen EJ Index measurements exceed the EPA's 80th percentile guidance compared to state or national levels.

Additionally, the EPA computes 13 supplemental EJ indices ("Supplemental EJ Index"). The Supplemental EJ Index also incorporates the low-income socioeconomic indicator into the supplemental demographic index calculations—but replaces the people of color socioeconomic indicator with four others: percentage of population with disabilities, percentage of limited English-speaking households, percentage of population with less than a high school education, and low life expectancy.

The Supplemental EJ Index is determined by the multiplication of the calculated supplemental demographic index with the same 13 environmental indicators as the standard EJ Indices, followed by the identification of the percentile ranks. The Supplemental EJ Index offers further insight into the vulnerability of communities.

The Supplemental EJ Index results are presented in Table 10-2.

Table 10-2 – Supplemental EJ Index measurements (Expanded EJScreen Area).

Supplemental EJ Index	State Percentile	U.S. Percentile
Particulate Matter (2.5)	[redacted]	[redacted]
Ozone		
Nitrogen Dioxide (NO_2)		
Diesel Particulate Matter		
Toxic Releases to Air		
Traffic Proximity		
Lead Paint		
Superfund Proximity		
RMP Facility Proximity		
Hazardous Waste Proximity		
Underground Storage Tanks		
Wastewater Discharge		
Drinking Water Non-Compliance		

In the Expanded EJScreen Area, none of the thirteen Supplemental EJ Index measurements exceed the EPA's 80th percentile guidance compared to state or national levels.

10.3.3 Socioeconomic Indicators

The White House Council on Environmental Quality (CEQ) provides two methods for determining whether an affected area contains low-income or minority populations. One is the "Fifty Percent" threshold, and the other is the "Meaningfully Greater" standard. Operator used the Expanded EJScreen Area as the affected area for purposes of these analyses.

- **Fifty Percent Threshold Analysis**: If the ratio of low-income or minority populations of the area of analysis equals or exceeds 50% of the total population of the area of analysis, then increased scrutiny in Operator's EJ analysis may be appropriate. The socioeconomic indicators for the Expanded EJScreen Area are displayed in Table 10-3.

Table 10-3 – Socioeconomic indicator 50% threshold analysis.

Area	Minority Population (People of Color)	Low-Income Population	Unemployment Rate	Limited English-Speaking Households	Less Than High School Education	Low Life Expectancy
United States	40%	30%	6%	5%	11%	20%
State of Texas	58%	34%	5%	8%	16%	20%
Expanded EJScreen Area	[redacted]					

[redacted]

- **Meaningfully Greater Analysis**: This analysis compares the [redacted] Expanded EJScreen Area to an appropriate larger reference area (i.e., the entirety of Aransas and Refugio Counties) [redacted] The Meaningfully Greater analysis requires use of a reasonable, subjective threshold above the reference area. [redacted]

Table 10-4 – [redacted]

[redacted]

[redacted]

[6] Aransas County EJ Screen Community Report (run July 11, 2024)
[7] Refugio County EJ Screen Community Report (run July 11, 2024)

[redacted]

10.3.4 Health Disparities, Climate Change Indicators, and Critical Service Gaps

Several new map layers outlining health disparities, climate change indicators, and critical service gaps were added to the EPA's EJScreen tool in 2023 (version 2.2) and 2024 (version 2.3). [redacted]

[redacted]

10.3.5 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. These areas include, but are not limited to, hospitals, churches, 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 exist within the Project AOR. [redacted]

[redacted]

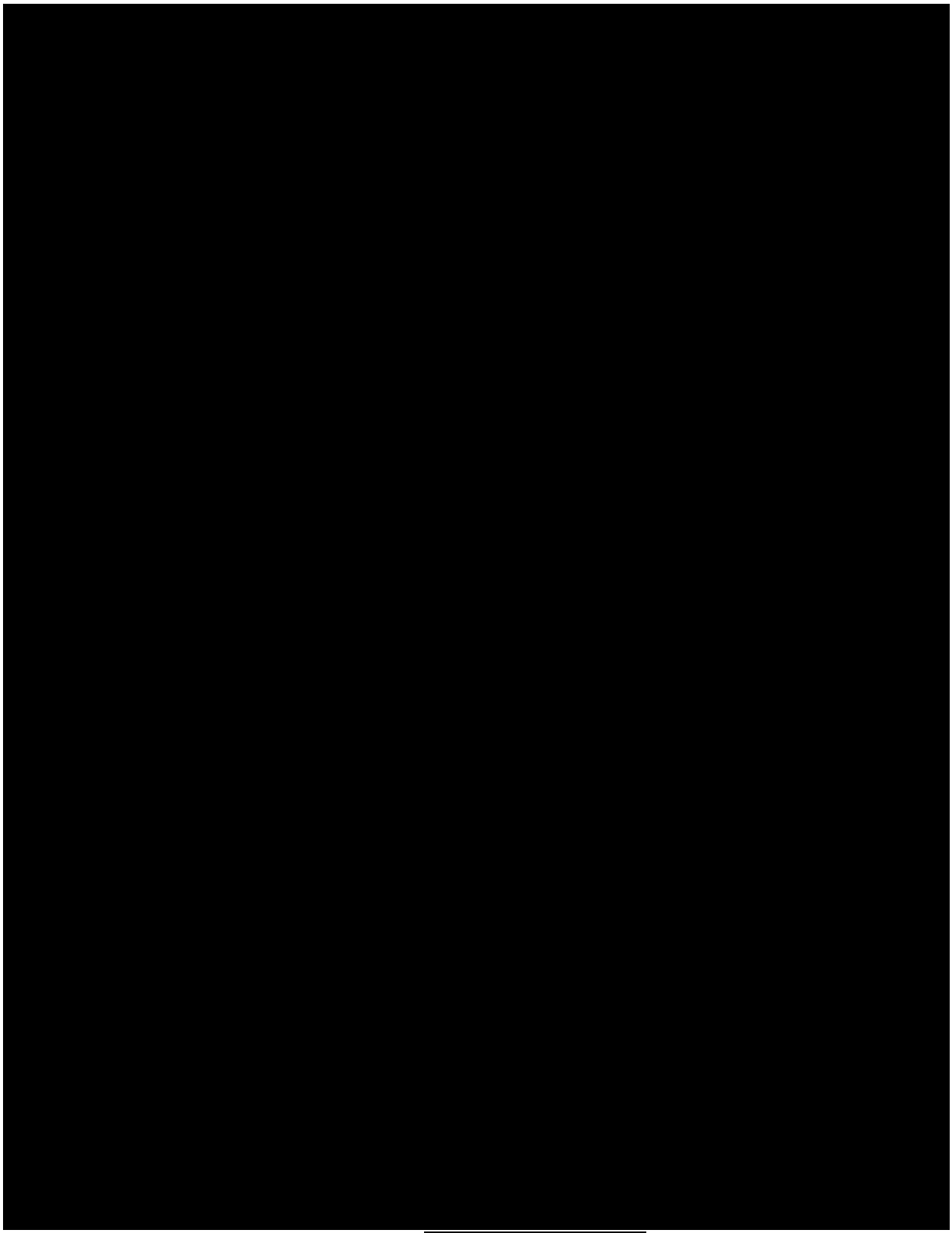


Figure 10-5 – [redacted]

10.3.6 EJ Guidance Themes

Table 10-5 summarizes the five primary themes of the EPA's *Environmental Justice Guidance for UIC Class VI Permitting and Primacy* (Aug. 17, 2023) memorandum and how Operator intends to address the guidance.

Table 10-55 – EJ guidance themes.

Theme	Guidance	Operator 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 AOR 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.	• Operator conducted an EJScreen assessment as part of this Class VI application (*Section 10.3* and *Appendix L-1*) preparation. When the AOR was used as the EJScreen boundary, EJScreen did not yield results due to sparse population within the boundary. The Expanded EJScreen Area includes the AOR plus a [redacted] buffer [redacted] • Operator compiled and will update a list of potential stakeholders. A community outreach log will be maintained. • Operator's community engagement plan is described in *Section 10.4*.
Enhance public involvement	UIC programs should encourage owner/operators to conduct community outreach early for all Class VI permit applications, regardless of apparent EJ concerns. Activities to consider are as follows: • 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.	• Operator will engage with the community throughout the permitting process and Project life as outlined in *Section 10.5*. • Early engagement with local community leaders and emergency responders is underway and will continue throughout the permitting process.
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	[redacted]

	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.	[redacted]
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.	• Operator will comply with applicable reporting regulations and collaborate with regulators on efforts to enhance transparency.

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 cleanup 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 the following: o Training for local responders while training facility staff to respond to emergencies at the facility. 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.	• As discussed in *Section 5* (Testing and Monitoring), Operator will install monitoring and notification systems across the Project site. • Operator collaborated with local emergency responders during development of the Emergency Response and Remediation Plan (*Section 8*) to address potential emergency events and ensure local responders and company personnel feel adequately trained and equipped to respond to potential scenarios. • Operator will continue to engage with the community to ensure its notification protocols are detailed and adequate in the event of an emergency. • Operator developed linguistically diverse communication mechanisms for community input, including a toll-free phone number, Project email address, and dedicated website.

10.4 Project Impact Analysis

As noted in *Section 10.3*, no EJ community was identified by the EJScreen within the AOR for the proposed injection wells. However, Operator considered potential Project impacts on nearby communities beyond the AOR. This analysis is outlined below ("Project Impact Analysis") and is comprised of the following three separate components:

- Community Impact Assessment (*Sec. 10.4.1*)
- Emergency Response Capacity (*Sec. 10.4.2*)
- Potential Project Impacts (*Sec. 10.4.3*)

Operator's Project Impact Analysis and the EJScreen results provided the foundation for Operator's community engagement strategy, described in detail in *Section 10.5.2*.

10.4.1 Community Impact Assessment

The Community Impact Assessment studies nearby communities, considering existing social (demographic, socioeconomic, historical, and cultural) and environmental characteristics and the anticipated Project scope.

The Project is situated on rural private property in south Texas. The Project AOR includes lands in both Refugio and Aransas counties.

Refugio County

Refugio County has a population of 6,822 as of 2021, decreasing approximately 8% since 2010 (U.S. Census Bureau 2021). Refugio County is predominantly White (76%), with smaller percentages of Black or African American (7%), Native American (1.3%), Asian (1%), Other Races (4%), and Multiracial (1.7%). Approximately 52.6% of the population identifies as Hispanic or Latino*. The town of Refugio is the largest town in Refugio County.

**Note that these racial demographics do not include Hispanic. On U.S. Census tracking, Hispanic is not limited to a single race.*

Refugio County's median age is approximately 34 years. Socioeconomically, Refugio County has a median household income of approximately $51,152, accompanied by a poverty rate of approximately 21%. Education attainment varies with 11.2% holding a bachelor's degree or higher, and 83.8% completing high school (or a high school equivalent). The average household size is approximately 3 people, with a homeownership rate of around 59.8%. Agriculture and oil-and-gas activities are the predominate Refugio County land uses.

Refugio County, initially inhabited by the Karankawa Indians, saw the establishment of a Spanish mission in 1793. After Mexico gained independence, Anglo-American immigration increased and in 1834, it was originally established as a municipality of Mexico. Following Texas independence,

Refugio County was among the original Texas counties but saw its territory decrease over time. The area became known for hide and tallow factories in the 1850s. Oil and gas discoveries in the 1920s transformed the county's economy, with production continuing to this day.

In August of 2017, Refugio County was hit especially hard by Hurricane Harvey. Because of the economic status of many residents along with the challenges of being a less populated county with limited resources, rebuilding efforts are still ongoing.

Aransas County

Aransas County has a population of 23,830 as of the 2021 U.S. Census, increasing approximately 7% from April 2020 to July 2023. Aransas County is predominantly White (87.4%), with smaller percentages of Black or African American (1.4%), Native American (0.6%), Asian (2.8%), Pacific Islander (0.1%), Other Races (5.3%), and Multiracial (2.4%). Approximately 20.3% of the population identifies as Hispanic or Latino*. Rockport is the largest city in Aransas County.

**Note that these racial demographics do not include Hispanic. On U.S. Census tracking, Hispanic is not limited to a single race.*

Aransas County's median age is approximately 51 years. Socioeconomically, Aransas County has a median household income of approximately $58,168, accompanied by a poverty rate of approximately 17.9%. Educational attainment varies, with 24.2% holding a bachelor's degree or higher, 7.1% earning an associate degree, and 31.8% completing high school (or a high school equivalent). The average household size is approximately 2.5 people, with a homeownership rate of around 79%.

Aransas County was officially established in 1871 by the Texas Legislature, carved out of parts of Refugio County. Before the establishment of the United States, Aransas County was home to a variety of indigenous people including the Aransas, Karankawa, and Coahuiltecans living as nomadic hunter-gatherers. Rockport is the county seat and became its administrative center, gaining prominence due to the cattle industry.

Aransas County faced significant challenges in August 2017 when Hurricane Harvey caused widespread damage. Rebuilding efforts are still ongoing. Similarly to Refugio County, a lack of available financial resources has slowed the recovery process.

Town of Refugio

The Project's location was selected in part due to its rural nature and limited populus. [redacted] The town of Refugio will potentially experience temporary heightened traffic and workforce increases during construction activities. In addition, the town of Refugio's emergency

responders and medical facilities may be utilized in the event of an emergency during Project construction or operations (described in more detail in *Section 10.4.2*).

The town of Refugio is the largest in Refugio County with a population of 2,728 (2022 census). The town of Refugio's population is currently declining 0.8% annually, and its population decreased by 0.9% since the most recent census count. The median age in the town of Refugio is 34.3 years. The town of Refugio is predominately White (59.7%), with smaller percentages of Black or African American (13.1%), Multiracial (23.2%), and Other Races (4.0%). Approximately 57.3% of the population identifies as Hispanic or Latino*.

**Note that these racial demographics do not include Hispanic. On U.S. Census tracking, Hispanic is not limited to a single race.*

The average household income in the town of Refugio is $68,932, with a poverty rate of 30.7%. The average household size is 3 people, with 54.7% owning their home and 45.3% renting. Approximately 44.2% of the population completed high school (or a high school equivalent), with an average income of $22,661. Within the town, 5.5% of the population has a bachelor's degree with an average income of $56,625.

Refugio Independent School district consists of three schools: Refugio Elementary School, Middle School, and High School. As of the 2021–2022 school year, 689 students were enrolled in all three schools. The district's enrollment is 80% minority and 53.1% of students are economically disadvantaged.

Holiday Beach

[redacted] Holiday Beach is a census-designated unincorporated community located in Aransas County established in the mid-1960s with a population of 526, according to the 2022 census[9]. The Expanded EJScreen Area conservatively included the full extent of Holiday Beach, utilizing the U.S. Census CDP boundaries, in its analysis.

Holiday Beach is approximately [redacted] from the Project site by road travel, and the community can be accessed via State Highway 35. Holiday Beach has 12 subdivision sections including Bayview, Belaire, Hillcrest, Mesquite Tree, Newcomb Bend, Northview, Oak Shores, Palmetto Point, St. Charles, Sherwood Downs, Southview, and Woodland Hills. Holiday Beach's public education is provided by Rockport-Fulton Independent School District, as there are no schools in Holiday Beach.

The median age is approximately 52 years old. Holiday Beach is 100% white. The average household income is $95,066 with a poverty rate of 7.9%. There are 262 housing units, 125 units owner-occupied and 137 units vacant for seasonal recreational use. Within the population of Holiday Beach, 92.8% graduated high school, and 11.9% have a bachelor's degree.

[9] https://www.statsamerica.org/town/

Tribal Nations and Indigenous Communities

According to the Texas Historical Commission, of the 29 federally recognized tribes, 3 are in Texas—but not within Refugio or Aransas Counties. Notwithstanding the fact that no formally recognized tribes currently exist within these counties, historically there was a tribal presence in the area. For example, the site of the present town of Refugio was a frequent camping ground of the Karankawa Indians, who later developed a permanent village there known as "Paraje de los Copanes" (Place of the Copanes, a Karankawan tribe). In addition, Comanche and Lipan Apache Indians were occasionally present in this area in the 19th century. While not federally recognized, several indigenous people groups are present in the region: The Indigenous Peoples of the Coastal Bend, the Society of Native Nations, and the Carrizo/Comecrudo Tribe of Texas. Operator intends to engage with these indigenous people groups to inform and gather their input.[10]

10.4.2 Emergency Response Capacity

In accordance with EPA EJ guidance, Operator assessed local emergency response capacity to identify potential Project impacts on local emergency resources. Early consultation with identified emergency service representatives was pivotal to the development of the Project's Emergency and Remedial Response Plan (*Section 8*) and will continue to inform Operator's supplemental Tier 1 Emergency Response Plan, responder training, equipment inventories, and educational awareness needs. Transparent engagement with this public service sector minimizes impacts on the community.

The closest hospital to the Project is the Refugio County Memorial Hospital (107 Swift Street, Refugio, TX 78377) in the town of Refugio. The hospital is a Basic (Level IV) trauma facility with a 24-hour emergency room. Refugio County Memorial Hospital has 20 hospital beds and 3 emergency room beds, and operates 4 rural health clinics throughout Refugio County. Corpus Christi has six designated trauma facilities, listed in Table 10-6.

[10] USA Counties in Profile: StatsAmerica Refugio, TX (tshaonline.org)
https://indigenouspeoplesofthecoastalbend.org/

Table 10-6 – Corpus Christi designated trauma facilities[11].

Corpus Christi Hospital	Trauma Designation
CHRISTUS Spohn Hospital Corpus Christi Shoreline	Major (Level II)
Corpus Christi Medical Center – Bay Area	Major (Level II)
Driscoll Children's Hospital	Advanced (Level III)
CHRISTUS Spohn Hospital Corpus Christi South	Basic (Level IV)
Corpus Christi Medical Center – Doctors Regional	Basic (Level IV)
Corpus Christi Medical Center – Northwest	Basic (Level IV)

The nearby communities are serviced by volunteer fire departments. The Refugio Volunteer Fire Department provides fire and rescue services for citizens of the town of Refugio and Refugio County, Texas. Aransas and Refugio counties are also serviced by the Coastal Plain Local Emergency Planning Committee (CPLEPC). The CPLEPC actively works to meet the requirements of the federal Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986. This work is performed strictly on a volunteer basis with industry and county government working together. The CPLEPC coordinates projects in the Aransas and Refugio County school districts, a shelter-in-place emergency preparedness campaign, and a "take-shelter and all-clear" emergency alert system—and also provides emergency information pamphlets and additional education materials.

Refugio and Aransas Fire Departments coordinate between counties and regularly conduct fire drills together. [redacted] Area law enforcement resources include the Refugio Police Department, the Refugio County Sheriff's Office, and the Aransas County Sherriff's department.

Aransas and Refugio counties utilize Code Red, an emergency notification system that sends voice or text messages to residents about issues of public concern. There is also an emergency notification radio station, 1610 AM, which broadcasts community emergency messages.

Operator continues to evaluate local emergency response capacity and supplemental, third-party options to ensure appropriate resources are available. Figure 10-6 shows the locations of nearby emergency response resources.

[11] https://www.dshs.texas.gov/dshs-ems-trauma-systems/trauma-system-development/texas-trauma-facilities

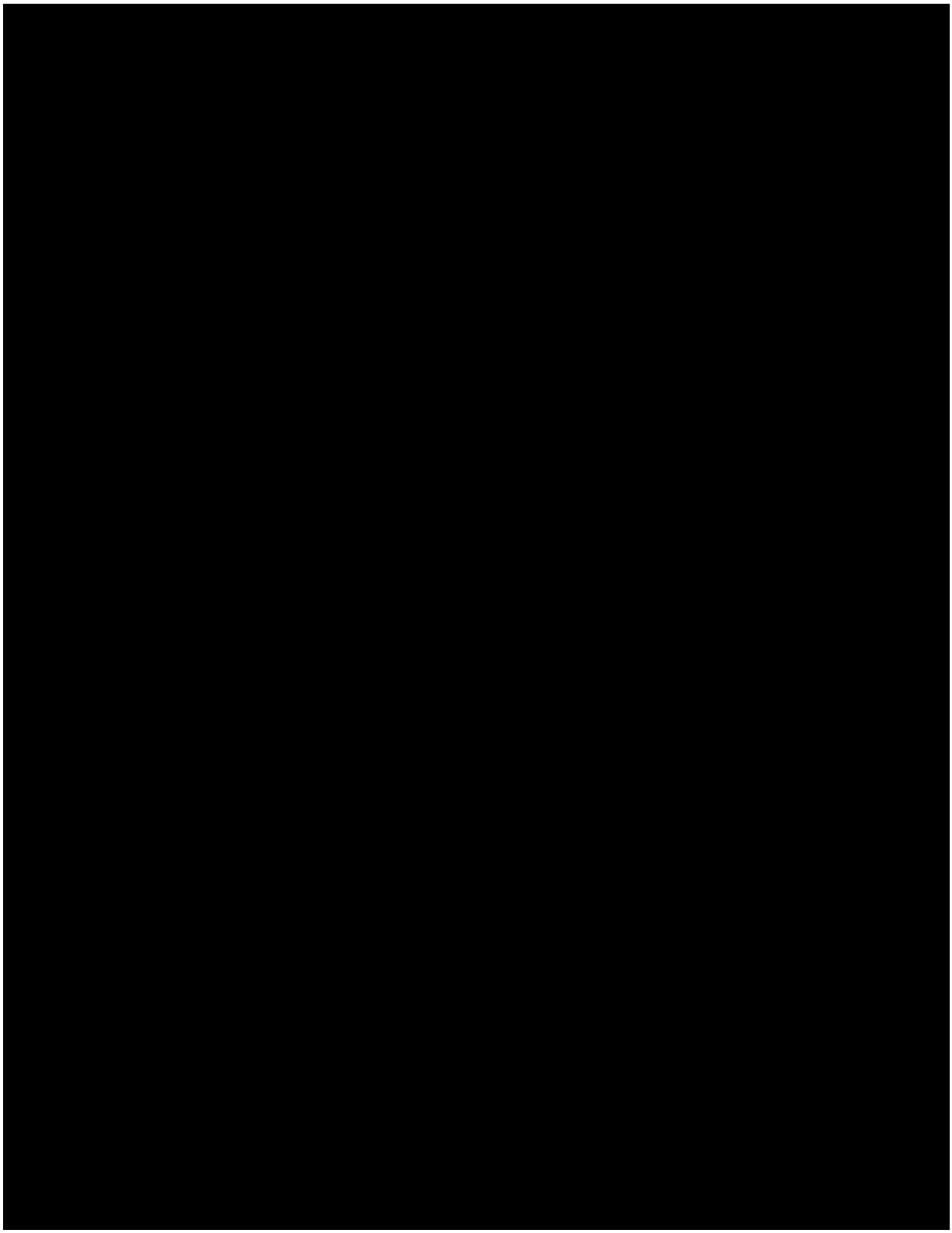


Figure 10-6 – Emergency response capacity map.

10.4.3 Potential Project Impacts and Mitigation Measures

The following subsections address potential Project impacts and resource demands, as well as Operator's plans to minimize or mitigate these impacts and demands.

Air Impacts

Neither Refugio County or Aransas County are listed as National Ambient Air Quality Standards non-attainment areas[12], meaning that the air quality in these counties meets or exceeds ambient air quality standards set forth by the EPA for Criteria Pollutants, and is therefore cleaner than the national air quality standards. Based on a review of the Texas Commission on Environmental Quality (TCEQ) Air Quality Division Map of Texas, Refugio and Aransas Counties are below 70 parts per billion (ppb) ozone based on the 2015 ozone design value.

Project-related impacts to air quality have been evaluated to determine what, if any, long-term and short-term (temporary) impacts to air quality may occur as a result of the proposed permitting action.

As no permanent sources of emissions (i.e., no fixed equipment or stationary emission units) are currently proposed, no long-term impacts to ambient air quality during the operational phase of the Project are anticipated. [redacted] However, intermittent vehicle and equipment use, rig operations, and road maintenance activities may potentially generate temporary emissions or dust and are the only anticipated air impacts during operation.

During the construction and well drilling phase of the Project (including road and pad construction, pipeline installation, and well drilling activities), all impacts to ambient air quality within the Project vicinity are anticipated to be temporary and occur from the operation of mobile and non-road emission units and equipment associated with construction and drilling related activities. Additionally, Project construction equipment and movement of material for land clearing, grading, excavation, drilling, and concrete work, along with vehicular traffic, has the potential to generate dust within the Project vicinity. Dust generation is variable and dependent on the area of construction, silt and moisture contents of the soil, wind speed, frequency of precipitation, amount of vehicle traffic, vehicle types, and season.

As a mitigation measure during construction activities, Operator will employ dust suppression techniques such as watering to address impacts and propagation of fugitive dust, as needed.

[12] https://www3.epa.gov/airquality/greenbook/popexp.html

Water Quality and Demand

Water volumes to support construction, development drilling, and testing operations are expected to be minimal and temporary in nature. [redacted]

During the injection operation phase of the Project, groundwater is not anticipated to be required.

Operator does not expect any operational impacts to USDWs or surface waters. No point-source discharges are proposed as part of the Project.

To ensure the protection of USDWs, CO_2 will be sequestered several thousand feet below the lowest USDW and will be contained within underground rock formations. As outlined in *Section 5 – Testing and Monitoring Plan*, Operator is committed to extensive groundwater quality and geochemical monitoring in the lowermost USDW formation above the confining zone to ensure protection of USDWs. The monitoring wells will track CO_2 pressures and movement to ensure it remains safely in the intended storage formation(s).

During construction and operations, Operator is committed to ensuring that activities do not adversely impact surface water resources in the Project vicinity. To ensure protection of surface waters adjacent and interconnected to the Project, Operator will develop and implement Stormwater Pollution Prevention Plans (SWPPPs) and Spill Prevention, Control, and Countermeasure Plans (SPCCs) in accordance with EPA and TCEQ guidance prior to all construction and drilling operations—to mitigate and prevent stormwater contamination, to control sedimentation and erosion, and to comply with the requirements of the federal Clean Water Act.

[redacted]

Sensitive Soils and Vegetation

Operator will develop and implement SWPPPs and SPCCs in accordance with EPA and TCEQ guidance prior to all Project construction and drilling operations to prevent the introduction of contaminants, control sedimentation and erosion, and ensure protection against releases that may impact sensitive soils and vegetation.

The total Project footprint and land disturbance to accommodate the Project facilities will be limited to the extent practicable and necessary for safe operations. Additionally, considerations

to protect forested areas, multiple species of mature/legacy hardwood trees, and other designated sensitive vegetation will be implemented to the extent practicable, while meeting Project needs.

Operator will coordinate with the U.S. Army Corps of Engineers (USACE), Galveston District to obtain permit approval for unavoidable impacts to Waters of the United States as defined by the Clean Water Act from construction of the well pads, access roads, and associated facilities. In addition, Operator will mitigate any unavoidable permanent impacts to wetlands.

Sensitive Wildlife and/or Habitat

The Project is not located on, nor will it impact any designated wildlife protection areas, state or national parks, or otherwise designated habitat areas. The closest wildlife protection area to the Project is the Aransas National Wildlife Refuge [redacted] Established in 1937, the Aransas National Wildlife Refuge serves as a refuge and breeding ground for migratory birds and other wildlife and as an inviolate sanctuary, or for any other management purpose, for migratory birds.

The U.S. Fish and Wildlife Service (USFWS) Information for Planning and Consultation (IpaC) database was reviewed to identify species of concern specific to the proposed Project location. The IpaC database generates data on a regional level and is to be utilized as a tool to guide further studies and research into species' presence and impacts. The IpaC database does not guarantee that the proposed Project area will or will not contain species of concern, or associated habitat. Species identified within the IpaC database that also have a potential to occur within the Project area are listed in Table 10-7.

Table 10-77 – Species identified in IpaC database with potential to occur in Project area.

Species Common Name	Species Scientific Name	Federal Listing Status
[redacted]		

Operator will conduct field-based habitat surveys and wetland delineations on all planned surface disturbance areas associated with the Project to determine the presence or absence of endangered or threatened species or associated critical habitats in the Project area. Based on the results of those surveys, Operator will consult with the USFWS to determine if any federally listed species and their critical habitats are known or expected to be in the vicinity of the Project and implement appropriate mitigations as needed.

Cultural, Historical, and Archaeological Resources

As outlined in *Section 10.4.1*, there was a historic tribal presence in this region. As a result, there is potential for archaeological and historic resources in the Project area.

Should the Project require a Section 404 permit from the USACE, Operator is committed to collaboration with the landowners, the Texas Historical Commission, and applicable federal agencies to ensure archaeological and historic resources are sufficiently documented and protected in accordance with the National Historic Preservation Act of 1966 (NHPA) and agency guidance, prior to Project construction. This effort includes conducting all required archeological surveys, generating necessary cultural reports, and implementing unanticipated discovery plans prior to Project construction.

Hurricane and Flooding Impacts

The Texas Coastal Bend Region is prone to hurricanes and flooding. In August 2017, Hurricane Harvey made landfall as a Category 4 hurricane, causing extensive damage in Aransas County, Nueces County, Refugio County, and the eastern part of San Patricio County. Approximately 15,000 homes were destroyed in these areas, with another 25,000 damaged. Tens of thousands of South Texas residents and businesses lost power for days, with the hardest hit areas likely losing power for several weeks. It was the second-most costly hurricane in U.S. history, behind Hurricane Katrina.

As the Texas Coastal Bend Region and these communities continue to rebuild, Operator acknowledges the sensitivity of this recovery and has ensured that its Tier 1 Emergency Response Plan, which is a supplement to its Emergency and Remedial Response Plan (ERRP), includes comprehensive hurricane and flooding response procedures (*Section 10.6*).

The principal type of flood posing the greatest risk in terms of potential impacts to the Project area, due to geographic location and topography, is coastal flooding. Coastal flooding refers to irregular tidal water and wave action that temporarily inundates areas near land-ocean boundaries. The Project wells are within the 500-year floodplain. The 500-year floodplains are moderate flood hazard areas known to have a 0.2% annual chance of flooding. These areas are known to flood, only at a much less frequent rate than the 100-year floodplains.

[redacted]

Table 10-88 – [redacted]

[redacted]

Table 10-99 – [redacted]

[redacted]

Noise and Light Pollution

All construction and operations will occur on private, rural land, [redacted] Therefore, no noise pollution impact from Project construction or operations is anticipated to affect neighboring populations.

Increased noise has the potential to temporarily displace avian species that forage and nest in the habitats adjacent to the Project site. Drilling will create ground vibrations that could disturb or displace nearby wildlife.

[redacted]

Lighting on the drilling rig and from mobile light plants will be present during drilling operations. Downcast lights will be focused on the Project site to minimize light pollution into nearby habitats or wetlands. Operator has no plans for permanent lighting on the well pads or new access roads.

[13] H&P FlexRig3 Noise Level Data

If protected species are identified in the vicinity of the Project, Operator will evaluate potential noise and light impacts on those species and consult with agencies for guidance. Both the noise and the light impacts will be temporary.

Waste

The primary anticipated waste streams would be generated during well drilling operations and could include drill cuttings, used oil- and water-based drilling muds, used engine oil, and construction debris. These primary waste streams are expected to be nonhazardous industrial solid wastes; however, final waste classification will be determined by on-site waste sampling and analyses and would be managed appropriately under applicable industrial and hazardous waste, municipal solid waste, and recyclable materials regulations.

All waste generated on-site will be stored in appropriate Waste Management Areas (WMAs) on the well pad(s) until transported off-site for disposal. [redacted]

A Project waste management plan, including a complete list of anticipated waste streams, waste classifications, and anticipated authorized disposal facilities, will be developed prior to initiation of Project operations. The Project waste management plan will ensure that all wastes are managed in accordance with both EPA's Resource Conservation and Recovery Act (RCRA) and TCEQ's waste management regulations and guidance throughout the life cycle of the Project.

Traffic

Project construction materials and process equipment will be delivered to the injection sites and associated Project facilities via trucks on existing public and private roads and new site access roads. [redacted] The Project will not impact any TDOT-designated evacuation routes[14].

Operator will continue to evaluate potential traffic impacts and if necessary, conduct a formal traffic impact assessment. Operator will coordinate with local officials and other applicable stakeholders to mitigate traffic disturbances.

[14] https://www.txdot.gov/content/dam/docs/trf/hurricane-preparation/corpus.pdf

Surface Land Footprint

Operator secured surface use agreements with the private landowners to address surface impacts from the injection well pads, monitoring well pads, associated facilities, and new access roads.

10.4.4 Project Impact Analysis Summary

Operator incorporated the findings of the three components of the Project Impact Analysis (*Sections 10.4.1* through *10.4.3*) and EJScreen while developing its community engagement strategy. As previously noted, no EJ community, or any community population, exists within the AOR. The Expanded EJScreen Area encompasses a population of [redacted] individuals and a household count of [redacted], within a [redacted] sq mi area. Operator strives to use robust community engagement to integrate input from this community and additional surrounding communities into its plans and operations and to seek opportunities to contribute to economic development in the communities surrounding the Project.

Accordingly, Operator identified the following locations of focus for engagement: Refugio County, town of Refugio, Aransas County, and Holiday Beach community. Operator considered the baseline, overarching socioeconomic vulnerabilities and characteristics of these locations while developing the Project-specific community engagement strategy.

10.5 Community Engagement

Operator is implementing active community engagement to build understanding and seek meaningful involvement to ensure a social license to operate. Initially, stakeholders are identified as affected communities due to proximity to the Project. These include members of the community, workforce, elected, regulatory, and nongovernmental organizations in Refugio and Aransas counties. The approach is built on the identification of baseline issues in the vicinity to the Project and analyzed with the Project's potential to impact those issues. The EJScreen and supplemental Project Impact Analysis have and will continue to inform Operator's community engagement and communication strategies.

Community engagement is ongoing, and *Section 10.5* is intended to reflect Operator's current activities and plans. Stakeholder engagement and monitoring will be dynamic as the Project evolves. This monitoring includes research and early engagement with key stakeholders to inform and seek input recognizing local interests. An on-the-ground team is responsible for consulting with the community and other stakeholders to identify, record, and address inputs through permitting, construction, and operations.

Operator's community engagement program is centered around three goals:

- Build understanding of the community interests and issues to assist in responsible Project

development.
- Communicate Project facts proactively with diverse stakeholders to enhance knowledge and address concerns.
- Establish mutual respect for long-term collaboration.

Since January 2024, Operator has engaged with local elected and appointed officials (including county judges and emergency response management) and local emergency responders, sharing preliminary Project details and discussing local emergency response capacity. Additionally, a local emergency responder visited the Project's appraisal site to increase awareness and collaboration between parties. Community outreach will be ongoing over the life of the Project to maintain an open line of communication.

Please reference *Appendix L-2* for a list of identified community stakeholders.

10.5.1 Community Engagement Strategy

The community engagement strategy incorporates the EPA's *Environmental Justice Guidance for UIC Class VI Permitting and Primacy Memorandum* (August 17, 2023) and *UIC Quick Reference Guide: Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process* (June 2011), as well as ConocoPhillips' publicly stated principles of environmental justice[15]. The strategy is an ever-evolving framework established to address analysis of community and regulatory expectations as well as data gathered from the EPA's EJScreen tool.

The Project's community engagement strategy is outlined in six phases (assessment and preparation, building awareness and feedback solicitation, permitting engagement, construction engagement, operations engagement, and post-injection engagement), as well as by methodology.

10.5.2 Engagement Phases

Engagement is an opportunity to assess and address stakeholder impacts as a feedback loop. Community engagements will be documented, and input will be collected in digital and written form. Table 10-10 provides the proposed phases and associated activities.

[15] https://www.conocophillips.com/sustainability/integrating-sustainability/sustainable-development-governance/policies-positions/environmental-justice-principles/

Table 10-1010 – Community engagement phases.

Phase	Activity
<u>Phase 1</u>: **Assess and Prepare** **(Timing: Project ideation)**	• Contracted local vendor and community liaison to advise and assist with community engagements. • Conducted community assessment to inform initial community engagement approach. • Developed communications materials and public sentiment monitoring tools. • Researched and analyzed potential community benefits, budgets, and community investments. • Established multiple communication channels for community input.

<u>Phase 2</u>:
Build Awareness and Solicit Feedback
 	
(Timing: Project concept and design; ongoing)
	• Commenced initial dialogue with county elected officials, community leaders, and emergency responders to establish relations.
	  ○ Solicited feedback to better understand community needs and capabilities.
	  ○ Conveyed initial feedback and expectations to Operator's design and engineering team for consideration.
	• Continue to seek cultural context and assess community topics of interest, challenges, and opportunities.
	• Shared and continue to share Project information utilizing subject matter experts (SMEs) to inform and improve public understanding as part of initial outreach.
	• Developed Project messaging and engagement methodologies.
	• Updated stakeholder lists and communication materials.

<u>Phase 3a</u>: **Permitting Engagement** **(Timing: Prior to Class VI submittal)**	• Incorporated feedback from initial community dialogue into the Project's community engagement strategy. • Updated stakeholder lists based on results of Expanded EJScreen. • Assessed and will continue to assess local emergency response capabilities. • Held pre-application meeting with EPA and TRRC.

<u>Phase 3b*</u>: Permitting Engagement (Timing: after Class VI submittal, through public comment and hearing) ***Phase 3b and beyond will occur after permit submittal**	• Expand engagement scope to reflect additional stakeholders. • Consider the effectiveness of communication and feedback channels and adjust as necessary. • Leverage local organizations, non-profits, and community events as opportunities to engage, provide information and solicit feedback. • Assess public comments to address, minimize, or eliminate potential Project impacts. • Incorporate feedback from community engagement strategy into Project plans when feasible.
<u>Phase 4</u>: Construction Engagement	• Update stakeholder lists and communications. • Continue to validate effectiveness of Project messaging and communication methodologies. • Share Project plans and timelines, and identify, address, and mitigate potential construction impacts from traffic, noise, dust, and temporary-worker population increases. • Continue to assess local emergency response capabilities and needs. • Host opportunities for feedback with interested community members and impacted stakeholders in the surrounding area. • Implement community investment plan, addressing community needs.
<u>Phase 5</u>: Operational Engagement	• Host community meetings to understand and address community input. • Conduct regular engagements with local elected officials on Project updates. • Continue implementation of community investment plan. • Cooperate and comply with regulatory requirements for public access to Project operational data. • Collaborate with local emergency responders on emergency response drills and preparation.
<u>Phase 6</u>: Post-Injection Engagement	• Continue two-way communication and feedback channels with community. • Continue implementation of community investment plan. • Cooperate and comply with regulatory requirements for public access to Project monitoring data.

10.5.3 Communication Methodology

Active stakeholder engagement and dialogue are key components of the Project action plans and are fit-for-purpose solutions to assess and address stakeholder priorities at all stages of Project development.

Written and verbal communications will focus on key outcomes from engagement including access and information transparency, improved awareness, technical education, and consultation to maximize public opportunity for engagement. Table 10-11 details the methods Operator may employ:

Table 10-1111 – Communication methodologies.

Communication Methodologies	
Access and transparency	Establish and update proactive and reactive communications mechanisms including a local community liaison to provide access and transparency to Project information and materials.
Spanish interpretation/translation services	Address communication needs for linguistically diverse stakeholders when possible.
Open houses	Provide access to Project overviews or updates as needed in an open forum utilizing visual aids, SMEs, digital access, Spanish translation/interpretation services, and various times to optimize participation.
Toll-free phone line, email, and website	Establishing two-way, linguistically diverse communication mechanisms for community input, including a toll-free phone number, Project email address, and website.
Mailings and handouts	Provide timely, structured, understandable messaging to the community about Project updates, upcoming events, etc.
Safety roundtables	Meet with applicable first responders throughout various Project phases and share emergency response updates and plans to ensure awareness.
Focus groups	Seek feedback from small-group, guided discussions to gather diverse perspectives and additional community feedback during permitting.
One-to-one engagements	Meet one-to-one with certain parties.

Using the continuous improvement process methodology, the stakeholder engagement and communications methodologies may be adjusted to enable maximum participation and understanding as the Project matures though the phases.

10.5.4 Community-Specific Engagement Methodology

The community-specific engagement methodology is guided by thorough data gathering and analysis, response to technical education, and direct feedback on the Project's potential to impact the community. Sensitivities to existing socioeconomic and environmental vulnerabilities are addressed intentionally in Operator's engagement activities.

Incorporating findings from Project Impact Analysis (*Section 10.4.1*) and results from the EJScreen (*Section 10.3*), Operator's community engagement strategy specifically addresses the company's commitment to meaningful engagement with marginalized, disadvantaged, and overburdened communities. Community-specific engagement methods include the following:

- **Adaptive action**: To aid Project understanding, communications (verbal and written) will be accessible and transparent through both physical (liaison, hardcopy, mailings) and digital (electronic, phone, web) dissemination channels for stakeholders with limited broadband internet connection or proficiency.
    - **Related finding**: [redacted]

- **Adaptive action**: To engage with Spanish speakers, translation/interpretation options will be made available as practicable.
    - **Related finding**: Refugio County is 51.2% Hispanic or Latino, primarily Spanish speaking households[16].

- **Adaptive action**: To aid access to Project updates and technical education, communications will be provided in English and Spanish to the extent practicable. The EPA's draft Class VI permit will be provided in dual language and will made publicly available prior to the public comment period. Project fact sheets, mailings, and the Project website will also be disseminated in English and Spanish.
    - **Related finding**: Refugio County is 51.2% Hispanic or Latino, primarily Spanish speaking households.

- **Adaptive action**: To provide multiple opportunities and optimize participation, Operator aims to offer accessible meeting options (including virtual) to accommodate a variety of schedules and needs (shift workers, elderly, people with disabilities, etc.) and ensure in-person meetings are located within a reasonable distance to most stakeholders. Operator will allow abundant time for questions and answers, and facilitate meetings to optimize meaningful, virtual participation.
    - **Related finding**: [redacted]

[16] https://www.statsamerica.org/town/

- **Adaptive action**: Operator will provide multiple feedback channels to accommodate communication preferences as needed: in person, a 1-800 phone line ([redacted]), a contact email[17]—and a dedicated Project website[18] will be live in 2024.
    - **Related finding**: The Project Impact Analysis revealed demographic diversity in nearby communities, underscoring the need to accommodate a variety of communication preferences.

10.6 Emergency Response Coordination

Operator is designing the Project facilities, monitoring systems, and prevention mechanisms in accordance with regulatory standards and in alignment with its longstanding commitment to safety. A critical part of safety is ensuring that appropriate emergency response capabilities are in place.

Once in operation, the Project will utilize continuous monitoring and maintain trained Incident Management Teams and response equipment (available through third-party contracts). In addition to a dedicated ERRP, Operator will implement a supplemental Tier 1 Emergency Response Plan for the Project. This plan will outline initial response procedures and identify responsible personnel for managing potential incidents or emergencies not specifically included in the ERRP, such as injuries, transportation incidents, hurricanes and flooding, suspicious items, vandalism, fires, unauthorized personnel on location, etc.

Operator is dedicated to protecting the health and safety of those involved in our operations and who live in the communities surrounding our operations. During the Project's planning stages, Operator held multiple meetings with local emergency response personnel. These meetings included high-level Project introductions through individual and group sessions with county emergency officials. Operator-solicited feedback will be incorporated as learnings into the ERRP and supplemental Tier 1 Emergency Response Plan. Operator continues to evaluate existing local emergency response capacity and will supplement with third-party response contractors as necessary.

Operator places great value on trained and capable emergency responders. Operator will conduct emergency response exercises and drills with local responders and third-party response contractors, and sponsor community emergency response training as well as educational conferences for responders.

As part of Operator's preparedness efforts, Operator continues to evaluate and maintain existing relationships with various well control and emergency response contractors who provide access to substantial inventories of the latest advances in proven response equipment. A

[17] stakeholderrelations@conocophillips.com [redacted]

comprehensive list of these response resources will be included with the emergency response plans, and procedures will be in place to activate these resources quickly and efficiently.

10.7 Community Benefits and Community Investments Plan

Operator recognizes the importance of creating mutual benefits in the communities where it operates. Operator strives to develop strategic community benefits that specifically address local interests and needs through multi-disciplinary engagement.

The Project will provide economic and social benefits to the region and the State of Texas. Operator will continue to conduct thorough assessments of the Project area, including an economic impact analysis, to evaluate the temporary, permanent, direct, indirect, and induced economic effects from construction and operation at both state and county levels.

Through community consultation, Operator is developing a community investment plan. This plan will identify and address areas of local concern through localized charitable investments and volunteerism efforts in support of education, health and safety, the environment, the arts, civic and social services, and disaster relief. The community liaison identifies opportunities for effective charitable investments through strategic relationships with organizations dedicated to serving community needs. The process, eligibility and time frame for grant requests and the contribution guidelines are publicly available, and typically runs from April 1 to July 31. During this time frame, eligible 501(C) charitable organizations or equivalent may apply for funding consideration the following year. Proposals are submitted online through Operator's Cybergrants system and are evaluated based on mutual alignment with the recipient, focus areas, business objectives, and proximity to the Project.

Operator will work closely with the regulators to update these plans prior to public comment and over the life of the Project, as appropriate.

10.8 Additional Mitigation

Section 10.4.3 (Potential Project Impacts and Mitigation Measures) describes Operator's robust Testing and Monitoring Plan, dust suppression strategy, traffic management commitment, stormwater pollution prevention plans, and other mechanisms designed to minimize Project impacts.

Operator will continue to evaluate results of the EJScreen, Project impacts, and community feedback to determine the appropriate extent of necessary mitigation as outlined and, if necessary, update its mitigation plan accordingly.

10.9 Conclusion

It is important to reiterate that no population or EJ community was identified within the Project's AOR. In addition, none of the thirteen EJ Index or Supplemental EJ Index measurements exceed the EPA's 80th percentile guidance compared to state or national levels within the Expanded EJScreen Area.

[redacted] Construction operations involve temporary increases in noise, lighting and traffic in the Project area. Noise and lighting is not anticipated to impact the surrounding community. Operator intends to coordinate with local officials and other applicable stakeholders to mitigate any local traffic pattern disturbances associated with construction activities.

[redacted] Cumulative Project impacts are anticipated to be minimal, and Operator is committed to ongoing analysis, engagement, and agency dialogue to minimize Project impacts even further. Operator will update this Environmental and Community Impact Analysis when supplemental data is available and incorporate feedback and learnings from ongoing community engagement.

Underground Injection Control – Class VI Permit Application for the ConocoPhillips Texas Gulf Coast CCS Project

Aransas and Refugio County, Texas

APPENDICES

July 2024

APPENDIX A: OVERVIEW MAPS AND PLATS

- Appendix A-1 Project Area Map
- Appendix A-2 Stratigraphic Test Well Locations Map
- Appendix A-3 Injection Well Location Plats

APPENDICES A-1 TO A-3 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX B: SITE CHARACTERIZATION MAPS

- Appendix B-1 Geocellular Model Data Map
- Appendix B-2 Cross Section Reference Map
- Appendix B-3 N-S Dip Structural Cross Section
- Appendix B-4 N-S Dip Stratigraphic Cross Section
- Appendix B-5 Strike North Structural Cross Section
- Appendix B-6 Strike North Stratigraphic Cross Section
- Appendix B-7 Strike South Structural Cross Section
- Appendix B-8 Strike South Stratigraphic Cross Section
- Appendix B-9 Upper Confining Zone Structure Map
- Appendix B-10 Miocene Injection Structure Map
- Appendix B-11 Anahuac Structure Map
- Appendix B-12 Frio Injection Structure Map
- Appendix B-13 Lower Confining Zone Structure Map
- Appendix B-14 Base Lower Confining Zone Structure Map
- Appendix B-15 Upper Confining Zone Isochore
- Appendix B-16 Miocene Injection Isochore
- Appendix B-17 Anahuac Isochore
- Appendix B-18 Frio Injection Isochore
- Appendix B-19 Lower Confining Zone Isochore
- Appendix B-20 Upper Confining Zone Net Shale
- Appendix B-21 Injection Zone Net Sand
- Appendix B-22 Lower Confining Zone Net Shale

APPENDICES B-1 TO B-22 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX C: HYDROGEOLOGY

- Appendix C-1 Base of USDW Structure Map
- Appendix C-2 USDW Cross Sections Reference Map
- Appendix C-3 N-S Dip USDW Structural Section
- Appendix C-4 N-S Dip USDW Stratigraphic Section
- Appendix C-5 Strike North USDW Structural Section
- Appendix C-6 Strike North USDW Stratigraphic Section
- Appendix C-7 Strike South USDW Structural Section
- Appendix C-8 Strike South USDW Stratigraphic Section

APPENDICES C-1 TO C-8 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX D: PLUME MODEL OUTPUTS

- Appendix D-1 Plume Model Outputs

APPENDIX D-1 IS

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX E: AREA OF REVIEW MAPS AND TABLES

- Appendix E-1 USDW Depth Map
- Appendix E-2 Pressure Front Map
- Appendix E-3 CO_2 Plume Map
- Appendix E-4 Final AOR Map
- Appendix E-5 AOR with Existing Wells Map
- Appendix E-6 Oil and Gas Well Penetrator List
- Appendix E-7 AOR with Groundwater Wells Map
- Appendix E-8 Groundwater Wells within AOR list
- Appendix E-9 Site Review Map
- Appendix E-10 Topographic Map of AOI
- Appendix E-11 [redacted]
- Appendix E-12 [redacted]
- Appendix E-13 [redacted]
- Appendix E-14 [redacted]
- Appendix E-15 [redacted]
- Appendix E-16 [redacted]
- Appendix E-17 [redacted]

APPENDICES E-1 TO E-17 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX F: WELL CONSTRUCTION SCHEMATICS AND PROCEDURES

- Appendix F-1 Injection Wellbore Schematics
- Appendix F-2 Injection Well Drilling and Completion Prognoses
- Appendix F-3 Supporting Well Construction Programs
- Appendix F-4 Preliminary Wellhead Design

APPENDICES F-1 TO F-4 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX G: METALLURGY SUMMARY

- Appendix G-1 Metallurgy Summary

APPENDIX G-1 IS

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX H: TESTING AND MONITORING

- Appendix H-1 Development and Monitoring Plan Map
- Appendix H-2 USDW Monitoring Wells Map
- Appendix H-3 USDW Monitoring Wells Wellbore Schematics
- Appendix H-4 Above-Zone Monitoring Wells Map
- Appendix H-5 Above-Zone Monitoring Wells Wellbore Schematics
- Appendix H-6 In-Zone Monitoring Wells Map
- Appendix H-7 In-Zone Monitoring Wells Wellbore Schematics
- Appendix H-8 [redacted]

APPENDICES H-1 TO H-8 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX I: EMERGENCY OPERATIONS PLAN

- Appendix I-1 Injection Well Locations Map
- Appendix I-2 Above-Zone Monitoring Well Locations Map
- Appendix I-3 USDW Monitoring Well Locations Map
- Appendix I-4 In-Zone Monitoring Well Locations Map
- Appendix I-5 AOR with Groundwater Wells Map
- Appendix I-6 Emergency Response Capacity Map
- Appendix I-7 FEMA National Risk Index Report – Aransas County
- Appendix I-8 FEMA National Risk Index Report – Refugio County
- Appendix I-9 Risk Assessment Table

APPENDICES I-1 TO I-6 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

National Risk Index

April 30, 2024

Aransas County, Texas

Summary

Risk Index is **Relatively Moderate** — Score **84.5**

Expected Annual Loss is **Relatively Low** — Score **83.4**

Social Vulnerability is **Very High** — Score **93.8**

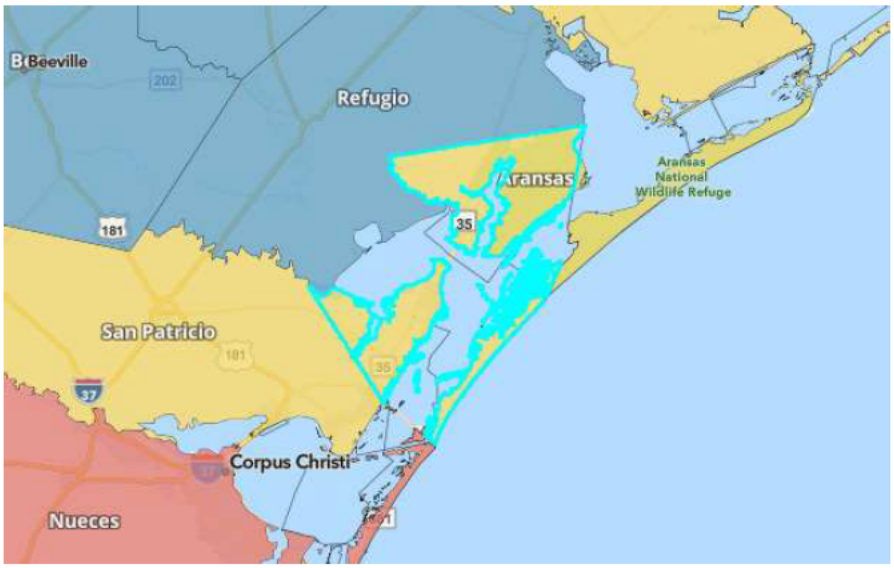
Community Resilience is **Relatively Moderate** — Score **46.3**

While reviewing this report, keep in mind that low risk is driven by lower loss due to natural hazards, lower social vulnerability, and higher community resilience.

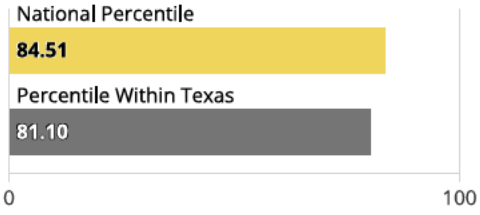
For more information about the National Risk Index, its data, and how to interpret the information it provides, please review the **About the National Risk Index** and **How to Take Action** sections at the end of this report. Or, visit the National Risk Index website at **hazards.fema.gov/nri/learn-more** to access supporting documentation and links.

Risk Index

The Risk Index rating is **Relatively Moderate** for **Aransas County, TX** when compared to the rest of the U.S.



Score **84.51**



85% of U.S. counties have a lower Risk Index

81% of counties in Texas have a lower Risk Index

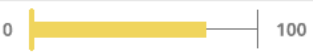
Risk Index Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low

No Rating | Not Applicable | Insufficient Data

Hazard Type Risk Index

Hazard type Risk Index scores are calculated using data for only a single hazard type, and reflect a community's Expected Annual Loss value, community risk factors, and the adjustment factor used to calculate the risk value.

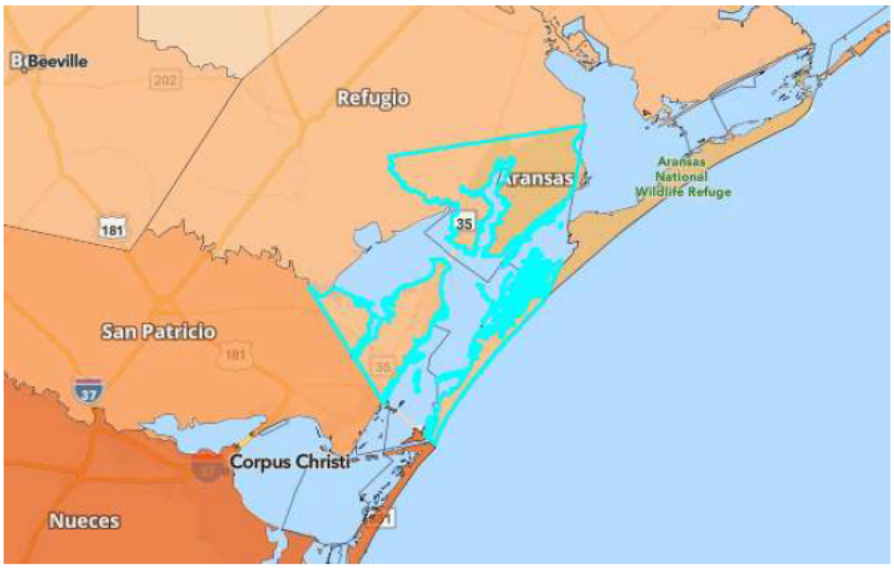
Hazard Type	Risk Index Rating	Risk Index Score	National Percentile
Avalanche	Not Applicable	–	
Coastal Flooding	Relatively High	95.4	
Cold Wave	Relatively Low	50.5	
Drought	Very Low	18.4	
Earthquake	Very Low	7.6	
Hail	Relatively Low	47.1	
Heat Wave	No Rating	0	
Hurricane	Relatively Moderate	87.8	
Ice Storm	Relatively Low	41.1	
Landslide	No Rating	0	
Lightning	Relatively Low	46.8	
Riverine Flooding	Relatively Moderate	77.9	
Strong Wind	Relatively Low	30.1	
Tornado	Relatively Low	52.8	
Tsunami	Insufficient Data	–	
Volcanic Activity	Not Applicable	–	
Wildfire	Very Low	60.7	
Winter Weather	Relatively Low	30	

Risk Factor Breakdown

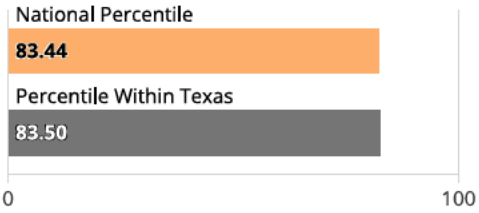
Hazard Type	EAL Value	Social Vulnerability	Community Resilience	CRF	Risk Value	Risk Index Score
Coastal Flooding	$10,344,682	Very High	Relatively Moderate	1.18	$11,691,140	95.4
Hurricane	$8,876,113	Very High	Relatively Moderate	1.18	$10,992,418	87.8
Riverine Flooding	$1,540,897	Very High	Relatively Moderate	1.18	$1,716,723	77.9
Tornado	$1,022,981	Very High	Relatively Moderate	1.18	$1,298,995	52.8
Strong Wind	$152,479	Very High	Relatively Moderate	1.18	$190,021	30.1
Lightning	$74,528	Very High	Relatively Moderate	1.18	$95,612	46.8
Hail	$76,507	Very High	Relatively Moderate	1.18	$95,272	47.1
Wildfire	$67,841	Very High	Relatively Moderate	1.18	$84,684	60.7
Cold Wave	$51,320	Very High	Relatively Moderate	1.18	$66,436	50.5
Ice Storm	$32,825	Very High	Relatively Moderate	1.18	$41,668	41.1
Winter Weather	$20,327	Very High	Relatively Moderate	1.18	$26,206	30
Earthquake	$2,684	Very High	Relatively Moderate	1.18	$3,391	7.6
Drought	$334	Very High	Relatively Moderate	1.18	$412	18.4
Heat Wave	$0	Very High	Relatively Moderate	1.18	$0	0
Landslide	$0	Very High	Relatively Moderate	1.18	$0	0
Avalanche	--	Very High	Relatively Moderate	1.18	--	--
Tsunami	--	Very High	Relatively Moderate	1.18	--	--
Volcanic Activity	--	Very High	Relatively Moderate	1.18	--	--

Expected Annual Loss

In **Aransas County, TX**, expected loss each year due to natural hazards is **Relatively Low** when compared to the rest of the U.S.



Score	83.44



83% of U.S. counties have a lower Expected Annual Loss

83% of counties in Texas have a lower Expected Annual Loss

Expected Annual Loss Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low

No Expected Annual Losses | Not Applicable | Insufficient Data

Composite Expected Annual Loss	**$22,263,519.61**
Composite Expected Annual Loss Rate National Percentile	**95.3**

Building EAL	**$19,472,968.41**	Population EAL	**0.24** fatalities
Building EAL Rate	**$1 per $264.02 of building value**	Population EAL Rate	**1 per 99.16K people**
Agriculture EAL	**$17,760.36**	Population Equivalence EAL	**$2,772,790.83**
Agriculture EAL Rate	**$1 per $125.15 of agriculture value**		

Expected Annual Loss for Hazard Types

Expected Annual Loss scores for hazard types are calculated using data for only a single hazard type, and reflect a community's relative expected annual loss for only that hazard type.

15 of 18 hazard types contribute to the expected annual loss for **Aransas County, TX**.

Hazard Type	Expected Annual Loss Rating	EAL Value	Score
Coastal Flooding	Relatively High	$10,344,682	96.1
Hurricane	Relatively Moderate	$8,876,113	85.0

Hazard Type	Expected Annual Loss Rating	EAL Value	Score
Riverine Flooding	Relatively Moderate	$1,540,897	79.1
Tornado	Relatively Low	$1,022,981	51.6
Strong Wind	Relatively Low	$152,480	31.0
Hail	Relatively Low	$76,507	47.4
Lightning	Relatively Low	$74,528	45.1
Wildfire	Very Low	$67,841	59.4
Cold Wave	Relatively Low	$51,320	50.2
Ice Storm	Relatively Low	$32,825	39.8
Winter Weather	Relatively Low	$20,327	30.6
Earthquake	Very Low	$2,684	6.9
Drought	Very Low	$334	20.1
Heat Wave	No Expected Annual Losses	$0	0.0
Landslide	No Expected Annual Losses	$0	0.0
Avalanche	Not Applicable	--	--
Tsunami	Insufficient Data	--	--
Volcanic Activity	Not Applicable	--	--

Expected Annual Loss Values

Hazard Type	Total	Building Value	Population Equivalence	Population	Agriculture Value
Avalanche	--	--	--	--	--
Coastal Flooding	$10,344,682	$10,333,264	$11,418	0.00	n/a
Cold Wave	$51,320	$1,693	$48,025	0.00	$1,602
Drought	$334	n/a	n/a	n/a	$334
Earthquake	$2,684	$2,160	$524	0.00	n/a
Hail	$76,507	$60,377	$15,504	0.00	$626
Heat Wave	$0	$0	$0	0.00	$0
Hurricane	$8,876,113	$8,509,969	$351,765	0.03	$14,379
Ice Storm	$32,825	$8,855	$23,970	0.00	n/a
Landslide	$0	$0	$0	0.00	n/a
Lightning	$74,528	$1,577	$72,951	0.01	n/a
Riverine Flooding	$1,540,897	$87,701	$1,452,638	0.13	$558

Hazard Type	Total	Building Value	Population Equivalence	Population	Agriculture Value
Strong Wind	$152,479	$119,382	$32,907	0.00	$190
Tornado	$1,022,981	$275,804	$747,122	0.06	$55
Tsunami	n/a	n/a	n/a	n/a	n/a
Volcanic Activity	--	--	--	--	--
Wildfire	$67,841	$67,541	$287	0.00	$13
Winter Weather	$20,327	$4,645	$15,680	0.00	$2

Exposure Values

Hazard Type	Total	Building Value	Population Equivalence	Population	Agriculture Value
Avalanche	--	--	--	--	--
Coastal Flooding	$74,163,380,132	$1,791,128,619	$72,372,251,513	6,238.99	n/a
Cold Wave	$274,452,951,157	$4,990,915,854	$269,459,821,719	23,229.29	$2,213,583
Drought	$62,449	n/a	n/a	n/a	$62,449
Earthquake	$281,569,100,000	$5,141,100,000	$276,428,000,000	23,830.00	n/a
Hail	$280,098,232,646	$5,141,209,888	$274,954,800,000	23,703.00	$2,222,758
Heat Wave	$0	$0	$0	0.00	$0
Hurricane	$280,098,225,541	$5,141,209,779	$274,954,793,003	23,703.00	$2,222,758
Ice Storm	$280,096,002,783	$5,141,209,779	$274,954,793,003	23,703.00	n/a
Landslide	$0	$0	$0	0.00	n/a
Lightning	$280,096,009,888	$5,141,209,888	$274,954,800,000	23,703.00	n/a
Riverine Flooding	$29,853,647,320	$848,463,834	$29,005,124,758	2,500.44	$58,728
Strong Wind	$280,098,232,646	$5,141,209,888	$274,954,800,000	23,703.00	$2,222,758
Tornado	$280,098,232,646	$5,141,209,888	$274,954,800,000	23,703.00	$2,222,758
Tsunami	n/a	n/a	n/a	n/a	n/a
Volcanic Activity	--	--	--	--	--
Wildfire	$26,478,336,237	$480,352,236	$25,997,477,653	2,241.16	$506,347
Winter Weather	$274,452,950,271	$4,990,915,854	$269,459,821,719	23,229.29	$2,212,698

Annualized Frequency Values

Hazard Type	Annualized Frequency	Events on Record	Period of Record
Avalanche	--	--	--

Hazard Type	Annualized Frequency	Events on Record	Period of Record
Coastal Flooding	3.7 events per year	n/a	Various (see documentation)
Cold Wave	0.2 events per year	2	2005-2021 (16 years)
Drought	33.1 events per year	854	2000-2021 (22 years)
Earthquake	0.014% chance per year	n/a	2021 dataset
Hail	1.2 events per year	30	1986-2021 (34 years)
Heat Wave	0 events per year	0	2005-2021 (16 years)
Hurricane	0.2 events per year	25	East 1851-2021 (171 years) / West 1949-2021 (73 years)
Ice Storm	0.4 events per year	18	1946-2014 (67 years)
Landslide	0 events per year	0	2010-2021 (12 years)
Lightning	61.4 events per year	969	1991-2012 (22 years)
Riverine Flooding	1.5 events per year	35	1996-2019 (24 years)
Strong Wind	1 event per year	24	1986-2021 (34 years)
Tornado	0.1 events per year	12	1950-2021 (72 years)
Tsunami	n/a	n/a	1800-2021 (222 years)
Volcanic Activity	--	--	--
Wildfire	0.126% chance per year	n/a	2021 dataset
Winter Weather	0.2 events per year	2	2005-2021 (16 years)

Historic Loss Ratios

Hazard Type	Overall Rating
Avalanche	--
Coastal Flooding	Relatively Low
Cold Wave	Very Low
Drought	Relatively Low
Earthquake	Very Low
Hail	Relatively Moderate
Heat Wave	No Rating
Hurricane	Very High
Ice Storm	Relatively Low
Landslide	No Rating
Lightning	Relatively Low

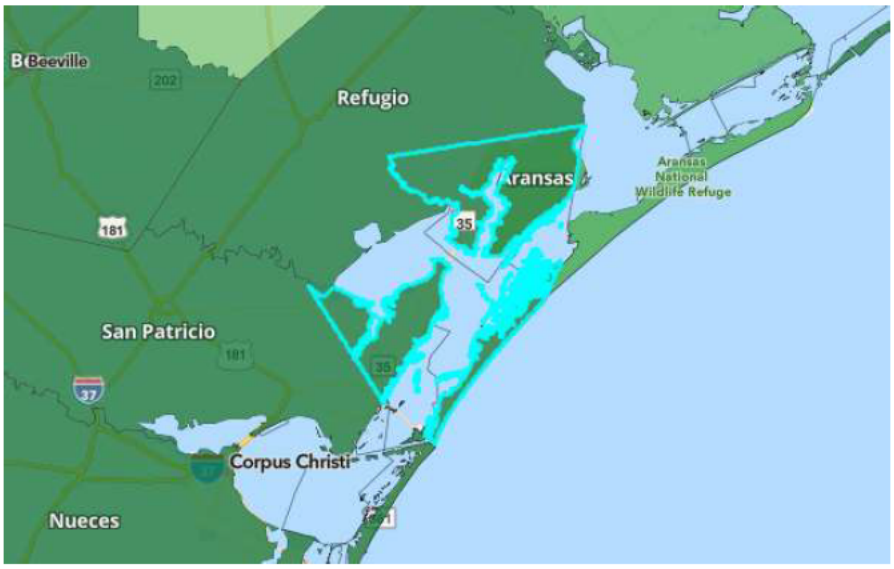
Hazard Type	Overall Rating
Riverine Flooding	Very Low
Strong Wind	Relatively Moderate
Tornado	Relatively High
Tsunami	Insufficient Data
Volcanic Activity	--
Wildfire	Very Low
Winter Weather	Relatively High

Expected Annual Loss Rate

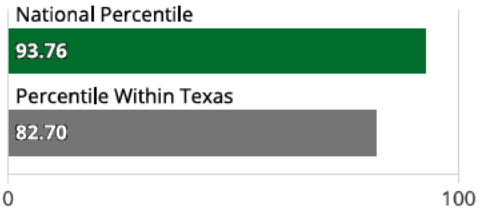
Hazard Type	Building EAL Rate (per building value)	Population EAL Rate (per population)	Agriculture EAL Rate (per agriculture value)
Avalanche	--	--	--
Coastal Flooding	$1 per $497.54	1 per 24.08M	–
Cold Wave	$1 per $3.04M	1 per 5.73M	$1 per $1.39K
Drought	–	–	$1 per $6.65K
Earthquake	$1 per $2.38M	1 per 524.56M	–
Hail	$1 per $85.15K	1 per 17.73M	$1 per $3.55K
Heat Wave	–	–	–
Hurricane	$1 per $604.14	1 per 781.64K	$1 per $154.58
Ice Storm	$1 per $580.60K	1 per 11.47M	–
Landslide	–	–	–
Lightning	$1 per $3.26M	1 per 3.77M	–
Riverine Flooding	$1 per $58.62K	1 per 189.28K	$1 per $3.98K
Strong Wind	$1 per $43.07K	1 per 8.36M	$1 per $11.70K
Tornado	$1 per $18.64K	1 per 368.02K	$1 per $40.15K
Tsunami	–	–	–
Volcanic Activity	--	--	--
Wildfire	$1 per $76.12K	1 per 957.13M	$1 per $169.79K
Winter Weather	$1 per $1.11M	1 per 17.54M	$1 per $1.16M

Social Vulnerability

Social groups in **Aransas County, TX** have a **Very High** susceptibility to the adverse impacts of natural hazards when compared to the rest of the U.S.



Score **93.76**



94% of U.S. counties have a lower Social Vulnerability

83% of counties in Texas have a lower Social Vulnerability

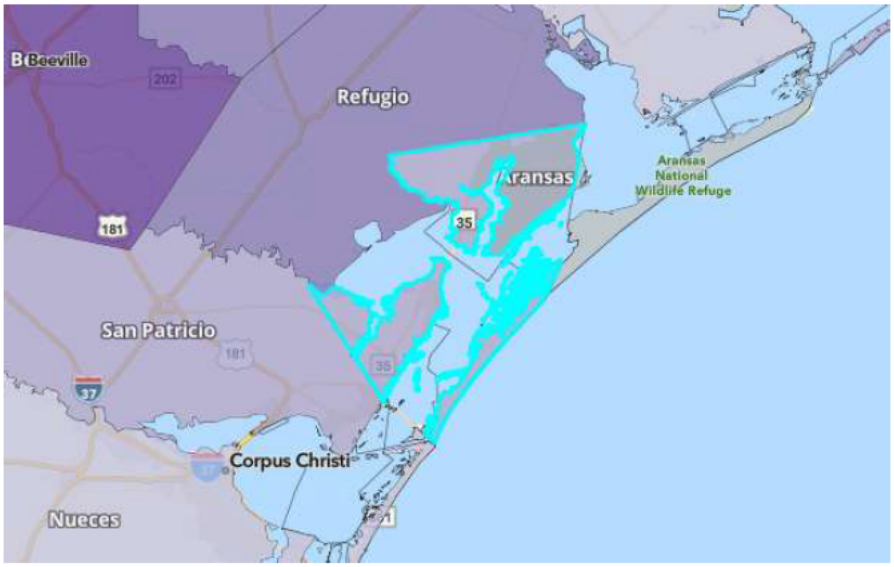
Social Vulnerability Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low

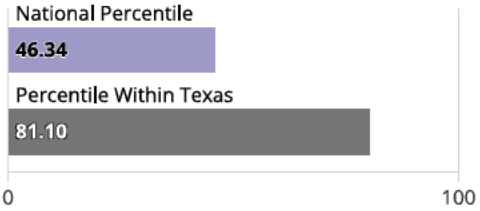
Data Unavailable

Community Resilience

Communities in **Aransas County, TX** have a **Relatively Moderate** ability to prepare for anticipated natural hazards, adapt to changing conditions, and withstand and recover rapidly from disruptions when compared to the rest of the U.S.



Score **46.34**



54% of U.S. counties have a higher Community Resilience

19% of counties in Texas have a higher Community Resilience

Community Resilience Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low | Data Unavailable

About the National Risk Index

The National Risk Index is a dataset and online tool to help illustrate the United States communities most at risk for 18 natural 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.

The National Risk Index leverages available source data for Expected Annual Loss due to these 18 hazard types, Social Vulnerability, and Community Resilience to develop a baseline relative risk measurement for each United States county and Census tract. These measurements are calculated using average past conditions, but they cannot be used to predict future outcomes for a community. The National Risk Index is intended to fill gaps in available data and analyses to better inform federal, state, local, tribal, and territorial decision makers as they develop risk reduction strategies.

Explore the National Risk Index Map at **hazards.fema.gov/nri/map**.

Visit the National Risk Index website at **hazards.fema.gov/nri/learn-more** to access supporting documentation and links.

Calculating the Risk Index

Risk Index scores are calculated using an equation that combines scores for Expected Annual Loss due to natural hazards, Social Vulnerability and Community Resilience:

Risk Index = Expected Annual Loss × Social Vulnerability ÷ Community Resilience

Risk Index scores are presented as a composite score for all 18 hazard types, as well as individual scores for each hazard type.

For more information, visit **hazards.fema.gov/nri/determining-risk**.

Calculating Expected Annual Loss

Expected Annual Loss scores are calculated using an equation that combines values for exposure, annualized frequency, and historic loss ratios for 18 hazard types:

Expected Annual Loss = Exposure × Annualized Frequency × Historic Loss Ratio

Expected Annual Loss scores are presented as a composite score for all 18 hazard types, as well as individual scores for each hazard type.

For more information, visit **hazards.fema.gov/nri/expected-annual-loss**.

Calculating Social Vulnerability

Social Vulnerability is measured using the Social Vulnerability Index (SVI) published by the Centers for Disease Control and Prevention (CDC).

For more information, visit **hazards.fema.gov/nri/social-vulnerability**.

Calculating Community Resilience

Community Resilience is measured at the County level using the Baseline Resilience Indicators for Communities (HVRI BRIC) published by the University of South Carolina's Hazards and Vulnerability Research Institute (HVRI).

For more information, visit **hazards.fema.gov/nri/community-resilience**.

How to Take Action

There are many ways to reduce natural hazard risk through mitigation. Communities with high National Risk Index scores can take action to reduce risk by decreasing Expected Annual Loss due to natural hazards, decreasing Social Vulnerability, and increasing Community Resilience.

For information about how to take action and reduce your risk, visit **hazards.fema.gov/nri/take-action**.

Disclaimer

The National Risk Index (the Risk Index or the Index) and its associated data are meant for planning purposes only. This tool was created for broad nationwide comparisons and is not a substitute for localized risk assessment analysis. Nationwide datasets used as inputs for the National Risk Index are, in many cases, not as accurate as available local data. Users with access to local data for each National Risk Index risk factor should consider substituting

the Risk Index data with local data to recalculate a more accurate risk index. If you decide to download the National Risk Index data and substitute it with local data, you assume responsibility for the accuracy of the data and any resulting data index. Please visit the **Contact Us** page if you would like to discuss this process further.

The methodology used by the National Risk Index has been reviewed by subject matter experts in the fields of natural hazard risk research, risk analysis, mitigation planning, and emergency management. The processing methods used to create the National Risk Index have produced results similar to those from other natural hazard risk analyses conducted on a smaller scale. The breadth and combination of geographic information systems (GIS) and data processing techniques leveraged by the National Risk Index enable it to incorporate multiple hazard types and risk factors, manage its nationwide scope, and capture what might have been missed using other methods.

The National Risk Index does not consider the intricate economic and physical interdependencies that exist across geographic regions. Keep in mind that hazard impacts in surrounding counties or Census tracts can cause indirect losses in your community regardless of your community's risk profile.

Nationwide data available for some risk factors are rudimentary at this time. The National Risk Index will be continuously updated as new data become available and improved methodologies are identified.

The National Risk Index Contact Us page is available at **hazards.fema.gov/nri/contact-us**.

National Risk Index

April 30, 2024

Refugio County, Texas

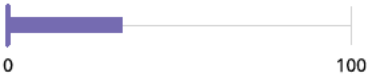
Summary

Risk Index is **Relatively Low** — Score **63.5**

Expected Annual Loss is **Relatively Low** — Score **55.4**

Social Vulnerability is **Very High** — Score **92.9**

Community Resilience is **Relatively Low** — Score **33.5**

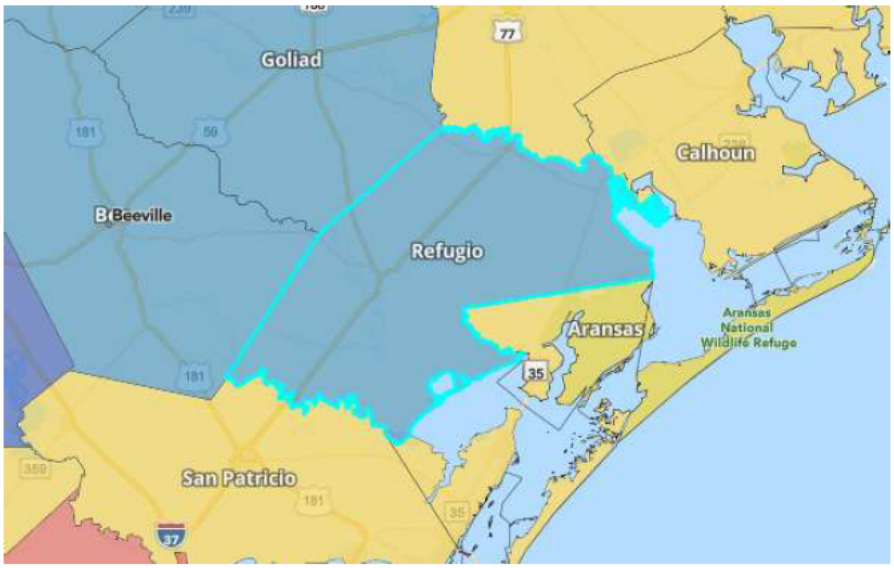


While reviewing this report, keep in mind that low risk is driven by lower loss due to natural hazards, lower social vulnerability, and higher community resilience.

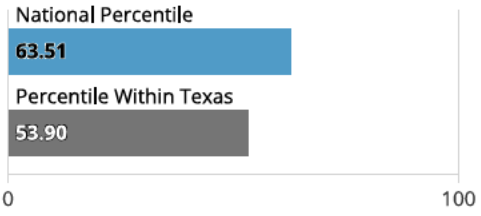
For more information about the National Risk Index, its data, and how to interpret the information it provides, please review the **About the National Risk Index** and **How to Take Action** sections at the end of this report. Or, visit the National Risk Index website at **hazards.fema.gov/nri/learn-more** to access supporting documentation and links.

Risk Index

The Risk Index rating is **Relatively Low** for **Refugio County, TX** when compared to the rest of the U.S.



Score **63.51**



64% of U.S. counties have a lower Risk Index

54% of counties in Texas have a lower Risk Index

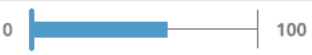
Risk Index Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low

No Rating | Not Applicable | Insufficient Data

Hazard Type Risk Index

Hazard type Risk Index scores are calculated using data for only a single hazard type, and reflect a community's Expected Annual Loss value, community risk factors, and the adjustment factor used to calculate the risk value.

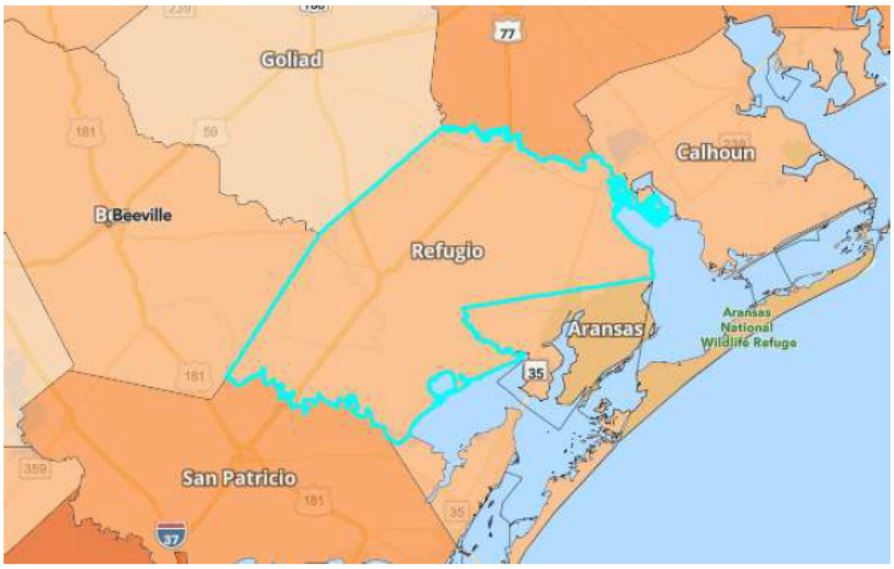
Hazard Type	Risk Index Rating	Risk Index Score	National Percentile
Avalanche	Not Applicable	–	
Coastal Flooding	Relatively Low	63	
Cold Wave	Relatively Low	53.5	
Drought	Relatively Low	74.9	
Earthquake	Very Low	5.2	
Hail	Relatively Low	45.6	
Heat Wave	No Rating	0	
Hurricane	Relatively Low	85.2	
Ice Storm	Very Low	24.2	
Landslide	No Rating	0	
Lightning	Very Low	21.2	
Riverine Flooding	Relatively Low	60.2	
Strong Wind	Very Low	20.4	
Tornado	Relatively Low	28.7	
Tsunami	Insufficient Data	–	
Volcanic Activity	Not Applicable	–	
Wildfire	Very Low	49.3	
Winter Weather	Very Low	15.9	

Risk Factor Breakdown

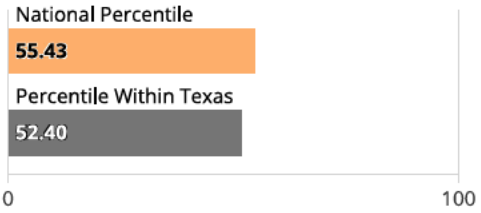
Hazard Type	EAL Value	Social Vulnerability	Community Resilience	CRF	Risk Value	Risk Index Score
Hurricane	$5,006,852	Very High	Relatively Low	1.5	$7,534,240	85.2
Riverine Flooding	$487,939	Very High	Relatively Low	1.5	$742,412	60.2
Tornado	$298,851	Very High	Relatively Low	1.5	$451,887	28.7
Coastal Flooding	$290,437	Very High	Relatively Low	1.5	$400,600	63
Drought	$141,606	Very High	Relatively Low	1.5	$196,421	74.9
Strong Wind	$72,935	Very High	Relatively Low	1.5	$110,200	20.4
Hail	$60,024	Very High	Relatively Low	1.5	$89,731	45.6
Cold Wave	$58,916	Very High	Relatively Low	1.5	$84,305	53.5
Wildfire	$27,094	Very High	Relatively Low	1.5	$38,913	49.3
Lightning	$25,381	Very High	Relatively Low	1.5	$38,387	21.2
Ice Storm	$10,202	Very High	Relatively Low	1.5	$15,328	24.2
Winter Weather	$7,841	Very High	Relatively Low	1.5	$11,819	15.9
Earthquake	$1,377	Very High	Relatively Low	1.5	$2,111	5.2
Heat Wave	$0	Very High	Relatively Low	1.5	$0	0
Landslide	$0	Very High	Relatively Low	1.5	$0	0
Avalanche	--	Very High	Relatively Low	1.5	--	--
Tsunami	--	Very High	Relatively Low	1.5	--	--
Volcanic Activity	--	Very High	Relatively Low	1.5	--	--

Expected Annual Loss

In **Refugio County, TX**, expected loss each year due to natural hazards is **Relatively Low** when compared to the rest of the U.S.



Score	55.43



55% of U.S. counties have a lower Expected Annual Loss

52% of counties in Texas have a lower Expected Annual Loss

Expected Annual Loss Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low

No Expected Annual Losses | Not Applicable | Insufficient Data

Composite Expected Annual Loss	**$6,489,453.93**
Composite Expected Annual Loss Rate National Percentile	**93.6**

Building EAL	**$5,444,060.01**	Population EAL	**0.05** fatalities
Building EAL Rate	**$1 per $278.89 of building value**	Population EAL Rate	**1 per 133.85K people**
Agriculture EAL	**$461,182.22**	Population Equivalence EAL	**$584,211.69**
Agriculture EAL Rate	**$1 per $89.27 of agriculture value**		

Expected Annual Loss for Hazard Types

Expected Annual Loss scores for hazard types are calculated using data for only a single hazard type, and reflect a community's relative expected annual loss for only that hazard type.

15 of 18 hazard types contribute to the expected annual loss for **Refugio County, TX**.

Hazard Type	Expected Annual Loss Rating	EAL Value	Score
Hurricane	Relatively Low	$5,006,852	81.0
Riverine Flooding	Relatively Low	$487,939	54.4

Hazard Type	Expected Annual Loss Rating	EAL Value	Score
Tornado	Very Low	$298,851	27.4
Coastal Flooding	Relatively Low	$290,437	62.4
Drought	Relatively Low	$141,606	73.3
Strong Wind	Relatively Low	$72,935	19.5
Hail	Very Low	$60,024	42.2
Cold Wave	Relatively Low	$58,916	52.0
Wildfire	Very Low	$27,094	44.4
Lightning	Very Low	$25,381	16.9
Ice Storm	Very Low	$10,202	21.7
Winter Weather	Very Low	$7,841	15.9
Earthquake	Very Low	$1,377	4.3
Heat Wave	No Expected Annual Losses	$0	0.0
Landslide	No Expected Annual Losses	$0	0.0
Avalanche	Not Applicable	--	--
Tsunami	Insufficient Data	--	--
Volcanic Activity	Not Applicable	--	--

Expected Annual Loss Values

Hazard Type	Total	Building Value	Population Equivalence	Population	Agriculture Value
Avalanche	--	--	--	--	--
Coastal Flooding	$290,437	$289,667	$770	0.00	n/a
Cold Wave	$58,916	$568	$15,149	0.00	$43,198
Drought	$141,606	n/a	n/a	n/a	$141,606
Earthquake	$1,377	$1,082	$295	0.00	n/a
Hail	$60,024	$43,126	$4,401	0.00	$12,497
Heat Wave	$0	$0	$0	0.00	$0
Hurricane	$5,006,852	$4,665,668	$93,982	0.01	$247,201
Ice Storm	$10,202	$2,835	$7,367	0.00	n/a
Landslide	$0	$0	$0	0.00	n/a
Lightning	$25,381	$2,092	$23,290	0.00	n/a
Riverine Flooding	$487,939	$265,675	$209,799	0.02	$12,465

Hazard Type	Total	Building Value	Population Equivalence	Population	Agriculture Value
Strong Wind	$72,935	$60,209	$9,176	0.00	$3,549
Tornado	$298,851	$84,377	$213,929	0.02	$544
Tsunami	n/a	n/a	n/a	n/a	n/a
Volcanic Activity	--	--	--	--	--
Wildfire	$27,094	$26,905	$122	0.00	$67
Winter Weather	$7,841	$1,855	$5,930	0.00	$55

Exposure Values

Hazard Type	Total	Building Value	Population Equivalence	Population	Agriculture Value
Avalanche	--	--	--	--	--
Coastal Flooding	$2,714,252,574	$41,651,849	$2,672,600,725	230.40	n/a
Cold Wave	$79,755,047,225	$1,518,277,381	$78,195,600,000	6,741.00	$41,169,844
Drought	$20,519,696	n/a	n/a	n/a	$20,519,696
Earthquake	$79,713,854,000	$1,518,254,000	$78,195,600,000	6,741.00	n/a
Hail	$79,755,047,225	$1,518,277,381	$78,195,600,000	6,741.00	$41,169,844
Heat Wave	$0	$0	$0	0.00	$0
Hurricane	$79,754,882,263	$1,518,277,381	$78,195,600,000	6,741.00	$41,004,882
Ice Storm	$79,713,877,381	$1,518,277,381	$78,195,600,000	6,741.00	n/a
Landslide	$0	$0	$0	0.00	n/a
Lightning	$79,713,877,381	$1,518,277,381	$78,195,600,000	6,741.00	n/a
Riverine Flooding	$4,137,026,188	$63,020,147	$4,072,730,525	351.10	$1,275,516
Strong Wind	$79,755,047,225	$1,518,277,381	$78,195,600,000	6,741.00	$41,169,844
Tornado	$79,755,047,225	$1,518,277,381	$78,195,600,000	6,741.00	$41,169,844
Tsunami	n/a	n/a	n/a	n/a	n/a
Volcanic Activity	--	--	--	--	--
Wildfire	$3,276,782,991	$73,881,450	$3,199,565,922	275.82	$3,335,620
Winter Weather	$79,755,047,225	$1,518,277,381	$78,195,600,000	6,741.00	$41,169,844

Annualized Frequency Values

Hazard Type	Annualized Frequency	Events on Record	Period of Record
Avalanche	--	--	--

Hazard Type	Annualized Frequency	Events on Record	Period of Record
Coastal Flooding	3.7 events per year	n/a	Various (see documentation)
Cold Wave	0.3 events per year	5	2005-2021 (16 years)
Drought	47.2 events per year	1,092	2000-2021 (22 years)
Earthquake	0.009% chance per year	n/a	2021 dataset
Hail	1.2 events per year	40	1986-2021 (34 years)
Heat Wave	0 events per year	0	2005-2021 (16 years)
Hurricane	0.1 events per year	24	East 1851-2021 (171 years) / West 1949-2021 (73 years)
Ice Storm	0.3 events per year	24	1946-2014 (67 years)
Landslide	0 events per year	0	2010-2021 (12 years)
Lightning	59 events per year	1,298	1991-2012 (22 years)
Riverine Flooding	1.5 events per year	36	1996-2019 (24 years)
Strong Wind	0.8 events per year	29	1986-2021 (34 years)
Tornado	0.3 events per year	19	1950-2021 (72 years)
Tsunami	n/a	n/a	1800-2021 (222 years)
Volcanic Activity	--	--	--
Wildfire	0.155% chance per year	n/a	2021 dataset
Winter Weather	0.3 events per year	5	2005-2021 (16 years)

Historic Loss Ratios

Hazard Type	Overall Rating
Avalanche	--
Coastal Flooding	Relatively Low
Cold Wave	Very Low
Drought	Relatively Low
Earthquake	Very Low
Hail	Relatively Moderate
Heat Wave	No Rating
Hurricane	Very High
Ice Storm	Relatively Low
Landslide	No Rating
Lightning	Relatively Low

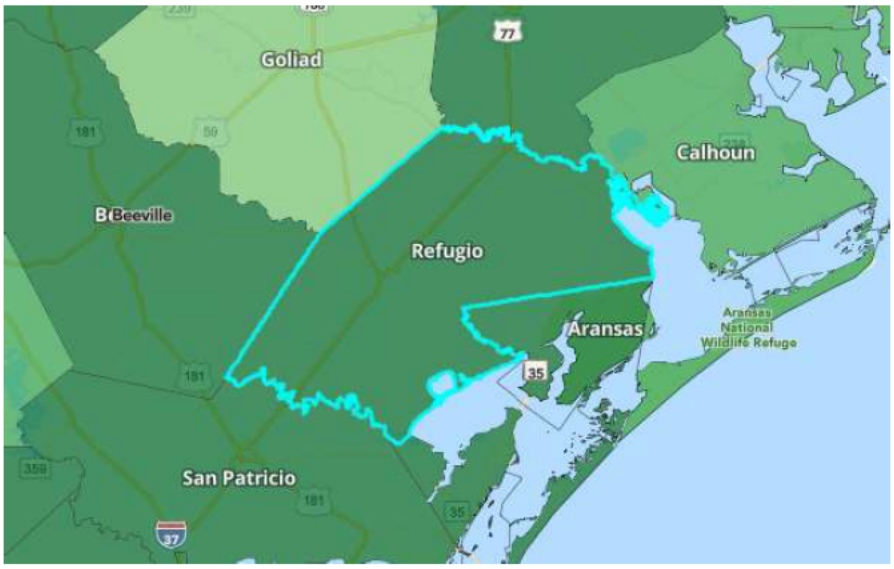
Hazard Type	Overall Rating
Riverine Flooding	Relatively Low
Strong Wind	Relatively Moderate
Tornado	Relatively Moderate
Tsunami	Insufficient Data
Volcanic Activity	--
Wildfire	Relatively Low
Winter Weather	Relatively Moderate

Expected Annual Loss Rate

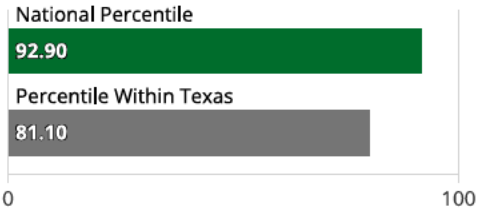
Hazard Type	Building EAL Rate (per building value)	Population EAL Rate (per population)	Agriculture EAL Rate (per agriculture value)
Avalanche	--	--	--
Coastal Flooding	$1 per $5.24K	1 per 101.50M	–
Cold Wave	$1 per $2.67M	1 per 5.16M	$1 per $953.05
Drought	–	–	$1 per $290.73
Earthquake	$1 per $1.40M	1 per 264.99M	–
Hail	$1 per $35.21K	1 per 17.77M	$1 per $3.29K
Heat Wave	–	–	–
Hurricane	$1 per $325.41	1 per 832.02K	$1 per $166.54
Ice Storm	$1 per $535.59K	1 per 10.61M	–
Landslide	–	–	–
Lightning	$1 per $725.83K	1 per 3.36M	–
Riverine Flooding	$1 per $5.71K	1 per 372.72K	$1 per $3.30K
Strong Wind	$1 per $25.22K	1 per 8.52M	$1 per $11.60K
Tornado	$1 per $17.99K	1 per 365.52K	$1 per $75.68K
Tsunami	–	–	–
Volcanic Activity	--	--	--
Wildfire	$1 per $56.43K	1 per 638.46M	$1 per $618.38K
Winter Weather	$1 per $818.30K	1 per 13.19M	$1 per $749.29K

Social Vulnerability

Social groups in **Refugio County, TX** have a **Very High** susceptibility to the adverse impacts of natural hazards when compared to the rest of the U.S.



Score **92.9**



93% of U.S. counties have a lower Social Vulnerability

81% of counties in Texas have a lower Social Vulnerability

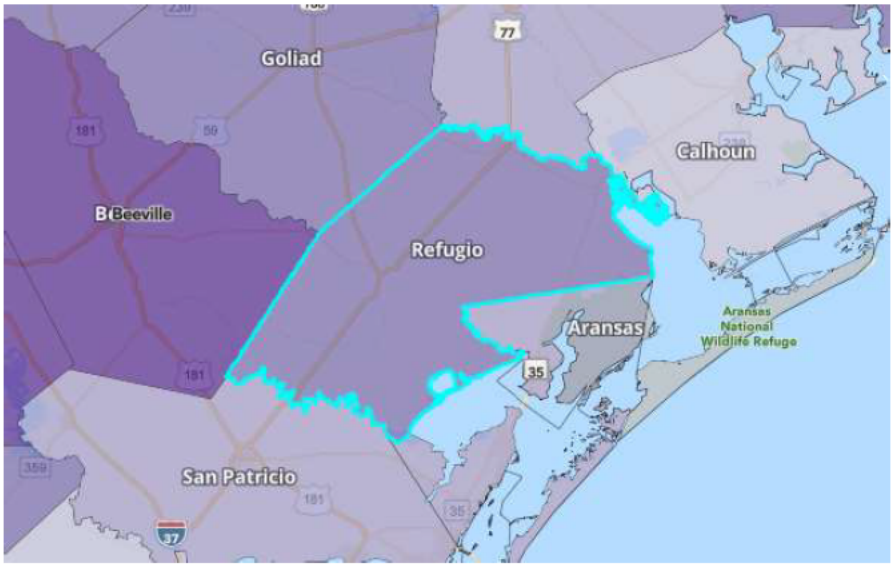
Social Vulnerability Legend

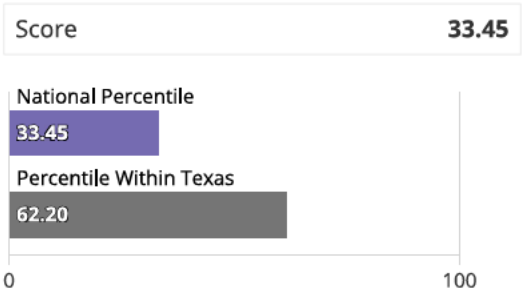
Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low

Data Unavailable

Community Resilience

Communities in **Refugio County, TX** have a **Relatively Low** ability to prepare for anticipated natural hazards, adapt to changing conditions, and withstand and recover rapidly from disruptions when compared to the rest of the U.S.





67% of U.S. counties have a higher Community Resilience

38% of counties in Texas have a higher Community Resilience

Community Resilience Legend

Very High | Relatively High | Relatively Moderate | Relatively Low | Very Low | Data Unavailable

About the National Risk Index

The National Risk Index is a dataset and online tool to help illustrate the United States communities most at risk for 18 natural 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.

The National Risk Index leverages available source data for Expected Annual Loss due to these 18 hazard types, Social Vulnerability, and Community Resilience to develop a baseline relative risk measurement for each United States county and Census tract. These measurements are calculated using average past conditions, but they cannot be used to predict future outcomes for a community. The National Risk Index is intended to fill gaps in available data and analyses to better inform federal, state, local, tribal, and territorial decision makers as they develop risk reduction strategies.

Explore the National Risk Index Map at **hazards.fema.gov/nri/map**.

Visit the National Risk Index website at **hazards.fema.gov/nri/learn-more** to access supporting documentation and links.

Calculating the Risk Index

Risk Index scores are calculated using an equation that combines scores for Expected Annual Loss due to natural hazards, Social Vulnerability and Community Resilience:

Risk Index = Expected Annual Loss × Social Vulnerability ÷ Community Resilience

Risk Index scores are presented as a composite score for all 18 hazard types, as well as individual scores for each hazard type.

For more information, visit **hazards.fema.gov/nri/determining-risk**.

Calculating Expected Annual Loss

Expected Annual Loss scores are calculated using an equation that combines values for exposure, annualized frequency, and historic loss ratios for 18 hazard types:

Expected Annual Loss = Exposure × Annualized Frequency × Historic Loss Ratio

Expected Annual Loss scores are presented as a composite score for all 18 hazard types, as well as individual scores for each hazard type.

For more information, visit **hazards.fema.gov/nri/expected-annual-loss**.

Calculating Social Vulnerability

Social Vulnerability is measured using the Social Vulnerability Index (SVI) published by the Centers for Disease Control and Prevention (CDC).

For more information, visit **hazards.fema.gov/nri/social-vulnerability**.

Calculating Community Resilience

Community Resilience is measured at the County level using the Baseline Resilience Indicators for Communities (HVRI BRIC) published by the University of South Carolina's Hazards and Vulnerability Research Institute (HVRI).

For more information, visit **hazards.fema.gov/nri/community-resilience**.

How to Take Action

There are many ways to reduce natural hazard risk through mitigation. Communities with high National Risk Index scores can take action to reduce risk by decreasing Expected Annual Loss due to natural hazards, decreasing Social Vulnerability, and increasing Community Resilience.

For information about how to take action and reduce your risk, visit **hazards.fema.gov/nri/take-action**.

Disclaimer

The National Risk Index (the Risk Index or the Index) and its associated data are meant for planning purposes only. This tool was created for broad nationwide comparisons and is not a substitute for localized risk assessment analysis. Nationwide datasets used as inputs for the National Risk Index are, in many cases, not as accurate as available local data. Users with access to local data for each National Risk Index risk factor should consider substituting

the Risk Index data with local data to recalculate a more accurate risk index. If you decide to download the National Risk Index data and substitute it with local data, you assume responsibility for the accuracy of the data and any resulting data index. Please visit the **Contact Us** page if you would like to discuss this process further.

The methodology used by the National Risk Index has been reviewed by subject matter experts in the fields of natural hazard risk research, risk analysis, mitigation planning, and emergency management. The processing methods used to create the National Risk Index have produced results similar to those from other natural hazard risk analyses conducted on a smaller scale. The breadth and combination of geographic information systems (GIS) and data processing techniques leveraged by the National Risk Index enable it to incorporate multiple hazard types and risk factors, manage its nationwide scope, and capture what might have been missed using other methods.

The National Risk Index does not consider the intricate economic and physical interdependencies that exist across geographic regions. Keep in mind that hazard impacts in surrounding counties or Census tracts can cause indirect losses in your community regardless of your community's risk profile.

Nationwide data available for some risk factors are rudimentary at this time. The National Risk Index will be continuously updated as new data become available and improved methodologies are identified.

The National Risk Index Contact Us page is available at **hazards.fema.gov/nri/contact-us**.

APPENDIX I-9 IS

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX J: PLUGGING SCHEMATICS AND PROCEDURES

- Appendix J-1 Snapper Injection Well Zonal Isolation Schematics
- Appendix J-2 Injection Well Detailed Plugging Procedure
- Appendix J-3 Injection Well Final Plugging Schematics
- Appendix J-4 USDW Monitoring Well Detailed Plugging Procedure
- Appendix J-5 USDW Monitoring Well Final Plugging Schematics
- Appendix J-6 AZM Well Detailed Plugging Procedure
- Appendix J-7 AZM Well Final Plugging Schematics
- Appendix J-8 IZM Well Detailed Plugging Procedure
- Appendix J-9 IZM Well Final Plugging Schematics

APPENDICES J-1 TO J-10 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX K: FAULT STABILITY ANALYSIS

- Appendix K-1 Fault Stability Analysis

APPENDIX K-1 IS

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX L: ENVIRONMENTAL AND COMMUNITY IMPACT ANALYSIS

- Appendix L-1 Project EJScreen Community Report
- Appendix L-2 Community Stakeholders

APPENDICES L-1 TO L-2 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.