Subpart RR Monitoring, Reporting, and Verification Plan
Titan Treating Facility

Lea County, New Mexico

Prepared for *Northwind Midstream Partners LLC.*
Houston, TX

By

Lonquist Sequestration, LLC
Austin, Texas

Version 1.4
January 2025

INTRODUCTION

Northwind Midstream Partners LLC (Northwind) has Class II wells permitted by the New Mexico Oil Conservation Division (NMOCD) for the purposes of acid gas injection (AGI) in Lea County, NM. The two AGI wells are associated with Northwind's Titan Gas Gathering Plant, which is located adjacent to the wells in Section 21, Township 26S, Range 36E. Salt Creek AGI No. 3 was drilled and completed as a vertical well in October 2023 for injection into the Delaware Mountain Group (DMG) formation. Salt Creek AGI No. 2 is permitted as a directional well for injection into the Siluro-Devonian formation. Drilling for the Salt Creek AGI No. 2 commenced in August 2024 and is expected to be completed and starting injection by the end of 2024. Salt Creek AGI No. 2 is being drilled directionally approximately 1,400 feet (ft) to the southeast of its surface location to access more favorable reservoir conditions based on 3D seismic evaluation. Several of the supporting documents provided with this application may refer to the Salt Creek AGI No. 1 well. This well was originally permitted for injection into the DMG. However, issues arose during drilling that prevented it from being completed and was therefore plugged and abandoned. The Salt Creek AGI No. 3 was then approved as a replacement well to the Salt Creek No. 1.

Salt Creek AGI No. 2 is permitted for 12 million standard cubic feet per day (MMscf/d) of treated acid gas (TAG) from the Titan Treating Facility with a maximum allowable surface injection pressure (MASIP) of 5,798 pounds per square inch (psi). Salt Creek AGI No. 3 is permitted for 8 MMscf/d of TAG with a MASIP of 2,149 psi.

Northwind is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). Northwind intends to inject into these wells for approximately 30 years at up to a maximum of 12 MMscf/d into Salt Creek AGI No. 2 and 8 MMscf/d into Salt Creek AGI No. 3. The primary source of this injected CO_2 gas is the Titan Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered.

Table 1 – Expected Gas Composition

	Mol Percent
Carbon Dioxide (CO_2)	70
Hydrogen Sulfide (H_2S)	30

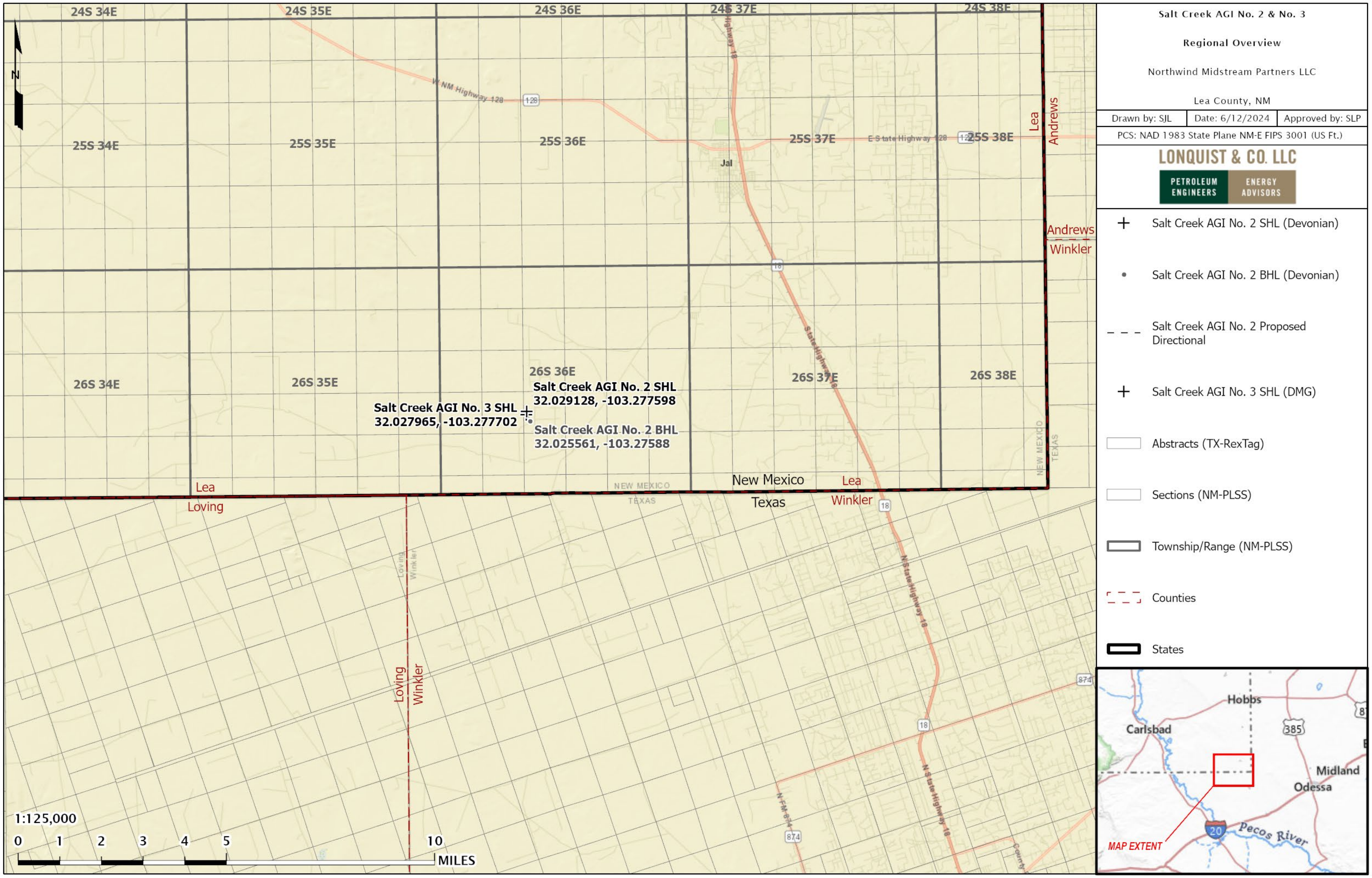


Figure 1 – Locations of Salt Creek AGI No. 2 and No. 3.

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AGI	Acid Gas Injection
AMA	Active Monitoring Area
API	American Petroleum Institute
BCF	Billion Cubic Feet
BHP	Bottomhole Pressure
CFR	Code of Federal Regulation
CH_4	Methane
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
MCF	Thousand Cubic Feet
mD	Millidarcy(ies)
mg/l	Milligrams per liter
Mi	Mile(s)

MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/d	Thousand Standard Cubic Feet per Day
MMscf/d	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
N_2	Nitrogen
NIST	National Institute of Standards and Technology
NMOCD	New Mexico Oil Conservation Division
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PEL	Permissible Exposure Limit
PG	Pore Gradient
pH	Scale of Acidity
PISC	Post Injection Site Care
ppm	Parts per Million
psi	Pounds per Square Inch
psi/ft	Pounds per Square Inch per Foot
psig	Pounds per Square Inch Gauge
RFD	Rock Flow Dynamic
S	South
SCADA	Supervisory Control and Data Acquisition
SE	Southeast
SF	Safety Factor
SLB	Schlumberger

SWD	Saltwater Disposal
TAG	Treated Acid Gas
TDS	Total Dissolved Solid
TOC	Total Organic Carbon
TVD	True Vertical Depth
TWA	Time-Weighted Average
TWDB	Texas Water Development Board
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
W	West
WHP	Wellhead Pressure

TABLE OF CONTENTS

FIGURES

TABLES

Appendices

Appendix A – New Mexico Salt Creek AGI Forms
Appendix A-1 – UIC Class II Order, Salt Creek No. 2
Appendix A-2 – UIC Class II Order, Salt Creek No. 3
Appendix A-3 – Drilling Permit, Salt Creek No. 3
Appendix A-3 – Completion Report (as submitted), Salt Creek No. 3

Appendix B – Site Safety and Layout
Appendix B-1 – Titan Plant Safety Location Plan
Appendix B-2 – Salt Creek AGI No. 2 Piping and Instrumentation Diagram
Appendix B-3 – Salt Creek AGI No. 3 Piping and Instrumentation Diagram
Appendix B-4 – Titan Safety Layout Schematic

Appendix C – Area of Review
Appendix C-1 – Maximum Monitoring Area Delineation
Appendix C-2 – Active Monitoring Area
Appendix C-3 – Map of Oil and Gas Wells in the MMA/AMA
Appendix C-4 – List of Oil and Gas Wells in the MMA
Appendix C-5 – Map of Penetrating Oil and Gas wells in the MMA/AMA
Appendix C-6 – Map of Penetrating Oil and Gas wells in the MMA with plumes
Appendix C-7 – Map of Groundwater Wells in the MMA/AMA
Appendix C-8 – List of Groundwater Wells in the MMA/AMA

Appendix D – Section 2 Geology
Appendix D-1 – Structure map of top of the Delaware Mountain Group
Appendix D-2 – Structure map of top of the Siluro-Devonian
Appendix D-3 – Fault Slip potential model results

SECTION 1 – FACILITY INFORMATION

1.1 Underground Injection Control Permit Class: Class II

The New Mexico Oil Conservation Division (NMOCD) regulates oil and gas activities in New Mexico and has primacy over the underground injection control (UIC) Class II program. Northwind is the operator of record for the two permitted Class II AGI wells associated with their Titan Treating Facility.

1.2 UIC Well Identification Number

Salt Creek AGI No. 2 (Devonian):

API No.:	30-025-TBD
Order No.:	SWD-2580
Surface Location:	32.029128, -103.277598 (NAD 83)
Bottomhole Location:	32.025561, -103.275880 (NAD 83)

Salt Creek AGI No. 3 (Delaware):

API No.	30-025-51865
Order No.	R-20913
Location:	32.027965, -103.277702 (NAD 83)

1.3 Reporting Information

- Facility Name: Titan Treating Facility
- Greenhouse Gas Reporting Program ID: 574428
- Operator Name: Northwind Midstream Partners LLC
- Organization ID: 1482782

NOTE: No data has previously been reported for injection at the Salt Creek AGI No. 3 well. Data for both wells will be reported under Subpart RR under the Program ID shown here.

1.4 Facility Address

108 Beckham Rd
Jal, New Mexico 88252

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Salt Creek AGI No. 2 and No. 3 wells. The Salt Creek AGI No. 2 and No. 3 will inject TAG consisting of both H_2S and CO_2 into the Siluro-Devonian formation and Delaware Mountain Group formations, respectively. The two wells and the gas treating plant are designed to protect against the leakage out of the injection interval, protect against contaminating other subsurface formations, and prevent surface releases.

2.1 Sources of CO_2/H_2S

The CO_2/H_2S stream to be injected into the Salt Creek AGI wells will be captured and piped via buried pipelines from Northwind's Titan Treating Facility, approximately 0.1 miles (mi) and 0.2 mi respectively from the Salt Creek AGI No. 2 and No. 3. The natural gas treated at these plants is produced from oil and gas wells in New Mexico, particularly Lea County.

2.2 Regional Geology

The Titan Treating Facility is located on the eastern edge of the Delaware Basin on the transition boundary from the Central Basin Platform (CBP) within the larger Permian Basin, as seen in Figure 2. The Delaware Basin is a depositional and structural basin located in the western portion of the Permian Basin.

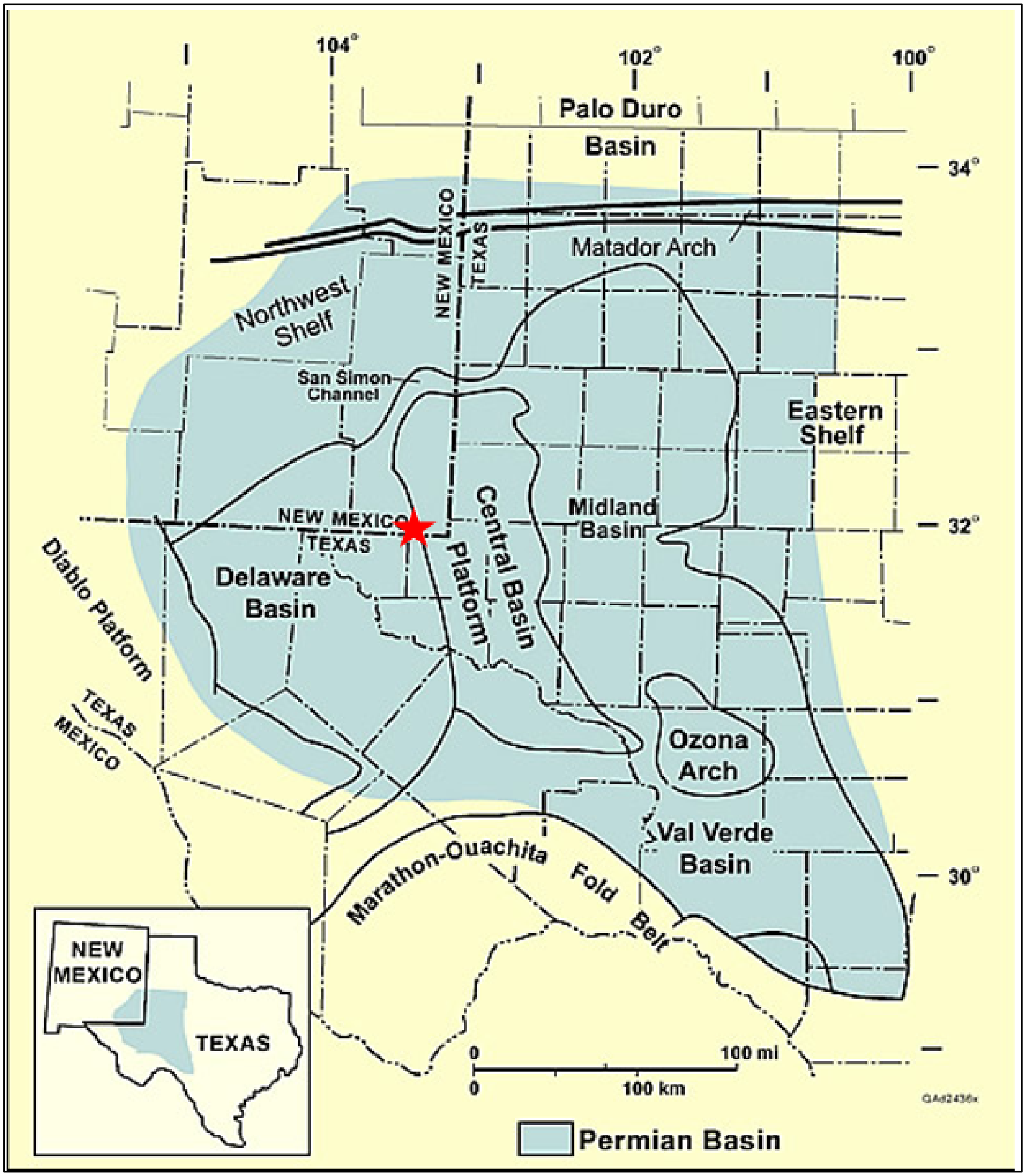


Figure 2 – Regional Map of the Permian Basin. The red star is the approximate location of Titan Treating Facility.

Figure 3 depicts the stratigraphic column found at the area of the Titan Treating Facility with a green star referencing the injection formation and red stars indicating the productive intervals in the area. The primary injection interval for Salt Creek AGI No. 2 is found within the "Silurian-Devonian" or "Siluro-Devonian" formation, and for Salt Creek AGI No. 3 is Delaware Mountain Group. The Siluro-Devonian includes the Thirtyone formation, the Wristen Group, and the Fusselman formation, as depicted in Figure 4. Note, while the Fusselman is productive of hydrocarbons in some parts of the basin, there is no historical production from the Fusselman within four miles of the Titan Treating Facility.

SYSTEM	SERIES/ STAGE	NORTHWEST SHELF	CENTRAL BASIN PLATFORM	MIDLAND BASIN & EASTERN SHELF	DELAWARE BASIN	VAL VERDE BASIN
PERMIAN	OCHOAN	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO CASTILE	RUSTLER SALADO
	GUADALUPIAN	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES GLORIETA	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES GLORIETA	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES SAN ANGELO	DELAWARE MT. GROUP BELL CANYON CHERRY CANYON BRUSHY CANYON	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES
	LEONARDIAN	CLEARFORK YESO WICHITA ABO	CLEARFORK WICHITA	LEONARD SPRABERRY, DEAN	BONE SPRING	LEONARD
	WOLFCAMPIAN	WOLFCAMP	WOLFCAMP	WOLFCAMP	WOLFCAMP	WOLFCAMP
PENNSYLVANIAN	VIRGILIAN	CISCO	CISCO	CISCO	CISCO	CISCO
	MISSOURIAN	CANYON	CANYON	CANYON	CANYON	CANYON
	DESMOINESIAN	STRAWN	STRAWN	STRAWN	STRAWN	STRAWN
	ATOKAN	ATOKA BEND	ATOKA BEND	ATOKA BEND	ATOKA BEND	(ABSENT)
	MORROWAN	MORROW	(ABSENT)	(ABSENT ?)	MORROW	(ABSENT)
MISSISSIPPIAN	CHESTERIAN MERAMECIAN OSAGEAN KINDERHOOKIAN	CHESTER MERAMEC OSAGE KINDERHOOK	CHESTER MERAMEC OSAGE "BARNETT" KINDERHOOK	CHESTER MERAMEC OSAGE "BARNETT" KINDERHOOK	CHESTER MERAMEC OSAGE "BARNETT" KINDERHOOK	MERAMEC OSAGE "BARNETT" KINDERHOOK
DEVONIAN		WOODFORD DEVONIAN	WOODFORD DEVONIAN	WOODFORD DEVONIAN	WOODFORD DEVONIAN	WOODFORD DEVONIAN
SILURIAN		SILURIAN (UNDIFFERENTIATED)	SILURIAN SHALE FUSSELMAN	SILURIAN SHALE FUSSELMAN	MIDDLE SILURIAN FUSSELMAN	MIDDLE SILURIAN FUSSELMAN
ORDOVICIAN	UPPER	MONTOYA	MONTOYA	SYLVAN MONTOYA	SYLVAN MONTOYA	SYLVAN MONTOYA
	MIDDLE	SIMPSON	SIMPSON	SIMPSON	SIMPSON	SIMPSON
	LOWER	ELLENBURGER	ELLENBURGER	ELLENBURGER	ELLENBURGER	ELLENBURGER
CAMBRIAN	UPPER	CAMBRIAN	CAMBRIAN	CAMBRIAN	CAMBRIAN	CAMBRIAN
PRECAMBRIAN						

Figure 3 – Stratigraphic column of the Delaware Basin. Green star indicates injection interval. Red star indicates productive intervals.

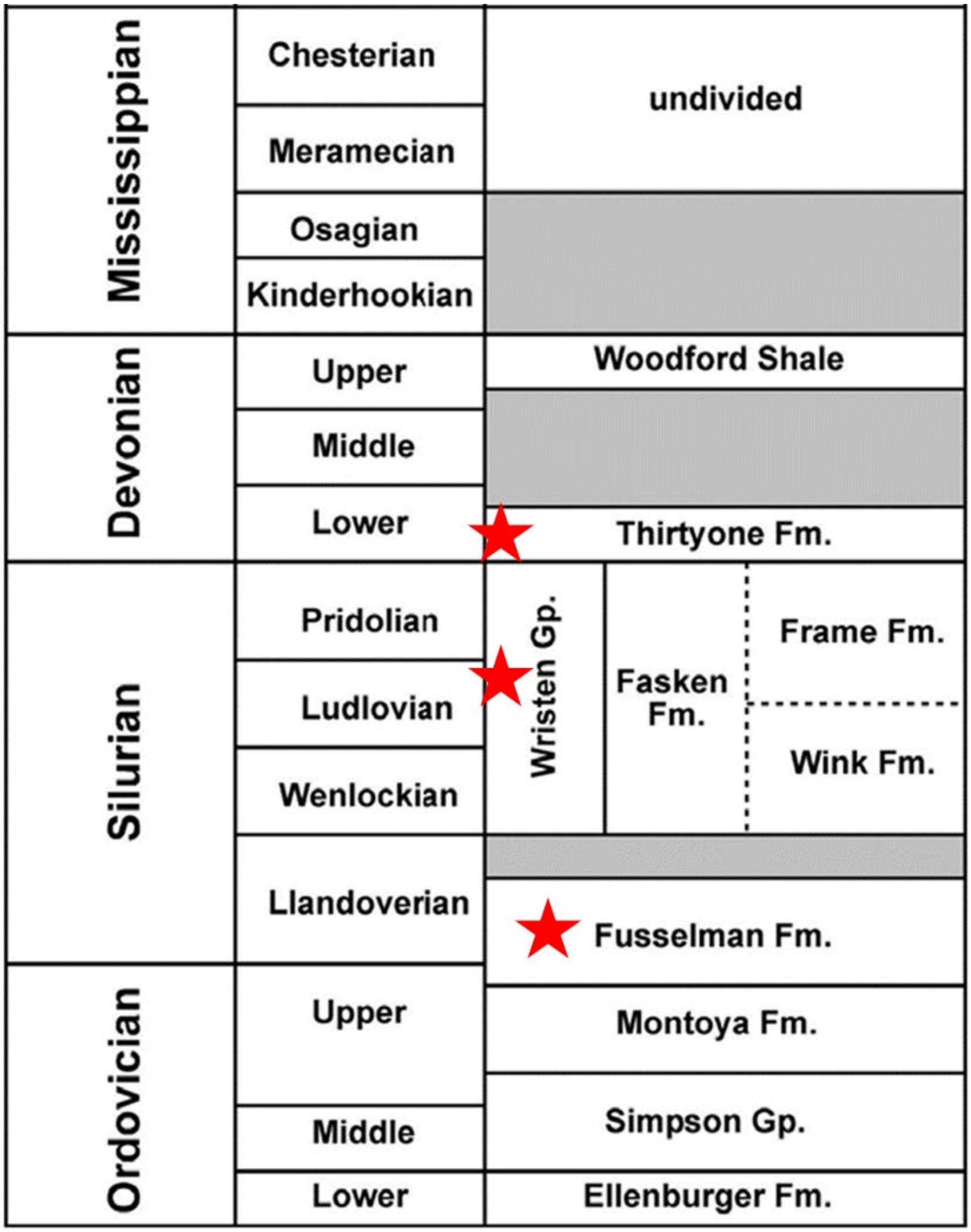


Figure 4 – Stratigraphic column of the Devonian Silurian. Red stars represent the proposed injection targets (Broadhead, 2005).

2.2.1 Siluro-Devonian

The Thirtyone Formation was deposited in an "outer platform to basin setting" which allowed for accumulations of chert and carbonates (Ruppel and Holtz, 1994). The extents and thickness of the Thirtyone formation are displayed in Figure 5, with the extents to the north and south being controlled by erosion. The southern erosion event was directly affected by the pre-Late Devonian Fort Stockton Uplift while the northern erosion event was a Middle Devonian-aged event that is truncated in central Andrews County (Ruppel and Holtz, 1994). Facies ratios within the Thirtyone formation vary across the deposited area with chert being the prominent facies to the south around the depocenter with carbonates being the prominent to the north (Ruppel and Holtz, 1994). The Titan Treating Facility is located on the western boundary of the Thirtyone deposit and will encounter both chert and carbonates within the Thirtyone formation.

The Wristen Group at the Titan Treating Facility is primarily composed of the Frame and Wink formations. The muddy texture within the Frame formation indicates a "deep-water, below-wave-base conditions, probably representative of a slope or basinal setting" (Ruppel and Holtz, 1994). The Wink resembles an outer platform environment below wave base conditions that was the "beginning of the drowning of the extensive shallow-water Fusselman platform" (Ruppel and Holtz, 1994). Facies within these formations at the Titan Treating Facility will consist of outer ramp-slope mudstone and skeletal wackestone within the Frame formation and outer ramp-slope pelmatozoan packstone and grainstone, locally siliceous within the Wink formation (Ruppel and Holtz, 1994). Extents of the Wink and Frame formations within the Wristen Group are predominantly found in the southern half to the Silurian subcrop with the Wristen platform margin, found in central Andrews County, as the boundary where the Frame and Wink grade into the Fasken formation to the north. This distribution is depicted in Figure 6 where the Titan Treating Facility is located just south of the Wristen platform margin.

The Fusselman formation was deposited in an "open-marine, shallow water carbonate platform" that "comprises a diverse succession of shallow-water carbonate facies" (Ruppel and Holtz, 1994). Primary carbonate rock successions within the Fusselman at the Titan Treating Facility will be shallow shelf ooid grainstone and pelmatozoan packstone. Dolomitization boundaries within the Fusselman indicate repeated sea level falls, with the Titan Treating Facility being located at the southern boundary of dolomite distribution seen in Figure 7 (Ruppel and Holtz, 1994).

Similar diagenetic processes occurred within each of the formations within the injection zone. These processes heavily altered the rocks within these formations that include features, such as silica replacement, vug and karst development, and dolomitization (Ruppel and Holtz, 1994). These processes were heavily influenced by the rising and falling of sea level and have a large impact on the reservoir development within the injection interval. This reservoir development process resulted in the formation of secondary porosity and permeability features within the injection zone, which will serve as the main reservoirs to accept the injectate from Salt Creek AGI No. 2.

A map showing the thickness of the Silurian system, which includes both the Wristen Group and the Fusselman, is depicted in Figure 8. The thickness of the Silurian-age rock is approximately 1,200 ft at the Salt Creek AGI No. 2 well location. Figure 9 shows a regional cross section showing the carbonate rock types previously described. The cross section reference line can be found in Figure 5 as D-D'.

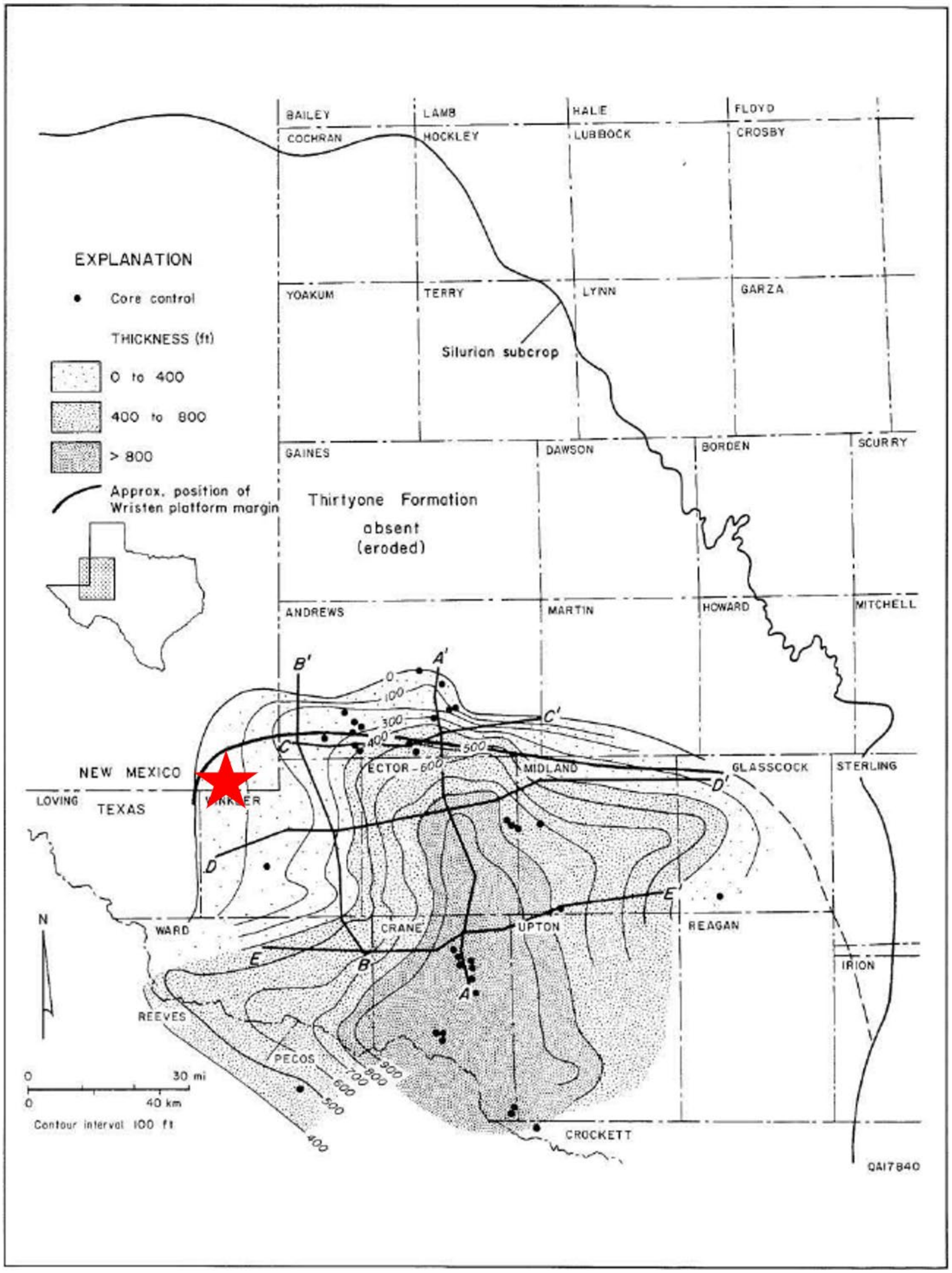


Figure 5 – Thickness map of Thirtyone formation. Red star indicates Salt Creek AGI No. 2 (Ruppel and Holtz, 1994).

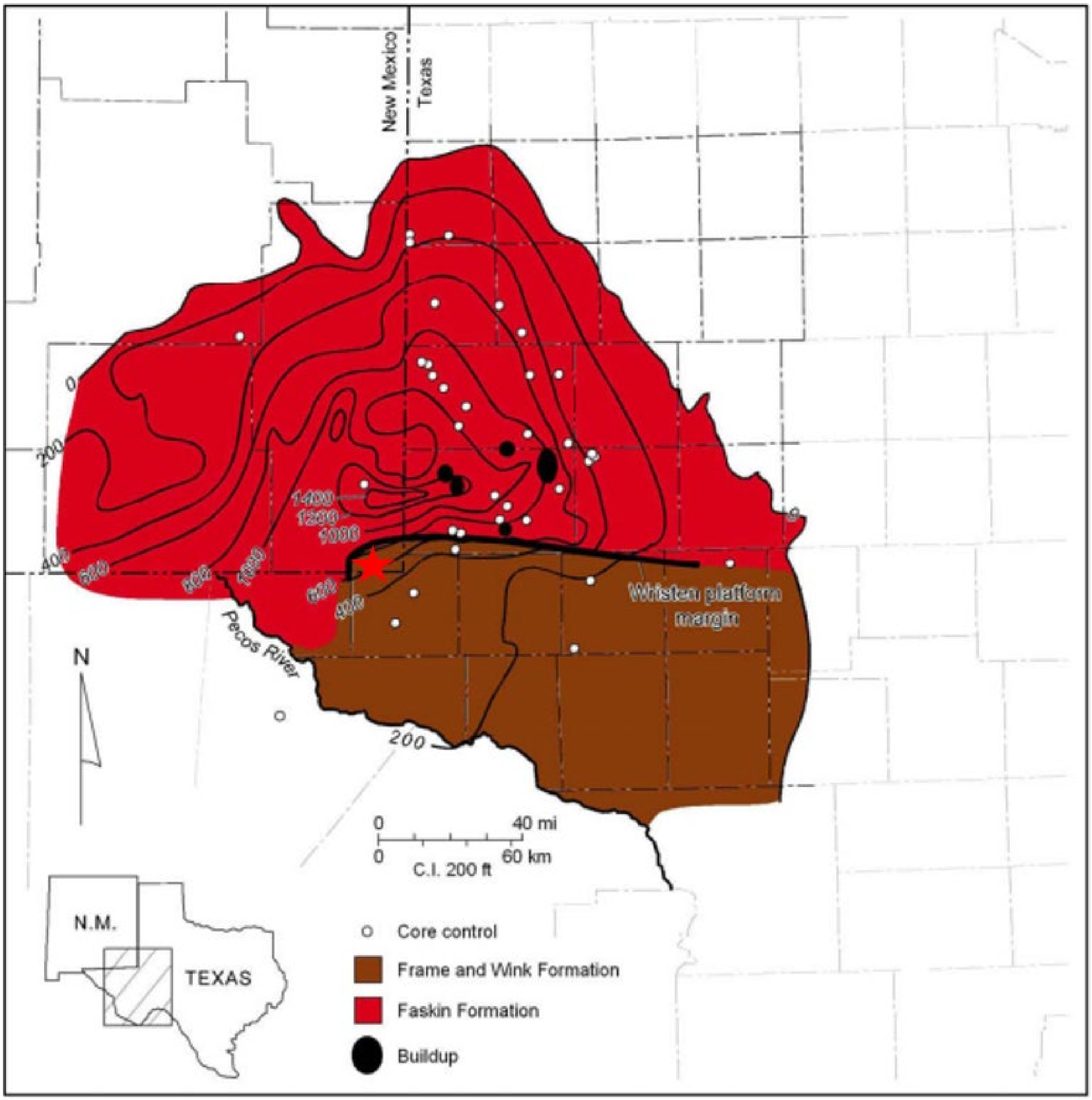


Figure 6 – Thickness and distribution map of the Wristen Group. Red star represents Salt Creek AGI No. 2 location (Ruppel S. C., 2006).

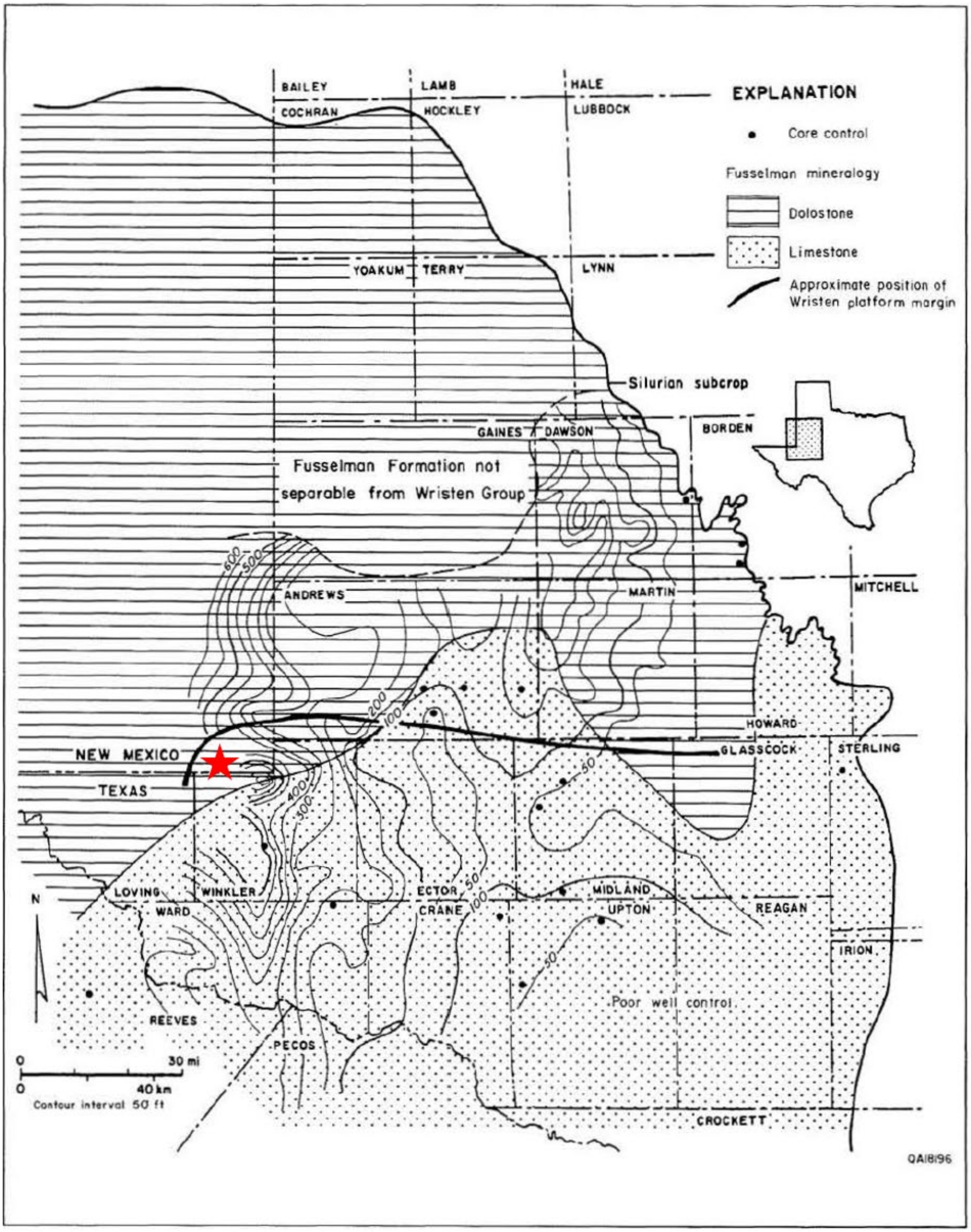


Figure 7 – Thickness and facies distribution map of the Fusselman formation. Red star represents Salt Creek AGI No. 2 location (Ruppel and Holtz, 1994).

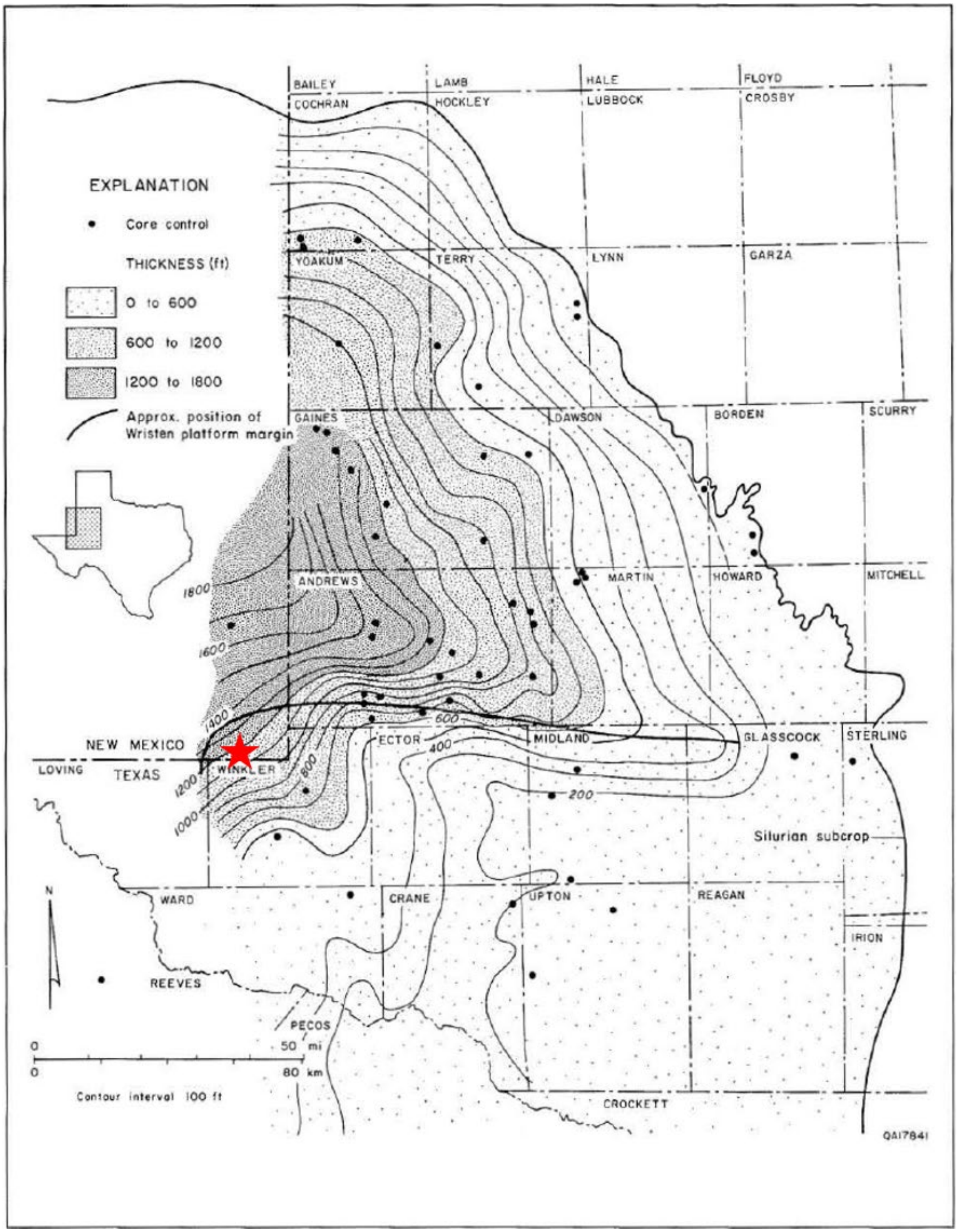


Figure 8 – Thickness map of the Silurian System. Red star represents the Salt Creek AGI No. 2 location (Ruppel and Holtz, 1994).

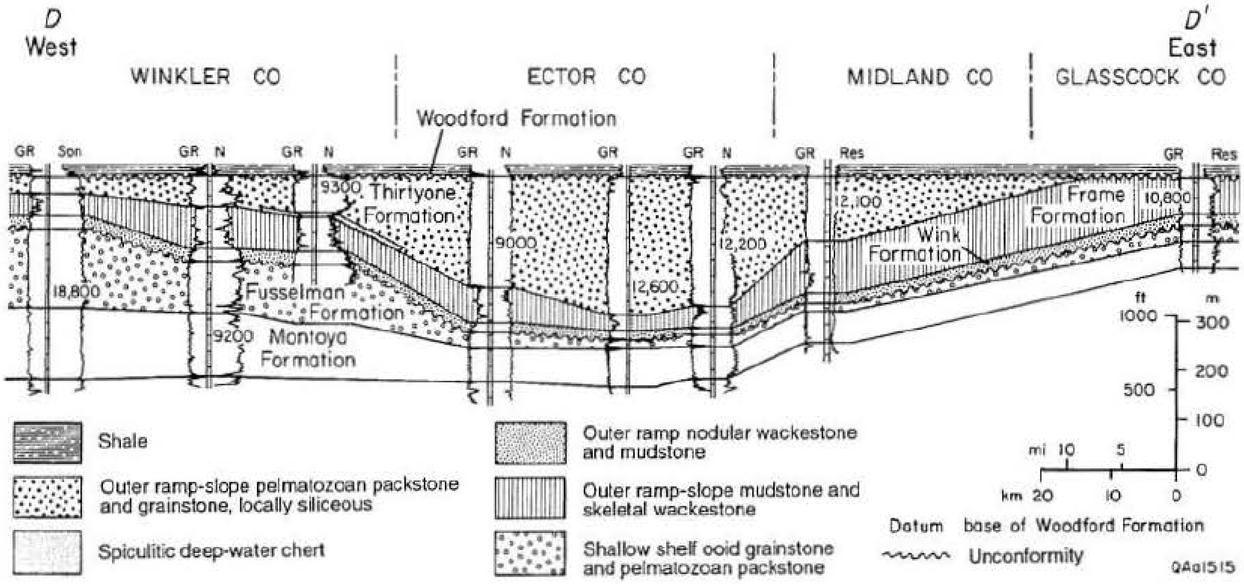


Figure 9 – Regional cross section showing distributions of Silurian and Devonian carbonate rock successions. Cross section reference line can be seen in Figure 5 (Ruppel and Holtz, 1994).

2.2.2 Delaware Mountain Group

The Delaware Mountain Group (DMG) is of Guadalupian age and primarily consists of subarkosic sandstone, siltstone, and detrital limestone (Nance). The DMG is only present within the Delaware Basin, a sub-basin of the greater Permian Basin as seen previously in Figure 2. This basin is bounded by carbonate ramp and carbonate rim margins that allowed for shelf-derived siliciclastics and shelf-margin-derived carbonates to be deposited within the DMG during intermittent sea level lowstands (Nance). Within the DMG, there are three formations identified as the Bell Canyon, Cherry Canyon, and Brushy Canyon, as depicted in the stratigraphic column found in Figure10. The proximity to the CBP leads to unconformities within the DMG along the eastern margin of the Delaware Basin, posing challenges in defining the boundaries of these formation tops. As a result, the injection interval for the Salt Creek AGI No. 3 well at the Titan Treating Facility will be referred to simply as the "Delaware" or DMG.

Primary facies within the DMG are subarkosic sandstones and siltstones with carbonates being of secondary importance with increasing prominence shelfward (Nance). This increase is proven through the presence of carbonates at the Titan Treating Facility. Diagenetic processes within the DMG, such as feldspar dissolution, feldspar and quartz authigenesis, clay authigenesis, and calcite cementation, directly impacted reservoir development (Nance). Sub-facies within the sandstones are composed of channel, levee, overbank splay, and lobe sands with turbidity flows being the primary transport for coarser sediment (Nance). These features and distributions allow for optimal injection reservoirs in the Titan Treating Facility area.

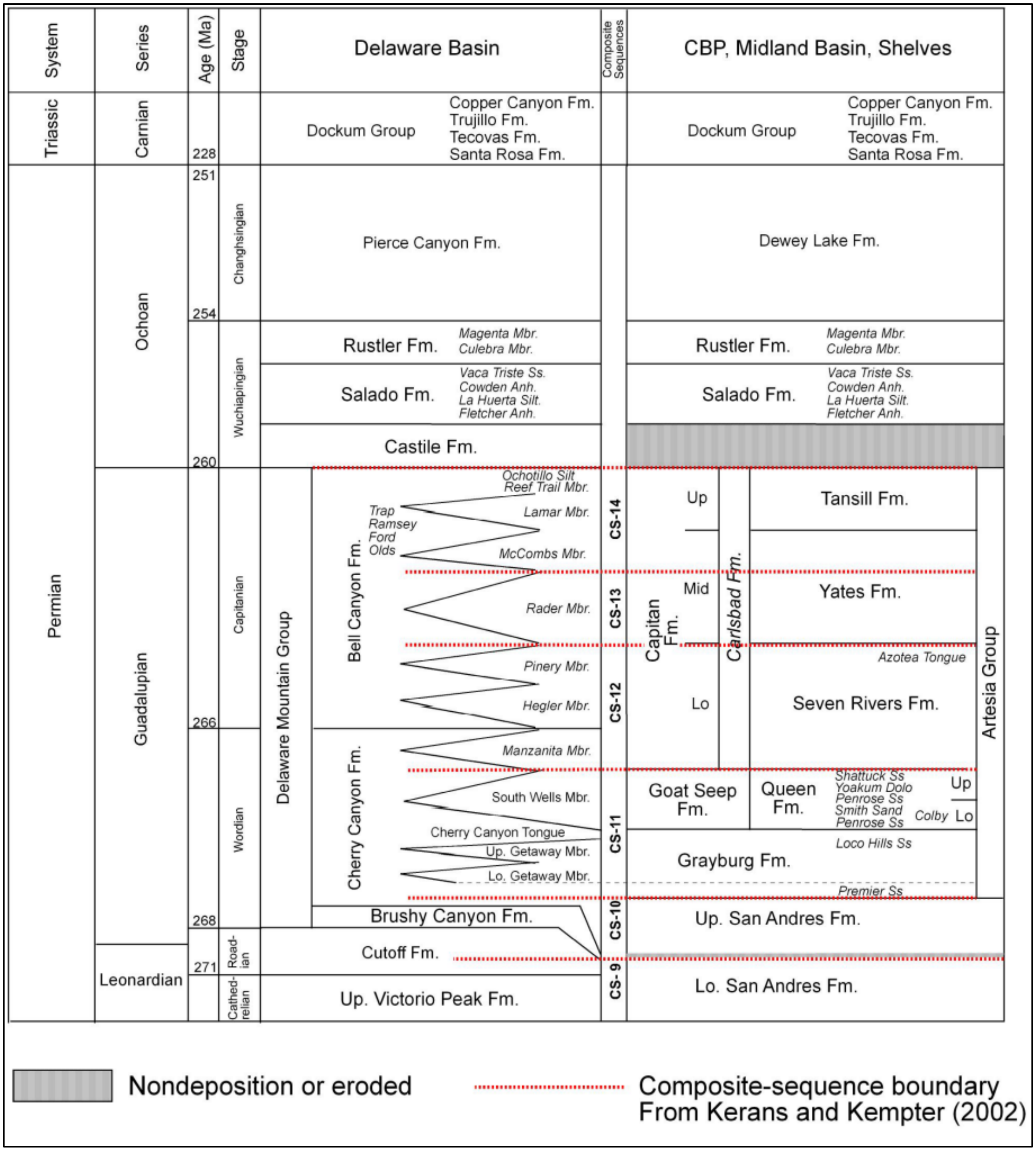


Figure 10 – Stratigraphic column depicting uppermost Leonardian and Guadalupian strata (Nance).

2.2.3 Regional Faulting

Regional faulting within the area of Titan Treating Facility is heavily influenced by the CBP, which was caused by basement-cored uplifts during the Middle Pennsylvanian Epoch that subsided within the Middle Permian Period (Horne, Zahm, and Hennings , 2021). Most faults within the area reflect high angle reverse faults with a north-northwest to south-southeast strike (Horne, Zahm, and Hennings, 2021). Because of the subsidence of this major event occurring within the Middle Permian Period, which correlates to the Lower Bone Spring formation, faulting is not seen in stratigraphy above the Bone Spring formation. Therefore, any concern with faults transmitting injected fluids into shallower freshwater bearing zones is unlikely. Further details of the faults interpreted within the area of Salt Creek AGI No. 2 are described in Section 2.3.2.4.

2.3 Site Characterization

The Salt Creek AGI No. 2 and No. 3 wells are in Section 21 Township 26S 36E, in Lea County, New Mexico. Northwind owns the 68.5-acre surface tract where the Titan Treating Facility is located. The following discusses the geological character of this site.

2.3.1 Stratigraphy and Lithologic Characteristics

Figure 11 depicts an openhole log from an offset well (API No. 30-025-23197) to the Salt Creek AGI wells indicating the injection and primary upper confining zones (UCZ).

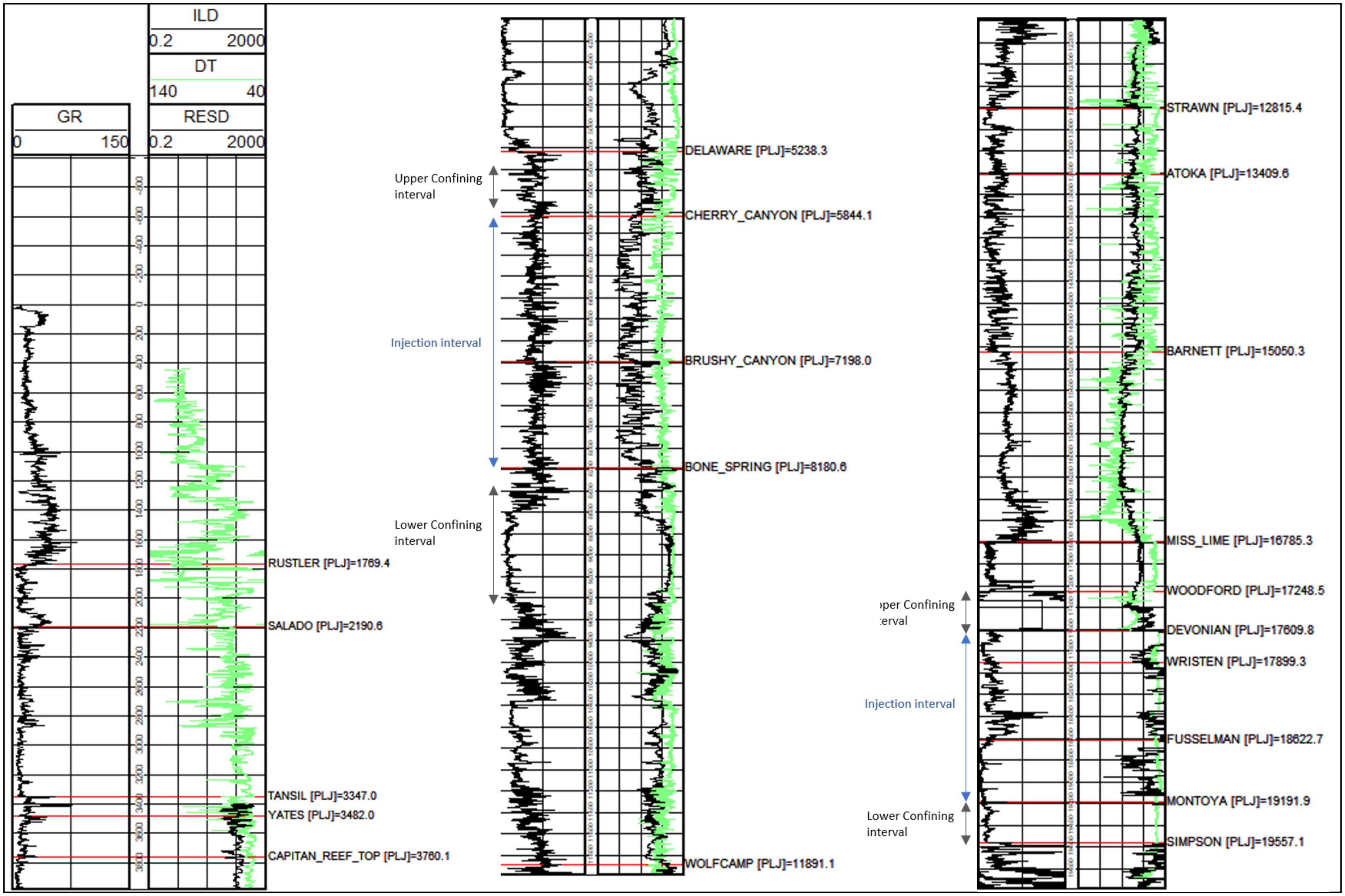


Figure 11 – Type Log (30-025-23197) with tops, confining and injection zones depicted.

2.3.2 Site Characterization – Salt Creek AGI No. 3 (Devonian)

2.3.2.1 Upper Confining Interval – Woodford Shale

The Woodford formation, formed during the late Devonian period, consists of organic-rich shale that originated from a widespread marine transgression. This flooding event covered most of the Permian Basin. The Woodford's "blanketlike geometry and nearly uniform lithology" suggests deposition in a low-relief environment (Comer, 1991). The two major lithofacies found within the Woodford are black shale and siltstone with the black shale exhibiting "parallel laminae, abundant pyrite, very high radioactivity, and high concentration of marine organic matter (Comer, 1991)." This high radioactive feature allows for easy identification within openhole logs where the gamma ray reads well over 150 API, usually going off scale. This feature can be seen in the cross sections found in Section 2.3.2.4 (Figures 19 and 20).

Within the Comer 1991 study, core samples were evaluated within the Permian Basin to better understand the lithologic features of the Woodford formation. Two core samples closest to the Salt Creek AGI No. 2 well are referenced in Figures 12 and 13. Core C12 is from a well in northern Ward County and C13 came from a well in northern Lea County. Both exhibit shale features with high clay and pyrite content with parallel lenticular laminae. The mineralogic and lithologic properties recorded in these cores serve as excellent sealant characteristics to prohibit any injected fluids from migrating above the injection interval. Additionally, the Woodford formation is identified as an adequate seal for Class II injection within the Siluro-Devonian in more than 150 disposal wells within Lea County.

The Woodford at the Salt Creek AGI well locations is encountered at approximately 17,185 ft and is 364 ft thick. The significant vertical depth difference between the Woodford formation and any freshwater-bearing layers, coupled with the consistently thick nature of the formation, suggests excellent containment properties.

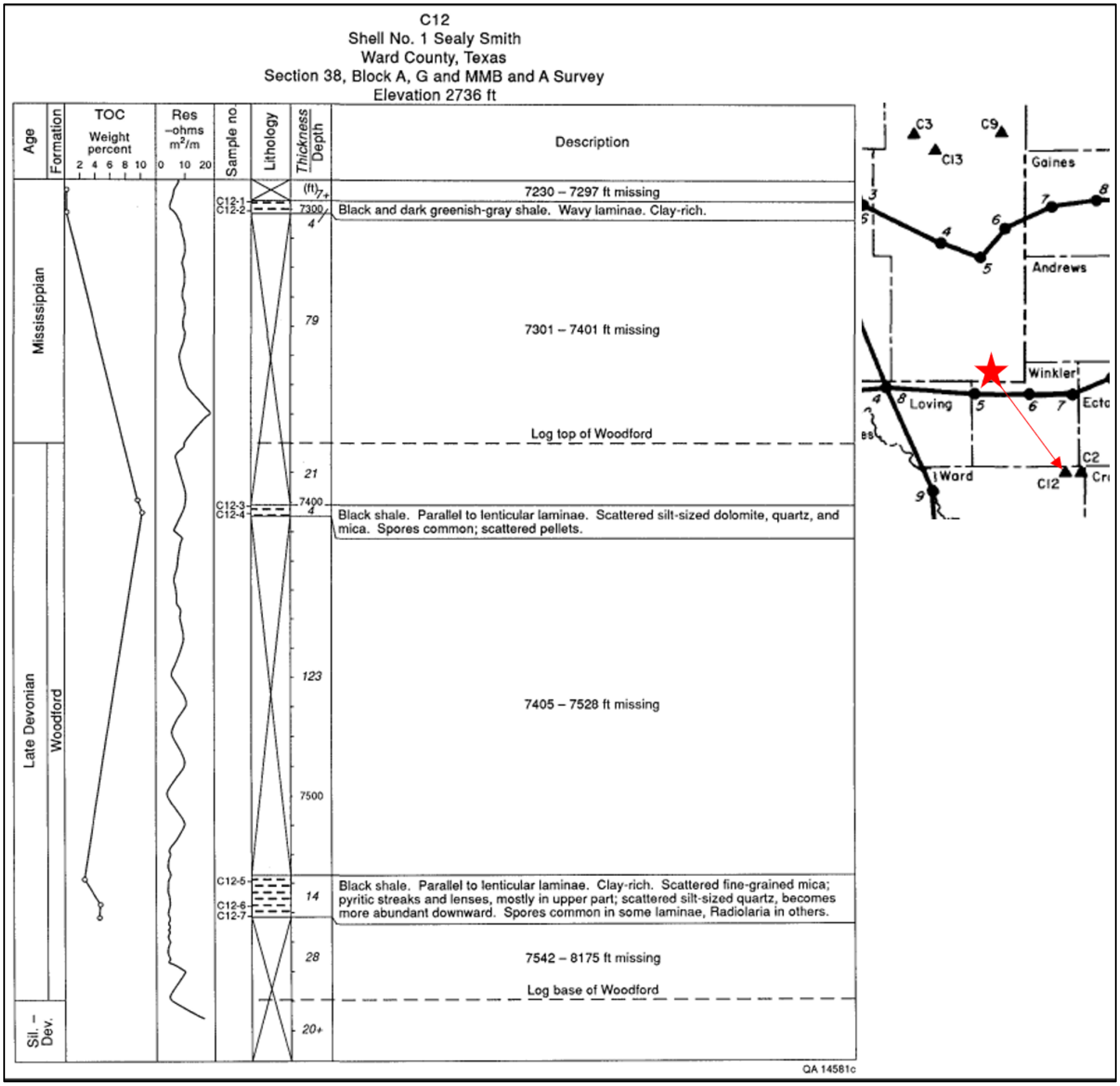


Figure 12 – Core description of the Woodford Shale. Red star represents Salt Creek AGI No. 2 location in relation to the core sample (Comer, 1991).

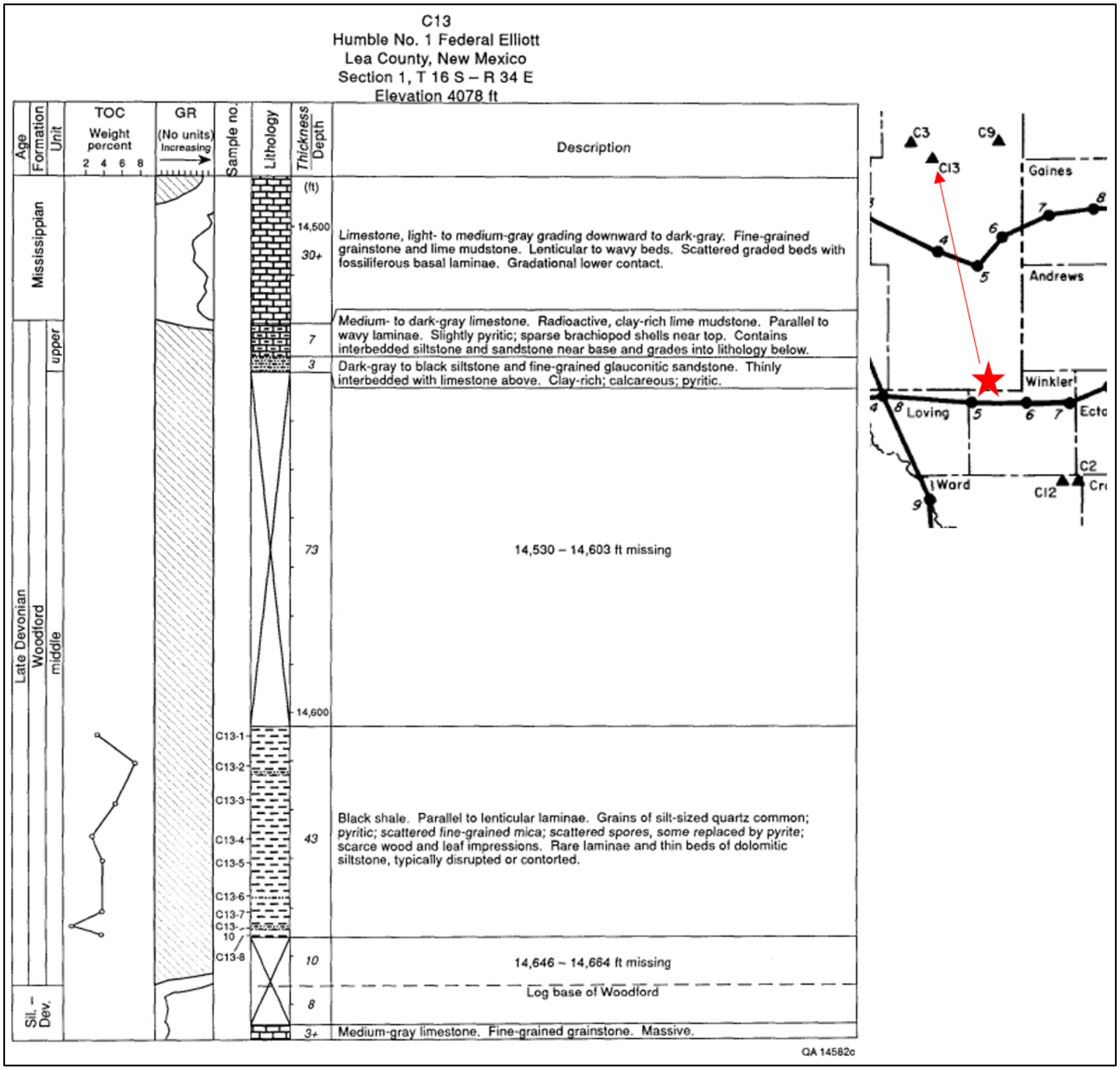


Figure 13 – Core description of the Woodford Shale. Red star represents Salt Creek AGI No. 2 location in relation to the core sample (Comer, 1991).

2.3.2.2 Injection Interval – Siluro-Devonian

The Salt Creek AGI No. 2 well has a proposed total depth of 18,650 ft, which is projected to penetrate 250 feet into the Fusselman formation. Carbonates within the Siluro-Devonian underwent multiple leaching and diagenetic episodes which developed secondary porosity and permeability. Features, such as vugs, karsts, and microfractures, are the primary reservoirs targeted for injection within the Siluro-Devonian.

Porosity/Permeability Development

Porosity in the Fusselman formation at the Salt Creek AGI No. 2 well location is typically broken down into three styles: "primary intergranular pores in basal ooid grainstones, leached intergranular pores in pelmatozoan packstones, and strongly leached, predominantly vuggy and intercrystalline pores (Ruppel and Holtz, 1994)." Within the Wristen Group, intergranular pores are observed in basal ooid grainstones, accompanied by moldic and intercrystalline features associated with the leaching of allochem-rich intervals (Ruppel and Holtz, 1994). Furthermore, primary porosity development within the Thirtyone formation occurs in "thick-bedded laminated calcareous chert" that exhibit "intercrystalline to microcrystalline porosity" (Ruppel and Holtz, 1994). Figure 14 displays summarized data from cores extracted from the proposed injection formations within the Permian Basin, presenting ranges and averages of reservoir attributes. The table highlights three main reservoir categories pertinent to the Salt Creek AGI No. 2 well: the Fusselman Shallow Platform Carbonate play, Wristen Buildups and Platform Carbonate play, and Thirtyone Deep-Water chert play. Porosity within the injection reservoir formations, as determined from the core data, ranges from 1% to 30% with permeability ranging from 0.4 to 400 millidarcies.

Utilizing the range of reservoir data derived from these core findings, an offset porosity log (API No. 42-495-32161) was analyzed. A permeability curve was then derived from the porosity curve, thereby employing the data table in Figure 14 to establish a porosity-permeability correlation, aiming to replicate similar ranges and averages. Figure 15 presents a visual representation of the openhole log section, depicting porosity and permeability in Tracks 2 and 3, respectively. As depicted in Figure 15, elevated porosity and permeability are evident throughout the injection interval, primarily concentrated in the upper Wristen Group and upper Fusselman formations. These curves are extrapolated to the injection site and used to delineate reservoir characteristics within the plume model.

	Fusselman Shallow Platform Carbonate play	Wristen Buildups and Platform Carbonate play	Thirtyone Ramp Carbonate play	Thirtyone Deep-Water Chert play
		Porosity (%)		
Number of data points	33	30	16	35
Mean	7.93	7.10	6.41	14.85
Minimum	1.00	2.70	3.50	2.00
Maximum	17.70	14.00	9.50	30.00
Standard deviation	4.01	2.67	1.75	6.76
		Permeability (md)		
Number of data points	21	24	12	33
Mean	11.61	45.28	1.51	8.56
Minimum	0.60	2.90	0.40	1.00
Maximum	84.80	400.00	30.00	100.00
Standard deviation	22.48	99.17	8.36	22.23
		Initial water saturation (%)		
Number of data points	24	28	10	31
Mean	26.96	31.55	24.70	31.46
Minimum	10.00	20.00	16.00	10.00
Maximum	50.00	55.00	40.00	45.00
Standard deviation	9.31	10.45	7.39	8.33
		Residual oil saturation (%)		
Number of data points	8	13	5	22
Mean	34.06	30.54	21.30	29.17
Minimum	30.00	20.00	9.00	14.00
Maximum	50.00	35.00	35.00	48.20
Standard deviation	6.99	4.61	11.66	9.76
		Oil viscosity (cp)		
Number of data points	11	12	5	21
Mean	0.69	1.16	0.33	0.68
Minimum	0.13	0.32	0.04	0.07
Maximum	1.08	2.00	1.00	1.03
Standard deviation	0.81	0.75	0.40	0.42
		Oil formation volume factor		
Number of data points	21	22	6	32
Mean	1.57	1.22	1.65	1.50
Minimum	1.05	1.05	1.31	1.30
Maximum	1.91	1.55	1.66	1.73
Standard deviation	0.28	0.14	0.48	0.16
		Bubble-point pressure (psi)		
Number of data points	9	9	5	19
Mean	2,272	1,055	3,750	2,752
Minimum	798	450	2,660	1,755
Maximum	4,050	2,600	4,440	4,656
Standard deviation	1,300	689	756	667

Figure 14 – Table of reservoir properties found within the Siluro-Devonian (Ruppel and Holtz, 1994).

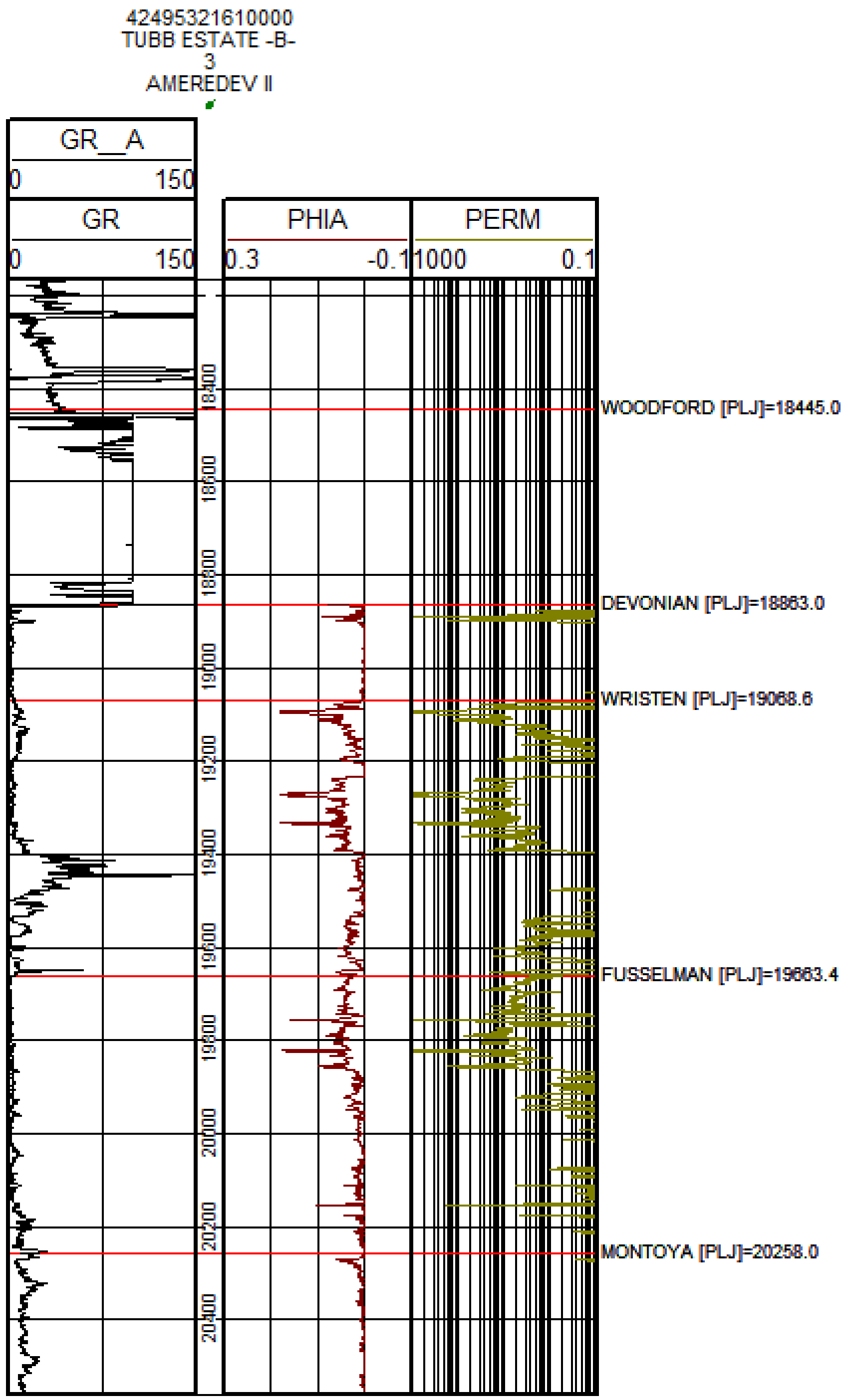


Figure 15 – Offset openhole log (42-495-32161) with effective porosity (maroon) and permeability (yellow).

Formation Fluid

A review of chemical analyses from the U.S. Geological Survey National Produced Waters Geochemical Database version 3.0 identified fifteen wells within the Devonian, Siluro-Devonian, or Fusselman formations, located offset of the Salt Creek AGI No. 2 well. The locations of these wells are depicted in Figure 16, with the corresponding data detailed in Table 2. All fluid samples exhibit total dissolved solids (TDS) exceeding 20,000 parts per million (ppm), classifying these aquifers as saline. The average salinity among the data in Table 2 is calculated at 70,514 ppm. These analyses affirm that the in situ reservoir fluids of the Siluro-Devonian and Fusselman formations are compatible with the proposed injection fluids.

Table 2 – Analysis of Siluro-Devonian Age Formation Fluids from Nearby Oil-field Brine Samples

API	Concentration (parts per million)						
	TDS	HCO_3	Ca	Cl	Na	Mg	SO_4
30-025-11568	55,183	1,158	2,451	31,600	17,310	860	1,804
30-025-11812	99,879	687	4,753	60,410	32,610	828	591
30-025-11818	27,506	1,089	1,384	15,270	8,144	540	1,079
30-025-11863	158,761	476	17,240	100,300	35,400	5,345	N/A
30-025-11886	101,036	540	5,393	61,630	30,380	2,183	910
30-025-11890	80,055	934	6,384	48,090	22,550	139	1,958
30-025-11950	31,931	302	7,196	20,450	1,151	2,241	591
30-025-11907	58,224	367	1,546	32,788	20,351	378	2,816
30-025-11556	57,675	595	2,850	34,030	18,370	619	1,211
30-025-11568	55,183	1,158	2,451	31,600	17,310	860	1,804
30-025-11747	82,794	977	2,408	47,200	28,190	851	3,168
30-025-11760	63,817	360	2,774	35,870	20,750	621	3,442
30-025-11763	61,040	900	2,680	35,600	19,560	800	1,500
30-025-11765	66,418	690	3,002	37,650	20,390	1,339	3,347
30-025-11907	58,220	367	1,546	32,790	20,430	278	2,816

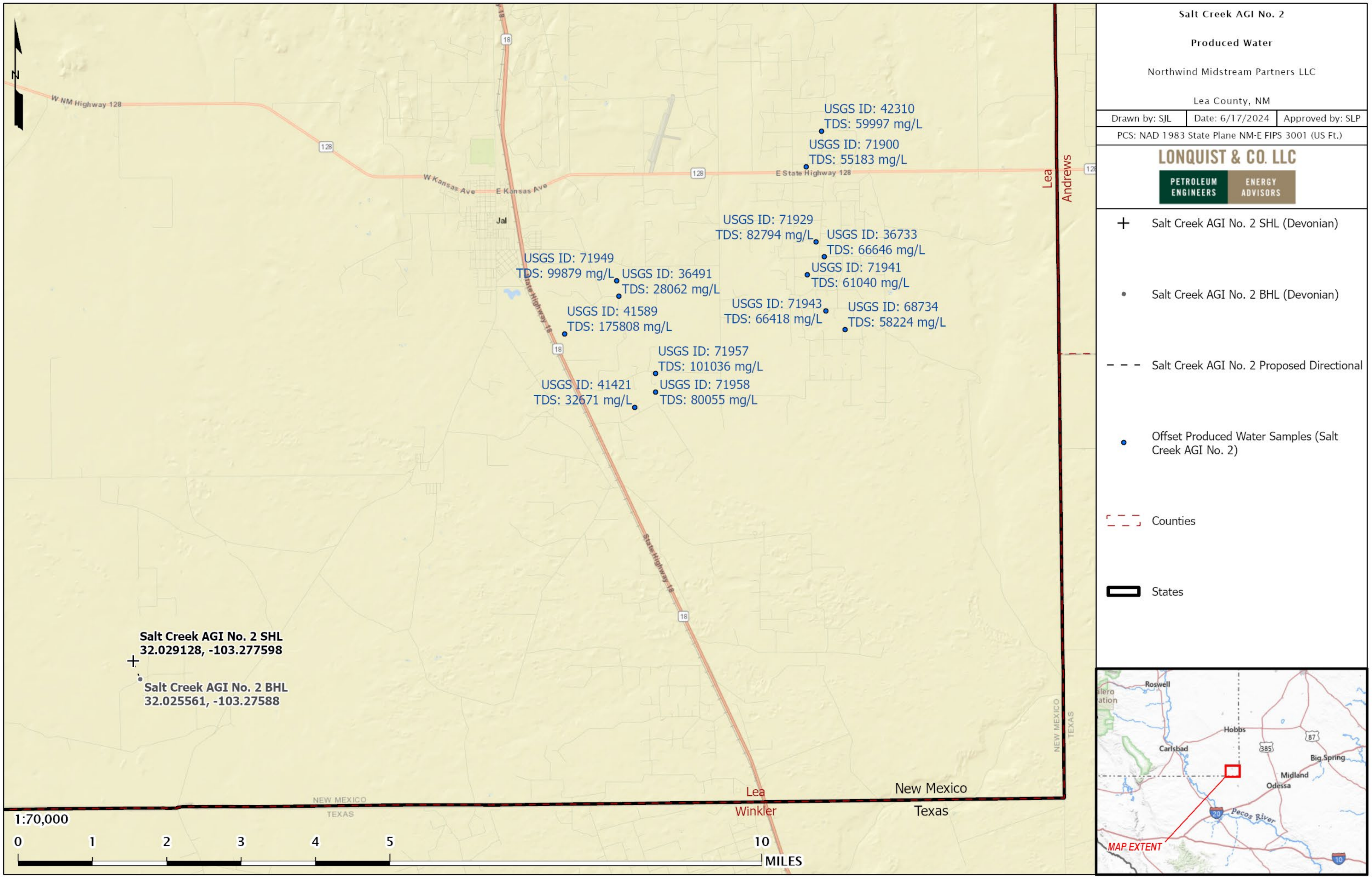


Figure 16 – Offset wells used for Formation Fluid Characterization, Siluro-Devonian.

2.3.2.3 Lower Confining Zone – Montoya Formation

The Montoya formation serves as the lower confining unit for the injection interval. The Montoya is an Ordovician carbonate ramp succession, primarily characterized by reservoir development in dolomitized facies, with limestones exhibiting the least favorable development, particularly evident in the Montoya section of the Salt Creek AGI No. 2 area (Jones). This characteristic is depicted in Figure 17, a lithology log cross plot of the Montoya formation within well 42-495-32161, illustrating bulk density (y-axis) versus neutron porosity (x-axis), where most data points fall within the limestone matrix, indicating minimal to no porosity.

This deficiency in porosity is further evident in the previously shown Figure 11, with the openhole log section of the Montoya indicating tight limestone rock and an average porosity of 0.5%. Such lower porosity likely corresponds to permeabilities in the nanodarcy range. These petrophysical attributes signify optimal sealing properties, effectively preventing any migration of injected fluid beyond the designated injection interval.

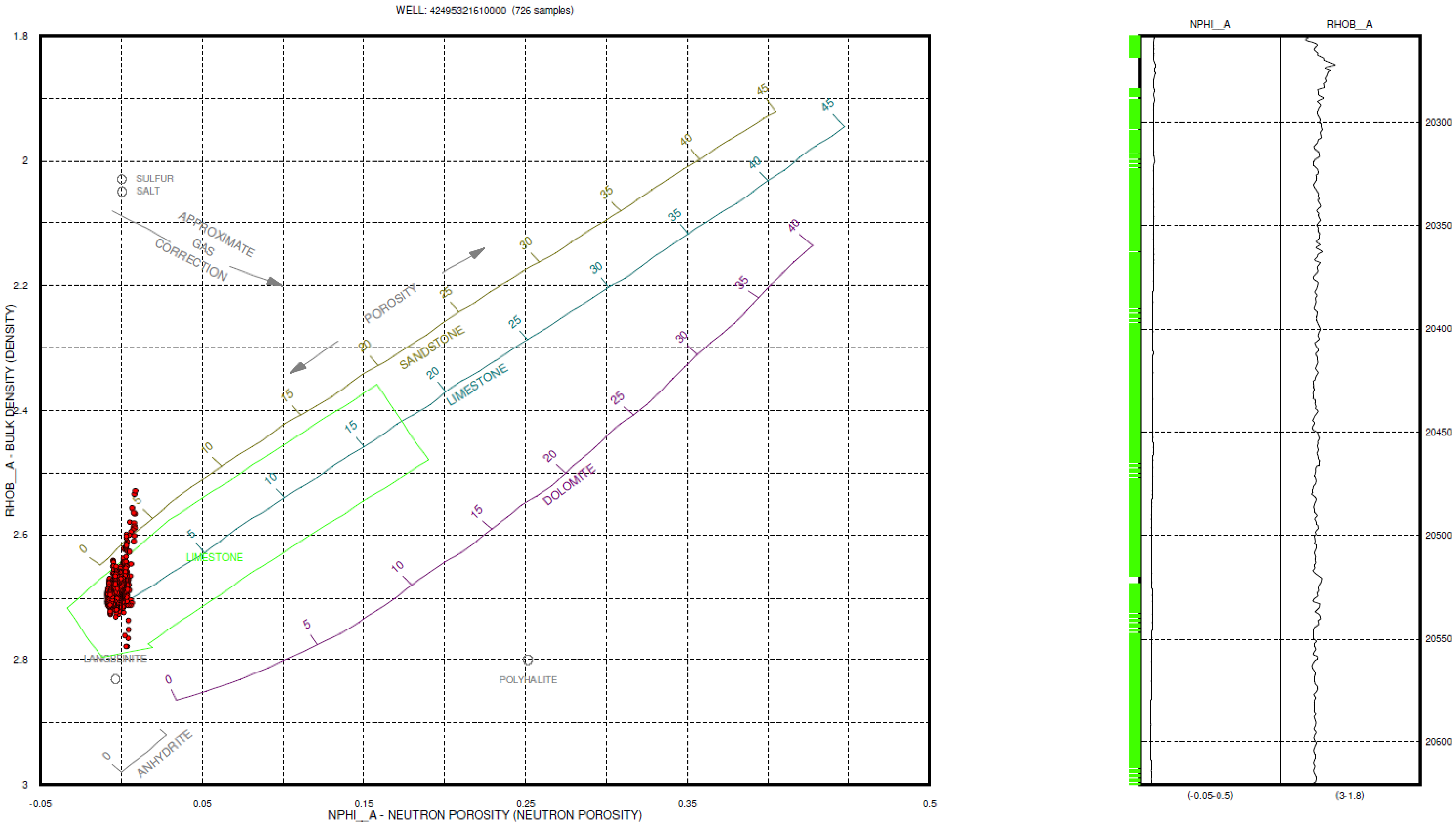


Figure 17 – Lithology cross plot of the Montoya formation showing a predominantly limestone facies. Data from offset well (42-495-32161).

2.3.2.4 Local Structure – Siluro-Devonian

The regional structure around Salt Creek AGI No. 2 is dictated by an uplifting event known as the Ancestral Rocky Mountain orogeny, which was responsible for the CBP (Horne, Zahm, and Hennings, 2021). Salt Creek AGI No. 2 is specifically located immediately west of the CBP in between a series of thrust faults coming off the platform, with primary strikes being north to south. Figure 18 is a structure map of the Siluro-Devonian formation in subsea depths with the star representing the location of Salt Creek AGI No. 2. The red and blue lines represent the cross-section reference lines.

Faulting can be seen in all directions from the Salt Creek AGI No. 2 well location, with the closest fault being found roughly 0.5 miles to the north. All faults interpreted near the Salt Creek AGI No. 2 well are thrust faults with the hanging walls (i.e., upthrown side) being on the west and the footwalls (i.e., downthrown side) being on the east. Fault offsets range from 50 ft to 700 ft. Dip trends generally follow regional trends of downdip to the southwest toward the Delaware Basin and updip to the northeast towards the CBP. Figures 19 and 20 are north-south and west-east structural cross sections showing the structural dips. As seen in these figures, the Woodford is laterally present above the injection interval with ample thickness to act as the upper seal for the proposed injection interval.

A higher resolution version of Figure 18 is provided in Appendix D.

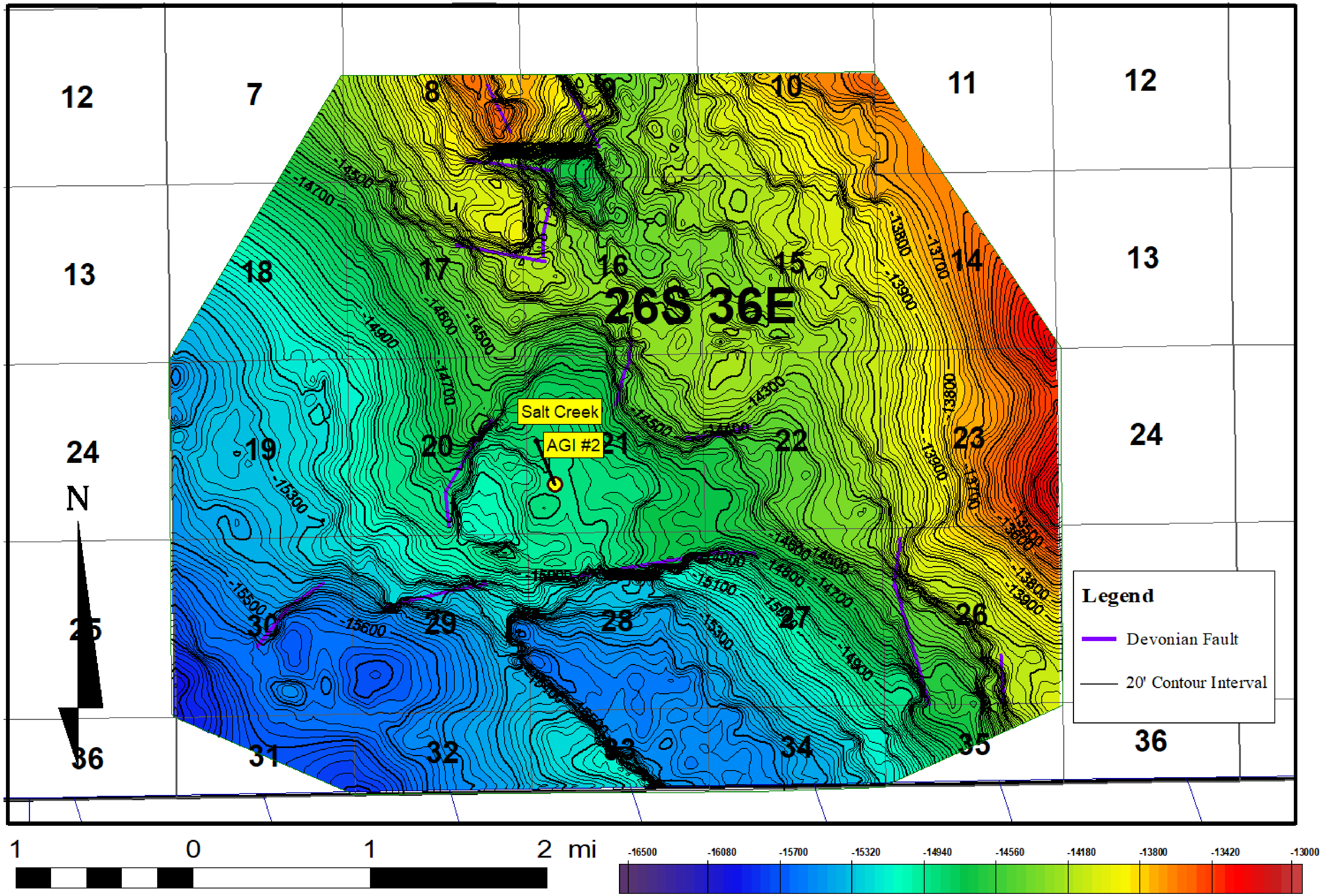


Figure 18 – Siluro-Devonian Structure Map (subsea depths).

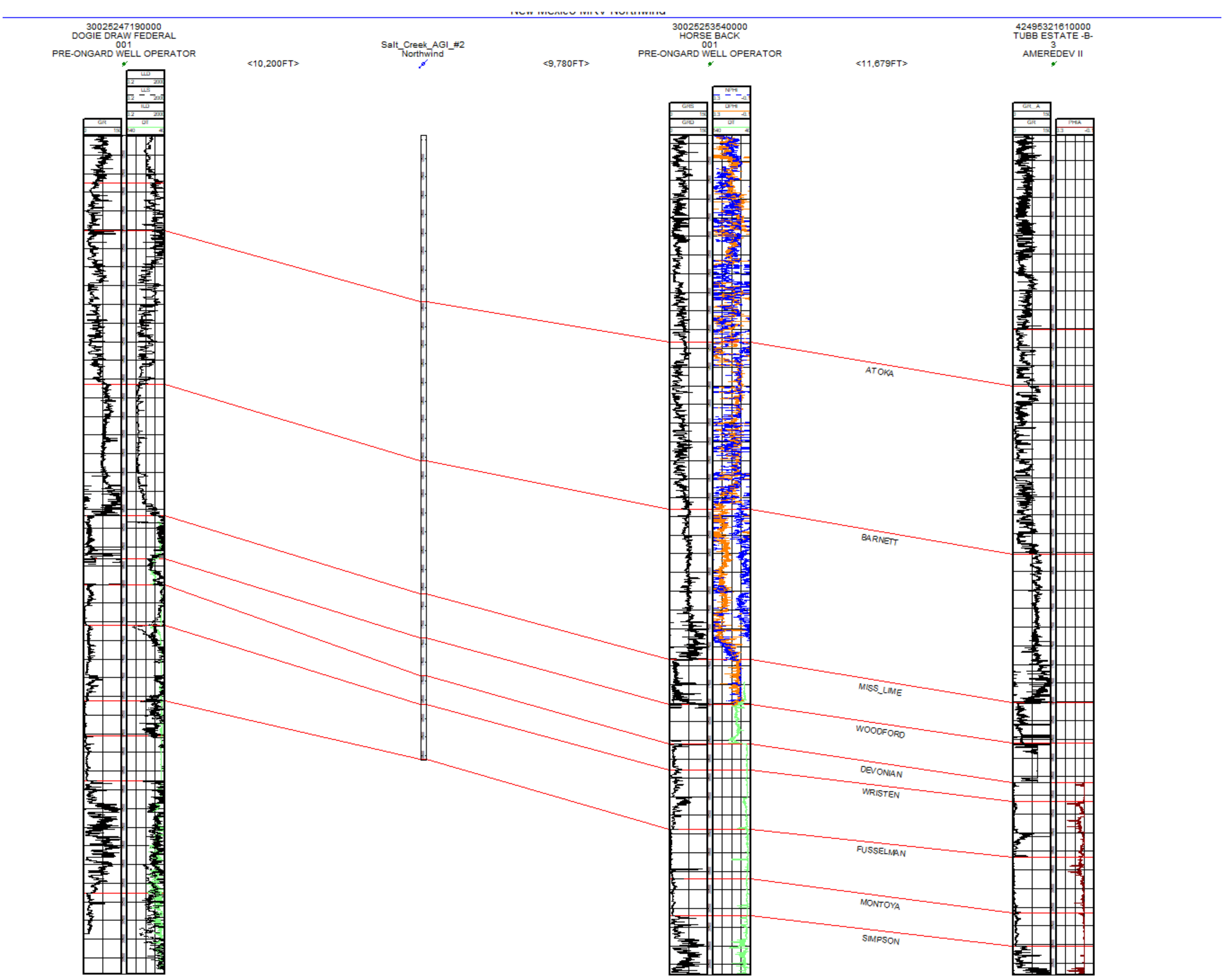


Figure 19 – N-S Structural Cross Section.

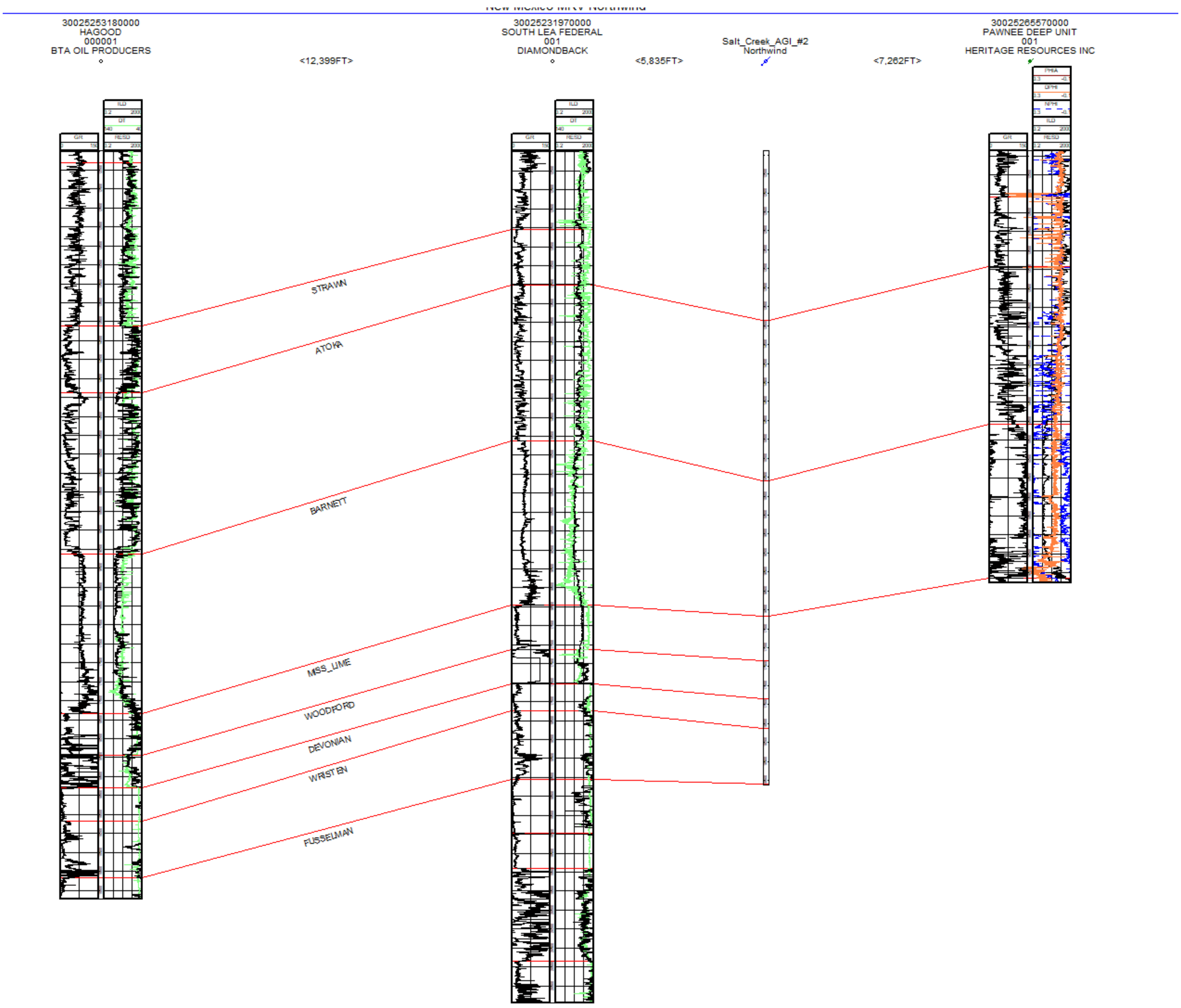


Figure 20 – W-E Structural Cross Section.

2.3.3 Site Characterization – Salt Creek AGI No. 3 (Delaware Mountain Group)

2.3.3.1 Upper Confining Zone

The UCZ at the Salt Creek AGI No. 3 location was defined in the Class II application as low porosity forereef deposits that isolate the DMG injection interval from the overlying Capitan Reef. This facies coincides with the previous discussion found in *Section 2.2.2* describing the increased abundance of carbonate rocks near the margins of the Delaware Basin. This relationship is depicted in Figure 21, which is an openhole log from Salt Creek AGI No. 3. As seen in the figure, multiple carbonate forereef deposits were deposited above the DMG injection interval, depicting low porosity, therefore sealing rock characteristics.

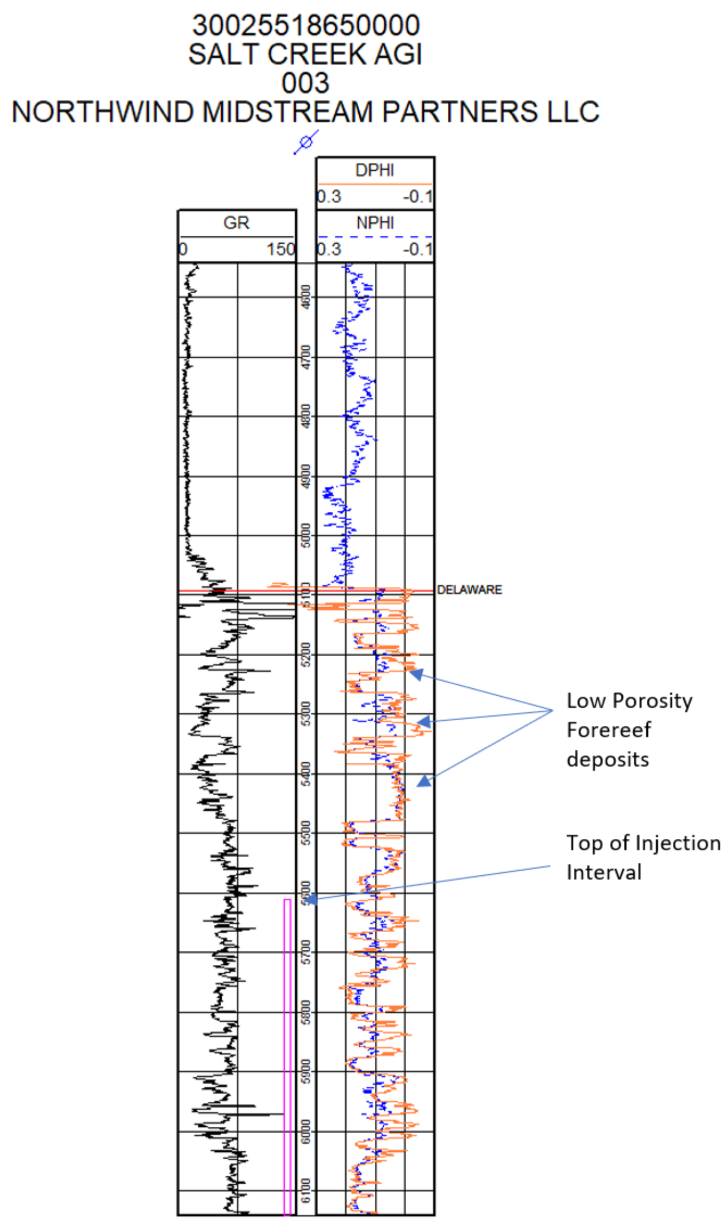


Figure 21 – Openhole log of the Salt Creek No. 3 AGI. Porosity is displayed in Track 2 where low porosity carbonate facies are identified.

2.3.3.2 Injection Zone

The Salt Creek AGI No. 3 well was drilled to a total depth of 7,040 ft, encountering approximately 1,950 ft of Delaware strata that includes the upper portion considered low porosity forereef strata. The Salt Creek AGI No. 3 was completed from 5,610 ft to 7,000 ft within the DMG which most likely consists of all three formations (Bell, Cherry, and Brushy Canyon) found within the DMG. Interbedded sands, siltstones, and carbonates are present within this interval, each directly impacting the preferential flow of the injectate. The highly porous sands will be the primary reservoirs within the injection interval with the interbedded siltstones and carbonates acting as intermittent baffles between the injection sands.

Porosity/Permeability Development

Porosity and permeability development in the DMG reflects the complexities of primary and secondary diagenetic processes. The primary dictators of permeability within the DMG are the presence of clays such as illite and smectite and abundance of calcite cementation within the matrix (Nance). Openhole logs can assist in determining these concentrations within the DMG and can be utilized to generate accurate porosity and permeability values within the injection interval for the simulation model. A literature review was conducted and yielded core data from offset DMG fields based on a study done within the injection interval (Jenkins, 1961). A relationship was established between porosity and permeability of the cores from the study and implemented into the model. This relationship can be seen in Figure 22.

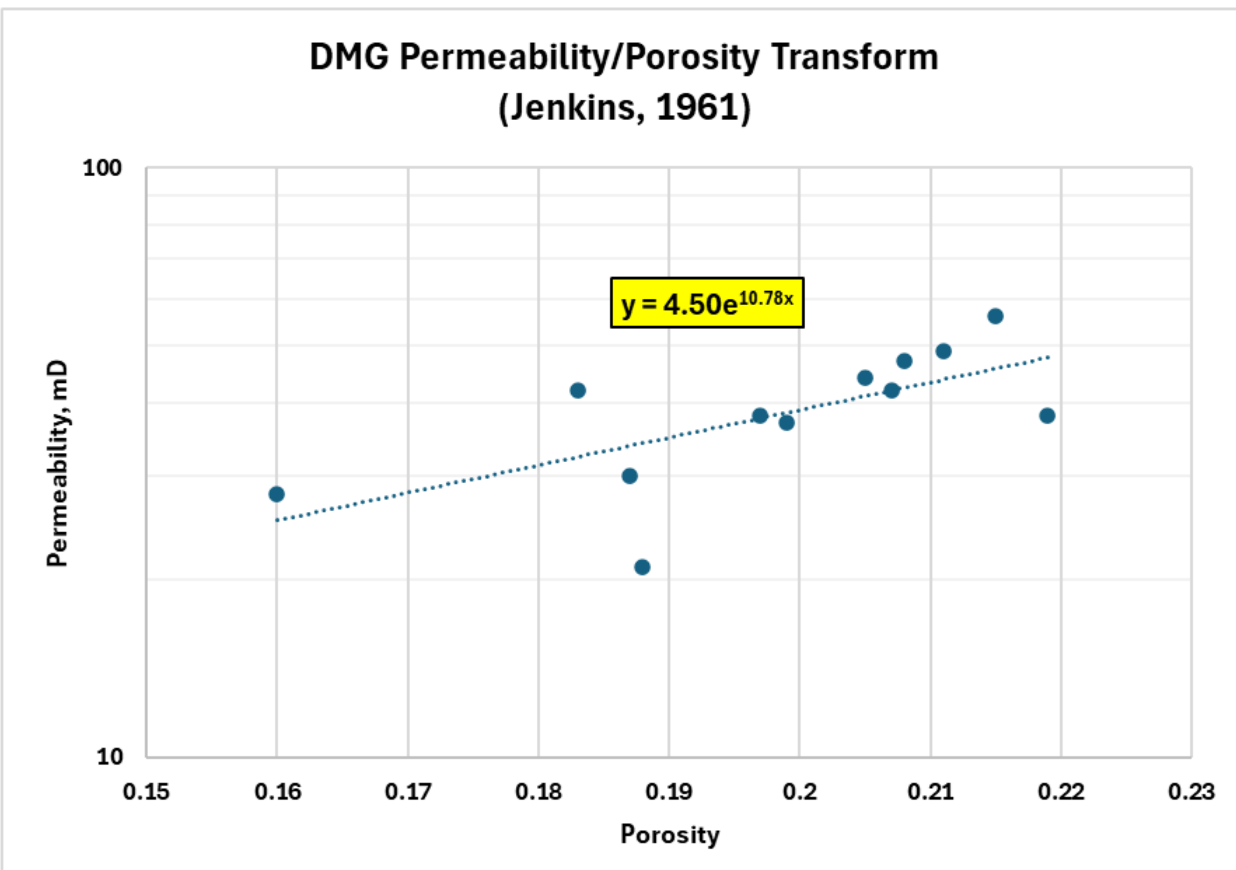


Figure 22 – Permeability Porosity Relationship for the DMG (Jenkins, 1961).

These relationships were then applied to the porosity data retained from the openhole logs collected from the Salt Creek AGI No. 3. Figure 23 presents a visual representation of the openhole log section, depicting porosity and permeability in Tracks 2 and 3, respectively. As shown in Figure 23, elevated porosity and permeability generally correlate with the cleaner sands as indicated by the Vshale curve. The Vshale curve is calculated from the gamma-ray curve to determine the amount of clay content within the interval. These curves are extrapolated surrounding the injection site and used to delineate reservoir characteristics within the plume model.

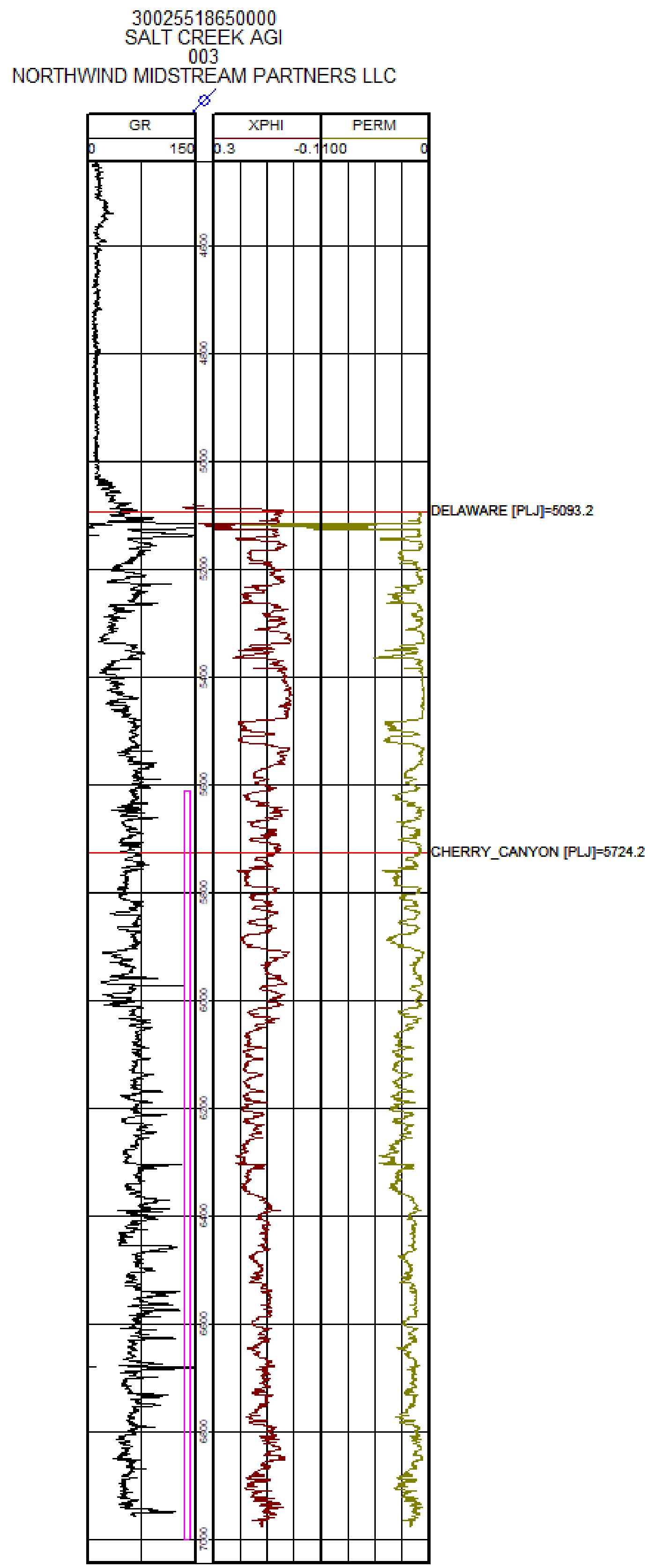


Figure 23 – Openhole log of the Salt Creek No. 3 AGI. Porosity is displayed in Track 2 and permeability in Track 3. Clean sands are identified as higher porosity and perm intervals.

2.3.3.3 Formation Fluid

A review of chemical analyses from the U.S. Geological Survey National Produced Waters Geochemical Database version 3.0 identified nine wells within the Delaware located near the Salt Creek AGI No. 3 well. The locations of these wells are depicted in Figure 24, with corresponding data detailed in Table 3. All fluid samples exhibit TDSs exceeding 20,000 ppm classifying these aquifers as saline. The average salinity among the data in Table 3 is calculated at 313,662 ppm.

Table 3 – Analysis of Delaware Formation Fluids from Nearby Oil-Field Brine Samples.

	Average	**Low**	**High**
Total Dissolved Solids (ppm)	313,662	271,231	358,379
pH	6.47	5.8	7.8
Sodium (ppm)	87,481	77,617	113,359
Chlorides (ppm)	191,500	167,311	225,612

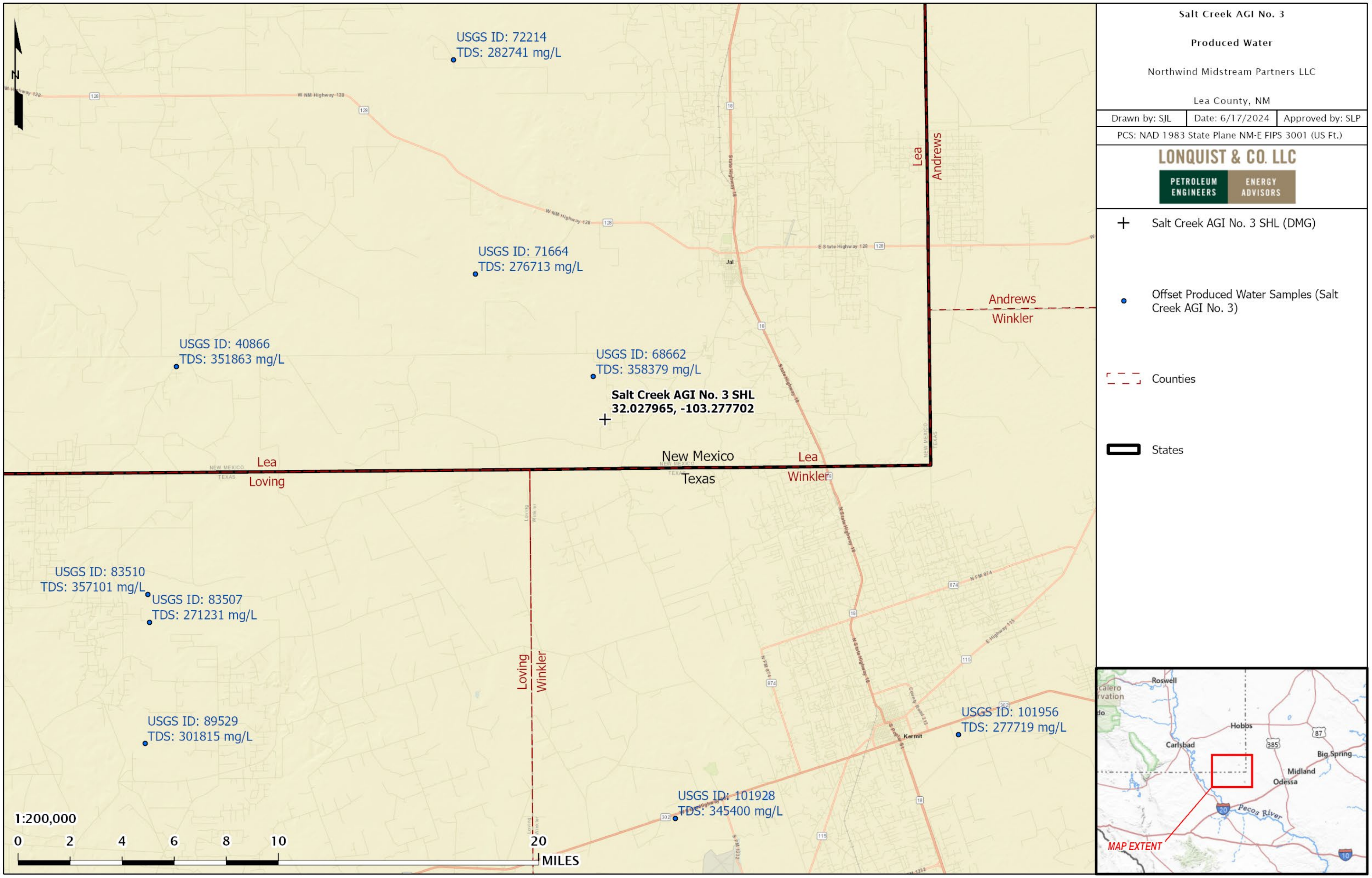


Figure 24 – Offset wells used for formation fluid characterization, Delaware Mountain Group.

2.3.3.4 Lower Confining Zone

The lower confining zone (LCZ) for Salt Creek AGI No. 3 is identified as tight siltstones found in the lower Delaware or Brushy Canyon. As discussed in the permeability/porosity section, layers with high clay contents that resemble fine grained siltstones will act as low permeable layers. The abundance of these alternating layers within the lower Delaware will act as an adequate seal to prevent any migration of the injectate outside of the DMG.

2.3.3.5 Local Structure – Delaware Mountain Group

The regional structure around Salt Creek AGI No. 3 is highly influenced by the boundary of the Delaware Basin and the unconformity that occurs towards the CBP. Sand thickness of the DMG decreases westward as the forereef strata replaces the upper DMG strata portraying a downdip structure westward. This decrease in thickness is displayed in the cross section in Figure 25 depicting a wedge-like feature where the thickness of the DMG is decreasing westward as the forereef strata displaces the upper Delaware section and the Bone Spring is thrust up by the CBP. Figure 26 is a north-south striking cross section showing a more continuous thickness of the DMG as the cross section parallels the boundary margin of the basin. Figure 27 is a structure map of the DMG formation in subsea depths with the star representing the location of the Salt Creek AGI No. 3 well. The red and blue lines represent the cross-section reference lines.

Faulting in the area does not extend shallow enough to intersect the DMG. Structural interpretations from offset 3D seismic data indicated most faults die within the Pennsylvanian strata, much deeper than the DMG. Therefore, there is no concern of fault transmissibility within the DMG injection interval.

A larger version of Figure 27 is provided in Appendix D.

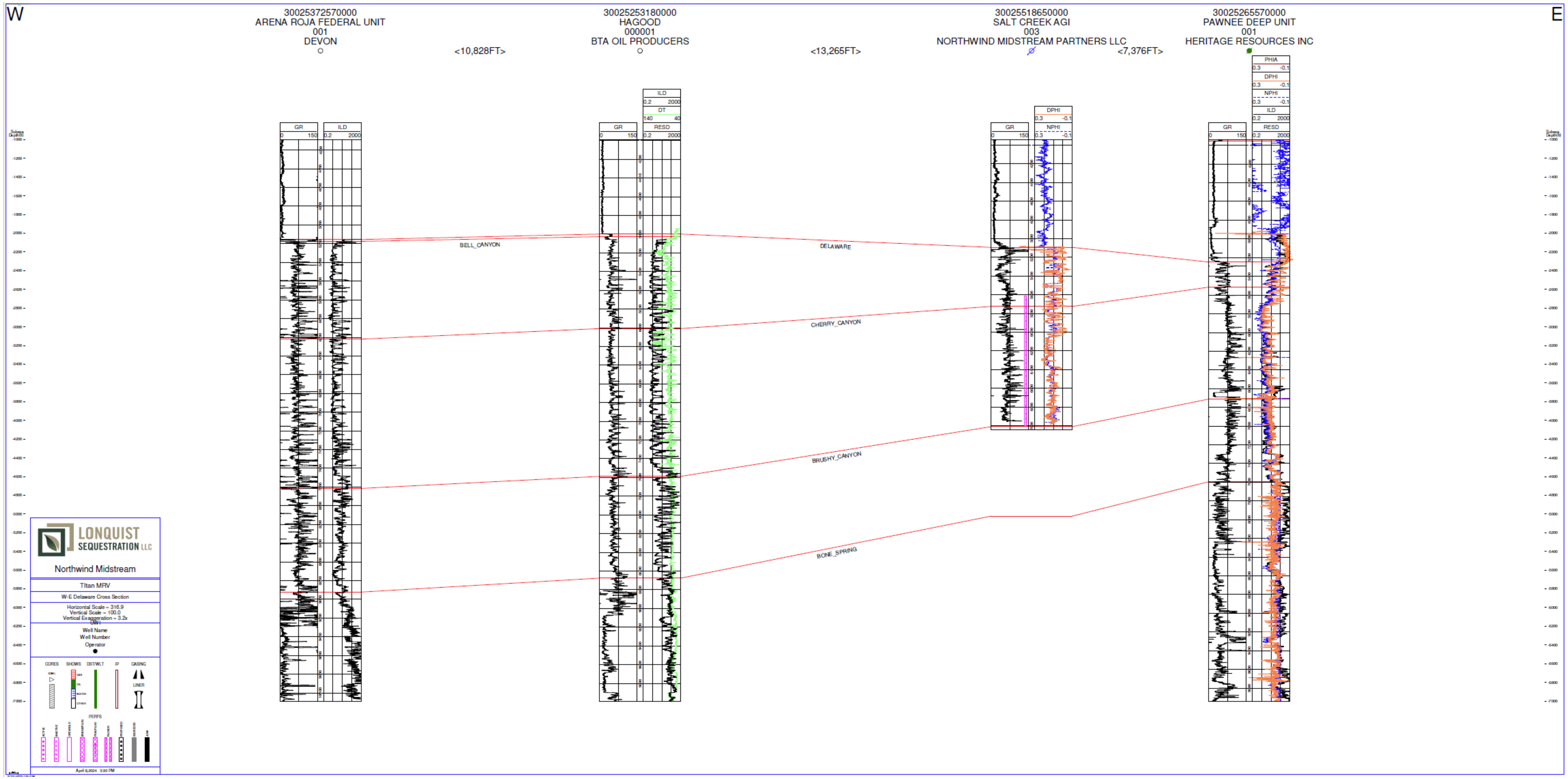


Figure 25 – W-E Structural Cross Section.

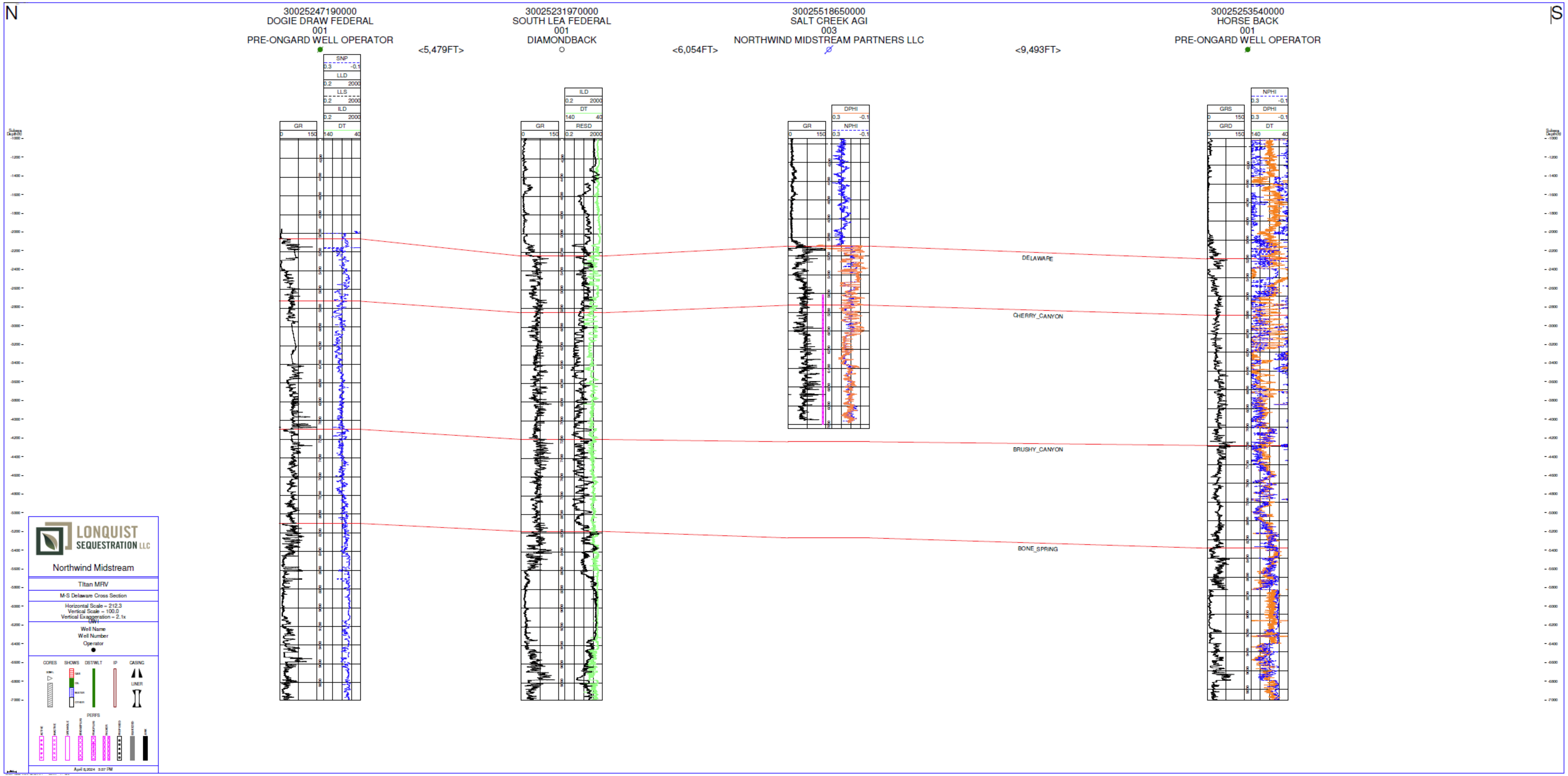


Figure 26 – N-S Structural Cross Section.

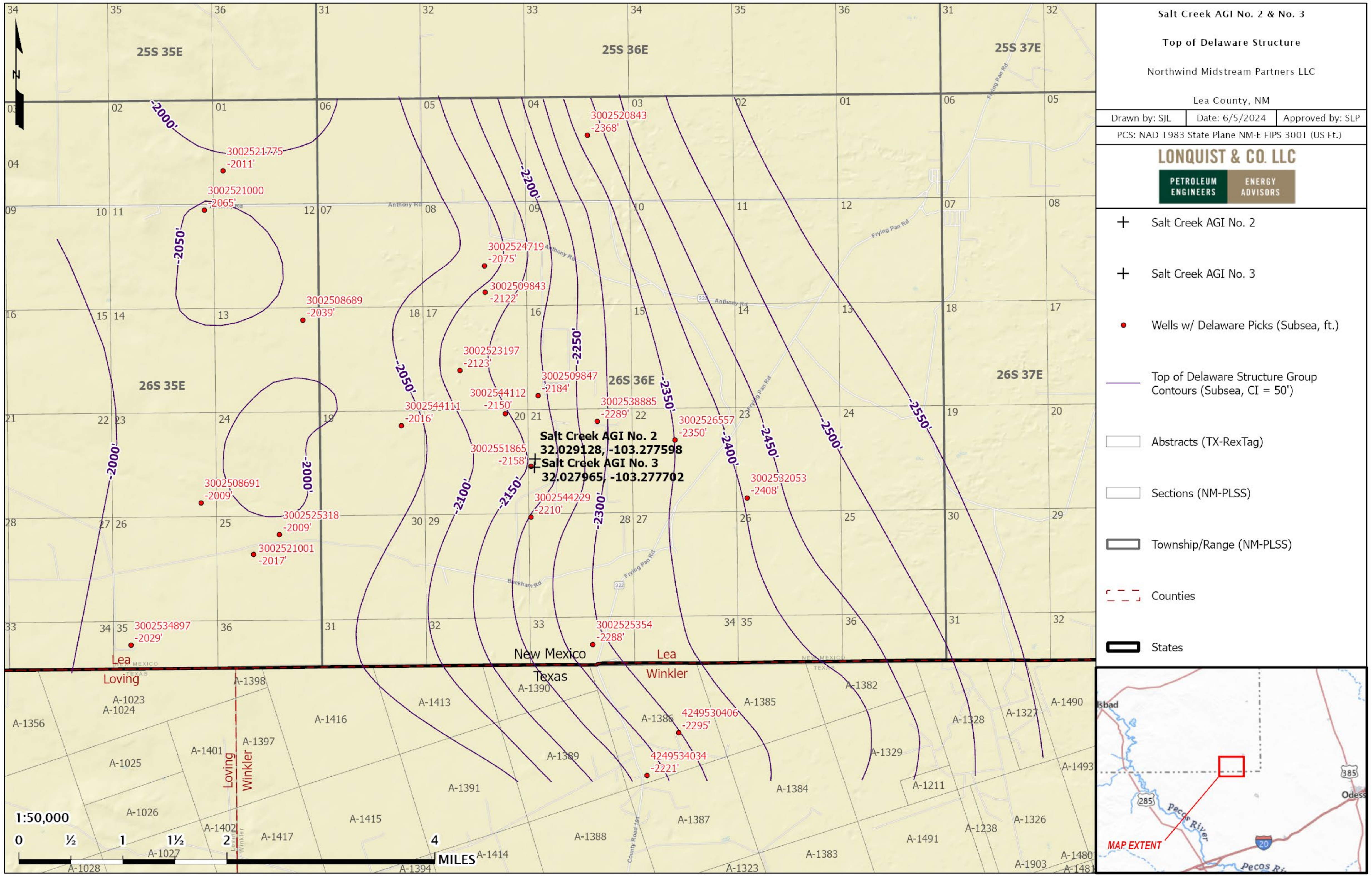


Figure 27– Delaware Structure Map (subsea depths).

2.4 Geomechanics

The fracture pressure gradient for the Siluro-Devonian and Delaware Mountain Group formations was estimated using Eaton's equation. Eaton's equation is widely considered the standard practice for calculating the fracture gradient (FG). Variables such as Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG) can be changed to best reflect the site-specific injection and confining zone's fracture pressure gradient. The anticipated fracture gradient was derived from site-specific data, literature reviews and industry standard practices.

For the Siluro-Devonian formation, a PG of 0.433 psi/ft was assumed. The OBG was chosen to be 1.1 psi/ft based on industry best practices when site specific data is unavailable. A Poisson's ratio of 0.3 was assumed based on literature (Molina et al, 2017) for carbonate formations. Using the variable values listed above, an FG of 0.72 psi/ft was calculated, based on the equation shown subsequently. A 10% safety factor was implemented, resulting in a maximum allowed BHP of 0.65 psi/ft. This safety factor was set to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

The Woodford shale above the Siluro-Devonian and the Montoya carbonate below the Siluro-Devonian are the upper and lower confining formations, respectively. For both the upper and lower confining intervals, a similar OBG and Poisson's ratio as the injection interval was assumed (Molina et al, 2017).

For the DMG, the PG was assumed to be 0.43 psi/ft, based on literature (Snee and Zoback, 2018). The OBG was calculated to be 1.1 psi/ft based on log data from the Salt Creek AGI No. 3 and confirmed based on industry best practice. Lastly, Poisson's ratio was conservatively assumed to be 0.27 based on literature review (Molina et al, 2017) for sandstone formations. Using the variable values listed above, an FG of 0.68 psi/ft was calculated, based on the equation below. A 10% safety factor was implemented, resulting in a maximum allowed bottomhole pressure of 0.61 psi/ft. This safety factor was set to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

The low porosity forereef above the DMG and the Bone Spring formation below the DMG are carbonate formations. For both the upper and lower confining intervals, a similar OBG as the injection interval was assumed. Poisson's ratio was chosen to be 0.3 for carbonate formations. Carbonates tend to have higher Poisson's ratios compared to sandstone formations (Molina et al, 2017).

Tables 4 and 5 provide the inputs and results of the FG calculations for the two Salt Creek AGI wells.

Table 4 – Fracture Gradient Calculation Inputs and Results, Salt Creek AGI No. 2.

Depth (ft)	Zone	Member	Overburden Gradient (psi/ft)	Pore Gradient (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)	90% Fracture Gradient (psi/ft)
17,186	Upper Confining	Woodford	1.1	0.433	0.3	0.72	0.65
17,550	Injection	Devonian	1.1	0.433	0.3	0.72	0.65
18,403	Lower Confining	Montoya	1.1	0.433	0.3	0.72	0.65

Table 5 – Fracture Gradient Calculation Inputs and Results, Salt Creek AGI No. 3.

Depth (ft)	Zone	Member	Overburden Gradient (psi/ft)	Pore Gradient (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)	90% Fracture Gradient (psi/ft)
5,083	Upper Confining	Forereef Deposit	1.1	0.43	0.3	0.72	0.65
5,510	Injection	DMG	1.1	0.43	0.27	0.68	0.61
8,479	Lower Confining	Bone Spring	1.1	0.43	0.3	0.72	0.65

Example Fracture Gradient Calculation for Injection Interval of the DMG:

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

$$FG = \frac{0.27}{1-0.27}(1.1 - 0.43) + 0.43 = 0.68\, psi/ft$$

$$FG\ with\ SF = 0.68\ \times 90\% = \mathbf{0.61\, psi/ft}$$

2.5 Injection and Confinement Summary

The lithologic and petrophysical features of the Siluro-Devonian formation at the Salt Creek AGI No. 2 well site suggest that it possesses adequate thickness, porosity, permeability, and lateral continuity to accommodate the proposed injection fluids. Conversely, the Woodford formation shale at the Salt Creek AGI wells exhibits low permeability but is adequately thick and laterally continuous to function as the UCZ. Below the injection interval, the Montoya formation, characterized by low permeability and low porosity, is unsuitable for fluid migration and thus serves as the LCZ.

Likewise, the DMG possesses the needed reservoir characteristics for injection. The low porosity forereef deposits above the DMG provides adequate confinement to prevent movement out of the UCZ.

2.6 Groundwater Hydrology

2.6.1 Introduction

Lea County is home to more than 70,000 residents with the county seat being the city of Lovington. Lea County is approximately 4,400 square miles and serviced by the Lea Soil and Water Conservation District. Groundwater resources are primarily used for irrigation and public water supply. These resources include many aquifers, but very few surface water sources with most being limited to smaller bodies of water, such as streams and small lakes.

2.6.2 Groundwater Resources

Lea County in New Mexico contains many ground water aquifers. In the southern area of Lea County, most of the potable water comes from three geologic units. These units are the Dockum group, Ogallala formation, and Quaternary alluvium (Nicholson and Clebsch, 1961). The Capitan Reef complex aquifer is also found in Lea County. While present in the county, the Ogallala and Quaternary aquifers are not present at the proposed well location in the southern area of the county and will not be discussed in this report.

The Rustler anhydrite formation has been deemed as the lowest limit of potable water with most wells bottoming at the Triassic-aged or younger rocks with only one well that penetrates the Permian aged rocks (Nicholson and Clebsch, 1961). This well has been noted as extending down to 1,150 ft and provides potable water, but it is uncertain if the well penetrates past the Triassic rocks. Figure 28 displays the stratigraphic units as well as their general characteristics and water-bearing properties. Water is primarily pumped from the Santa Rosa and Chinle formations of the Dockum Group in southern Lea County with the Santa Rosa sandstone being the primary aquifer in the western side. Precipitation and possibly groundwater flow from the Ogallala aquifer are the primary forms of recharge for the Santa Rosa formation. Figure 28 also displays a potentiometric map of the entirety of Lea County. Both the Santa Rosa and Chinle formations have outcroppings, but none in the direct vicinity of the proposed well location.

As of 1961, mean annual precipitation in southern Lea County ranged from 12 to 15.6 in. (Nicholson and Clebsch, 1961). As of 1997, precipitation in Lea County was approximately 15 in. per year. The county received 16 inches of precipitation in 2023. Figure 29 shows the annual precipitation over a 6-year period from 1949 to 1955.

The Capitan Reef Complex overlies the Delaware Mountain Group and is beneath the Salado Formation. The complex extends from the Glass Mountains in Texas moving north to Lea and Eddy Counties in New Mexico and back around to the Apache and Davis Mountains in Culberson and Jeff Davis Counties in Texas. Large-scale erosion occurred during the Upper Guadalupian through the Ochoan epochs, which then had a deposition during the Artesian Group (Standen et al., 2009). Overall, the reef complex is noted as a grouping of Permian carbonate reef-forming rock limestones that include the Goat Seep, Capitan, and the Carlsbad limestones. Faulting has occurred throughout the entirety of the aquifer, thereby creating a largely discontinuous aquifer. Many smaller aquifers combine to create the overall Capitan Reef Complex.

Geologic age		Geologic unit	Thickness (ft)	General character	Water-bearing properties
Cenozoic Quaternary	Recent and Pleistocene	Sand	0–30±	Dune sand, unconsolidated stabilized to drifting, semiconsolidated at depth; fine- to medium-grained.	Above the zone of saturation, hence, does not yield water to wells. Aids recharge to underlying formations by permitting rapid infiltration of rainwater.
		Alluvium	0–400±	Channel and lake deposits; alternating thickbedded calcareous silt, fine sand, and clay; thickest in San Simon Swale; less than 100 feet thick in most places.	Saturated and highly permeable in places in east end of Laguna Valley. Forms continuous aquifer with Ogallala formation. Wells usually yield less than 30 gpm. Locally above the water table.
Cenozoic Tertiary	Pliocene	Ogallala	0–300±	Semiconsolidated fine-grained calcareous sand capped with thick layer of caliche; contains some clay, silt, and gravel.	Major water-bearing formation of the area. Unsaturated in many localities, such as north side of Grama Ridge, west side of Eunice Plain, Antelope Ridge area, and Rattlesnake Ridge. Greatest saturated thickness along east side of Eunice Plain, west of Monument Draw, where wells yield up to 30 gpm. Highest yields, up to 700 gpm, obtained from wells along south edge of Eunice Plain, east of Jal.
Mesozoic Cretaceous		Undifferentiated	35±	Small isolated and buried residual blocks of limestone, about 3 miles east of Eunice.	Possibly small isolated bodies of water locally.
Mesozoic Triassic	Dockum group	Chinle formation	0–1,270±	Claystone, red and green; minor fine-grained sandstones and siltstones; underlies all of eastern part of southern Lea County area; thins westward; absent in extreme west.	Yields small quantities of water from sandstone beds. Yields are rarely over 10 gpm. Water has high sulfate content.
		Santa Rosa sandstone	140–300±	Sandstone, chiefly red but locally white, gray, or greenish-gray; fine- to coarse-grained; exposed in extreme west; underlies Cenozoic rocks in western part of area, and is present at depth in eastern part.	Yields small quantities of water over most of the area. Some wells are reported to yield as much as 100 gpm. Water has high sulfate content.
Paleozoic Permian or Triassic		Undifferentiated	90–400±	Siltstone, red, shale, and sandstone; present at depth under all of southern Lea County.	No wells are known to be bottomed in the red beds. Probably can yield very small quantities of high-sulfate water.
Paleozoic Ordovician through Permian			6,500–17,000±	Thick basin deposits ranging in character from evaporites to coarse clastics; thinnest on the east side of the area over the Central basin platform, thickest toward the southwest.	No presently usable water supply available from these rocks. Source of highly mineralized oil-field waters.
Precambrian				Granite, granodioritic and other igneous and metamorphic rocks; complex structure.	Not hydrologically significant.

Figure 28 – Stratigraphic Units in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961).

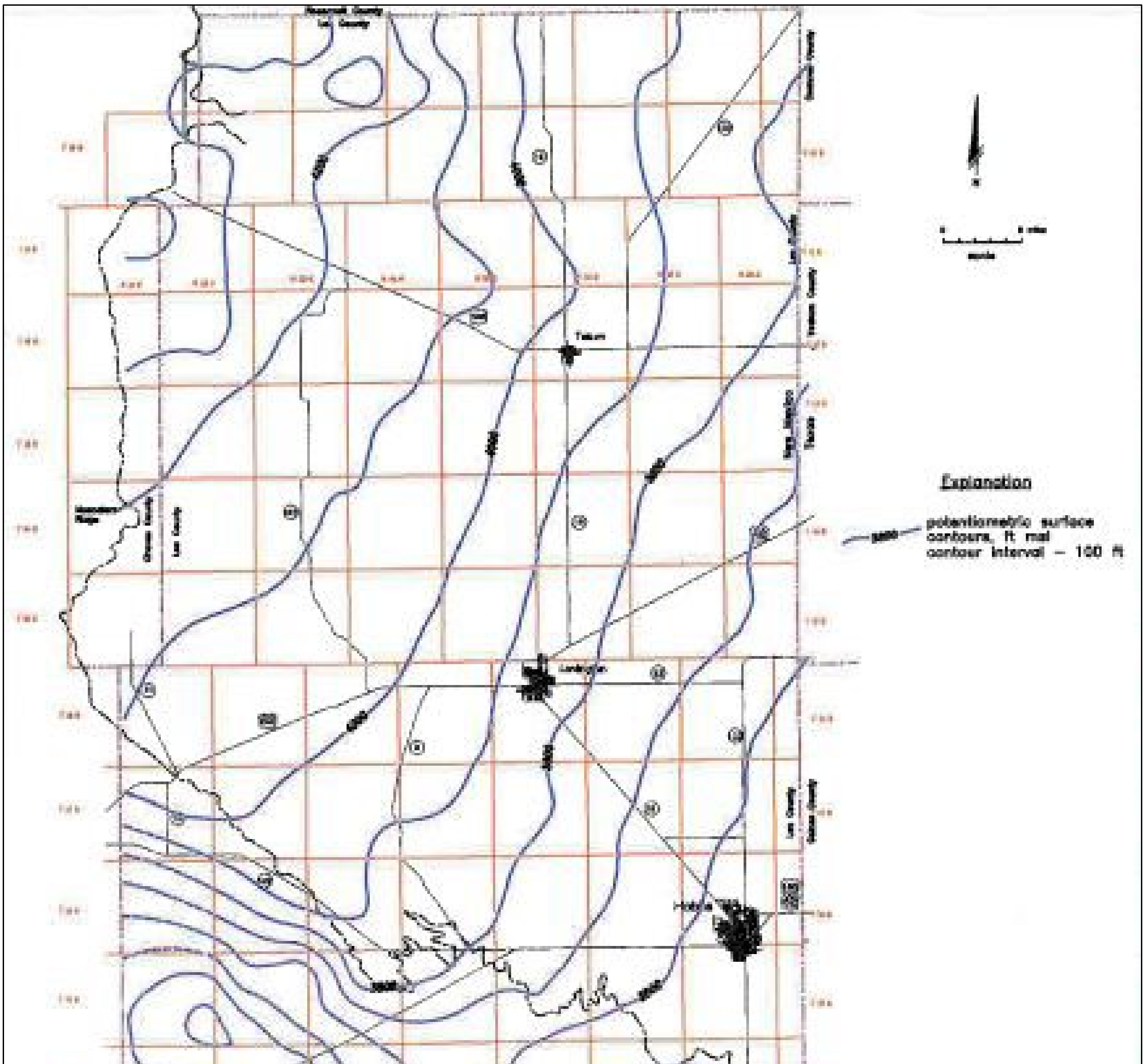


Figure 29 – Potentiometric map with surface elevation contours of Lea County, NM from 1995 to 1998 (Leedshill-Herkenhoff, Inc. et al., 2000).

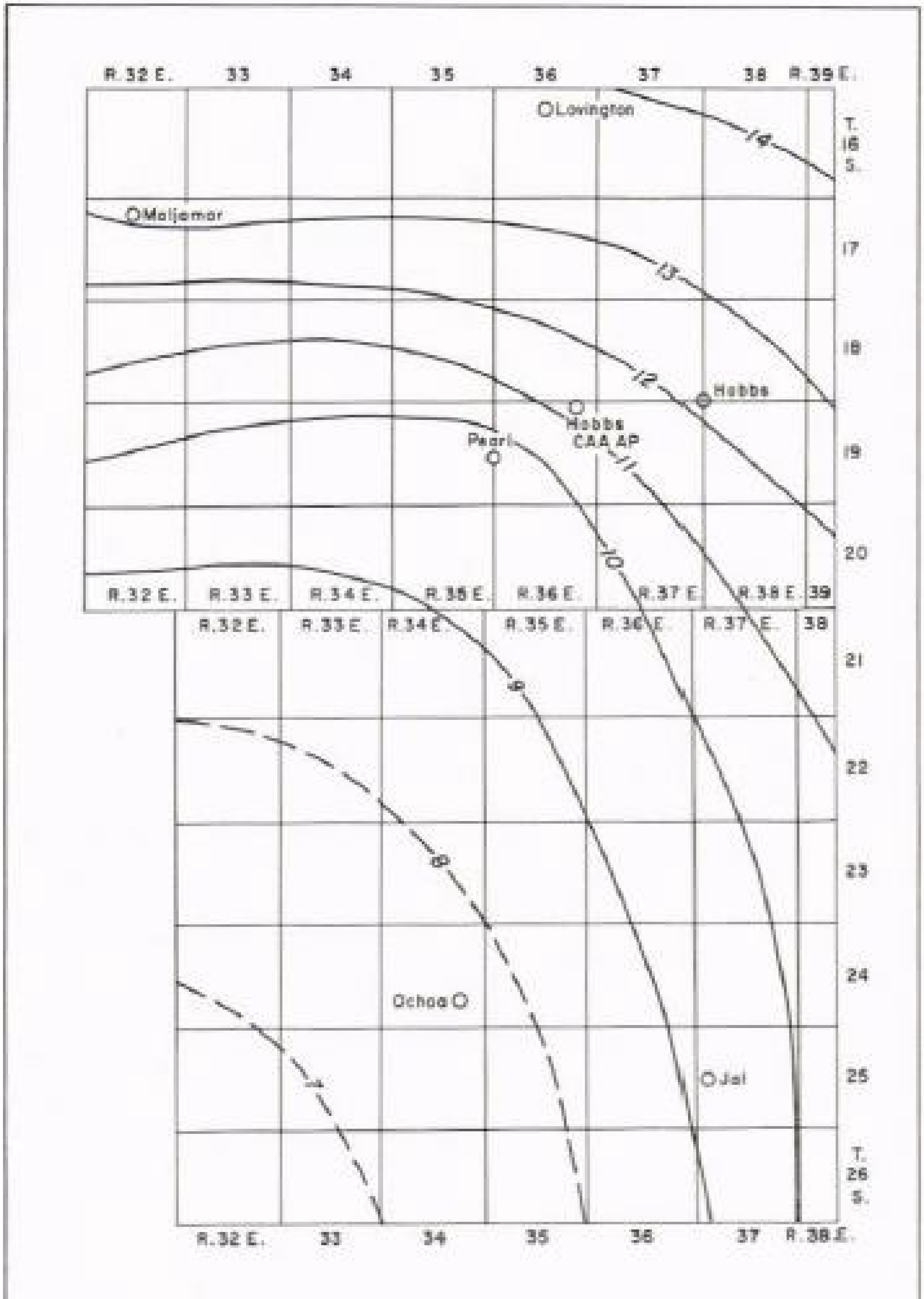


Figure 30 – Average Rainfall in Southern Lea County, NM during 1949 to 1955 (Nicholson and Clebsch, 1961).

Within the Capitan Reef Complex lies the Artesia Group which is made up of many smaller formations that include the Tansill (youngest), Yates, Seven Rivers, Queen, and Grayburg (oldest) Formations. Figure 31 shows the Capitan Reef Complex system. These formations will end up grading into the Capitan Reef Complex with the Grayburg and Queens formations grading to the Goat Seep Limestone and the Tansil, Yates, and Seven Rivers grade to the Capitan Limestone (Standen et al., 2009). The total thickness of these five formations can be a maximum of 2,000 ft with the thinnest being the Tansil formation and the thickest being the Seven Rivers formation.

The Dockum Group is a group of Triassic rocks that are primarily made up of red beds. These beds are also separated by an erosional unconformity. The Dockum can be split into the Santa Rosa sandstone and Chinle formation but cannot be differentiated because of similar lithologies and poor exposures (Nicholson and Clebsch, 1961). The Santa Rosa thickness can vary up to a maximum of 160 ft with the sandstone being 300 feet at its thickest while the Chinle drastically differs from zero to approximately 1,300 ft thick. The Santa Rosa is primarily made of fine- to coarse-grained sandstone. The Chinle is comprised more of a red and green claystone with small fine-grained sandstone and siltstone. The Chinle is thicker in the eastern areas of the county while being vacant from the western dissolved solids tend to be from 1,000 to 5,000 milligrams per liter (mg/l) in southern Lea County with some areas showing less than 1,000 mg/l. Figure 32 shows the amount of TDS in the Dockum Aquifer covering West Texas and North Texas as well as Eastern New Mexico, including Lea County, with the red star portraying the approximate position of the proposed Salt Creek AGI locations.

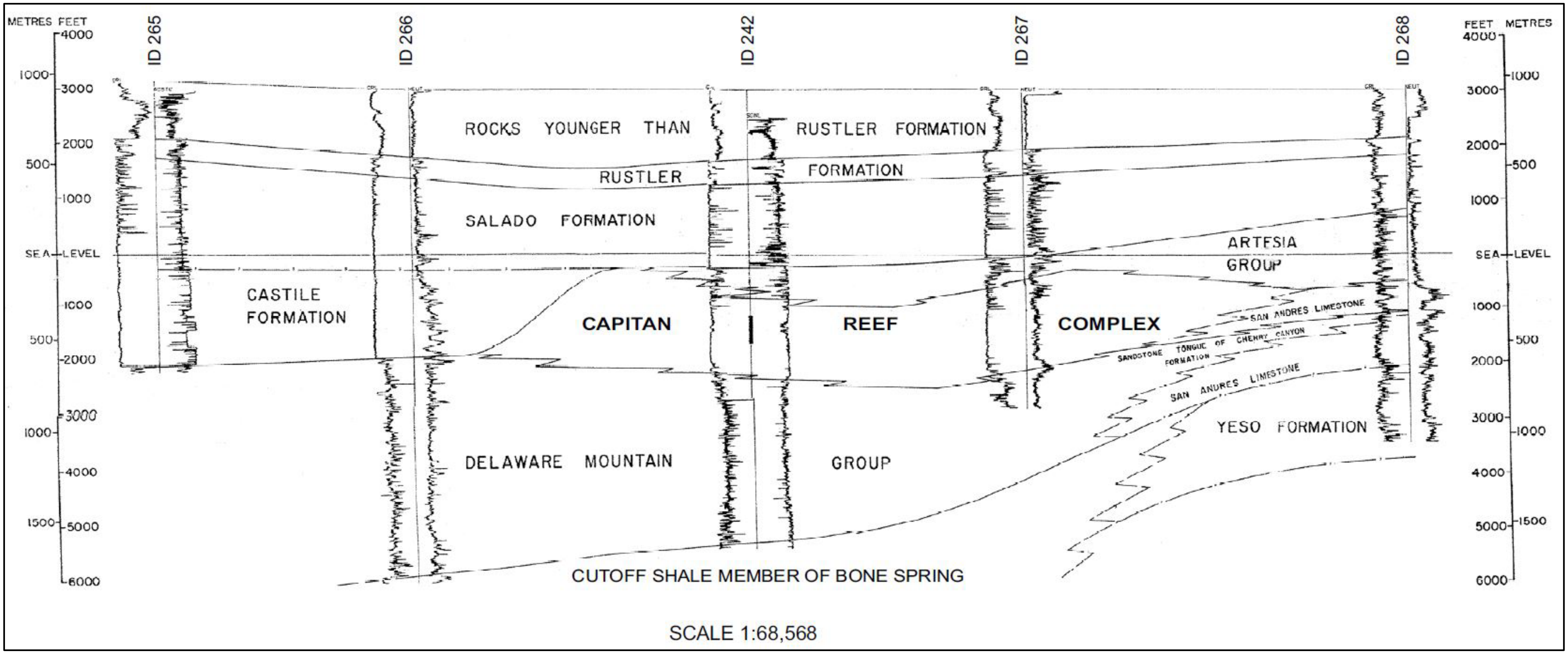


Figure 31 – Capitan Reef Complex in Southern Lea County from West to East (Standen et al., 2009).

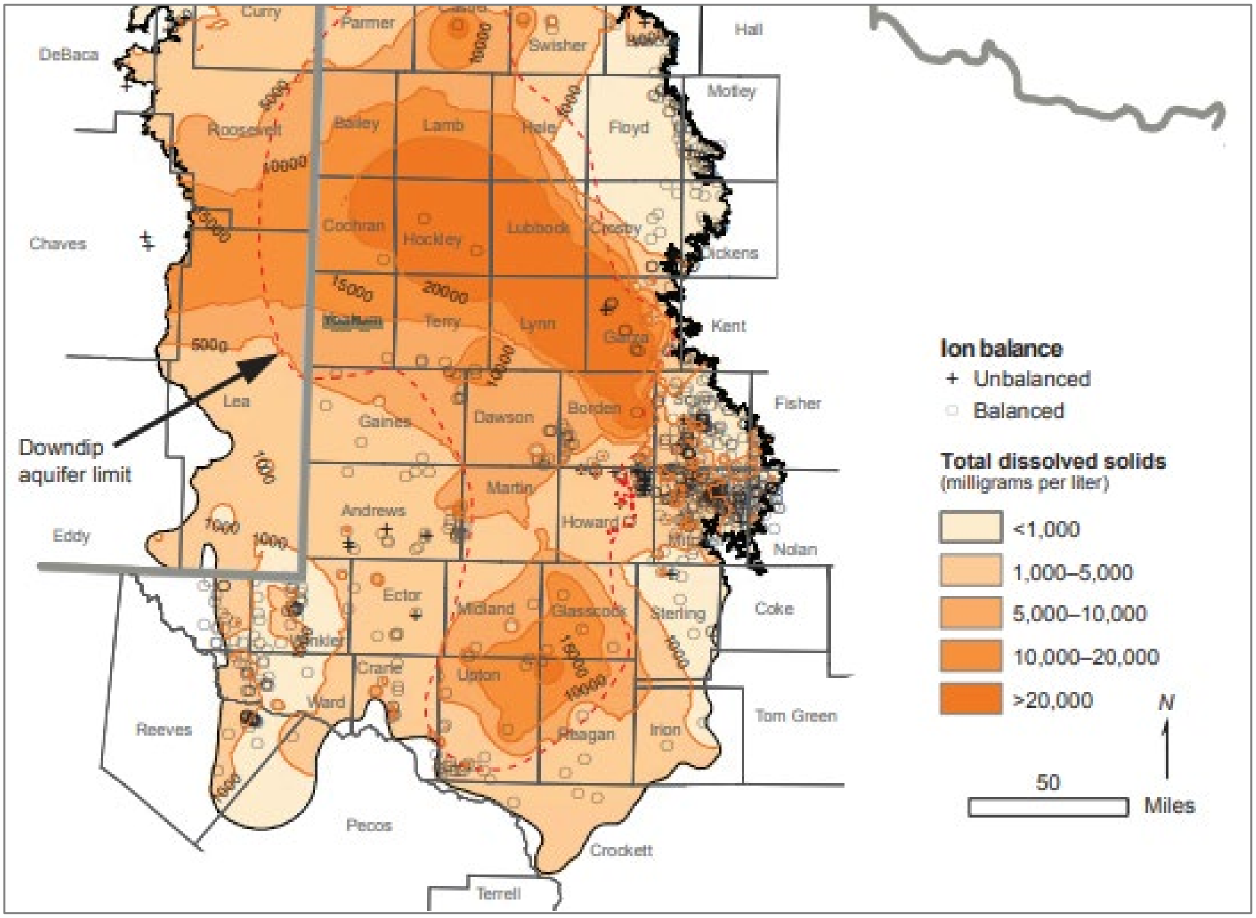


Figure 32 – Total dissolved solids in groundwater from the Dockum Aquifer (Ewing et al., 2008).

2.6.3 Surface Water Resources

As stated previously, nearly all surface water resources in the general vicinity are limited to streams and smaller lakes. While more than a dozen small lakes are present in the county, the only lake in the vicinity of the proposed well location is Rock Lake near the New Mexico and Texas border.

2.6.4 Conclusion

While the Ogallala and Alluvium aquifers are void in the area of the proposed Salt Creek AGI wells and most surface water sources also not present, there are still ground water sources available. Water levels have been declining and roughly 20% of the county's groundwater reserves have been lost during the past 5 years.

2.7 Description of the Injection Process

2.7.1 Current and Proposed Operations

Salt Creek AGI No. 2 is permitted for injection into the Siluro-Devonian with a maximum rate of injection 12 MMscf/d (225,000 metric tons per year (MT/yr)). Injection is expected to begin in mid-2024 and Northwind plans to inject into both wells for 30 years. Salt Creek AGI No. 3 is permitted for injection into the DMG formation with a maximum rate of injection of 8 MMscf/d (150,000 MT/yr). The Salt Creek AGI No. 3 well began injection operations in June 2024.

The TAG from the outlet of the treating facility is 70% CO_2, which equates to 158,000 and 105,000 MT/yr of CO_2 each year, respectively. The current composition of the TAG stream is provided in Table 6.

Table 6 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide (CO_2)	70%
Hydrogen Sulfide (H_2S)	30%
Nitrogen and C_1-C_7	<1%

The Titan Treating Facility is designed to dehydrate, treat, and compress the natural gas produced from the surrounding acreage in Lea County. The gas is dehydrated to remove the water content and then treated to remove CO_2 and H_2S. The compressed rich gas stream is then transported via pipeline to a separate facility for processing to separate the natural gas liquids from the methane. The TAG is then directly routed from the Plant's amine unit to the Salt Creek AGI wells. The Plant will be manned 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

Two reservoir modeling software packages were used to simulate the injection of acid gas into the Delaware Mountain Group and Siluro-Devonian formations. For the DMG injection, Rock Flow Dynamic's (RFD) tNavigator version 24.1 simulator was used. For the Devonian, Schlumberger's (SLB) Eclipse was used. These reservoir models are also referred to as "dynamic models"

Both dynamic models are advanced modeling and simulation platforms used for understanding reservoir dynamics, flow patterns, and risks associated with carbon injection. Different modeling software platforms were used for the different target injection zones as the modeling efforts were undertaken by different teams.

2.8.1 Reservoir Modeling – Siluro-Devonian

The Siluro-Devonian formation is the target formation for Salt Creek AGI No. 2. The Petrel software package was used to construct the geological model for this target formation. Within Petrel, eight reservoir zones were generated for the Siluro-Devonian formation and imported into Eclipse to run the dynamic model. The geologic model for the Siluro-Devonian formation is heterogeneous in nature, assuming porosity and permeability are spatially distributed throughout the model.

Porosity distribution across the reservoir zones has been mapped using average porosity values derived from local well data, ensuring spatial accuracy. These values have been correlated with impedance characteristics to enhance the reliability of the porosity maps. The porosity varies across the eight distinct reservoir zones, providing critical insights for reservoir characterization and simulation. Permeability distribution has been mapped for the eight distinct reservoir zones using average permeability values derived from both published and collected Siluro-Devonian data. This data has been calibrated against nearby, history-matched operating data from within the Siluro-Devonian formation to ensure accuracy and relevance.

The reservoir is estimated to be at hydrostatic equilibrium. The well will be perforated throughout the injection interval. The model assigns heterogeneous porosity and permeability values in each grid cell, spatially distributed throughout the model. The modeled injection interval has an average permeability of 5.1 mD and an average porosity of 2.1%. All layers within the injection interval are modeling as being perforated. An infinite-acting reservoir has been created to simulate the boundary conditions.

The acid gas injectate is composed of CO_2, H_2S and trace components of hydrocarbons (C_1 – C_7) as shown previously in Table 6. The modeled composition considers CO_2 and H_2S. The gas composition for the proposed injection period is assumed to remain constant.

The relative permeability curves were generated using published literature (Figure 33). The literature focused on analogous, low permeability rocks in the western United States, providing foundational data and characteristic trends pertinent to such geological formations (Bennion, 2002). Additionally, internal experience particularly from gas storage applications in aquifers, to refine and validate the curves. This dual approach ensured that the curves accurately represented the fluid flow properties in low permeability reservoirs, enhancing the reliability of their reservoir simulations and predictions. There is no maximum residual gas saturation modeled for the Siluro-Devonian formation, allowing for larger, more conservative sized plume.

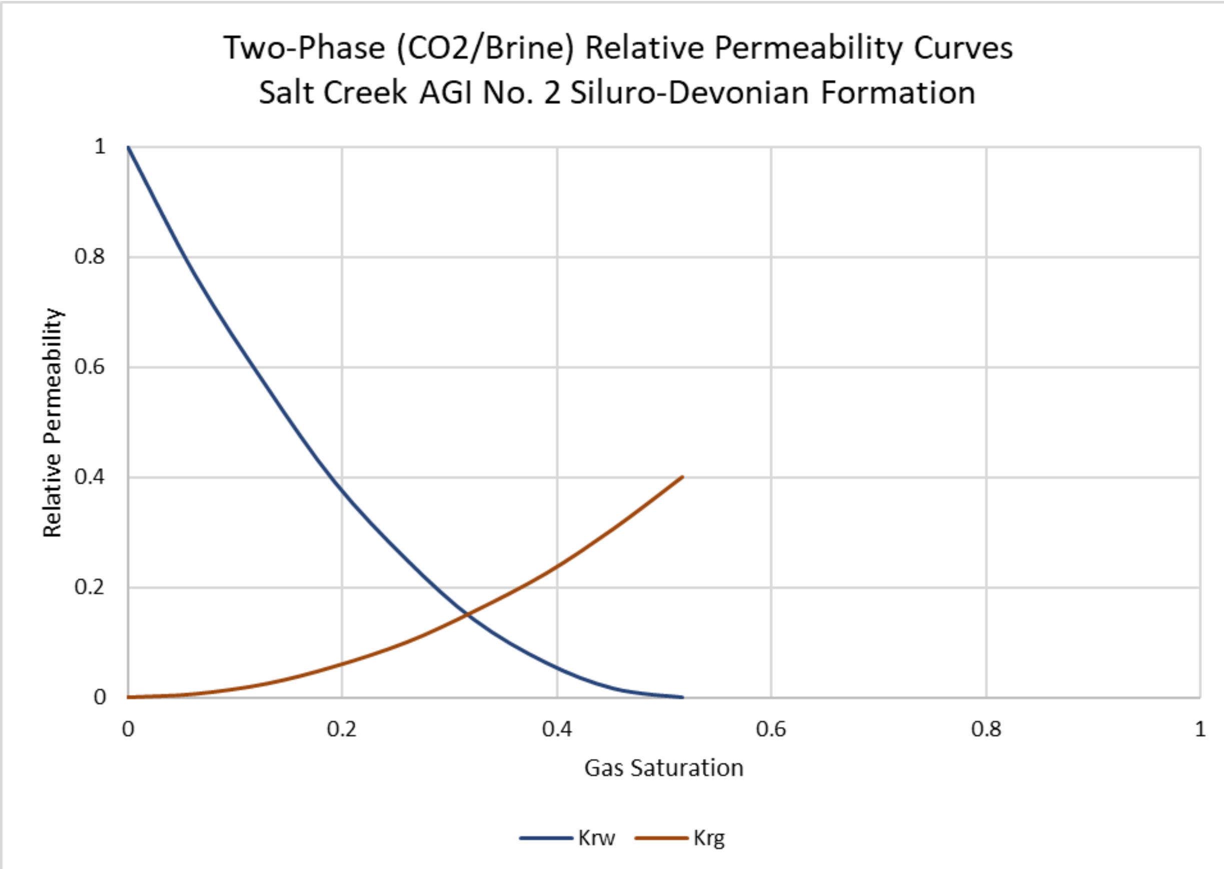


Figure 33 – Two-Phase Relative Permeability Curves Used in the Siluro-Devonian Dynamic Model.

The grid contains 161 blocks in the x-direction (east to west) and 131 blocks in the y-direction (north to south), resulting in a total of 21,091 grid blocks per layer. Each grid block spans dimensions of 165 ft x 165 ft. This configuration yields a grid size measuring 26,565 ft x 21,615 ft, equating to just under 20 square miles in area.

In the model, each layer is defined by heterogeneous permeability and porosity values, derived from the geostatistical distribution of properties based on nearby porosity log data implemented in Petrel. The model comprises a total of 161 layers, each with varying thicknesses, averaging approximately 10 ft per layer. As previously mentioned, the structure of the Siluro-Devonian formation was constructed using eight contour packages, with the summarized property values for each package presented in Table 7.

Table 7 – Dynamic Model Layer Package Properties, Siluro-Devonian.

Contour Package	No. of Layers	Top (ft)	Thickness (ft)	Perm. (mD)	Porosity
Zone 1	12	17,550	118	2.1	0.9
Zone 2	10	17,668	98	1.2	1.9
Zone 3	10	17,766	126	2.4	3.2
Zone 4	12	17,892	374	0.9	1.4
Zone 5	36	18,266	199	1.7	1.8
Zone 6	22	18,465	220	0.01	2.6
Zone 7	24	18,685	38	10.5	2.4
Zone 8	55	18,723	378	12.3	2.1

2.8.2 Simulation Modeling – Siluro-Devonian

The primary objectives of the model simulation were as follows:

1. Estimate the maximum areal extent and density drift of the acid gas plume after injection.
2. Assess the impact of any offset SWD well injection on density drift of the plume.
3. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
4. Assess the likelihood of the acid gas plume migrating into potential leak pathways.

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 70,000 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, version 3.0), typical for the region and formation. The formation temperature gradient is assumed to be 1.00°F per 100 ft, with an ambient surface temperature of 70°F and is based on the bottomhole temperature reading of the Salt Creek AGI No. 2 well. The acid gas stream is primarily composed of CO_2 and H_2S, as stated previously. Core data was used to generate relative permeability curves (Bennion, 2002). As previously mentioned, analogous cores that most closely represent the Siluro-Devonian carbonate in this region were identified from literature. No SWDs were identified near the Titan Treating Facility area that penetrated the Siluro-Devonian formation; therefore, there is no impact from offset well injection to consider.

The dynamic model is initialized with a reference pressure of 7,641 psig at a subsea depth of 14,720 ft. This pressure, when a Kelly Bushing (KB) elevation of 2,926 ft is considered, correlates to a gradient of 0.433 psi/ft. This pressure gradient is in line with regional trends (Snee and Zoback, 2018). The FG of the injection zone was estimated to be 0.72 psi/ft, using Eaton's method. A 10% safety factor was then applied to this number, putting the maximum BHP allowed in the model at 0.65 psi/ft, which is equivalent to 11,407.5 psig at the top of the Siluro-Devonian injection interval.

The model, which begins in 2025, runs for a total of 80 years, with 30 years of active injection, and succeeded by 25 years of density drift. Throughout the entire 30-year injection period, an injection rate of 12 MMscf/d is used to model the maximum available rate, yielding the largest estimate of the plume size. After the 30-year injection period, when Salt Creek AGI No. 2 ceases injection, the density drift of the plume continues until the plume stabilizes 25 years later. The maximum plume extent during the 30-year injection period is shown in Figure 34. The final extent after 25 years of density drift after injection ceases is shown in Figure 35.

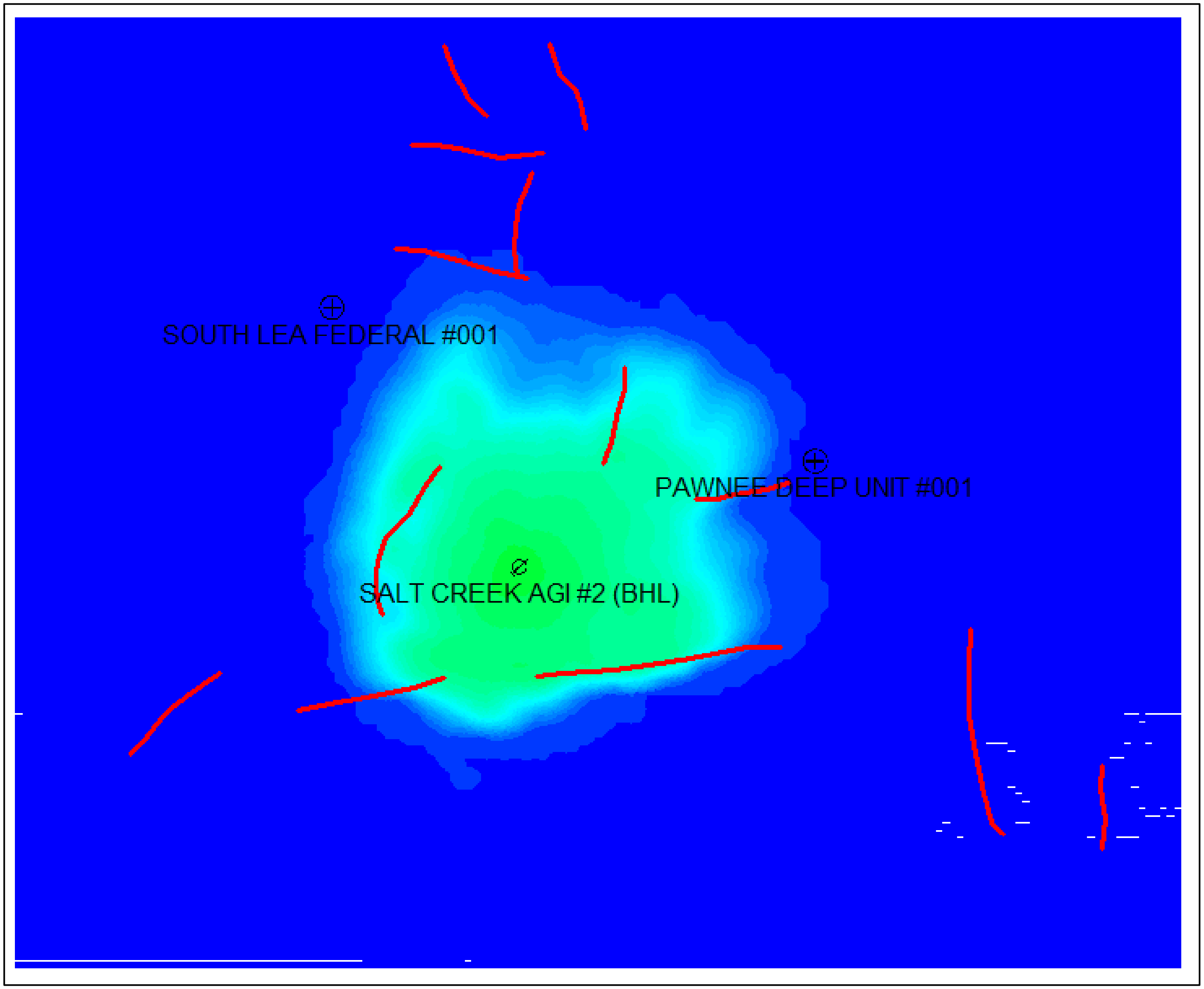


Figure 34 – Areal View of Gas Saturation Plume at Shut-in (End of Injection), Siluro-Devonian

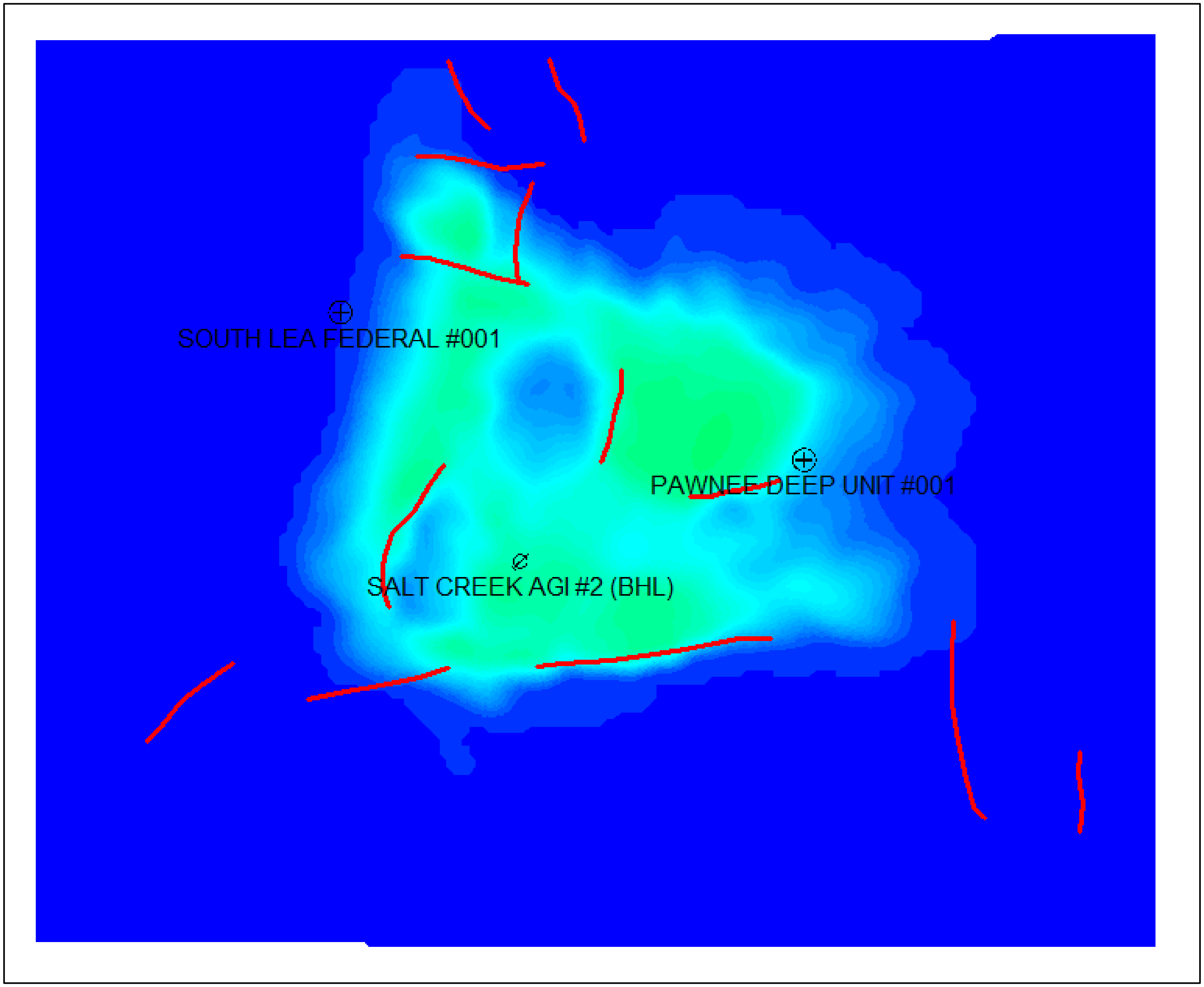


Figure 35 – Areal View of Saturation Plume at 50 Years After Shut-in (End of Simulation), Siluro-Devonian.

The cross-sectional view of the Salt Creek AGI No. 2 shows the extent of the Devonian plume from a side-view angle cutting through the formation at the wellbore. Figure 36 shows the maximum plume extent during the 30-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 37 shows the final extent of the plume after 50 years of migration. At this point, the effects of migration caused by density drift are clearly shown. Because the gas is less dense than the formation brine, it travels mostly vertically until an impermeable layer is reached. The gas then migrates laterally along the confining layer. Both figures are shown in a north-to-south view.

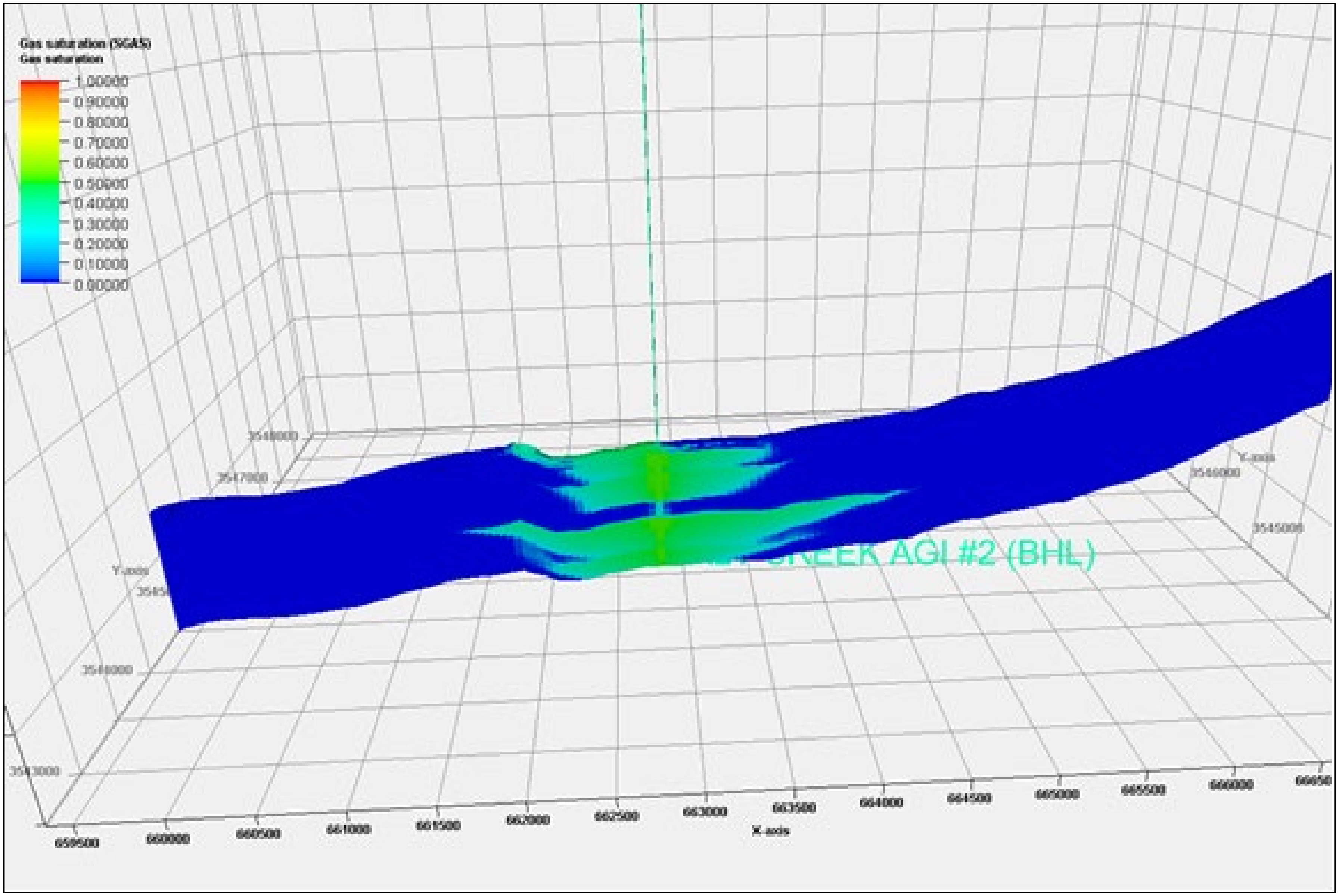


Figure 36 – North-South Cross-Sectional View of Gas Saturation Plume after 30 years (End of Injection), Siluro-Devonian

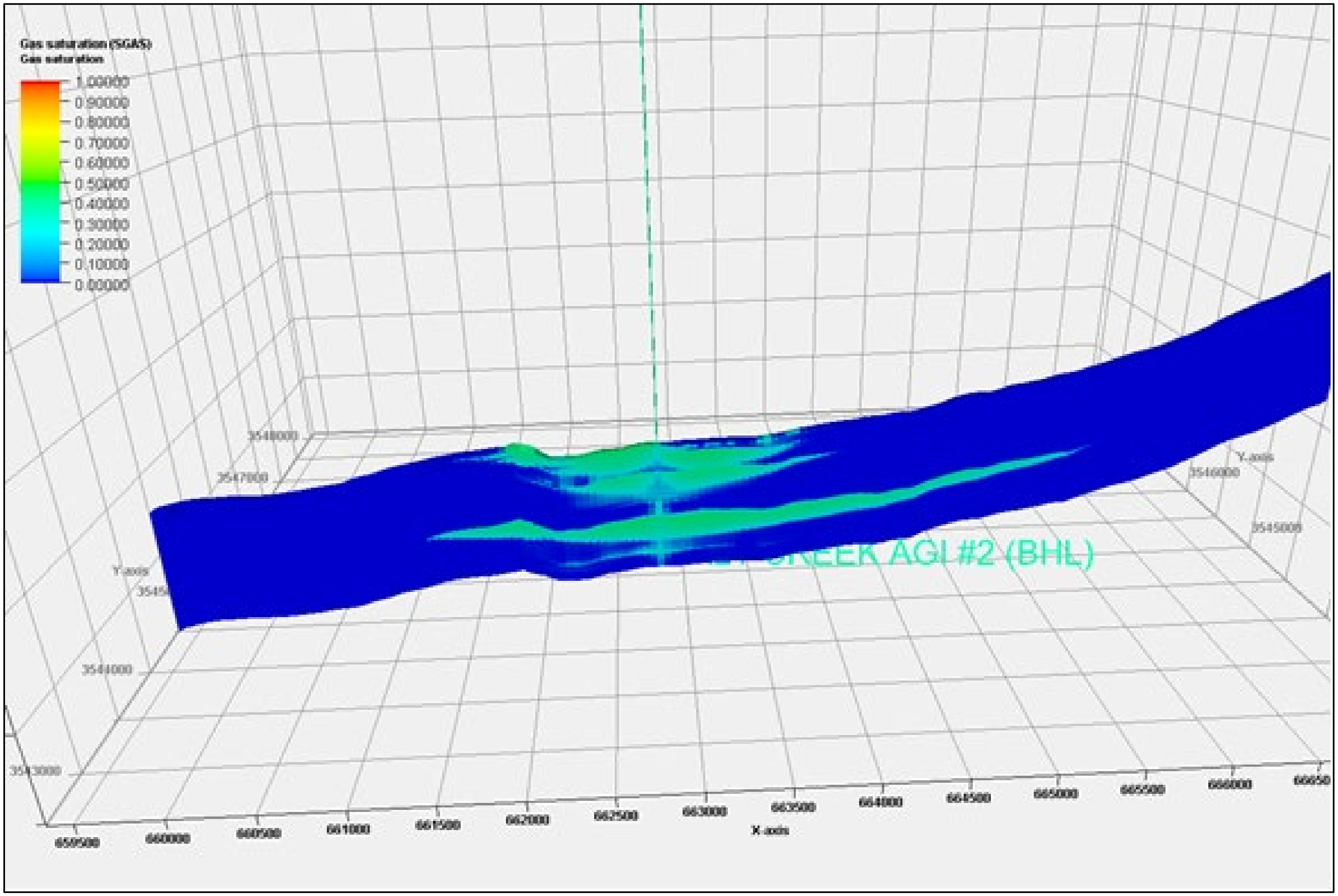


Figure 37 –North-South Cross-Sectional View of Gas Saturation Plume at 50 Years After End of Injection, Siluro-Devonian

Figure 38 shows the surface injection rate, BHP, and wellhead pressure (WHP) over the injection period. The BHP increases steadily throughout the injection. The BHP reaches a maximum of 8,677 psig. This buildup of 653 psig keeps the BHP below the 90% fracture pressure constraint of 11,407.5 psi. The maximum WHP associated with the maximum BHP reached is 3,217 psig, which is considerably less than the maximum allowable 5,797 psig in accordance with the NMOCD UIC permit application for this well. BHPs and WHPs are provided in Table 8.

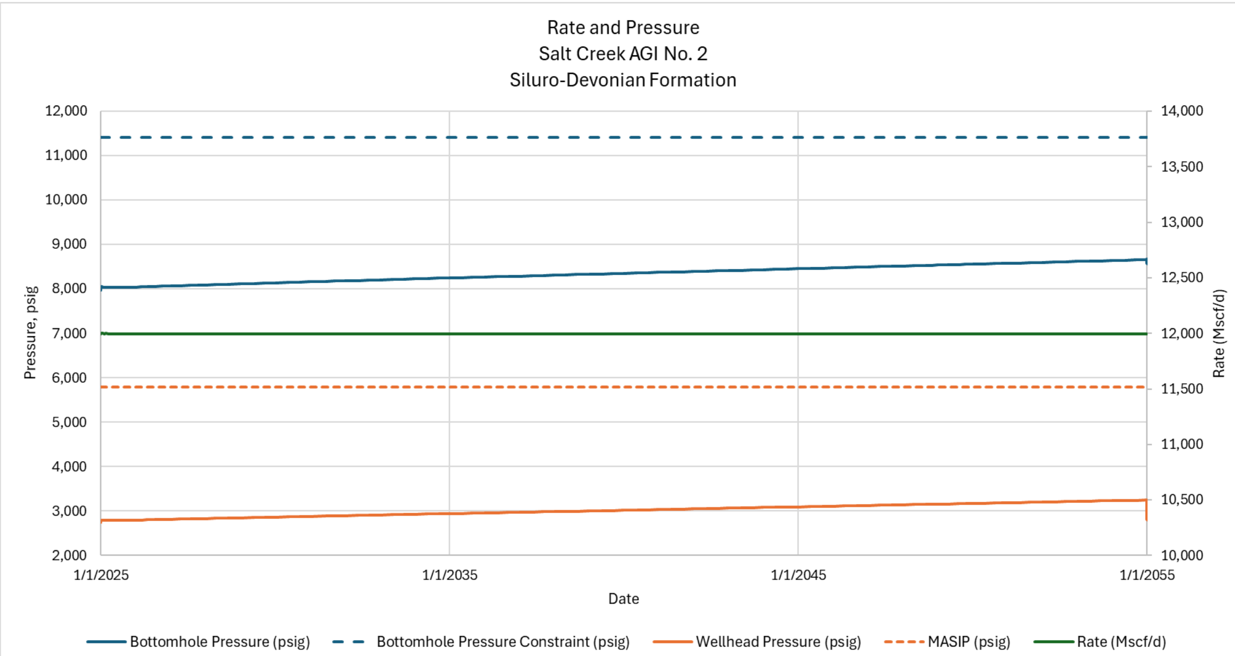


Figure 38 – Well Injection Rate and Bottomhole and Surface Pressures Over Time, Siluro-Devonian.

Table 8 – Bottomhole and Wellhead Pressures Over Time from Start of Injection, Siluro-Devonian.

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	0	0
10	8,249	2,944
20	8,456	3,097
30 (End of Injection)	8,677	3,217
40	8,441	0
50	8,427	0
60	8,423	0
70	8,420	0
80	8,417	0

2.8.2.1 Plume Stabilization, Siluro-Devonian

Figure 39 demonstrates that the growth rate of the plume will decrease to less than 1% increase in area per year by 2080 (25 years after injection ceases) and is therefore effectively stabilized by that time.

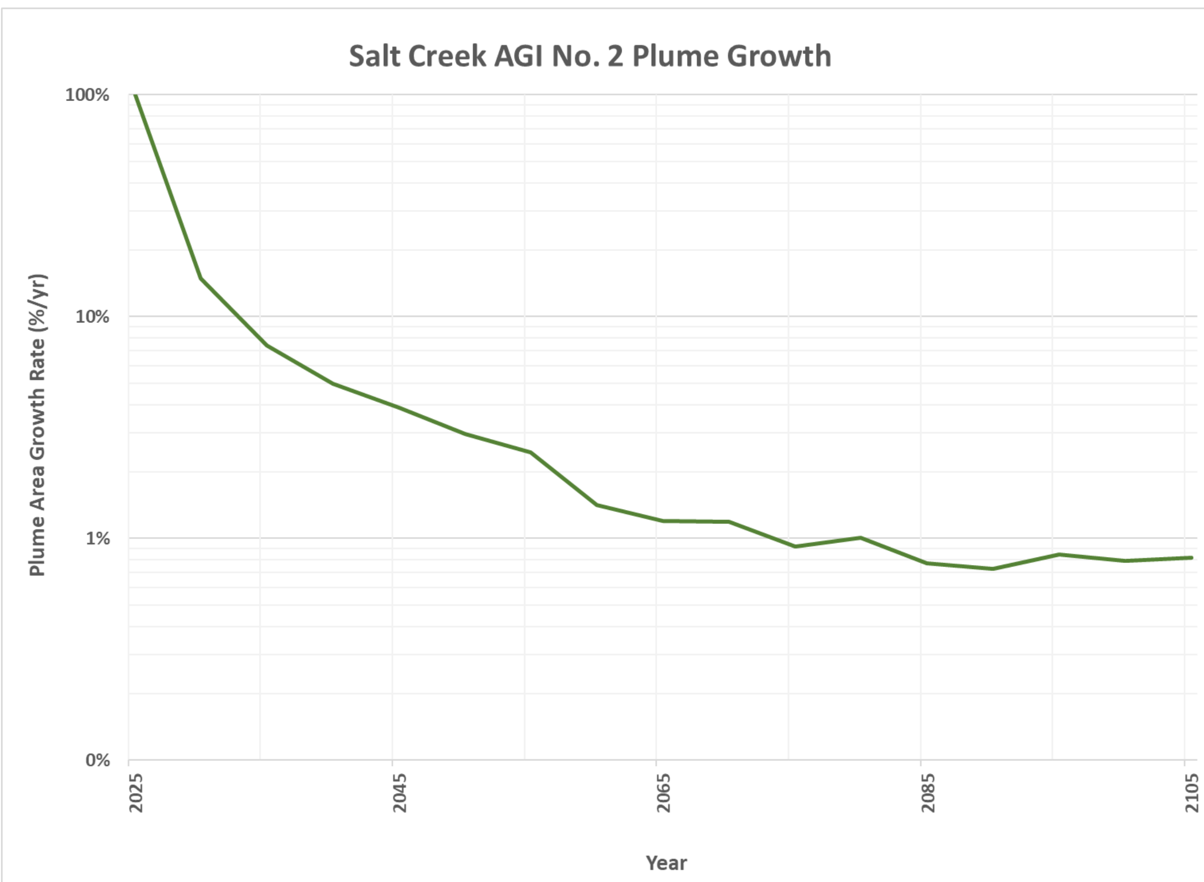


Figure 39 – Annual Growth Rate of CO_2 Plume, Siluro-Devonian

2.8.3 Reservoir Modeling – Delaware Mountain Group

The Delaware Mountain Group formation is the target formation for Salt Creek AGI No. 3. The Petra software package was used to construct the geological model for this target formation. Within Petra, formation top contours were generated for the Delaware Mountain Group formation and subsequently brought into tNavigator to outline the geological structure to be used in the dynamic model.

Porosity was determined using the porosity log from the Salt Creek AGI No. 3 well. A literature review was then conducted to establish a correlation between the porosity values from the type log and permeability (Jenkins, 1961). Both the porosity and permeability estimates from the type log and core analysis were incorporated into the model with the assumption that they exhibit lateral homogeneity throughout the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium. The well is assumed to be perforated throughout the entire injection interval. Each layer has an assigned porosity and permeability value based on the porosity log and transform applied to it from the core analysis. The modeled injection interval exhibits an average permeability of 18 mD and an average porosity of 12%. All layers within the modeled injection interval have been perforated. An infinite-acting reservoir has been created to simulate the boundary conditions.

The acid gas injectate is composed of CO_2, H_2S and trace components of hydrocarbons ($C_1 – C_7$), as shown in Table 9. The modeled composition considers CO_2 and H_2S. The gas composition for the proposed injection period remains constant.

Table 9 – Modeled Initial Gas Composition.

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Carbon Dioxide (CO_2)	70.0	70
Hydrogen Sulfide (H_2S)	30.0	30
Nitrogen and $C_1 – C_7$	<1.0	0

Core data from literature review (Holtz, 2005) was used to determine residual gas saturation and relative permeability curves between carbon dioxide and the connate brine from analogous formations to the Delaware Mountain Group sandstones (Bachu, 2013). Relative permeability curves were created using the Corey-Brooks method. The key inputs used in the model are provided in Table 10. The relative permeability curves used for the dynamic model are shown in Figure 40.

Table 10 – Key Inputs to Reservoir Model, Delaware Mountain Group.

Parameter	Value
Corey exponent, brine	2.0
Corey exponent, gas	2.8

Irreducible brine saturation	50%
Gas permeability at irreducible brine saturation	30%
Maximum residual gas saturation	30%

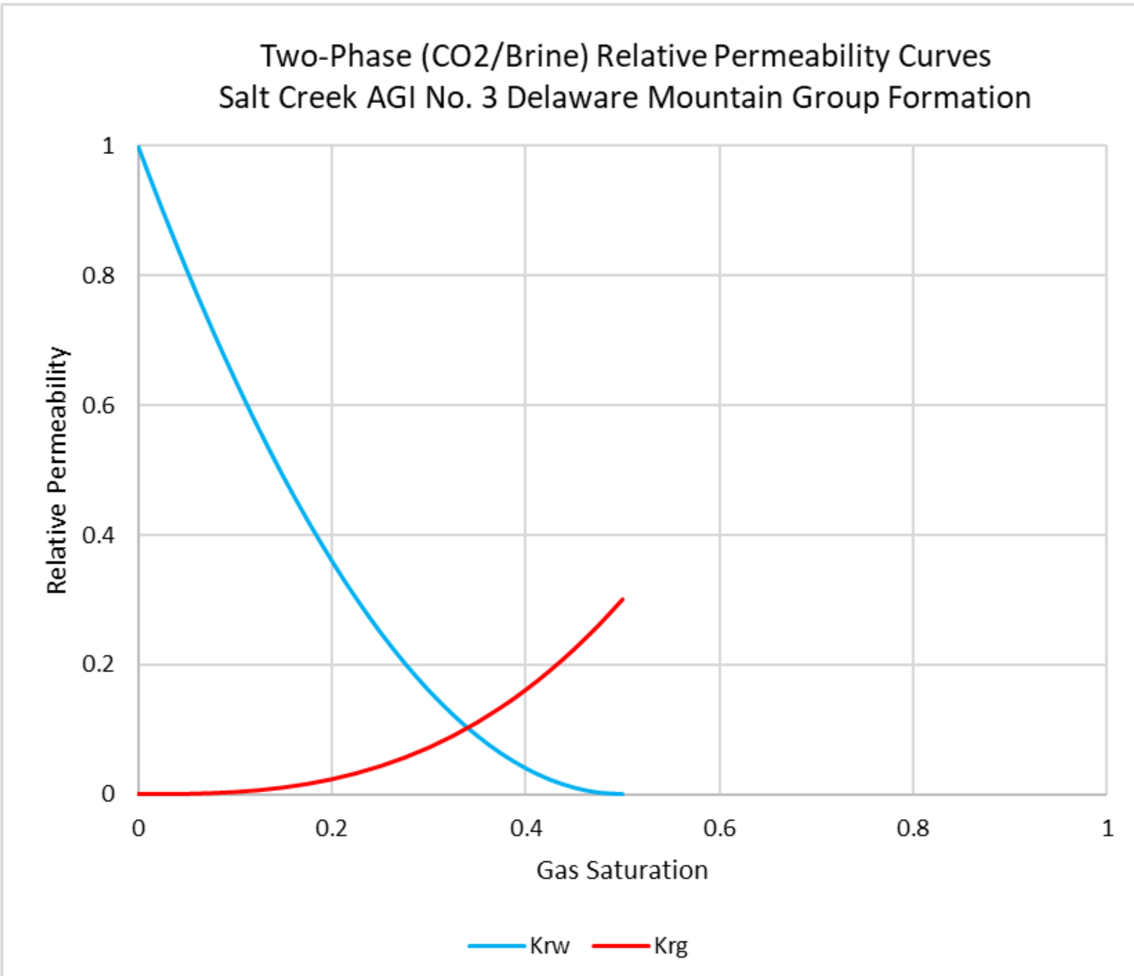


Figure 40 – Two-Phase Relative Permeability Curves Used in the Delaware Mountain Group Dynamic Model

The grid contains 101 blocks in the x-direction (east to west) and 101 blocks in the y-direction (north to south), resulting in a total of 10,201 grid blocks per layer. Each grid block spans dimensions of 500 ft x 500 ft. This configuration yields a grid size measuring 50,500 ft x 50,500 ft, equating to just over 91 square miles in area. The grid cells in the vicinity of the Salt Creek facility, within a radius of 0.5 miles, have been refined to dimensions of 167 ft x 167 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume and pressure effects felt near the wellbore.

In the model, each layer is characterized by homogeneous porosity and permeability values. These values are derived from a porosity log of the Salt Creek AGI No. 3 well and core analysis taken from literature (Jenkins, 1961). The intervals of sand are assigned the values from the porosity log and permeability values assigned from the transform. If the interval is assumed to be shale, values of 5% porosity and 0.001 mD permeability are assigned. Upscaled porosity and permeability values from the type log are used to define each layer in the model. From the type log, intervals of shale greater than 5 feet become impermeable shale layers in the model. These layers are implemented into the model and grouped as “packages” as seen in Table 11. From the porosity log, intervals where shale is greater than 5 ft in thickness are assumed to have porosity and permeability values of 5% and 0.001 mD, respectively, for those modeled layers. The model encompasses the entire injection interval, with the top layer being the top of the DMG and bottom layer being the base of the DMG. A total of 376 layers are modeled. Grid cell thickness within the model is variable with an average thickness of 5 ft. As previously mentioned, the well is perforated in each layer of the injection interval to best represent an openhole wellbore.

Table 11 –Dynamic Model Layer Package Properties, Delaware Mountain Group

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Sand 1	4	5,093.5	19.5	9	0.07
Shale 1	2	5,113.0	11.5	0.001	0.05
Sand 2	1	5,124.5	6.5	14	0.09
Shale 2	2	5,131.0	9.5	0.001	0.05
Sand 3	245	5,140.5	1,226.0	18	0.12
Shale 3	2	6,366.5	7.0	0.001	0.05
Sand 4	16	6,373.5	80.0	14	0.10
Shale 4	2	6,453.5	8.5	0.001	0.05
Sand 5	15	6,462.0	760	19	0.13
Shale 5	2	6,538.0	10.0	0.001	0.05
Sand 6	85	6,548.0	425.5	15	0.11

2.8.4 Simulation Modeling, Delaware Mountain Group

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 313,662 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, version 3.0), typical for the region and formation. The formation temperature gradient is assumed to be 0.89°F per 100 ft, with an ambient surface temperature of 72°F and is based on the bottomhole temperature reading at Salt Creek AGI No. 3. The acid gas stream is primarily composed of CO_2 and H_2S, as stated previously. Core data was used to generate relative permeability curves (Jenkins, 1961). As previously mentioned, cores that most closely represent the Delaware Mountain Group sandstone in this region were identified from literature, and the Corey-

Brooks equations were used to develop the curves (Bachu, 2013). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Holtz, 2005).

The dynamic model is initialized with a reference pressure of 2,555 psig at a subsea depth of 3,000 ft. This pressure, when a Kelly Bushing “KB” elevation of 2,942 ft is considered, correlates to a gradient of 0.43 psi/ft. This pressure gradient is in line with regional trends (Snee and Zoback, 2018). The fracture gradient of the injection zone was estimated to be 0.68 psi/ft, using Eaton’s method. A 10% safety factor was then applied to this number, putting the maximum BHP allowed in the model at 0.61 psi/ft, which is equivalent to 3,422 psig at the top of the Delaware Mountain Group injection interval.

The model considers the injection of water into the DMG formation from offset SWD wells. A comprehensive review of the area was performed and determined that no active injectors are within a 7-mile radius of the proposed Salt Creek AGI No. 3 are injecting within the injection interval. However, two such wells are permitted for injection near the proposed Salt Creek AGI No. 3. Projected injection rates of the two permitted wells are conservatively assumed to be the maximum permitted injection rate and injecting for the entire time the Salt Creek AGI No. 3 well is injecting. This approach is done so the effects of water disposal are felt on the Salt Creek AGI No. 3 BHP and the resulting plume. The two SWDs included in the model are shown in Table 12.

Table 12 - Offset SWD Wells Included in the Delaware Mountain Group Dynamic Model.

API Number	Well Name	Well Number
42-495-34281	COM 27-C23	2D
42-495-34283	COM 27-C23	1D

The model, which begins in 2025, runs for 80 years, comprising 30 years of active injection, and is then succeeded by 50 years of potential density drift. Throughout the entire 30-year injection period, an injection rate of 8 MMscf/d is used to model the maximum available rate, yielding the largest estimate of the plume size. After the 30-year injection period, when Salt Creek AGI No. 3 ceases injection, the density drift of the plume continues until the plume stabilizes 20 years later. The maximum plume extent during the 30-year injection period is shown in Figure 41. The final extent after 20 years of density drift after injection ceases is shown in Figure 42.

The cross-sectional view of the Salt Creek AGI No. 3 shows the extent of the DMG plume from a side-view angle cutting through the formation at the wellbore. Figure 43 shows the maximum plume extent during the 30-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 44 shows the final extent of the plume after 20 years of migration. At this point in time, the effects of residual gas saturation and migration caused by density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, because the gas is less dense than the formation brine, until an impermeable layer is reached. Because of the dense nature of the formation brine, the plume migrates vertically upwards and less laterally. Both figures are shown in a west-east view.

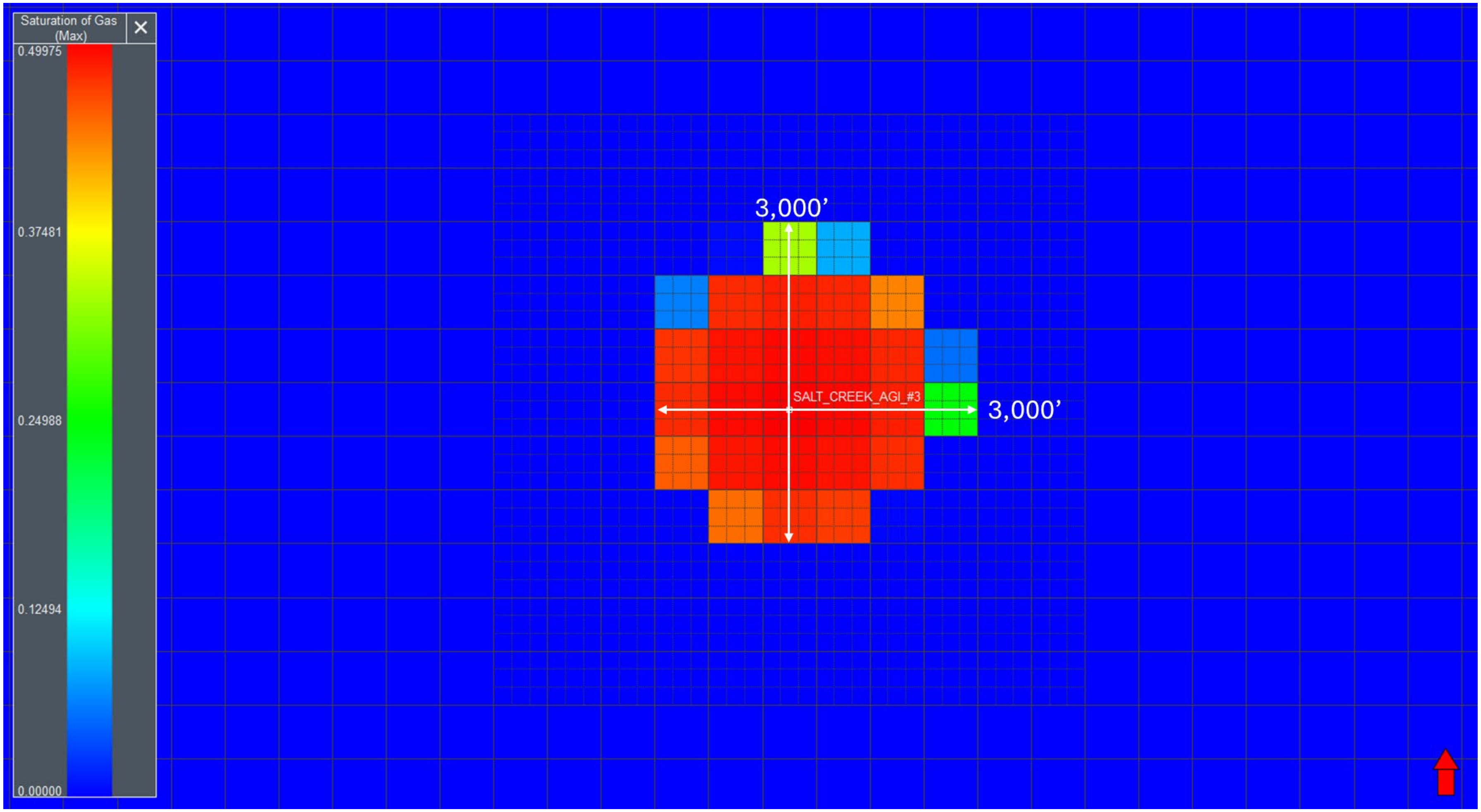


Figure 41 – Areal View of Delaware Mountain Group Gas Saturation Plume at Shut-in (End of Injection).

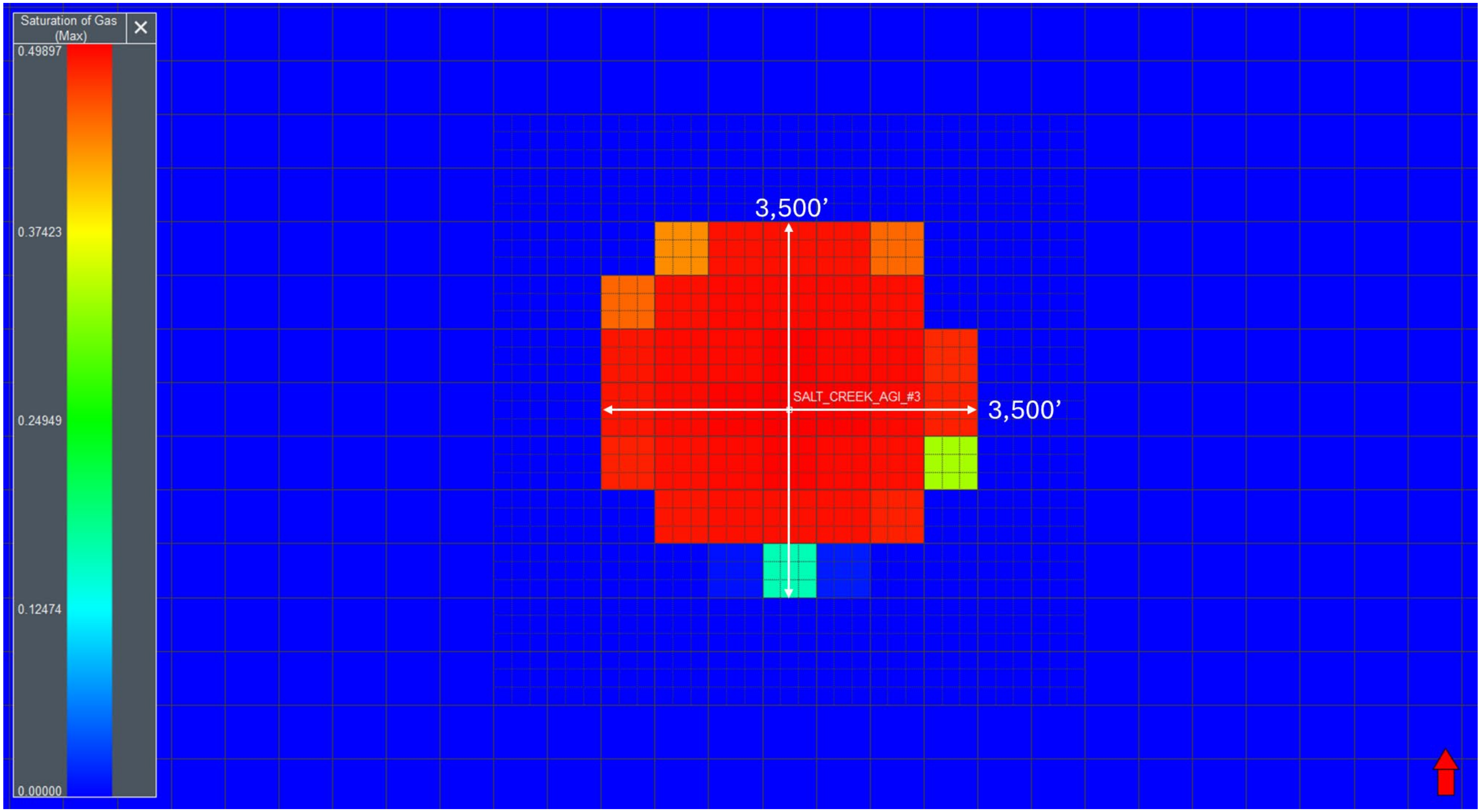


Figure 42 – Areal View of Delaware Mountain Group Saturation Plume at 20 Years After Shut-in.

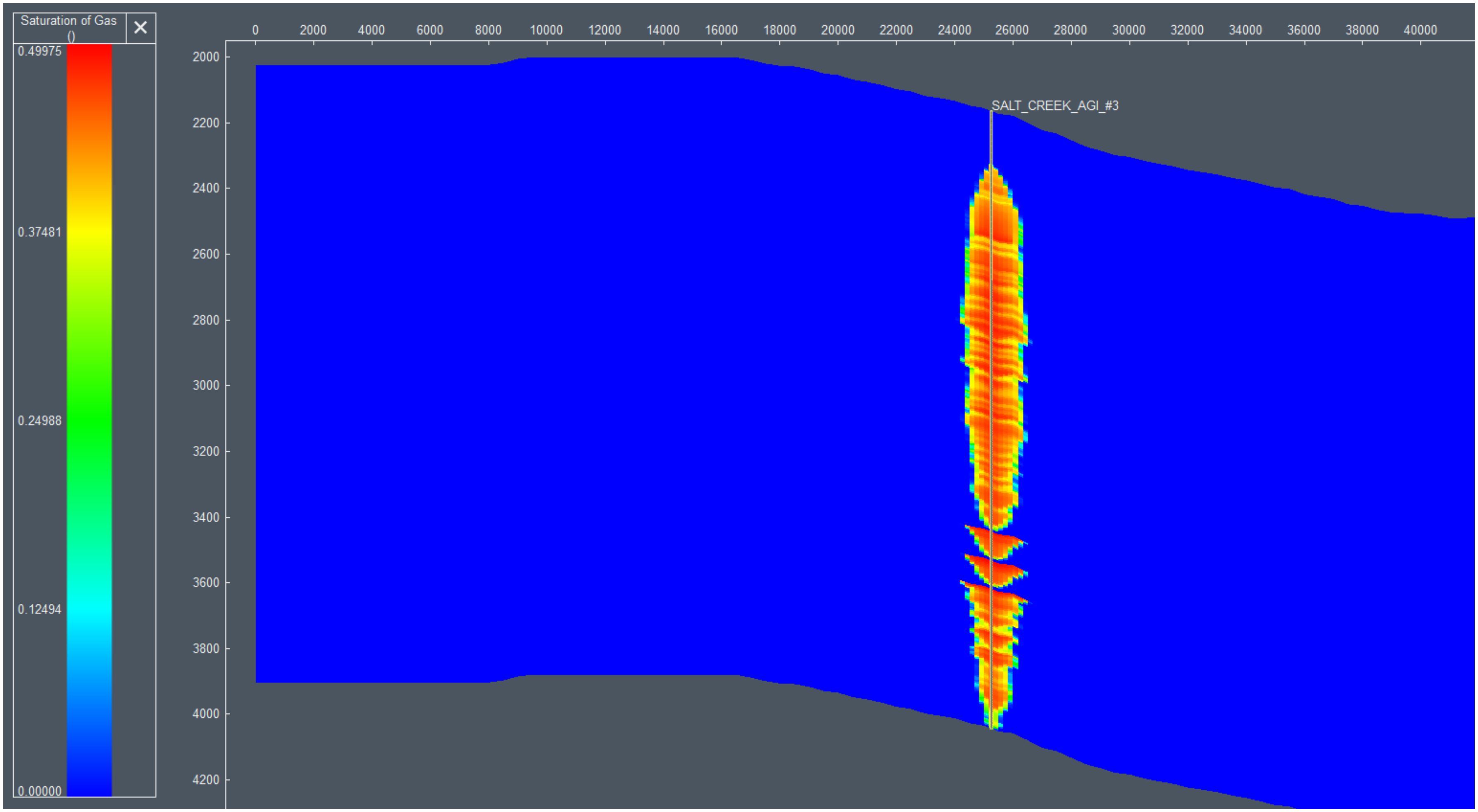


Figure 43 – West-East Cross-Sectional View of Delaware Mountain Group Gas Saturation Plume at Shut-in (End of Injection)

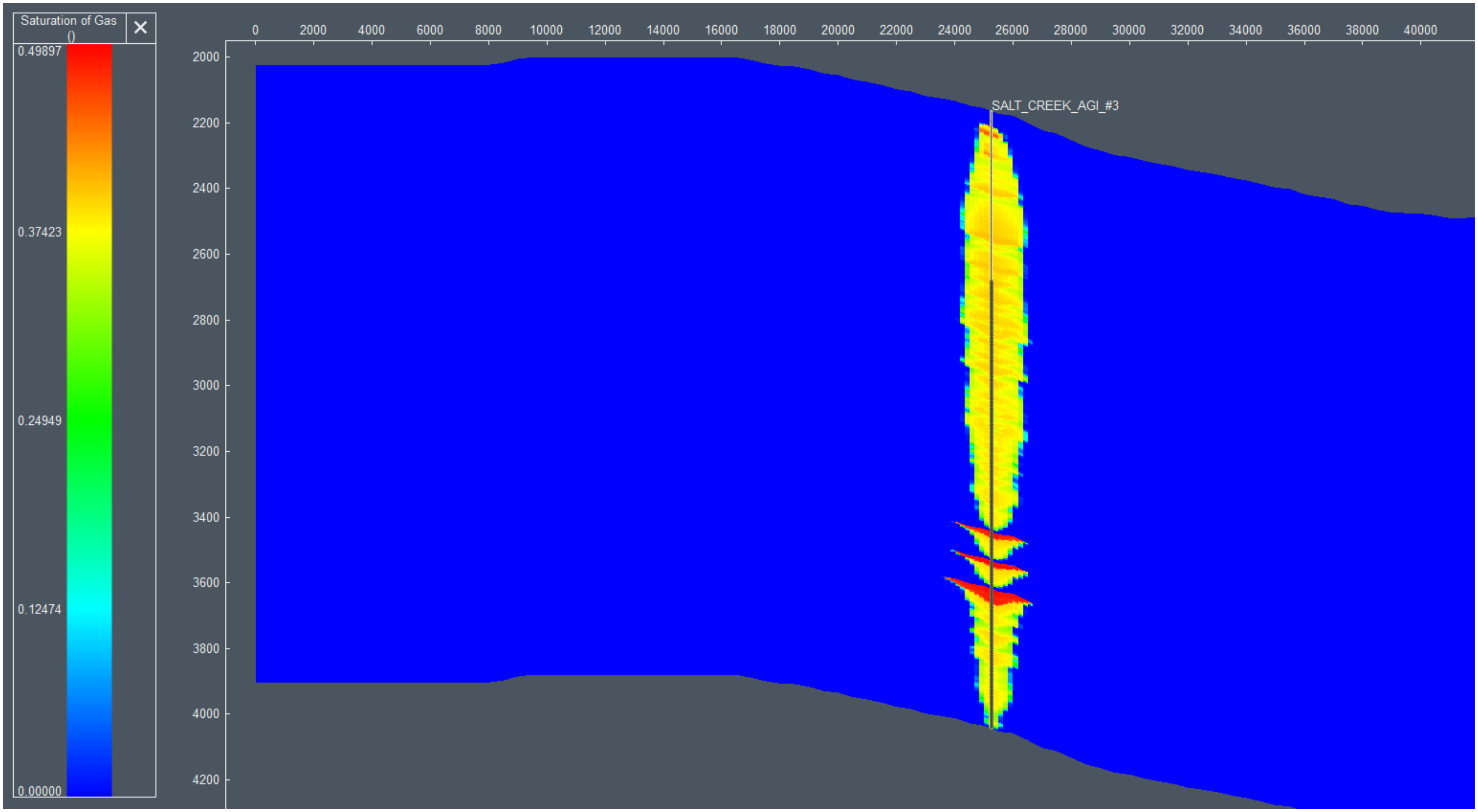


Figure 44 – West-East Cross-Sectional View of Delaware Mountain Group Gas Saturation Plume at 50 Years After Shut-in.

Figure 45 shows the surface injection rate, BHP and WHP over the injection period. The BHP reaches a maximum of 3,621 psig at the beginning of injection. This buildup of 554 psig hits the 90% fracture pressure constraint of 3,621 psig at the beginning of injection, causing a decrease in the rate over a short period of time. This modeled pressure buildup is overestimated during the initial introduction of gas, leading to a spike in BHP. Pressure stabilizes as gas flow is established, which causes the modeled BHP to align with anticipated values. The maximum WHP associated with the maximum BHP reached is 1,426 psig, less than the maximum allowable 2,149 psig as set in the NMOCD UIC permit application for this well. The two offset SWD wells, injecting at their maximum permitted rates, allow for a conservative BHP value to be assumed during the injection period. BHPs and WHPs are provided in Table 13.

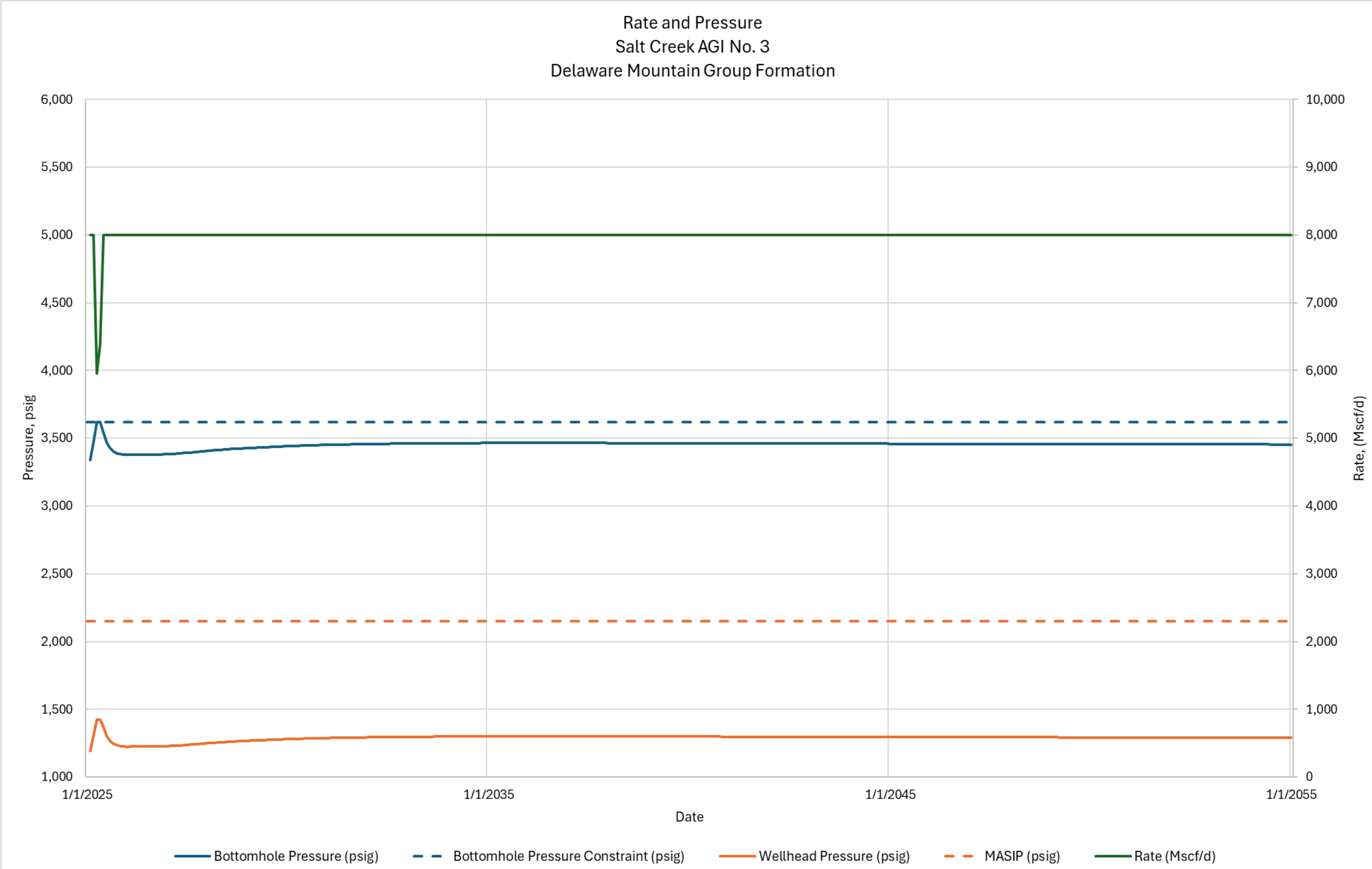


Figure 45 – Well Injection Rate and Bottomhole and Surface Pressures Over Time, DMG.

Table 13 – Bottomhole and Wellhead Pressures Over Time from Start of Injection, DMG.

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,056	0
10	3,465	1,300
20	3,460	1,295
30 (End of Injection)	3,454	1,291
40	3,043	0
50	3,017	0
60	3,006	0
70	3,026	0
80	3,034	0

2.8.4.1 Plume Stabilization, Delaware Mountain Group

Figure 46 demonstrates that the growth rate of the plume will decrease to less than 1% increase in area per year by 2075 (20 years after injection ceases) and is therefore effectively stabilized by that time.

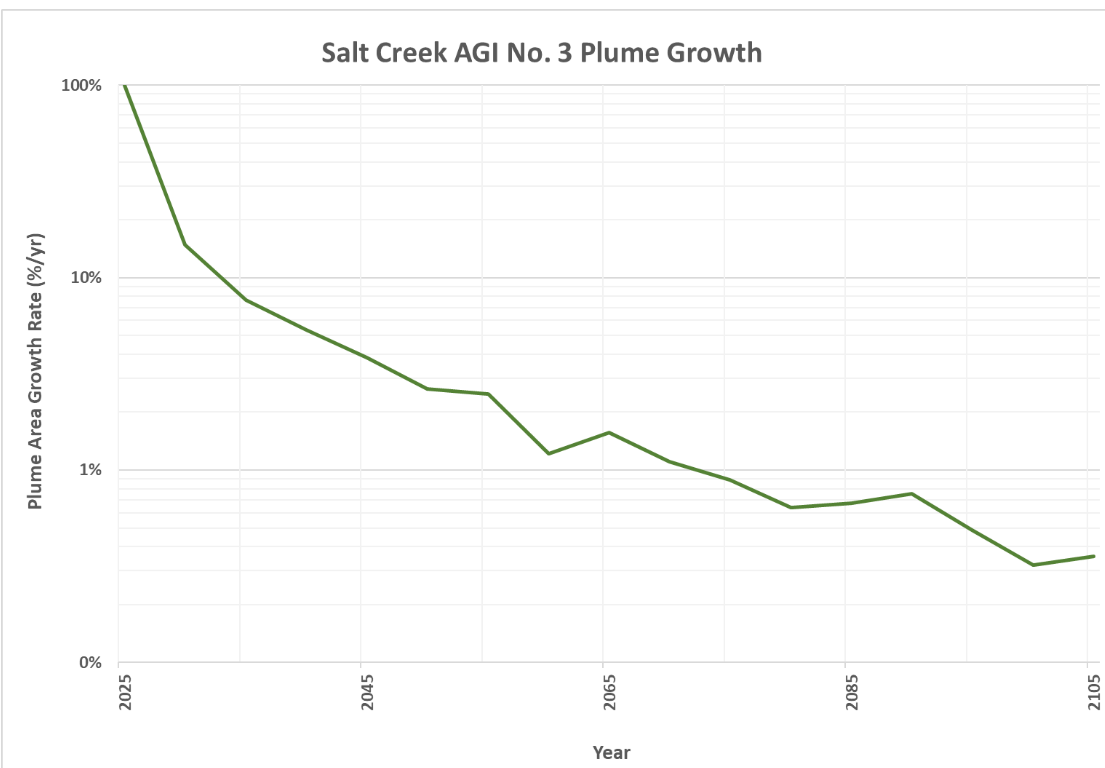


Figure 46 - Annual Growth Rate of CO_2 Plume, Delaware Mountain Group

SECTION 3 – DELINATION OF MONITORING AREA

The delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA), as described in EPA 40 CFR §98.448(a)(1) is discussed in this section.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile, as shown in Figure 47. Numerical simulation was used to predict the size and drift of the plume. Reservoir modeling was used to determine the areal extent and density drift of the plume, as described in Section 2.8. The model considers the following:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to adequately predict the density drift of the plume

The CO_2 plume extent for the DMG injection zone falls wholly within the plume extent for the Siluro-Devonian; therefore, the MMA delineation is driven by the Siluro-Devonian plume.

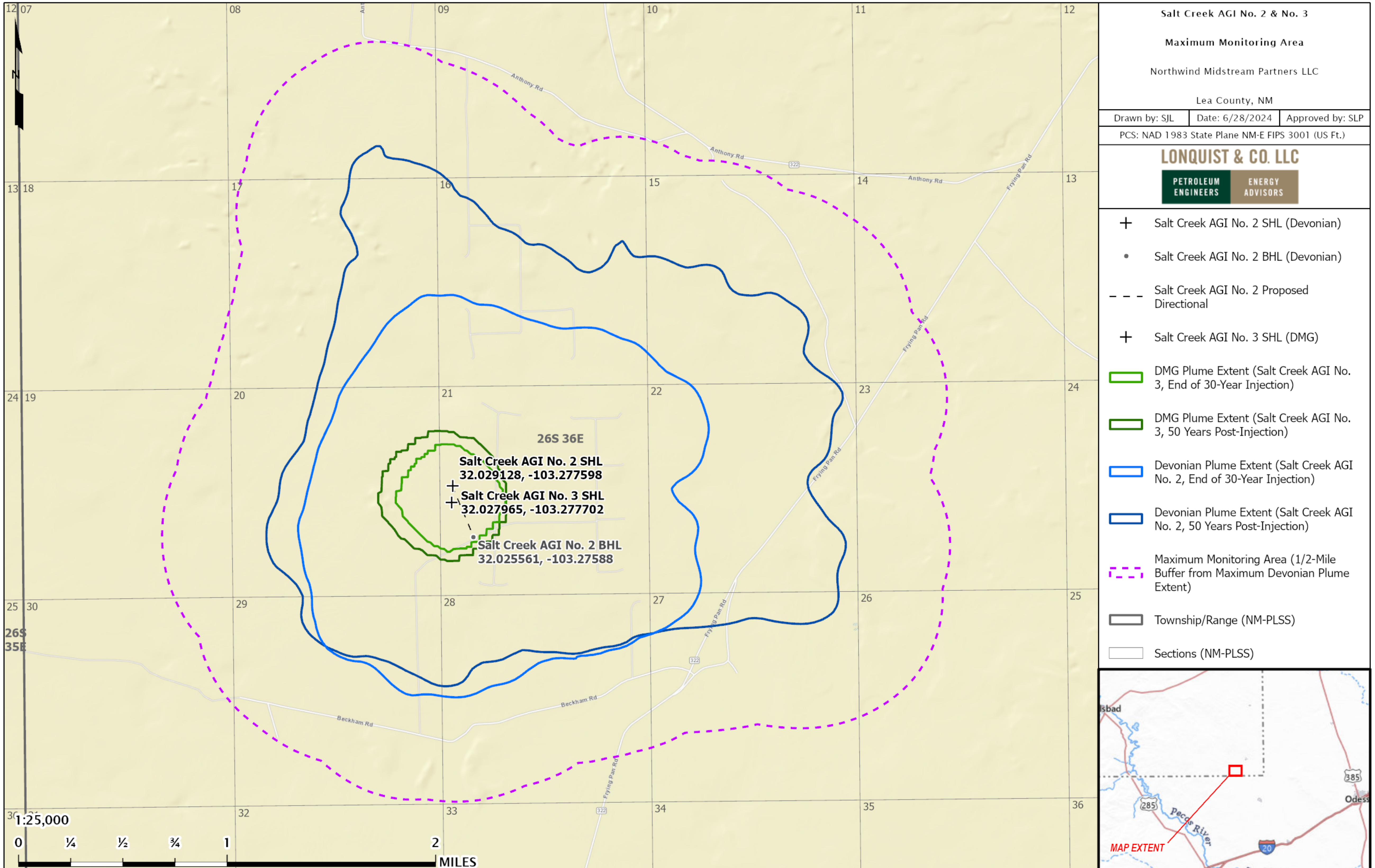


Figure 47 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area.

3.2 Active Monitoring Area

The initial AMA will cover a 5-year monitoring period. The AMA will be established by superimposing the area based on a half-mile buffer around the modeled combined extent of both CO_2 plumes at time (t) = 5 (Year 5) plus the extent of the projected plume at t+5 (Year 10). In this case, the combined plume extent in Year 10 is within the combined plume extent at Year 5 plus the half-mile buffer. By Year 5 at the latest, a revised MRV plan will be submitted to define a new AMA. Figure 48 shows the plumes in Year 5 and Year 10 and the area covered by the AMA.

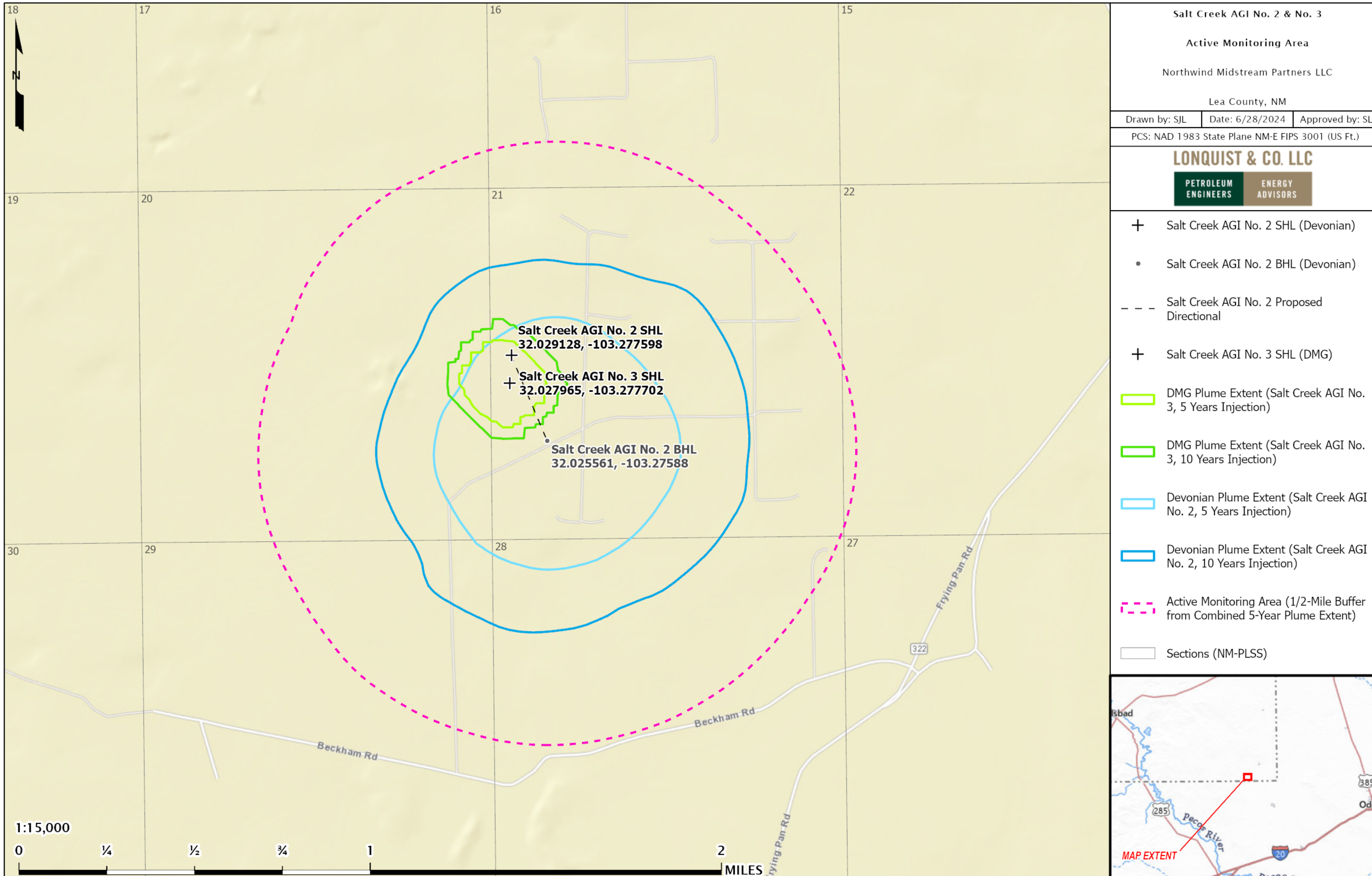


Figure 48 – Active Monitoring Area.

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

Potential CO_2 leakage pathways to surface within the MMA are identified in this section and evaluated for likelihood, timing, and magnitude. A summary of these paths is provided in Table 14. The potential leakage pathways include the following:

- Leakage from surface equipment
- Leakage from existing and future wells within MMA
- Leakage through faults and fractures
- Leakage through the upper confining zone
- Leakage from natural or induced seismicity

Table 14 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection.
Existing wells within the MMA	Very low – DMG plume does not reach the penetrators in the MMA; only two wells penetrate the Devonian within the MMA.	Low. The penetrating wellbores are constructed adequately and multiple confining zones above the injection zone will prevent movement to the surface.	During active injection and until the plume stabilizes 25 years after the end of injection.
Future wells within the MMA	Low. The DMG plume is small and wells unlikely to be located in the plume area. Other offset wells unlikely to target Siluro-Devonian or deeper. If potential penetrating well was permitted, Northwind will work with operator to ensure proper well design to prevent H_2S movement.	Low. Any proposed wells penetrating the injection intervals would be constructed to prevent migration of H_2S. Also, multiple confining zones above the injection zone will prevent movement to the surface.	During active injection and until the plume stabilizes 25 years after the end of injection.

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Faults and fractures	Low. None of the Devonian level faults identified in the area of review extend to the surface. No faults were identified in the DMG.	Low. Upper confining zones will contain any leakage that would migrate through deep offset faults.	During active injection and until the plume stabilizes 25 years after the end of injection.
Upper confining layers	Unlikely. The upper confining zones have sufficient thickness, continuity and confining characteristics.	Medium. Leakage out of the DMG into the Capitan Reef could impact the aquifer quality but unlikely to occur.	During active injection and until the plume stabilizes 25 years after the end of injection.
Natural or induced seismicity	Low. Fault slip potential models indicate that injection operations at the Salt Creek AGI wells have a low probability of causing induced seismicity.	Low. The UCZs should prevent migration out of the injection intervals in the event of induced seismicity.	During active injection.

Magnitude Assessment Description
Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.
Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.
High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

The identified potential pathways have the highest risk of leakage during the injection period. After injection ceases, the risks of leakage from the offset wells, fractures, etc. are quickly reduced until the plume fully stabilizes, which is modeled to occur in 2080, 25 years after the end of injection. Risks from surface equipment would be eliminated after the injection wells are plugged and the related surface equipment is removed.

4.1 Leakage from Surface Equipment

The Titan Plant (Figure 49) and the Salt Creek AGI wells (Figure 50 and Figure 51) are newly designed and constructed facilities for treating and injecting acid gas. The facility was built with the objective to ensure maximum safety for the public, employees, and environment. The Northwind treating facilities are designed to the highest level of midstream standards and compliant with the latest industry codes (i.e., National Association of Corrosions Engineers [NACE], American National

Standards Institute [ANSI], American Society of Mechanical Engineers [ASME], American Petroleum Institute [API], Natural Propane Gas Association [NPGA], and TEMA, etc.). Northwind will adhere to a full list of internal engineering standards, design specifications and required practices that meet or exceed these industry codes to ensure any potential failure points are limited and therefore minimizes any leakage. Monitors for H_2S are installed at key locations around the Plant, as depicted on the site plan in Appendix B. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will set off alarms at set points based on H_2S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the NMOCD with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm for the High Alarm and the High-High limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the Salt Creek AGI wells, gathering system, and other components of the facility as shown in Figure 49 and Appendix B. Northwind has installed a flare stack to safely de-pressure piping and equipment if an event occurs.

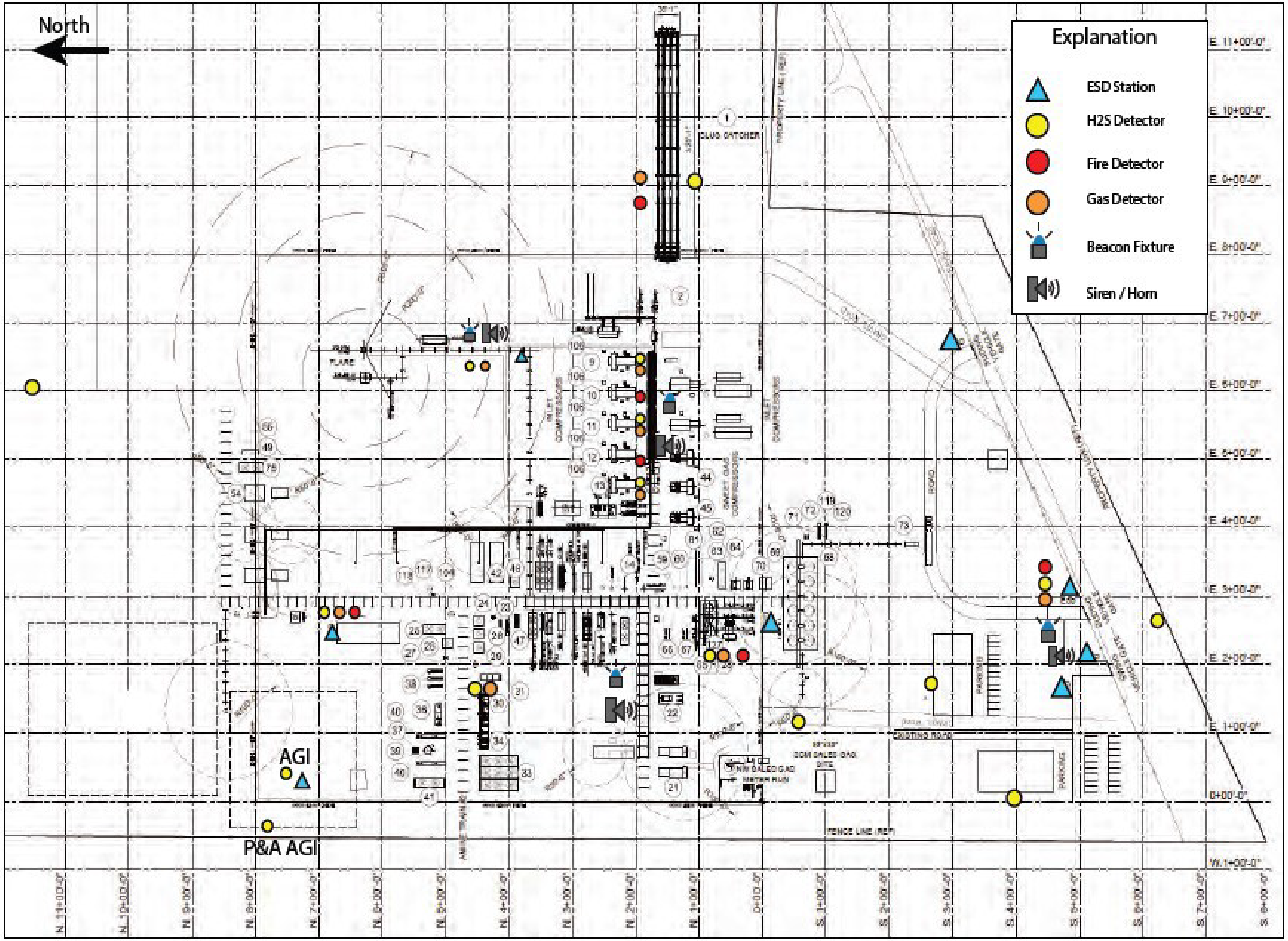


Figure 49 – Titan Safety Location Plan.

Any release of CO_2 would be quickly identified because of the monitoring systems in place at the Titan facility, as listed in Table 15. The safety systems and protocols implemented would minimize the release volume. The acid gas stream injected into the AGI well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the plant adjacent to the Salt Creek AGI wells. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Northwind concludes that the leakage of CO_2 through the surface equipment is unlikely.

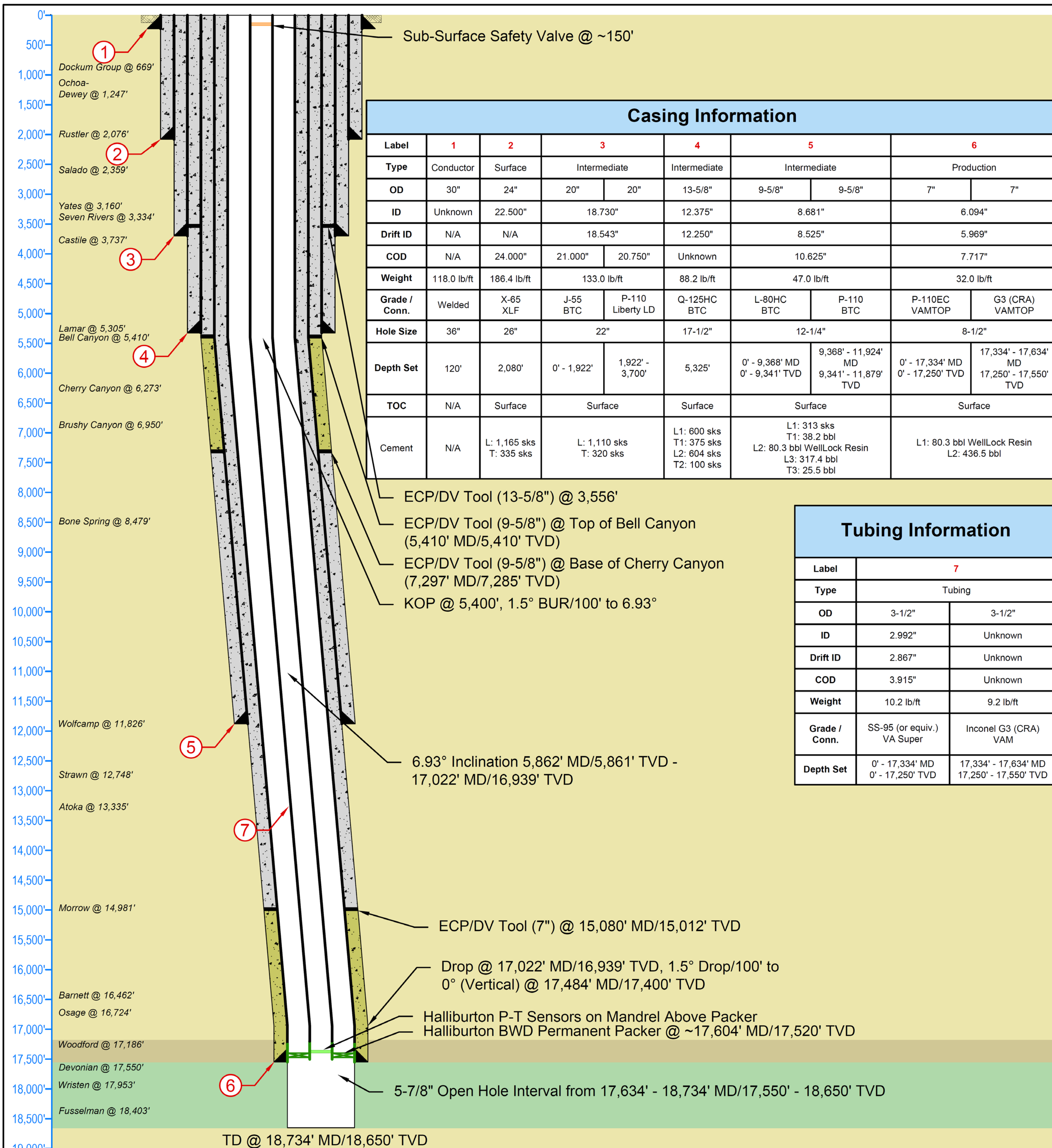
Table 15 – TAG Detection Equipment at Titan Gas Treating Plant and AGI Well Sites.

Device	**Location**	**Set Point**
H_2S detectors (1-X)	Salt Creek AGI No. 2 wellsite	10 ppm High Alarm 90 ppm Emergency Shutdown
H_2S detectors (Y-Z)	Salt Creek AGI No. 3 wellsite	10 ppm High Alarm 90 ppm Emergency Shutdown
H_2S detectors (AA-BB)	In-plant detectors	10 ppm High Alarm 90 ppm Emergency Shutdown
Flare stack	Plant site	N/A
AGI flowmeter	In-plant (downstream of the amine unit)	Calibrated per API specifications
Emergency shutdown	In-plant detectors	90 ppm Emergency Shutdown
Emergency shutdown	AGI well sites	90 ppm Emergency Shutdown

4.2 <u>Leakage from Wells in the MMA</u>

4.2.1 Existing and Planned Wells

The Salt Creek AGI wells are designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 50 and Figure 51. Additionally, subsurface safety valves are installed in each well approximately 100 ft beneath the surface on the injection tubing to assure that fluid cannot flow back out of the well in the event of a failure of the injection equipment. The annular spaces between the injection tubing and the long string casing are filled with corrosion-inhibited diesel fuel (i.e., an inert fluid) as a further safety measure. Mechanical integrity tests (MITs), required under New Mexico Administrative Code (NMAC) **§19.15.26.11** [40 CFR **§146.23 (b)(3)**], will take place annually to verify that each well and wellhead can contain the appropriate operating pressures. If an MIT were to indicate a leak, the well would be isolated, and the leak mitigated to prevent leakage of the injectate to the atmosphere.



Casing Information

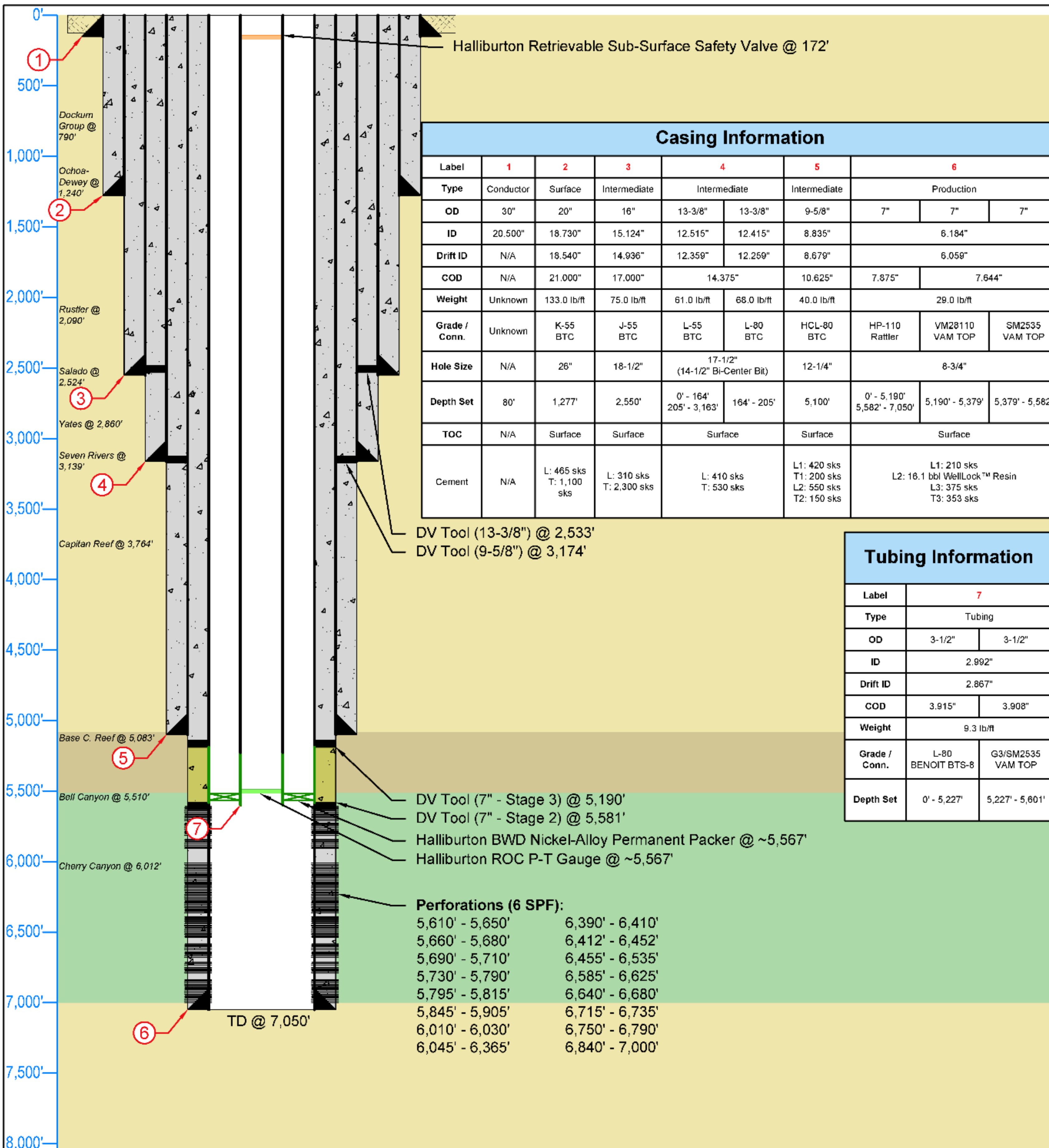
Label	1	2	3		4	5		6	
Type	Conductor	Surface	Intermediate		Intermediate	Intermediate		Production	
OD	30"	24"	20"	20"	13-5/8"	9-5/8"	9-5/8"	7"	7"
ID	Unknown	22.500"	18.730"		12.375"	8.681"		6.094"	
Drift ID	N/A	N/A	18.543"		12.250"	8.525"		5.969"	
COD	N/A	24.000"	21.000"	20.750"	Unknown	10.625"		7.717"	
Weight	118.0 lb/ft	186.4 lb/ft	133.0 lb/ft		88.2 lb/ft	47.0 lb/ft		32.0 lb/ft	
Grade / Conn.	Welded	X-65 XLF	J-55 BTC	P-110 Liberty LD	Q-125HC BTC	L-80HC BTC	P-110 BTC	P-110EC VAMTOP	G3 (CRA) VAMTOP
Hole Size	36"	26"	22"		17-1/2"	12-1/4"		8-1/2"	
Depth Set	120'	2,080'	0' - 1,922'	1,922' - 3,700'	5,325'	0' - 9,368' MD 0' - 9,341' TVD	9,368' - 11,924' MD 9,341' - 11,879' TVD	0' - 17,334' MD 0' - 17,250' TVD	17,334' - 17,634' MD 17,250' - 17,550' TVD
TOC	N/A	Surface	Surface		Surface	Surface		Surface	
Cement	N/A	L: 1,165 sks T: 335 sks	L: 1,110 sks T: 320 sks		L1: 600 sks T1: 375 sks L2: 604 sks T2: 100 sks	L1: 313 sks T1: 38.2 bbl L2: 80.3 bbl WellLock Resin L3: 317.4 bbl T3: 25.5 bbl		L1: 80.3 bbl WellLock Resin L2: 436.5 bbl	

Tubing Information

Label	7	
Type	Tubing	
OD	3-1/2"	3-1/2"
ID	2.992"	Unknown
Drift ID	2.867"	Unknown
COD	3.915"	Unknown
Weight	10.2 lb/ft	9.2 lb/ft
Grade / Conn.	SS-95 (or equiv.) VA Super	Inconel G3 (CRA) VAM
Depth Set	0' - 17,334' MD 0' - 17,250' TVD	17,334' - 17,634' MD 17,250' - 17,550' TVD

LONQUIST SEQUESTRATION LLC	Northwest Midstream Partners, LLC	Salt Creek AGI #2 Acid-Gas Injection Well - Proposed Well Design	
	Country: USA	**State/Province:** New Mexico	**County/Parish:** Lea
	API No: 30-025-TBD	**Field:**	**Well Type/Status:** AGI/Non-Permitted
Texas License 22610	**Location:** Sec. 21 T26S R36E	**Project No:** LS208	**Date:** 06/13/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Joseph Lovewell	**Reviewed:** Ramona Hovey	**Approved:**
	Rev No: 3	**Notes:** Revised well schematic proposed to accommodate a deviated well design, including the utilization of additional acid resistant cement and sour-service tubulars	

Figure 50 – Salt Creek AGI No. 2 Wellbore Schematic



Casing Information

Label	1	2	3	4		5	6		
Type	Conductor	Surface	Intermediate	Intermediate		Intermediate	Production		
OD	30"	20"	16"	13-3/8"	13-3/8"	9-5/8"	7"	7"	7"
ID	20.500"	18.730"	15.124"	12.515"	12.415"	8.835"	6.184"		
Drift ID	N/A	18.540"	14.936"	12.359"	12.259"	8.679"	6.059"		
COD	N/A	21.000"	17.000"	14.375"		10.625"	7.875"	7.644"	
Weight	Unknown	133.0 lb/ft	75.0 lb/ft	61.0 lb/ft	68.0 lb/ft	40.0 lb/ft	29.0 lb/ft		
Grade / Conn.	Unknown	K-55 BTC	J-55 BTC	L-55 BTC	L-80 BTC	HCL-80 BTC	HP-110 Rattler	VM28110 VAM TOP	SM2535 VAM TOP
Hole Size	N/A	26"	18-1/2"	17-1/2" (14-1/2" Bi-Center Bit)		12-1/4"	8-3/4"		
Depth Set	80'	1,277'	2,550'	0' - 164' 205' - 3,163'	164' - 205'	5,100'	0' - 5,190' 5,582' - 7,050'	5,190' - 5,379'	5,379' - 5,582'
TOC	N/A	Surface	Surface	Surface		Surface	Surface		
Cement	N/A	L: 465 sks T: 1,100 sks	L: 310 sks T: 2,300 sks	L: 410 sks T: 530 sks		L1: 420 sks T1: 200 sks L2: 550 sks T2: 150 sks	L1: 210 sks L2: 16.1 bbl WellLock™ Resin L3: 375 sks T3: 353 sks		

Tubing Information

Label	7	
Type	Tubing	
OD	3-1/2"	3-1/2"
ID	2.992"	
Drift ID	2.867"	
COD	3.915"	3.908"
Weight	9.3 lb/ft	
Grade / Conn.	L-80 BENOIT BTS-8	G3/SM2535 VAM TOP
Depth Set	0' - 5,227'	5,227' - 5,601'

LONQUIST SEQUESTRATION LLC	Northwest Midstream Partners, LLC	Salt Creek AGI #3 Acid-Gas Injection Well - As Built Well Design	
	Country: USA	**State/Province:** New Mexico	**County/Parish:** Lea
	API No: 30-025-51865	**Field:**	**Well Type/Status:** AGI/Non-Permitted
Texas License 22610	**Location:** Sec. 21 T26S R36E	**Project No:** LS208	**Date:** 03/04/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Joseph Lovewell	**Reviewed:** Ramona Hovey	**Approved:**
	Rev No: 1	**Notes:**	

Figure 51 – Salt Creek AGI No. 3 Wellbore Schematic

A map of all oil and gas wells within the MMA is shown in Figure 52. The MMA review map and a summary of all wells in the MMA is provided in Appendix C. The summary of all oil and gas wells in Appendix *C* also provides the total depth (TD) of all wells within the MMA. Figure 53 identifies all wells that penetrate the upper confining zone above the DMG.

In this area, most of the oil and gas production has targeted the Tansil/Yates/Seven Rivers formations which occur at depths less than 4,000 ft or the deeper Bone Spring and Wolfcamp formations. The Bone Springs is usually deeper than 8,000 ft and the Wolfcamp is found at approximately 11,800 ft in this area.

Figure 54 shows that only two existing wells penetrate the Siluro-Devonian formation within the half-mile buffer beyond the extent of the stabilized plume (API Nos. 30-025-24719 and 30-025-23197). Only the two Siluro-Devonian penetrating wells are potential conduits within the MMA. By the time the plume were to reach these two wells, the saturation of the CO_2 will be low (likely <5%) and therefore will have a low probability of creating leakage pathways as the fluid in the reservoir at that point would not experience a significant drop in pH. The magnitude of such leakage, if it were to occur, would be very low as, at that saturation, the amount of free CO_2 available to release would through a pathway would be negligible. The timing of such a potential leakage would be after injection ceases, until the DMG plume stabilizes 20 years after injection.

The remaining wells shown would not be impacted by injection into the Siluro-Devonian. Seventeen wells penetrate the DMG within the AMA plus there are an additional 61 penetrating wells in the full MMA. However, the CO_2 injection into the DMG from Salt Creek No. 3 is not expected to reach any of these wells. Therefore, there is little likelihood that leakage will occur from any offset existing DMG penetrating wells within the MMA. The plume model will be updated based on actual injection conditions and this MRV plan will be updated if either plume were determined to extend further than expected.

Salt Creek AGI No. 2 and No. 3 are both designed to prevent movement of fluids from the DMG and/or the Siluro-Devonian.

Unless new wells are drilled in the MMA, the two Siluro-Devonian wells are the main potential conduits for CO_2 released through existing or future wells. Northwind would ensure that any future wells drilled in the MMA are located and/or designed to ensure they will protect against leakage.

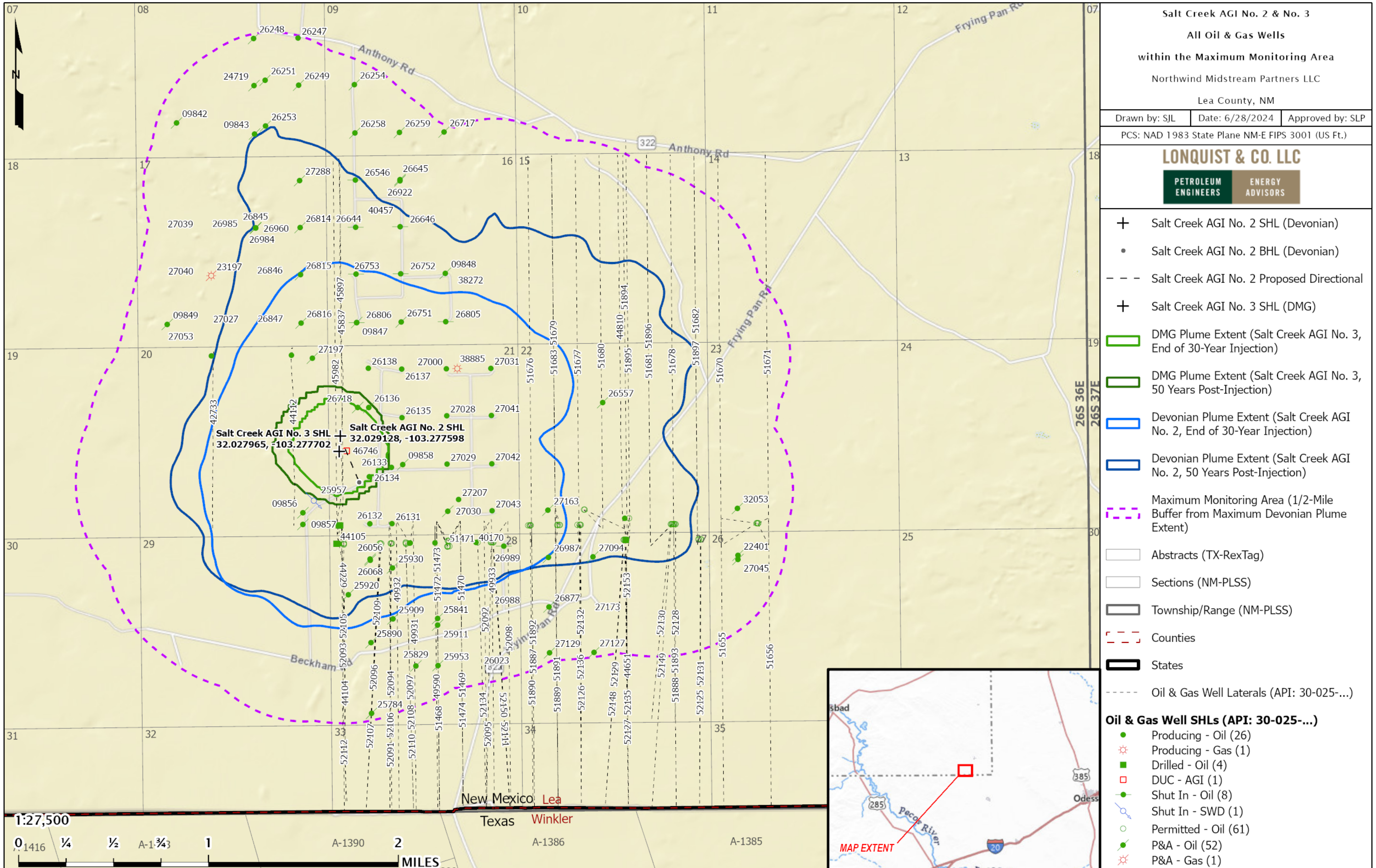


Figure 52 – All Oil and Gas Wells Within the Maximum and Active Monitoring Areas

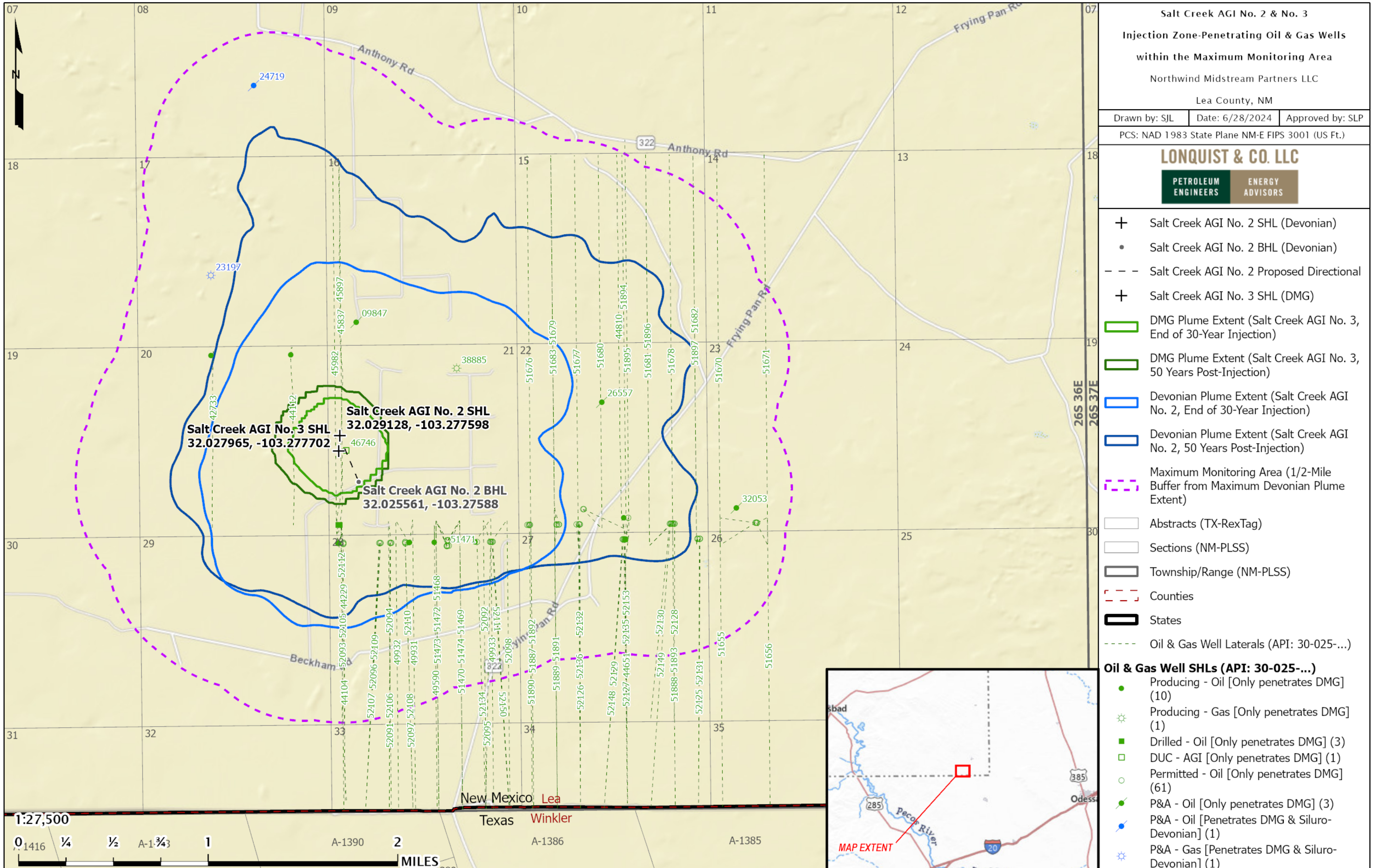


Figure 53 – All Oil and Gas Wells Within the Maximum and Active Monitoring Areas

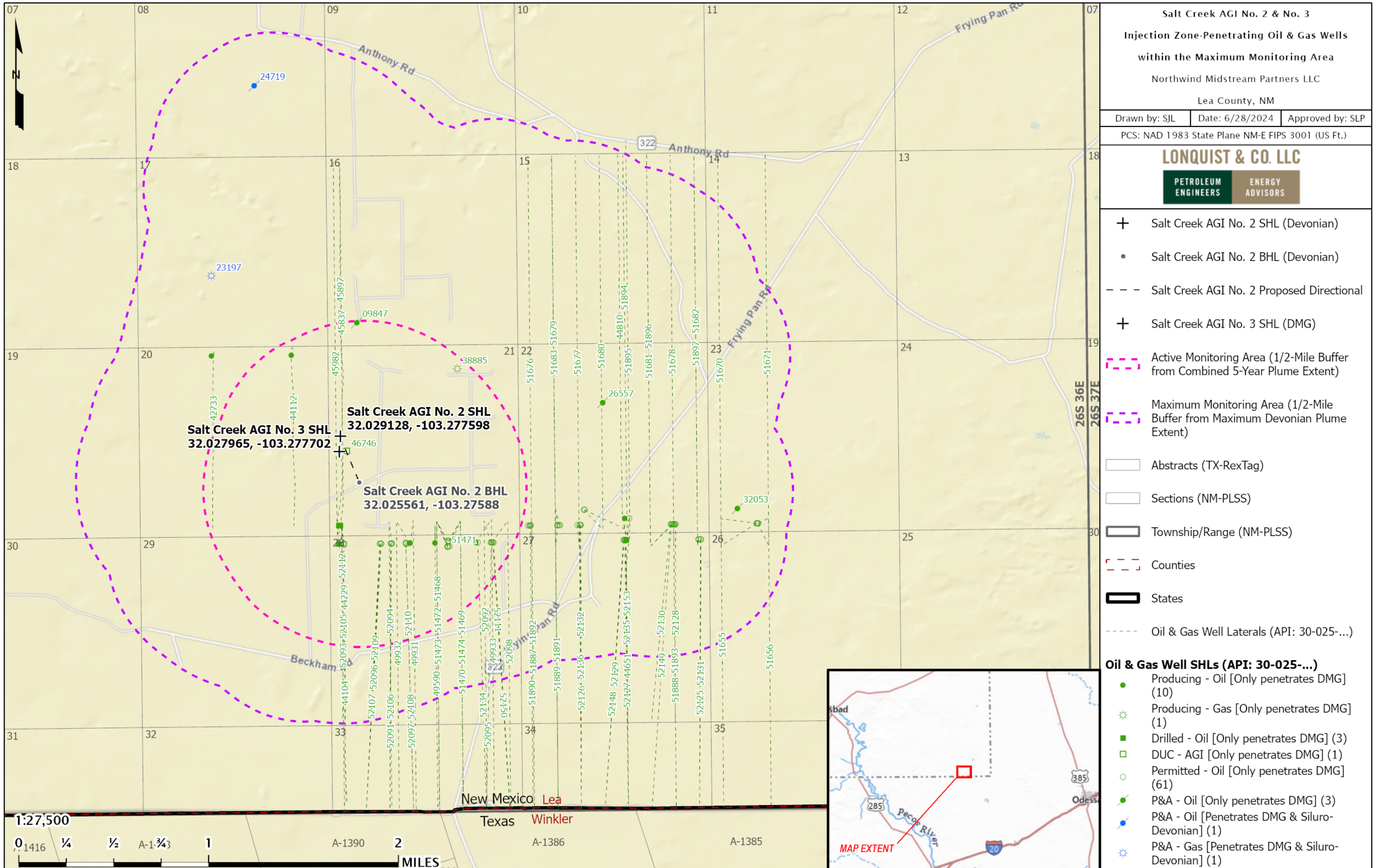


Figure 54 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the Maximum and Active Monitoring Areas

4.2.2 Future Drilling

Any drilling permits issued by the near the Salt Creek wells must comply with NMAC **§19.15.26.9** (entitled Casing and Cementing of Injection Wells) and NMAC **§19.15.16.10** (entitled Casing and Tubing Requirements). These regulations require operators to case injection wells "with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another zone or to the surface around the outside of a casing string." For any wells drilled for oil or gas with surface and intermediate casing, the regulations require "strings and cement as may be necessary to effectively seal off and isolate all water-, oil- and gas-bearing strata and other strata encountered in the well down to the casing point."

Around the Titan Treating Facility, the Siluro-Devonian and deeper formations are not productive. Therefore, it is unlikely that any new wells will be drilled to that depth. Because the CO_2 plume in the DMG is small, it is also unlikely that the vertical section of new well targeting the productive intervals between the DMG and Silurian will be proposed within that plume area. Northwind will monitor for any new permits and coordinate with the operator to ensure that if a proposed well may intersect the CO_2 plume that it will be constructed in a manner to prevent migration above the injection interval.

4.2.3 Groundwater Wells

A groundwater well search identified 36 wells within the MMA and 5 within the AMA, as identified by the New Mexico Office of the State Engineer[1] and shown in Figure 55. The deepest of these wells has a depth of 1,119 ft, which is significantly shallower than the upper confining zone of the DMG injection.

The surface, intermediate, and production casing strings in the Salt Creek AGI wells, as shown previously in Figure 50 and Figure 51, are designed to protect the shallow freshwater aquifers, consistent with applicable NMOCD regulations for this location. The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Additionally, these wells do not reach the confining interval above the DMG. Northwind concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

[1] https://gis.ose.state.nm.us/gisapps/ose_pod_locations/

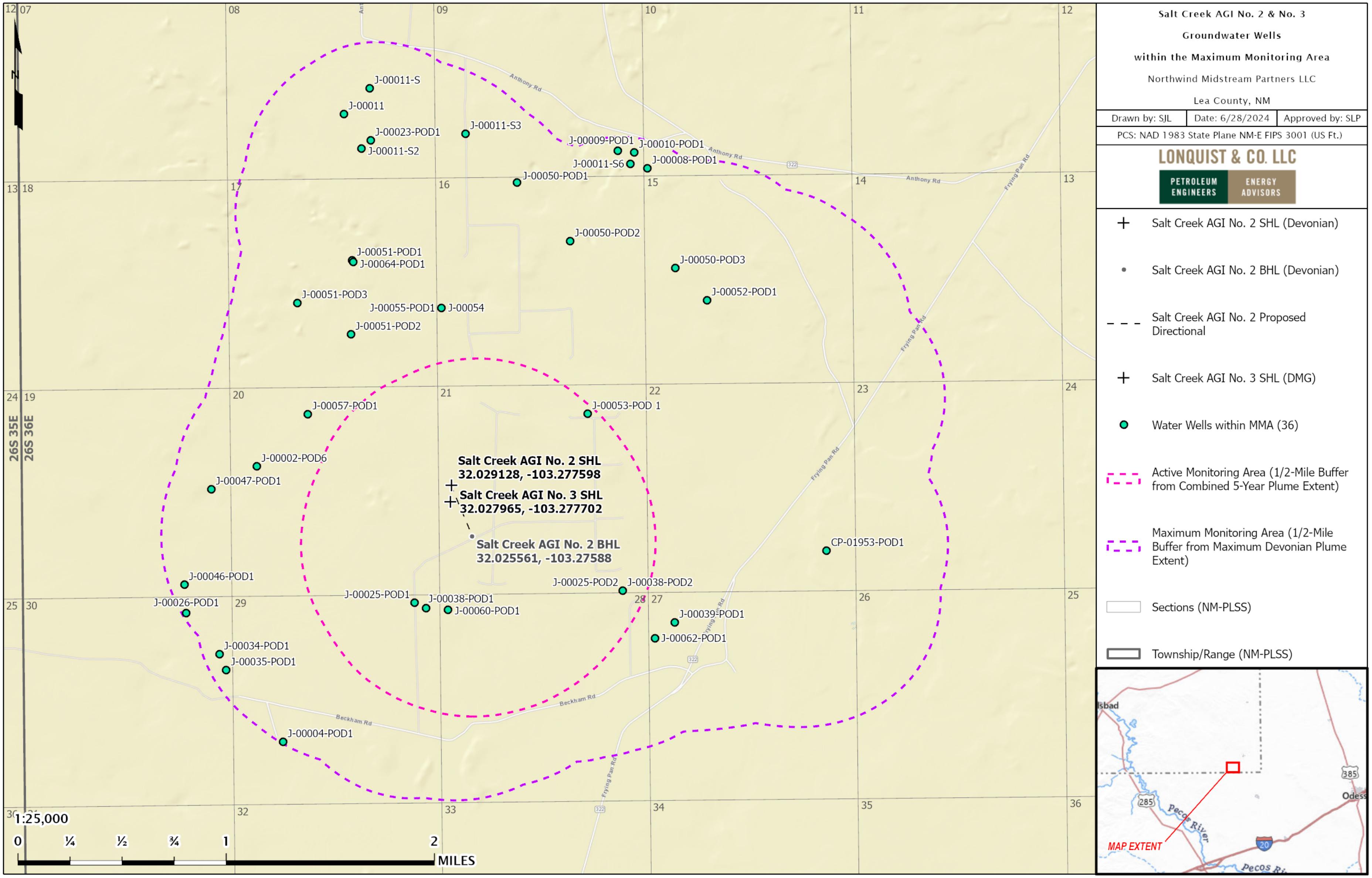


Figure 55 – Freshwater Wells within the MMA. Proposed groundwater monitor wells for the Salt Creek AGI wells are signified with red circles.

4.3 Leakage Through Faults or Fractures

4.3.1 Salt Creek AGI No. 2 – Siluro-Devonian

Northwind identified nine faults that intersect the projected CO_2 plume from Salt Creek AGI No. 2. These faults were deemed transmissive within the injection interval yet are sealing through the UCZ. This determination was made based on the shale smear factor (SSF) which Lindsay, et al. concluded from a study of more than 80 faults that if the SSF was greater than 7, the fault may become incompetent. Therefore, anything less than 7 would be deemed sealant in nature. The following equation is used to determine SSF.

$$SSF = \frac{\text{fault throw}}{shale\ layer\ thickness}$$

With the largest fault displacement within the plume boundary being approximately 200 ft (i.e., fault throw) and the Woodford thickness being approximately 370 ft at the projected location, the SSF value would equate to 0.54, far below the value of 7 determined by Lindsay et al. Additionally, this displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

4.3.2 Salt Creek AGI No. 3 – Delaware Mountain Group

No faults were interpreted at the DMG level within the 3D seismic coverage near Salt Creek AGI No. 3. This analysis includes areas significantly outside the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

There is little to no evidence of fracture features within the DMG siliciclastic matrix. This absence is most likely because of the deep marine depositional environment where no exposure events occurred to allow for fracture development. Therefore, transmissibility through fractures within the DMG is unlikely.

4.4 Leakage Through Confining Layers

4.4.1 Salt Creek AGI No. 2 – Siluro-Devonian

The overlying Woodford Shale formation acts as a competent sealing formation for the proposed Siluro-Devonian injection interval. The Woodford Shale contains ideal properties that will allow it to maintain sealing properties through the injection process. This sealing nature is validated through the ample offset injection operations within the Siluro-Devonian in New Mexico, along with historical production from the Siluro-Devonian where the Woodford Shale acted as the reservoir seal. Additional confining strata includes salt, shale, and tight carbonates that are present between the Woodford Shale and the USDW, which would alleviate any threat of migration of the injection into the USDW or to surface.

4.4.2 Salt Creek AGI No. 3 – Delaware Mountain Group

The overlying forereef carbonate deposits act as a competent sealing formation for the proposed Delaware Mountain Group injection interval. The forereef deposits contain ideal properties that will allow it to maintain sealing properties through the injection process. This confinement is validated through the openhole log within the Salt Creek AGI No. 3 well displaying little to no porosity development within these deposits.

4.5 Leakage from Natural or Induced Seismicity

The Titan Treating Facility is situated within the Delaware Basin region, an area that has experienced a small number of seismic events. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until the present) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 54, reveals that the closest seismic occurrence (unspecified whether natural or induced) occurred approximately 7 km (4.2 mi) from the Salt Creek AGI wells. Figure 56 shows all events with a magnitude greater than 2.0, which are concentrated along the southwest edge of a 9.08-kilometer (km) radius, approximately a 100-square mile area.

All seismic events depicted on the map were recorded at depths exceeding 5.8 km (30,000 ft), indicating their occurrence within the Precambrian basement rock. Three events had a magnitude of 3.0 or greater. Any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

The Stanford Center for Induced and Triggered Seismicity’s (SCITS) Fault Slip Potential (FSP) model was used to assess the risk of a seismicity event caused by injection into Salt Creek AGI No. 2. To ensure a conservative estimate of risk, the well was modeled using the fluid characteristics of a saltwater disposal well because water has greater density, dynamic viscosity, and is significantly less compressible than acid gas. The FSP model, provided in Appendix D, indicates that no structures within the MMA of the facility are expected to experience any significant increase in slip potential caused by injection into Salt Creek AGI No. 2. Because no faults were found in the DMG interval, an FSP model was not performed for that zone.

Stringent operating procedures will be programmed into the SCADA and controls systems to ensure that operating pressures stay below the FG of both the injection and confining intervals. Moreover, a combination of continuous well monitoring and monitoring of the USGS and TexNet sites for activity will promptly identify any irregularities in the operations linked to seismic events.

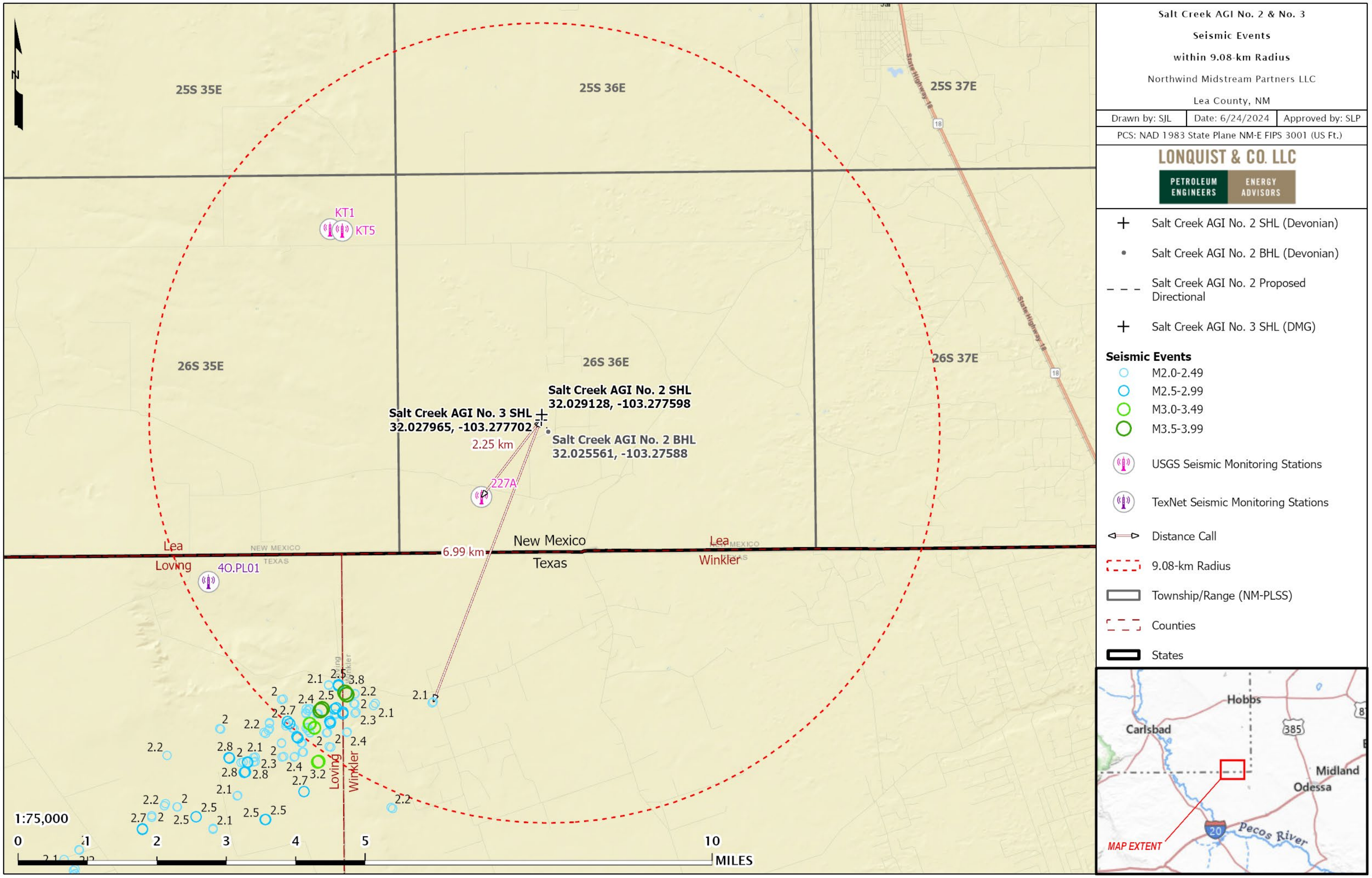


Figure 56 – Local Seismicity Review Map with Nearby Seismic Monitoring Stations

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Northwind will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage; and therefore, the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 16 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 30-year injection period or cessation of injection operations, plus a proposed 25-year post-injection period until the plume has stabilized.

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults, fractures
- Leakage through upper confining layer
- Leakage through natural or induced seismicity

Table 16 – Summary of Leakage Monitoring Methods.

Leakage Pathway	Monitoring Method	Frequency
Surface Equipment	Fixed H_2S monitors throughout the AGI facility	Continuous
	Visual inspections	Daily
	SCADA continuous monitoring of the AGI facility	Continuous
Existing Wells	SCADA Continuous Monitoring at the AGI Well	Continuous
	Mechanical Integrity Test of the AGI Well	Annually
	Visual Inspections	As needed
	Quarterly CO_2 Measurements within MMA	Quarterly
	Annual soil gas sampling at well locations that penetrate the UCZ within the AMA	Annually
Groundwater Wells	Groundwater samples from monitoring wells	Annually
Drilling through MMA	Compliance with NMOCD regulations	During operations
	Monitor Drilling Activity	During operations
Faults and Fractures	SCADA Monitoring at the AGI Well (volumes and pressures)	Continuous
Upper Confining Layer	SCADA Monitoring at the AGI Well (volumes and pressures)	Continuous
Natural or Induced seismicity	Seismic monitoring station	Continuous

5.1 Leakage from Surface Equipment

The Titan Treating Facility and the Salt Creek AGI wells were designed to operate in a manner to reduce the possibility of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. Through its design, the facility minimizes leak points through the equipment used. Critical areas within the facility are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established during commissioning of the plant. Ambient H_2S monitors are located at the plant and near the Salt Creek AGI wells with local alarms and are connected to the SCADA system for continuous monitoring.

The Titan Treating Facility will be continuously monitored through automated systems. Details surrounding these systems can be found in Appendix B. The locations of H_2S detectors and emergency shutdowns are identified throughout the facility on the Appendix B-1 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Northwind to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, in accordance with 40 CFR **§98.448(a)(5) and §98.444(d).**

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Northwind will quantify the leak in accordance with the strategies discussed in *Section 7*.

5.2 Leakage from Wells within MMA

Northwind will continuously monitor and collect injection volumes, pressures, and temperatures through their SCADA systems for the Salt Creek AGI wells. This data is to be reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, the annual MITs, as required by the NMOCD, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated, and the leak mitigated.

In addition to the fixed monitors described previously, Northwind will also establish and operate an in-field monitoring program to detect CO_2 leakage within the AMA. This program would include H_2S monitoring, a proxy for CO_2, at the AGI well site and annual soil gas samples taken near identified wells that penetrate the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of the MRV plan and through the post-injection site care period, Northwind will have these monitoring systems in place.

5.2.1 Leakage from Existing Oil and Gas Wells

There are only two wells in the MMA that could be potential conduits to leak CO_2 out of either injection zone. Neither of these wells are within the AMA; therefore, no monitoring of leakage from offset existing wells is proposed at this time. At least 180 days before the end of the initial 5-years of active injection, an amended MRV plan will be submitted for this facility with an updated plume extent based on measured conditions in the well. At that time, the extents of the MMA and AMA will be revised, with an AMA based on the next time period “t”. This revised MRV plan process will continue until the AMA is equal to the MMA. When an updated AMA contains any wells that penetrate the confining zone, baseline soil gas samples will be taken and analyzed by a third-party lab prior to the commencement of the revised plan. From that time forward, the monitoring results will be included in the annual report.

5.2.2 Leakage from Future Wells Within the MMA

<u>5.2.2.1 Salt Creek AGI Wells</u>

The Salt Creek AGI wells are designed to prevent any migration from the injection interval to surface. The casing strings for the proposed AGI wells will be designed in applicable NMOCD regulations to safeguard shallow freshwater aquifers and USDW. The construction will contain premium materials including corrosion resistant casing and cement across the lower confining zone, injection interval, and UCZ. The likelihood of leakage from the planned AGI injection well is remote.

Northwind will ensure the injection volumes, temperatures, pressures, and gas composition data are continuously monitored and recorded. The data will be recorded with SCADA systems and will be reviewed by qualified personnel who will respond according to designated response and reporting procedures if set performance limits are exceeded. A temperature and pressure gauge will be placed at the wellhead in the injection stream, and a pressure gauge will be placed on the casing annulus. Changes in annular pressure would signal the presence of a possible leak.

The Salt Creek AGI wells will be equipped with a volumetric flow meter, ESD valves and H_2S monitors as illustrated in Figure 57. Figure 57 also shows the location of the flow meters that will be used to calculate the total mass of CO_2 (in metric tons) as injected into the facility each year, in accordance with 40 CFR **§98.444(b).** A higher resolution version of this figure is provided in Appendix B-4.

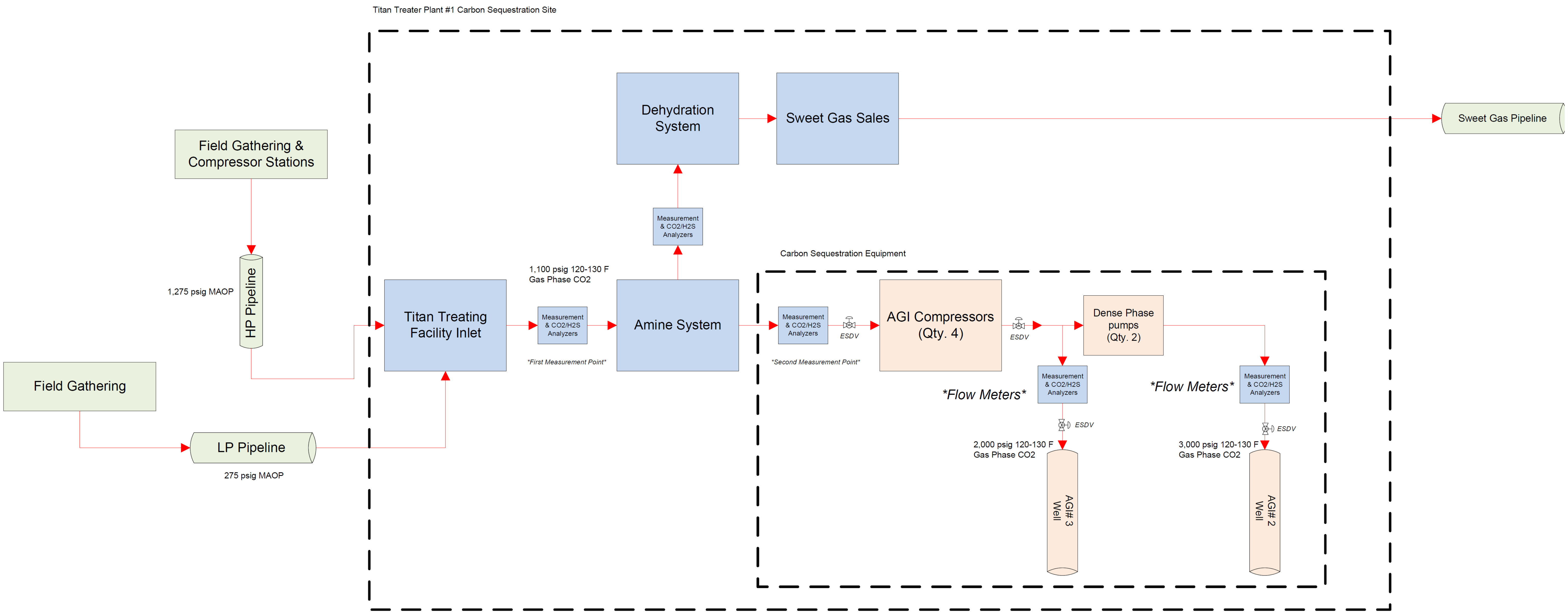


Figure 57 – Salt Creek AGI Monitoring Equipment

NMOCD regulations require MITs to be run every annually to confirm that the well and wellhead can properly hold the appropriate amount of pressure. Should an MIT indicate a leak, the well would then be isolated, and the leak quickly mitigated to prevent leakage to the atmosphere.

5.2.2.2 Offset Wells Not Monitored by Northwind

Northwind will routinely monitor for permits and drilling activities in the MMA and coordinate with those operators to ensure the operators have sufficient casing and cement both above and across all potential flow zones and zones containing corrosive formation fluids to ensure the likelihood of leakage from possible new wells is remote.

5.2.3 Leakage Through Groundwater Wells Within MMA

Thirty-six existing groundwater wells have been identified within the MMA, with five of those falling with the AMA. Northwind is working to secure access to three of these wells to monitor the groundwater quality above the uppermost confining interval. Samples will be analyzed by a third-party laboratory on an annual basis. The locations of these \groundwater monitoring wells are being finalized. A detailed list of the groundwater wells in the MMA is provided in Appendix C.

5.3 Leakage through Faults, Fractures or Confining Layer

Northwind will continuously monitor the operations of the Salt Creek AGI wells through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert caused by a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Should the CO_2 migrate vertically, the magnitude risk of this event is very low, as the UCZs have adequate confining properties to prevent migration out of the confinement. In the unlikely event a leak occurs, Northwind will quantify the leak using the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Northwind plans to use the nearest U.S. Geological Society (USGS) monitoring system check for activity near the Salt Creek AGI. The closest station is connected to the USGS system and is approximately 1.3 miles (2.2 km) west-southwest of the well locations, as shown previously in Figure 54. This distance is sufficient to allow for accurate and detailed monitoring of the seismic activity surrounding the Northwind facility. Northwind will monitor the USGS system for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected within 3 miles of the Titan facility, Northwind will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Northwind will quantify the leak using the strategies discussed in *Section 7*.

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Northwind will undertake to establish the expected baselines for monitoring CO_2 surface leakage in accordance with 40 CFR **§98.448(a)(4).** Northwind will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of injectate and corresponding amount of CO_2.

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Titan Treating Facility and the Salt Creek AGI wells. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken in a prudent and safe manner to address such issues.

6.2 H_2S/ CO_2 Detection

Because of the H_2S injected into the Salt Creek AGI wells, Northwind has an H_2S contingency plan in place to monitor for any releases. The H2S detection would be a proxy for CO_2 releases. Northwind has placed H_2S monitors located across the facility, as discussed in Section 5.1.

6.3 Operational Data

Initial reservoir pressure measurements were taken prior to commencing injection operations. Before starting injection operations for Salt Creek AGI No. 2, baseline measurements of pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel because of the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5) and §98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be diverted to a flare stack to be safely processed and vented. The event will be reported as required for the operation of the well.

6.5 <u>Groundwater Monitoring</u>

Northwind will collect samples from three wells surrounding the Titan Treating Facility. These samples will be submitted to a third-party laboratory. Those results of that analysis will create the baseline for future groundwater monitoring within the AMA.

SECTION 7 – SITE SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

This section identifies how Northwind will calculate the mass of CO_2 injected, emitted, and sequestered. This section also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, in accordance with 40 CFR **§98.448(a)(5) and §98.444(d)**.

7.1 Mass of CO_2 Received

In accordance with 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." As stated in 40 CFR **§98.444(a)(4),** "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for these injection wells is wholly injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

In accordance with 40 CFR **§98.444(b)**, because the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter)

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682

$C_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The Titan Treating Facility is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage will not be measured directly because the injection stream for this well contains high concentrations of H_2S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required, and those emissions sent to a flare stack and reported as a part of the required greenhouse gas (GHG) reporting for the plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO_2 and H_2S. The mass of the CO_2 released would be calculated for the operating conditions including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from Subpart W will be used to calculate CO_2 emissions caused by any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned previously, Northwind believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry-proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in *Section 10*.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. When the Salt Creek Facility commences operations, Northwind will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes will utilize the following equation because these wells will not actively produce oil, natural gas, or any other fluids:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part.

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHG. Because no venting is expected to occur, the calculations would be based upon the unusual event that requires a blowdown with resulting emissions sent to a flare stack and reported as part of the required GHG reporting for the plant.

Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

7.6 Mass of CO_2 Emitted from Leaks Other Than Surface Equipment

Given the uncertainty of sources other than surface equipment that may create leakage pathways, Northwind will quantify the mass of CO_2 released based on specific parameters at the time of release. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance. In the rare event that a leak occurs, it will be addressed, quantified, and documented within an appropriate timeline. Any records of leakage events will be kept and retained, as stated in Section 10.

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Salt Creek No. 3 well is currently reporting injection volumes and pressures under the NMOCD Class II regulations. Salt Creek No. 2 will also be subject to the New Mexico reporting requirements once injection starts. Northwind is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

Baseline surveys, as discussed in Section 6, are being conducted in mid-September 2024.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Northwind plans to manage quality assurance and quality control (QA/QC) to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring Quality Assurance and Quality Control

CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with applicable industry standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with either a continuous gas composition analyzer or representative sampling consistent with applicable industry standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The gas measurement equipment will be calibrated in accordance with the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.

CO_2 Emissions from Leaks and Vented Emissions

- Gas monitors within the Salt Creek Facility will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR **§98.3(i).**
- Flow meters will be operated and maintained in accordance with applicable standards, as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Northwind will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported in accordance with the procedures specified in Subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Northwind will revise and submit an amended MRV plan within 180 days to the Administrator for approval. At least 180 days before the end of the initial 5-years of active injection, an amended MRV plan will be submitted for this facility with an updated plume extent based on measured conditions in the well. At that time, the extents of the MMA and AMA will be revised, with an AMA based on the next time period "t". This revised MRV plan process will continue until the AMA is equal to the MMA.

SECTION 10 – RECORDS RETENTION

Northwind will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

- Quarterly records of the CO_2 injected
    - Volumetric flow at standard conditions
    - Volumetric flow at operating conditions
    - Operating temperature and pressure
    - Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

REFERENCES

Adams, D. C., and Keller, G. R. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective1. *AAPG*.

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

Bennion, D. B. (2002). A Correlation of Water and Gas-Oil Relative Permeability Properties for Various Western Canadian Sandstone and Carbonate Oil Production Formations. Paper presented at the Canadian International Petroleum Conference, Calgary, Alberta, June 2002.

Bradley, R. G., and Kalaswad, S. (2001). *Chapter 12: Dockum Aquifer in West Texas.* Texas Water Development Board.

Comer, J. B. (1991). Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas asn Southeatern New Mexico. *Bureau of Economic Geology.*

Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.

Domede, P. S. (2017). *Mechanical behaviour of granite. A compilation, analysis and correlation of data from around the world*. Retrieved from https://hal.insa-toulouse.fr/hal-01743870/document

Dutton, A. R., and Simpkins, W. W. (1986). *Hydrogeochemistry and Water Resources of the Triassic Lower Dockum Group in the Texas Panhandle and Eastern New Mexico.* Austin Texas: Bureau of Economic Geology.

Fanchi, J. R. (2010). Integrated Reservoir Asset Management .

Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.

Gunn, R. D. (1982). Desmoinesian Depostional Systems in the Knox Baylor Trough. *North Texas Geological Society*.

Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.

Horne, E. A., Zahm, C., and Hennings , P. (2021). Basement-rooted faults of the Delaware Basin and Central Basin Platform, Permian Basin West Texas and Southern New Mexico. *BEG*.

Hornhach, M. J. (2016). Ellenburger wastwater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.

Jones, R. H. (n.d.). PATTERNS OF MONTOYA GROUP DEPOSITION, DIAGENESIS, AND RESERVOIR DEVELOPMENT IN THE PERMIAN BASIN. *Bureau of Economic Geology*.

Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.

Lindsay, N. G.; Murphy, F. C.; Walsh, J. J.; and Watterson, J. (1993). Outcrop studies of shale smear on fault surfaces. *International Association of Sedimentologists Special Publication*, 113-123.

Lone Wolf Groundwater Conservation District. (2019). *Management Plan 2019-2024.* Colorado City, Tx.

Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.

Loucks, R. (2006). *Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas.* Austin, Texas: Bureau of Economic Geology.

Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

Merrill, M.; Slucher, E.; Roberts -Ashby, T.; Warwick, P.; Blondes, M.; Freeman, P.; . . . Lohr, C. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources–Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin. *USGS*.

Nance, H. S. (n.d.). MIDDLE PERMIAN BASINAL SILICICLASTIC DEPOSITION IN THE DELAWARE BASIN: THE DELAWARE MOUNTAIN GROUP (GUADALUPIAN) . *Bureau of Economic Geology*.

Popova, O. (2020). Permian Basin Part 1 Wolfcamp, Bone Spring, Delaware shale plays of the Delaware Basin Geology Review. *USDOE*.

Powers, R. B. (1989). *Petroleum Exploration Plays and Resource Estimates, 1989, On shore United States -- Region 5, West Texas and Eastern New Mexico.* USGS.

Ruppel, S. C. (2006). THE WRISTEN OF THE PERMIAN BASIN: EFFECT OF TECTONICS ON PATTERNS OF DEPOSITION, DIAGENESIS, AND RESERVOIR DEVELOPMENT IN THE LATE SILURIAN. *Bureau of Economic Geology*.

Ruppel, S. C., and Holtz, M. H. (1994). Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin. *Bureau of Economic Geology*.

Sanchez, T., Loughry, D., and Coringrato, V. (2019). Evaluating the Ellenburger Reservoir for Salt Water Disposal in the Midland Basin: An Assessment of Porosity Distribution Beyond the Scale of Karsts. *Unconventional Resources Technology Conference* (pp. 1-17). Denver: URTeC. doi:10.15530/urtec-2019-600

Scanlon, B. R., Reedy, R. C., Male, F., and Walsh, M. (n.d.). *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin.* Austin: Bureau of Economic Geology.

Shamburger Jr., V. M. (1967). *Report 50: Ground-Water Resources of Mitchell and Western Nolan Counties, Texas.* Austin, Texas: Texas Water Development Board.

Snee, J.-E. L., and Zoback, M. D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *The Leading Edge*, 810-819.

White, Jesse G.; Flaig, P.P.; Hasiotis, Stephen P.; and Over, Jeffrey, (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.

Waite, L. (2021, October 25). Geology of the Permian Basin. UT Dallas Geoscience Permian Basin Research Lab.

Zerwer, N.Y. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana:. *AAPG Bulletin*, 293-307.

APPENDICES

APPENDIX A – NEW MEXICO SALT CREEK AGI FORMS

Appendix A-1 – UIC Class II Order, Salt Creek No. 2

Appendix A-2 – UIC Class II Order, Salt Creek No. 3

Appendix A-3 – Drilling Permit, Salt Creek No. 3

Appendix A-3 – Completion Report (as submitted), Salt Creek No. 3

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

ORDER

GRANTING UIC PERMIT SWD-2580

Northwind Midstream Partners, LLC ("Applicant") filed an Application for Authorization to Inject (Form C-108) ("Application") with the New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("OCD") to inject treated acid gas ("TAG") at the Applicant's Salt Creek AGI Well No. 2 ("Well"), as more fully described in Appendix A.

THE OCD FINDS THAT:

1. Applicant provided the information required by 19.15.26 NMAC and the Form C-108 for an application to inject TAG into a Class II Underground Injection Control ("UIC") well.

2. The administrative approval of this Application for a redundant acid gas injection ("AGI") well was authorized by the Oil Conservation Commission ("OCC") in Ordering Paragraph 3 of Order No. R-20913-C.

3. Applicant complied with the notice requirements of 19.15.26.8 NMAC.

4. No person filed a protest on the Application.

5. The Well will inject TAG into the Devonian and Silurian formation(s).

6. The TAG injected into the Well will be confined by layers above and below the approved injection interval.

7. No other UIC AGI wells which inject or that are authorized to inject TAG into the same approved injection interval are permitted within 1.75 mile(s) of the Well.

8. Applicant affirmed in a sworn statement by a qualified person that it examined the available geologic and engineering data and found no evidence of open faults or other hydrologic connections between the approved injection interval and any underground sources of drinking water.

9. Applicant affirmed in a sworn statement by a qualified person that the injection of TAG over the predicted service life of the Well will not increase the potential for an induced seismic event.

10. Applicant is in compliance with 19.15.5.9 NMAC.

11. Applicant agrees to the Terms and Conditions in the attached Permit.

THE DIVISION CONCLUDES THAT:

1. OCD has authority under the Oil and Gas Act, NMSA 1978, §§70-2-1 *et seq.*, and its implementing regulations, 19.15.1 *et seq.* NMAC, and under the federal Safe Drinking Water Act, 42 U.S.C. 300f *et seq.*, and its implementing regulations, 40 CFR 144 *et seq.*, to issue this permit for an UIC Class II injection well. *See* 40 CFR 147.1600.

2. Based on the information and representations provided in the Application, the proposed injection, if conducted in accordance with the Application and the terms and conditions of the attached Permit, (a) will not result in waste of oil and gas; (b) will not adversely affect correlative rights; (c) will protect underground sources of drinking water; and (d) will protect the public health and environment.

3. Applicant is authorized to inject subject to the terms and conditions of the Permit.

IT IS THEREFORE ORDERED THAT:

The Applicant be granted UIC Permit SWD-2580 for the Salt Creek AGI No. 2.

______________________________ **Date:** 1/24/24

DYLAN M. FUGE
DIRECTOR (Acting)

DMF/mg

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

UIC CLASS II PERMIT SWD-2580

APPENDIX A – AUTHORIZED INJECTION

Permittee: Northwind Midstream Partners, LLC (successor to Salt Creek Midstream, LLC)

OGRID No.: 331501

Well name: Salt Creek AGI Well No. 2

Surface location: 2513 feet from the North line and 310 feet from the West line, Section 21,
Township 26 South, Range 36 East, NMPM, Lea County New Mexico
Latitude/Longitude: 32.029128˚ N; 103.277598˚ W (NAD83)

Bottom hole location (if different): Not applicable

Type of completion: Open hole

Type of injection: Gas waste production from Applicant's gas-processing facility

Injection fluid: Treated acid gas with carbon dioxide

Injection interval: Approximately 17550 feet to 18650 feet TVD; Devonian and Silurian formations.

Injection interval thickness (feet): Approximately 1100 feet

Confining layer(s): Woodford Shale (upper) and Montoya formation (lower)

Prohibited injection interval(s): Woodford Shale and shallower formations, Montoya formation and deeper Ordovician formations and any lost circulation zones.

Liner, tubing, and packer set: 3.5-inch, CRA (L80 and G3) tubing with a permanent CR packer set within 100 feet of the top of the open hole and with a subsurface safety valve ("SSSV") no greater than 150 feet below ground surface

Maximum daily injection rate: 12 MMSCF per day

Maximum surface injection pressure: 5798 PSI (as calculated using an average specific gravity of 0.7389)

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

UIC CLASS II PERMIT SWD-2580

Pursuant to the Oil and Gas Act, NMSA 1978, §§70-2-1 *et seq.*, ("Act") and its implementing regulations, 19.15.1 *et seq.* NMAC, ("Rules") and the federal Safe Drinking Water Act, 42 U.S.C. 300f *et seq.*, and its implementing regulations, 40 CFR 144 *et seq.*, the Oil Conservation Division ("OCD") issues this Permit to Northwind Midstream Partners, LLC ("Permittee") to authorize the construction and operation of a well to inject treated acid gas ("TAG") that includes carbon dioxide at the location and under the terms and conditions specified in this Permit and Appendix A.

I. GENERAL CONDITIONS

A. AUTHORIZATION

1. Scope of Permit. This Permit authorizes the injection of TAG into the well described on Appendix A ("Well"). Any injection not specifically authorized by this Permit is prohibited. Permittee shall be the "operator" of the Well as defined in 19.15.2.7(O)(5) NMAC.

a. Injection is limited to the approved injection interval described in Appendix A. Permittee shall not allow the movement of fluid containing any contaminant into an underground source of drinking water ("USDW") if the presence of that contaminant may cause a violation of a Primary Drinking Water Regulation adopted pursuant to 40 CFR Part 142 or that may adversely affect the health of any person. [40 CFR 144.12(a)]

b. The wellhead injection pressure for the Well shall not exceed the value identified in Appendix A.

c. Permittee shall not commence to drill, convert, or recomplete the Well until receiving this approval and until OCD approves a Form C-101 Application for Permit to Drill ("APD") pursuant to 19.15.14 NMAC or receives an approved federal Form 3160-3 APD for the Well. [40 CFR 144.11; 19.15.14.8 and 19.15.26.8 NMAC]

d. Permittee shall not commence injection into the Well until the Permittee complies with the conditions in Section I. C. of this Permit.

e. This Permit authorizes injection of any UIC Class II fluid or oil field waste defined in 19.15.2.7(E)(6) NMAC.

f. This Permit does not authorize injection for an enhanced oil recovery project as defined in 19.15.2.7(E)(2) NMAC.

2. Notice of Commencement. Permittee shall provide written notice on Form C-103 to OCD E-Permitting and notify OCD Engineering Bureau by email of the submittal no later than two (2) business days following the date on which injection commenced into the Well. [19.15.26.12(B) NMAC]

3. Termination. Unless terminated sooner, this Permit shall remain in effect for a term of thirty (30) years beginning on the date of issuance. Permittee may submit an application for a new permit prior to the expiration of this Permit. If Permittee submits an application for a new permit, then the terms and conditions of this Permit shall remain in effect until OCD denies the application or grants a new permit.

a. This Permit shall terminate one (1) year after the date of issuance if Permittee has not commenced injection into the Well, provided, however, that OCD may grant a single extension of no longer than one (1) year for good cause shown. Permittee shall submit a written request for an extension to OCD Engineering Bureau no later than thirty (30) days prior to the deadline for commencing injection.

b. One (1) year after the last date of reported injection into the Well, OCD shall consider the Well abandoned, the authority to inject pursuant to this Permit shall terminate automatically, and Permittee shall plug and abandon the Well as provided in Section I. E. of this Permit. Upon receipt of a written request by the Permittee no later than one year after the last date of reported injection into the Well, OCD may grant an extension for good cause. [19.15.26.12(C) NMAC]

B. DUTIES AND REQUIREMENTS

1. Duty to Comply with Permit. Permittee shall comply with the terms and conditions of this Permit. Any noncompliance with the terms and conditions of this Permit, or of any provision of the Act, Rules or an Order issued by OCD or the Oil Conservation Commission, shall constitute a violation of law and is grounds for an enforcement action, including revocation of this Permit and civil and criminal penalties. Compliance with this Permit does not relieve Permittee of the obligation to comply with any other applicable law, or to exercise due care for the protection of fresh water, public health and safety and the environment. The contents of the Application and Appendix A shall be enforceable terms and conditions of this Permit. [40 CFR 144.51(a); 19.15.5 NMAC]

2. Duty to Halt or Reduce Activity to Avoid Permit Violations. Permittee shall halt or reduce injection to avoid a violation of this Permit or other applicable law. It shall not be a defense in an enforcement action for Permittee to assert that it would have been necessary to halt or reduce injection in order to maintain compliance with this Permit. [40 CFR 144.51(c)]

3. Duty to Mitigate Adverse Effects. Permittee shall take all reasonable steps to minimize, mitigate and correct any waste or effect on correlative rights, public health, or the environment resulting from noncompliance with the terms and conditions of this Permit. [40 CFR 144.51(d)]

4. Duty to Operate and Maintain Well and Facilities. Permittee shall operate and maintain the Well and associated facilities in compliance with the terms and conditions of this Permit. [40 CFR 144.51(e)]

5. Duty to Provide Information. In addition to any other applicable requirement, Permittee shall provide to OCD by the date and on the terms specified by OCD any information which OCD requests for the purpose of determining whether Permittee is complying with the terms and conditions of this Permit. [40 CFR 144.51(h)]

6. Private Property. This Permit does not convey a property right or authorize an injury to any person or property, an invasion of private rights, or an infringement of state or local law or regulations. [40 CFR 144.51(g)]

7. Inspection and Entry. Permittee shall allow OCD's authorized representative(s) to enter upon the Permittee's premises where the Well is located and where records are kept for the purposes of this Permit at reasonable times and upon the presentation of credentials to:

a. Inspect the Well and associated facilities;

b. Have access to and copy any record required by this Permit;

c. Observe any action, test, practice, sampling, measurement or operation of the Well and associated facilities; and

d. Obtain a sample, measure, and monitor any fluid, material or parameter as necessary to determine compliance with the terms and conditions of this Permit. [40 CFR 144.51(i)]

8. Certification Requirement. Permittee shall sign and certify the truth and accuracy of all reports, records, and documents required by this Permit or requested by OCD. [40 CFR 144.51(k)]

9. Financial Assurance. Permittee shall provide and maintain financial assurance for the Well in the amount specified by OCD until the Well has been plugged and abandoned and the financial assurance has been released by OCD. [40 CFR 144.52; 19.15.8.12 NMAC]

C. PRIOR TO COMMENCING INJECTION

1. Construction Requirements.

a. Permittee shall construct the Well as described in the Application,

Appendix A and as required by the Special Conditions.

b. Permittee shall construct and operate the Well in a manner that ensures the injected fluid enters only the approved injection interval and is not permitted to escape to other formations or onto the surface.

2. Tests and Reports. Permittee shall complete the following actions prior to commencing injection in the Well.

a. Permittee shall obtain and comply with the terms and conditions of an approved APD prior to commencing drilling of the Well, or other OCD approval, as applicable, prior to converting or recompleting the Well. If the APD is approved by the OCD, the Well shall be subject to the construction, testing, and reporting requirements of 19.15.16 NMAC.

b. Permittee shall circulate to surface the cement for all casings. If cement does not circulate on any casing string, Permittee shall run a cement bond log ("CBL") to determine the top of cement, then notify the OCD Engineering Bureau and the appropriate OCD Inspection Supervisor and submit the CBL prior to continuing with any further cementing on the Well. If the cement did not tie back into next higher casing shoe, Permittee shall perform remedial cement action to bring the cement to surface. If the remedial action does not circulate the cement to surface, Permittee shall demonstrate that a minimum of three hundred (300) feet of cement is present above the next higher casing shoe in order to cease any further remedial actions.

c. If a liner is approved for the construction of the Well, Permittee shall run and submit to OCD E-Permitting and notify the OCD Engineering Bureau by email, a CBL for the liner to demonstrate placement cement and the cement bond with the tie-in for the casing string.

d. Permittee shall submit the mudlog, geophysical logs, and a summary of depths (picks) for the contacts of the formations demonstrating that only the permitted formation is open for injection. OCD may amend this Permit to specify the depth of the approved injection interval within the stratigraphic interval requested in the application. If Permittee detects a hydrocarbon show during the drilling of the Well, it shall notify OCD Engineering Bureau by email and obtain written approval prior to commencing injection into the Well.

e. Permittee shall obtain and submit on a Form C-103 a calculated or measured static bottom-hole pressure measurement representative of the completion in the approved injection interval.

f. Permittee shall conduct an initial mechanical integrity test ("MIT") on the Well in compliance with the terms and conditions of this Permit and 19.15.26 NMAC, and shall not commence injection into the Well until the results of the initial MIT have been approved by the appropriate OCD Inspection Supervisor. [19.15.26.11(A) NMAC]

g. Permittee shall submit and receive approval from the OCD for a hydrogen sulfide contingency plan that addresses the operation and monitoring of the Well. Permittee may revise an existing hydrogen sulfide contingency plan to incorporate the Well if disposal is part of a gas processing facility. [19.15.11.9 NMAC]

h. OCD retains authority to require a wireline verification of the completion and packer setting depths in this Well. [19.15.26.11(A) NMAC]

D. OPERATION

1. Operation and Maintenance.

a. Permittee shall equip, operate, monitor and maintain the Well to facilitate periodic testing, assure mechanical integrity, and prevent significant leaks in the tubular goods and packing materials used and significant fluid movements through vertical channels adjacent to the well bore. [19.15.26.10(A) NMAC]

b. Permittee shall operate and maintain the Well and associated facilities in a manner that confines the injected fluid to the approved injection interval and prevents surface damage and pollution by leaks, breaks and spills. [19.15.26.10(B) NMAC]

c. OCD may authorize an increase in the maximum surface injection pressure upon a showing by the Permittee that such higher pressure will not result in the migration of the disposed fluid from the approved injection interval or induced seismicity. Such proper showing shall be demonstrated by sufficient evidence, including an acceptable step-rate test.

d. If OCD has reason to believe that operation of the Well may have caused or determined to be contributing to seismic activity, Permittee shall, upon OCD's written request:

i. Take immediate corrective action, which could include testing and evaluating of the injection interval and confining layers; suspending or reducing of the rate of injection or maximum surface injection pressure, or both; and providing increased monitoring of the Well's operation; and

ii. Submit a remedial work plan or an application to modify the Permit to implement the corrective action, plug back the injection interval, or incorporate another modification required by OCD.

OCD may approve the remedial work plan, modify the Permit or issue an emergency order or temporary cessation order as it deems necessary.

2. Pressure Limiting Device.

a. The Well shall be equipped with a pressure limiting device, which is in workable condition and can be tested for proper calibration at the well site, that shall limit surface tubing pressure to the maximum surface injection pressure specified in Appendix A.

b. Permittee shall test the pressure limiting device and all gauges and other metering requirement to ensure their accuracy and proper function every year.

3. Mechanical Integrity. Permittee shall conduct a MIT prior to commencing injection, annually after the date of the previous MIT, and whenever the tubing is removed or replaced, the packer is reset, mechanical integrity is lost, Permittee proposes to transfer the Well, or requested by OCD.

a. MITs shall be conducted in accordance with 19.15.26 NMAC.

b. Permittee shall submit a sundry notice on Form C-103 of intent to install or replace injection equipment or conduct a MIT no later than three (3) business days prior to the event.

c. Permittee shall report the result of a MIT no later than two (2) business days after the test.

d. Permittee shall cease injection and shut-in the Well no later than twenty-four (24) hours after discovery if:

i. The Well fails a MIT; or

ii. Permittee observes conditions at the Well that indicate the mechanical failure of tubing, casing, or packer.

e. Permittee shall take all necessary actions to address the effects resulting from the loss of mechanical integrity in accordance with 19.15.26.10 NMAC.

f. Permittee shall conduct a successful MIT pursuant to 19.15.26.11 NMAC, including written approval from OCD prior to recommencing injection and the requirements contained in Section I G.3.

4. Additional Tests. Permittee shall conduct any additional test requested by OCD, including but not limited to step-rate tests, tracer surveys, injection surveys, noise logs, temperature logs, and casing integrity logs [19.15.26.11(A)(3) NMAC]

5. Records.

a. Permittee shall retain a copy of each record required by this Permit for a period of at least five (5) years and shall furnish a copy to OCD upon request. [40 CFR 144.51(h)]

b. Permittee shall retain a record of each test, sample, measurement, and certification of accuracy and function collected for the Well, including:

i. Date, location, and time of sample, measurement or calibration;

ii. Person who conducted the sample event, -measurement or calibration;

iii. Calibration of gauge or other equipment in accordance with the manufacturer's specifications;

iv. Description of method and procedures;

v. Description of handling and custody procedures; and

vi. Result of the analysis.

E. PLUGGING AND ABANDONMENT

1. Upon the termination of this Permit, Permittee shall plug and abandon the Well and restore and remediate the location in accordance with 19.15.25 NMAC.

2. If Permittee has received an extension pursuant to Section I. A. 3. b., Permittee shall apply for approved temporary abandonment pursuant to 19.15.25 NMAC.

3. If this Permit expires pursuant to 19.15.26.12 NMAC and OCD has not issued a new permit, then Permittee shall plug and abandon the Well and restore and remediate the location in accordance with 19.15.25 NMAC.

4. Permittee's temporary abandonment of the Well shall not toll the abandonment of injection in accordance with 19.15.26.12(C) NMAC.

F. REPORTING

1. Monthly Reports. Permittee shall submit a report using Form C-115 using the OCD's web-based online application on or before the 15th day of the second month following the month of injection, or if such day falls on a weekend or holiday, the first workday following the 15th, with the number of days of operation, injection volume, and injection pressure. [19.15.26.13 NMAC; 19.15.7.24 NMAC]

2. Additional AGI Well Reports. Permittee shall submit the required reports listed in II. Special Conditions. Submittal of quarterly or annual reports shall be done using Form C-103 and larger documents using the Engineering Bureau e-mail.

3. Corrections. Permittee shall promptly disclose to OCD any incorrect information in the Application or any record required by this Permit and submit corrected information. [40 CFR 144.51(h)(8)]

G. CORRECTIVE ACTION

1. Releases. Permittee shall report any unauthorized release of injection fluid at the Well or associated facilities in accordance with 19.15.29 and 19.15.30 NMAC.

2. Failures and Noncompliance. Permittee shall report the following incidents to appropriate OCD Inspection Supervisor and OCD Engineering Bureau verbally and by e-mail no later than 24 hours after such incident:

a. Any mechanical integrity failures identified in Section I. D. 3. d;

b. The migration of injection fluid from the injection interval [19.15.26.10 NMAC]; or

c. A malfunction of the Well or associated facilities that may cause waste or affect the public health or environment, including: (a) monitoring or other information which indicates that a contaminant may affect a USDW; or (b) noncompliance or malfunction which may cause the migration of injection fluid into or between USDWs. [40 CFR 144.51(l)(6)]

3. Corrective Action. Permittee shall submit a written report describing the incident in Sections I.G.1 or I.G.2, including a corrective active plan, no later than five (5) calendar days after discovery of the incident. [40 CFR 144.51(l)(6)] For an unauthorized release, Permittee also shall comply with the site assessment, characterization and remediation requirements of 19.15.29 and 19.15.30 NMAC.

4. Restriction or Shut-In. OCD may restrict the injected volume and pressure or shut-in the Well if OCD determines that the Well has failed or may fail to confine the injected fluid to the approved injection interval or has caused induced seismicity until OCD determines that Permittee has identified and corrected the failure. [19.15.26.10(E) NMAC]

H. PERMIT CHANGES

1. Transfer. This Permit shall not be transferred without the prior written approval of OCD. Permittee shall file Form C-145 for a proposed transfer of the Well. OCD may require, as a condition of approving the transfer, that this Permit be amended to ensure compliance and consistency with applicable law. If the Well has not been spud prior to the transfer, the OCD may require that the new operator reapply and submit to the OCD a new Form C-108 prior to constructing and injecting into the well. [19.15.26.15 NMAC; 19.15.9.9 NMAC]

2. Insolvency. Permittee shall notify OCD Engineering Bureau of the commencement of a voluntary or involuntary proceeding in bankruptcy which names Permittee or an entity which operates the Well on behalf of Permittee as a debtor no later than ten (10) business days after the commencement of the proceeding.

3. OCD Authority to Modify Permit and Issue Orders

a. The OCD may amend, suspend, or revoke this Permit after notice and an opportunity for hearing if it determines that:

i. The Permit contains a material mistake;

ii. Permittee made an incorrect statement on which OCD relied to establish a term or condition of the Permit or grant this Permit;

iii. this Permit must be amended to ensure compliance and consistency with applicable law, including a change to the financial assurance requirements;

iv. The Well's operation may affect the water quality of fresh water;

v. Injected fluid is escaping from the approved injection interval;

vi. Injection may be caused or contributed to seismic activity: or

vii. Injection may cause or contribute to the waste of oil, gas or potash resources or affect correlative rights, public health, or the environment.

b. OCD retains jurisdiction to enter such orders as it deems necessary to prevent waste and to protect correlative rights, protect public health, and the environment.

c. OCD retains jurisdiction to review this Permit as necessary and no less than once every five (5) years, and may determine whether this Permit should be modified, revoked and reissued, or terminated. [40 CFR 144.36(a)]

4. Permittee Request to Modify Permit. Permittee may apply to modify the terms of this Permit.

a. **Minor Modifications**. OCD may make a minor modification to this Permit without notice and an opportunity for hearing for:

i. Non-substantive changes such as correction of typographical errors;

ii. Requirements for more frequent monitoring or reporting;

iii. Changes to the Well construction requirements provided that any alteration shall comply with the conditions of the Permit and does not change the Area of Review considered in the application for the Permit;

iv. Amendments to the plugging and abandonment plan;

v. Changes in the types of fluids injected which are consistent with sources listed in the application for the Permit and do not change the classification of the Well;

vi. Corrections of the actual injection interval if within the approved formation; or

vii. Transfer of a Permit for a Well that has been spud. [40 CFR 144.41]

b. **Major Modifications.** OCD shall require notice and an opportunity for hearing for any modification that is not minor. For such modifications, Permittee shall submit Form C-108 and comply with the notice requirements of 19.15.26 NMAC. Upon review of the Form C-108, OCD may require a hearing before the OCC for approval of the modifications.

II. SPECIAL CONDITIONS

1. Permittee shall comply with the special conditions set forth in Ordering Paragraph 1. (e) of Order No. R-20913-F along with all conditions stipulated in prior amended orders which reference this Well. If any conditions contained in this Permit conflict with the conditions of Order No. R-20913, as amended, set by the OCC, then the requirements of the Order shall supersede the condition found in this Permit.

2. Permittee shall provide protection of the injection tree, located at the surface, utilizing the installation of barricades or similar protective structures that shall minimize the risk of damage to the wellhead.

3. Permittee shall complete a step-rate injection test prior to the completion of reservoir stimulation activities (acid pumping treatment). Permittee shall be allowed the exception for a spot acid treatment following drilling activities for cleaning of the injection zone.

III. ATTACHMENTS

1. Well Completion Diagram as submitted in Applicant's Exhibit A in Case No. 23943 [Received October 10, 2023]

2. Copy of OCD Exhibit 1 for Case No. 23463 as Approved in Order No. R-20913-F

WELL SCHEMATIC
SALT CREEK AGI #2
S21 - T26S - R36E

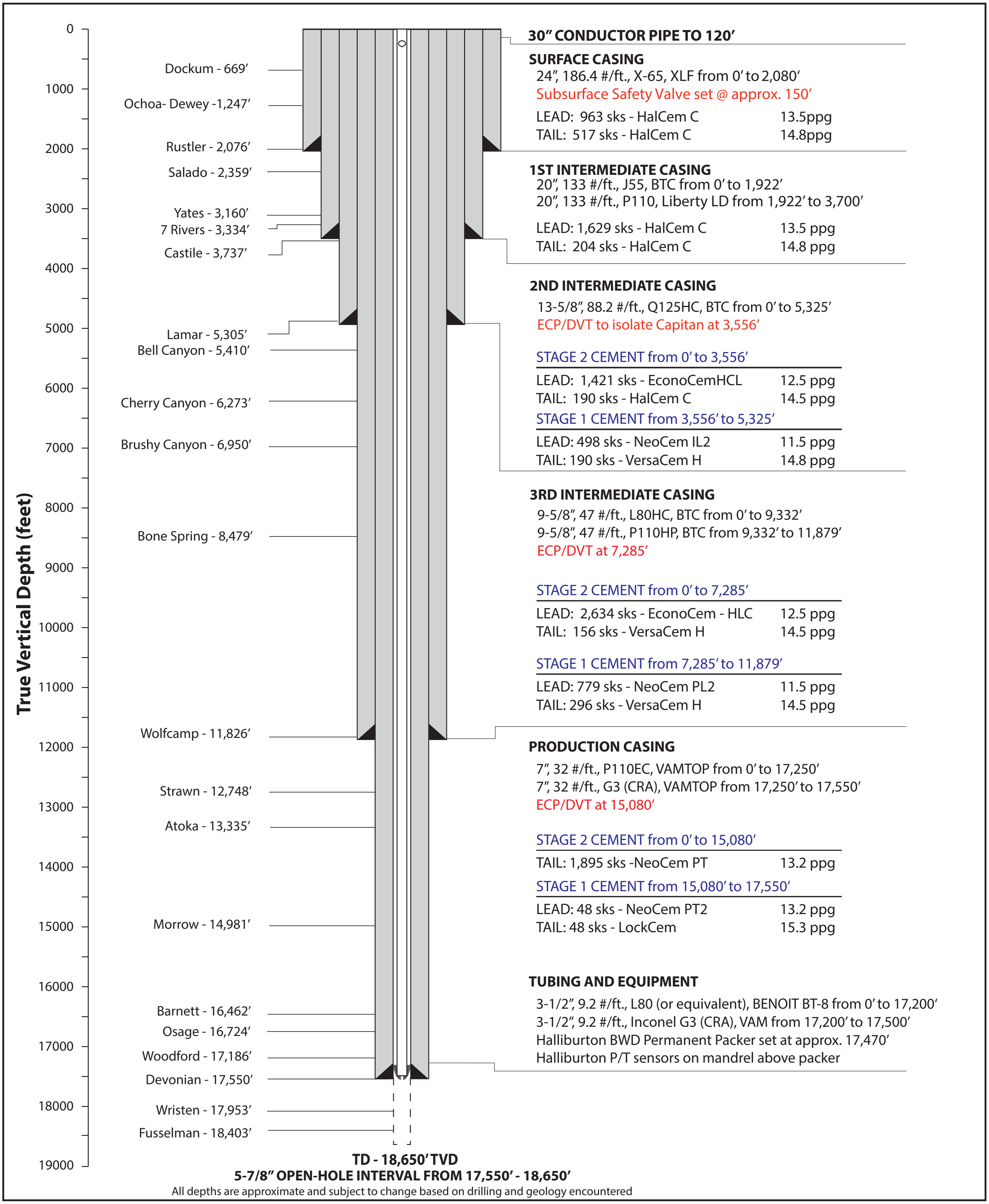


Figure 4. Well design consisting of a surface string of casing, three intermediate strings, and a production string with associating tubing/equipment and cement types.

CASE NO. 23463, OCD Exhibit 1

OCD's Recommended Conditions of Approval for Acid Gas Injection Wells:

OCD recommends these conditions of approval for acid gas injection (AGI) wells in addition to the general requirements for all UIC Class II wells issued under Rule 15.19.26 NMAC - *Injection*.

1. Operator shall conduct an annual mechanical integrity test (MIT) on the proposed well.

2. Operator shall conduct continuous monitoring of surface treated acid gas (TAG) injection pressure, temperature, rate, surface annular pressure, and bottom-hole (or "end of tubing") temperatures and pressures in the tubing and the annulus.

3. Operator shall conduct step-rate and fall-off tests on the completed well before commencing injection. Operator may adjust the maximum surface injection pressure for the well after these tests with the approval of the OCD.

4. Operator shall maintain a maintenance log, including the volume of annular fluid (diesel)with corrosion inhibiting and biocide additives replaced in the annulus of the well.

5. Operator shall establish temperature parameters for injected fluid, install and maintain temperature-activated controls to govern the temperature of injected fluid, and install and maintain an alarm system for the controls to indicate exceedance of the parameters.

6. Operator shall report on a quarterly basis the summary data for injection parameters monitored under the permit, subject to OCD approval of annual reports after one year of operation upon request by Operator.

7. Operator shall equip the well with a pressure-limiting device and a one-way safety valve (with the appropriate interior drift diameter) on the tubing approximately 100 feet to 250 feet below the surface.

8. Operator shall use a corrosion-inhibiting diesel with a biocide component as the annular fluid of the well.

9. Operator shall circulate cement for all casing to the surface.

10. Well construction shall be designed for exposure to corrosive environment including, but not limited to, casing, casing cement, tubing, and the packer in proximity of injection interval.

11. Prior to commencing injection, Operator shall obtain OCD's approval a hydrogen-sulfide contingency plan that complies with Rule 19.15.11.9 NMAC.

12. No later than thirty (30) days prior to commencing injection, Operator shall obtain OCD's approval of immediate notification parameters for annulus pressure and tubing and casing differential pressure at a set injection temperature.

13. No later than forty-five (45) days after Operator completes drilling the well, Operator shall submit to OCD's district office the well drilling logs including mudlogs, electric logs, daily reports, and the static bottom-hole pressure measured at completion of drilling the well.

14. No later than forty-five (45) days after completion of the well, Operator shall submit to OCD the final reservoir evaluation and confirm that the open-hole portion of the well does not intersect the fault plane of any identified fault that occurs within the approved injection interval.

15. No later than ninety (90) days after commencing injection, and no less frequently than annually thereafter, Operator shall consult with OCD regarding the immediate notification parameters. If OCD determines that the immediate notification parameters should be modified, Operator shall provide modified parameters within thirty (30) days of notification for review by OCD.

16. No later than thirty (30) days after the fifth (5^{th}) year of injection, Operator shall submit to OCD a report summarizing the well's performance including injected volumes by fluid type, reservoir pressures, the models calibrated using that information and seismic modeling.

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT OIL CONSERVATION COMMISSION

SECOND APPLICATION OF
SALT CREEK MIDSTREAM, LLC
TO AMEND ORDER NO. R-20913-C

CASE NOS. 23464 and 23294
ORDER NO. R-20913-F

ORDER OF THE COMMISSION

THIS MATTER comes before the New Mexico Oil Conservation Commission ("Commission") on Salt Creek Midstream, LLC's ("Salt Creek") *Second Application to Amend Order No. R-20913-D* ("Second Application") pursuant to Sections 70-2-6(B) and 70-2-13 NMSA 1978 of the Oil and Gas Act and 19.15.4.20 NMAC. The Commission, having considered the Second Application, enters the following findings of fact, conclusions of law, and order.

FINDINGS OF FACT

1. On August 5, 2019, Salt Creek filed an application seeking authority to inject treated acid gas ("TAG") from the Ameredev South Gas Processing Plant into the proposed Salt Creek Midstream AGI No. 1 Well ("Well"). The application was assigned Case No. 20780.

2. The Well is an Underground Injection Control Class II well subject to the requirements of 19.15.26 NMAC.

3. The Well is vertical with an approximate surface and bottomhole location at 594 feet from the West line and 2,370 feet from the South line of Section 21, Township 26 South, Range 36 East, Lea County.

4. The target injection zone for the Well is located in the Bell Canyon and Cherry Canyon formations of the Delaware Mountain Group ("DMG") at depths approximately 5,410 feet to 7,000 feet.

5. The New Mexico State Land Office ("SLO") and the Oil Conservation Division ("OCD") entered appearances in Case No. 20780.

6. Salt Creek, OCD, and SLO ("the Parties") negotiated a set of permit conditions. The permit conditions required Salt Creek to, within a specific timeframe, construct a second well in the Devonian formation that would become the primary disposal well.

7. The Commission heard Case No. 20780 on December 11, 2019.

8. On January 16, 2020, the Commission issued Order No. R-20913-C approving Salt Creek's application with the conditions agreed upon by the Parties.

9. Pursuant to Order No. R-20913-C, the deadline for Salt Creek to file the application for the Devonian Well was July 16, 2020, but no application was filed.

10. On September 17, 2020, Salt Creek filed an application in Case No. 21476 requesting that the Commission amend Order No. R-20913-C to: (1) reinstate Salt Creek's authorization to commence injection of TAG into the DMG Well; (2) require Salt Creek to commence injection of TAG into the DMG Well within two years of issuance of a new order; and (3) require Salt Creek to submit a C-108 for the Devonian Well within six months after Salt Creek Spuds the DMG Well.

11. The Commission heard Case No. 21476 on December 9, 2020.

12. The SLO and OCD entered appearances in Case No. 21476 and neither party opposed the request.

13. On December 28, 2020, the Commission issued Order No. R-20913-D approving Salt Creek's application with the conditions agreed upon by the Parties.

14. Salt Creek spudded the Well (API: 30-25-46746) on October 19, 2022, and commenced drilling on October 24, 2022. However, Salt Creek encountered technical complications which ultimately caused Salt Creek to plug the Well.

15. On December 6, 2022, Salt Creek filed an application, designated as Case No. 23294, seeking to amend Order No. R-20913-D to extend the deadline to commence injection of TAG into the DMG Well until six months from the date of the amended order.

16. On December 12, 2022, Salt Creek filed a second application, designated as Case No. 23464, to amend Order No. R-20913-D to: (1) approve a new well design and location for the Salt Creek Midstream AGI No. 1 Well; and (2) extend the deadline for Salt Creek to commence injection into the Well until twenty-four months from the date of the amended order.

17. According to the second application, the target injection zone for the Well will remain in the Bell Canyon and Cherry Canyon formations of the DMG, and the Well will have an injection interval of approximately 5,580 feet to 7,040 feet, which reflects the requirement of Order No. R-20912-C (Condition 6c) that the uppermost perforation of the injection interval will be at least 500 feet below the base of the Capitan Reef aquifer or stratigraphic equivalent.

18. Salt Creek has submitted an Amended C-108 outlining the proposed revisions to the Well design, including the addition of two casing strings and a new drill location 277 feet from the West line and 2,350 feet from the South line of Section 21, Township 26 South, Range 36 East, resulting in an as-drilled location approximately 120 feet from the original

location.

19. Salt Creek has provided notice of the Second Application to all affected parties who were notified of Salt Creek's second application in Case No. 23464.

20. The Commission heard Case No. 23464 on May 11, 2023.

21. OCD and Ameredev Operating, LLC entered appearances in Case No. 23464.

22. Ameredev Operating, LLC took no position on Salt Creek's second application.

23. OCD supports the approval of the second application subject to the inclusion of the permit conditions identified in OCD Exhibit 1 titled "OCD's Recommended Conditions of Approval for Gas Injection Wells."

24. The Well will facilitate the sequestration of CO2 and TAG, which is in the public interest.

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the Parties and the subject matter of this case.

2. Proper public notices of the Second Application were given.

3. The Second Application is complete.

4. Salt Creek's request to approve a new well design and new location for the Salt Creek Midstream AGI No. 1 Well and extend the deadline for Salt Creek to commence injection into the Well until twenty-four months from the date of this amended order will comply with the requirements of 19.15.26 NMAC and will not result in waste, impair correlative rights, or harm public health or the environment.

5. As a result of this Order, Salt Creek's application in Case No. 23294 is moot.

ORDER

1. The Second Application is approved, affirming and amending Order No. R-20912-D pursuant to Sections 70-2-6(B) and 70-2-13 NMSA 1978 of the Oil and Gas Act and 19.15.4.20 NMAC as follows:

    a. Salt Creek shall commence injection into the Well no later than twenty-four months from the date of this amended Order.

    b. Ninety days prior to spudding the Well, Salt Creek shall submit to OCD's Engineering Bureau an updated Area of Review map that identifies new wells that penetrate the approved injection interval and new affected parties, if any, and shall provide to such affected parties copies of the Amended Form C-108 for the approved Well and this Order. A new affected party may file an application for hearing pursuant to 19.15.4.8 NMAC.

c. Salt Creek shall file a Sundry with OCD when it spuds the Well ("Spud Sundry").

d. If Salt Creek fails to timely submit the Spud Sundry, or after receiving OCD approval, fails to construct the Well by the specified deadline, the permit shall terminate automatically and Salt Creek shall plug and abandon the Well pursuant to an OCD-approved plan.

e. The Second Application is hereby conditioned upon all other stipulated permit conditions identified by OCD in OCD's Exhibit 1 titled "OCD's Recommended Conditions of Approval for Gas Injection Wells," a copy of which is attached to this order as Exhibit 1.

2. All other conditions set out in Order No. R-20913-D shall remain in full force and effect.

3. Salt Creek's application in Case No. 23294 is hereby denied because it is superseded by this Order.

DONE at Santa Fe, New Mexico on the 8th day of June 2023.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

Greg Bloom

Greg Bloom, Commissioner

William Ampomah

William Ampomah, Commissioner

Dylan Fuge, Chair

CASE NO. 23463, OCD Exhibit 1

OCD's Recommended Conditions of Approval for Acid Gas Injection Wells:

OCD recommends these conditions of approval for acid gas injection (AGI) wells in addition to the general requirements for all UIC Class II wells issued under Rule 15.19.26 NMAC - *Injection*.

1. Operator shall conduct an annual mechanical integrity test (MIT) on the proposed well.

2. Operator shall conduct continuous monitoring of surface treated acid gas (TAG) injection pressure, temperature, rate, surface annular pressure, and bottom-hole (or "end of tubing") temperatures and pressures in the tubing and the annulus.

3. Operator shall conduct step-rate and fall-off tests on the completed well before commencing injection. Operator may adjust the maximum surface injection pressure for the well after these tests with the approval of the OCD.

4. Operator shall maintain a maintenance log, including the volume of annular fluid (diesel)with corrosion inhibiting and biocide additives replaced in the annulus of the well.

5. Operator shall establish temperature parameters for injected fluid, install and maintain temperature-activated controls to govern the temperature of injected fluid, and install and maintain an alarm system for the controls to indicate exceedance of the parameters.

6. Operator shall report on a quarterly basis the summary data for injection parameters monitored under the permit, subject to OCD approval of annual reports after one year of operation upon request by Operator.

7. Operator shall equip the well with a pressure-limiting device and a one-way safety valve (with the appropriate interior drift diameter) on the tubing approximately 100 feet to 250 feet below the surface.

8. Operator shall use a corrosion-inhibiting diesel with a biocide component as the annular fluid of the well.

9. Operator shall circulate cement for all casing to the surface.

10. Well construction shall be designed for exposure to corrosive environment including, but not limited to, casing, casing cement, tubing, and the packer in proximity of injection interval.

11. Prior to commencing injection, Operator shall obtain OCD's approval a hydrogen-sulfide contingency plan that complies with Rule 19.15.11.9 NMAC.

12. No later than thirty (30) days prior to commencing injection, Operator shall obtain OCD's approval of immediate notification parameters for annulus pressure and tubing and casing differential pressure at a set injection temperature.

13. No later than forty-five (45) days after Operator completes drilling the well, Operator shall submit to OCD's district office the well drilling logs including mudlogs, electric logs, daily reports, and the static bottom-hole pressure measured at completion of drilling the well.

14. No later than forty-five (45) days after completion of the well, Operator shall submit to OCD the final reservoir evaluation and confirm that the open-hole portion of the well does not intersect the fault plane of any identified fault that occurs within the approved injection interval.

15. No later than ninety (90) days after commencing injection, and no less frequently than annually thereafter, Operator shall consult with OCD regarding the immediate notification parameters. If OCD determines that the immediate notification parameters should be modified, Operator shall provide modified parameters within thirty (30) days of notification for review by OCD.

16. No later than thirty (30) days after the fifth (5th) year of injection, Operator shall submit to OCD a report summarizing the well’s performance including injected volumes by fluid type, reservoir pressures, the models calibrated using that information and seismic modeling.

District I
1625 N. French Dr., Hobbs, NM 88240
Phone: (575) 393-6161 Fax: (575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone: (575) 748-1283 Fax: (575) 748-9720
District III
1000 Rio Brazos Road, Aztec, NM 87410
Phone: (505) 334-6178 Fax: (505) 334-6170
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505
Phone: (505) 476-3460 Fax: (505) 476-3462

State of New Mexico
Energy Minerals and Natural Resources
Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-101
Revised July 18, 2013

☐AMENDED REPORT

APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE

1. Operator Name and Address	2. OGRID Number
Salt Creek Midstream, LLC 5775 N Sam Houston Pkwy W, Suite #600; Houston, TX 77086	373554
	3. API Number 30-025-51865

4. Property Code	5. Property Name	6. Well No.
326981	SALT CREEK AGI	3

7. Surface Location

UL - Lot	Section	Township	Range	Lot Idn	Feet from	N/S Line	Feet From	E/W Line	County
L	21	26-S	36-E		2329	SOUTH	278	WEST	LEA

8. Proposed Bottom Hole Location

UL - Lot	Section	Township	Range	Lot Idn	Feet from	N/S Line	Feet From	E/W Line	County
L	21	26-S	36-E		2329	SOUTH	278	WEST	LEA

9. Pool Information

Pool Name	Pool Code
AGI; DELAWARE	98335

Additional Well Information

11. Work Type	12. Well Type	13. Cable/Rotary	14. Lease Type	15. Ground Level Elevation
N	I	R	P	2926′
16. Multiple	17. Proposed Depth	18. Formation	19. Contractor	20. Spud Date
NO	7,040′	CHERRY CANYON		AUG 1, 2023

Depth to Ground water	Distance from nearest fresh water well	Distance to nearest surface water
APPROX. 250′		

☒ **We will be using a closed-loop system in lieu of lined pits**

21. Proposed Casing and Cement Program

Type	Hole Size	Casing Size	Casing Weight/ft	Setting Depth	Sacks of Cement	Estimated TOC
Surface	26″	20″	133	2,100′	2,850	Surface
Intermediate	17.5″	13.375″	54.5	3,100′	1,680	Surface
Intermediate	12.25″	9.625″	40	5,110′	715	Surface
Production	8.75″	7″	26	7,040′	214 bbls, 50 sks	Surface

Casing/Cement Program: Additional Comments

Production interval utilizes corrosion-resistant casing and cement (214 bbls WellLock Resin and CorrosaCem slurry (see attached well diagram)

22. Proposed Blowout Prevention Program

Type	Working Pressure	Test Pressure	Manufacturer
Annular	3,000	3,000	
Double Ram	5,000	5,000	

23. I hereby certify that the information given above is true and complete to the best of my knowledge and belief.
I further certify that I have complied with 19.15.14.9 (A) NMAC ☒ and/or 19.15.14.9 (B) NMAC ☒, if applicable.
Signature:

Printed name: David A. White, P.G.
Title: Consultant to Salt Creek Midstream, LLC
E-mail Address: dwhite@geolex.com
Date: July 13, 2023 Phone: (505)842-8000

OIL CONSERVATION DIVISION
Approved By:
Title:
Approved Date: 08/17/2023 Expiration Date: 08/17/2025
Conditions of Approval Attached

District I
1625 N. French Dr., Hobbs, NM 88240
Phone: (575) 393-6161 Fax: (575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone: (575) 748-1283 Fax: (575) 748-9720
District III
1000 Rio Brazos Road, Aztec, NM 87410
Phone: (505) 334-6178 Fax: (505) 334-6170
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505
Phone: (505) 476-3460 Fax: (505) 476-3462

State of New Mexico
Energy, Minerals & Natural Resources Department
OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-102
Revised August 1, 2011
Submit one copy to appropriate District Office

☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

API Number	Pool Code	Pool Name
30-025-51865	98335	AGI; DELAWARE

Property Code	Property Name	Well Number
326981	SALT CREEK AGI	#3

OGRID No.	Operator Name	Elevation
373554	SALT CREEK MIDSTREAM, LLC	2926'

Surface Location

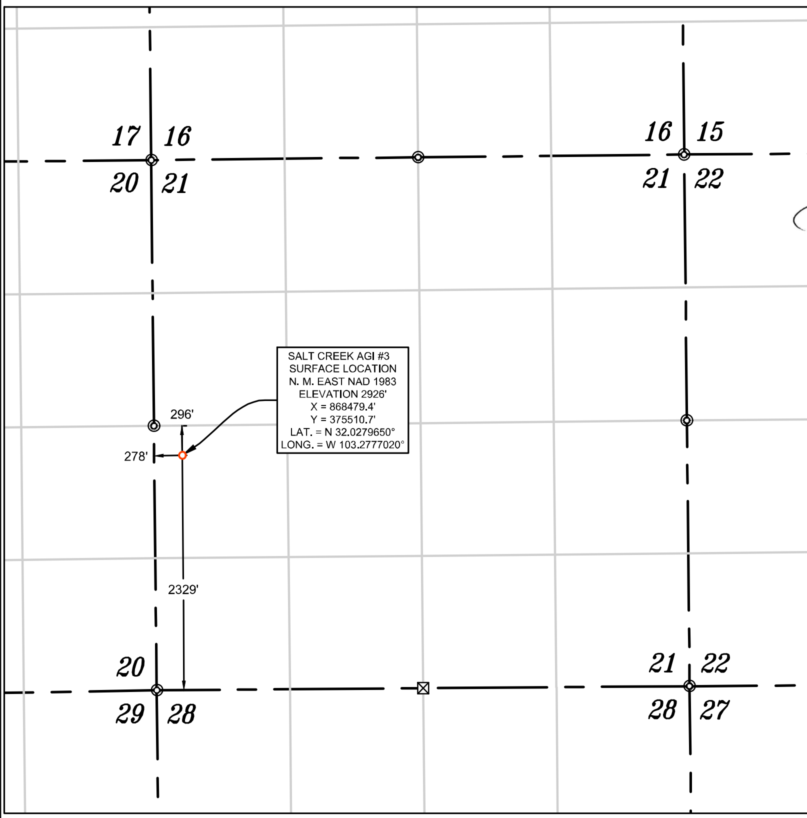
UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
L	21	26 S	36 E		2329	SOUTH	278	WEST	LEA

Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County

Dedicated Acres	Joint or Infill	Consolidation Code	Order No.

No allowable will be assigned to this completion until all interests have been consolidated or a non-standard unit has been approved by the division.



OPERATOR CERTIFICATION

I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief, and that this organization either owns a working interest or unleased mineral interest in the land including the proposed bottom hole location or has a right to drill this well at this location pursuant to a contract with an owner of such a mineral or working interest, or to a voluntary pooling agreement or a compulsory pooling order heretofore entered by the division.

Signature: [signature] Date: 07/18/2023

Printed Name: David A. White, P.G. -- Consultant to SCM

E-mail Address: dwhite@geolex.com

SURVEYOR CERTIFICATION

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief.

Date of Survey: JULY 18, 2023

Signature and Seal of Professional Surveyor:

MATTHEW B. TOMERLIN
NEW MEXICO
23203
PROFESSIONAL SURVEYOR

Job No.: 22-05-2051
MATTHEW B. TOMERLIN, N.M.P.L.S.
Certificate Number 23203

NAD 83 (SURFACE HOLE LOCATION)
LATITUDE = 32.027965°
LONGITUDE = 103.277702°
NAD 27 (SURFACE HOLE LOCATION)
LATITUDE = 32.027837°
LONGITUDE = 103.277245°
STATE PLANE NAD 83 (N.M. EAST)
N: 375510.69' E: 868479.42'
STATE PLANE NAD 27 (N.M. EAST)
N: 375453.20' E: 827290.85'

◎ FND. U.S.G.L.O. MON. UNLESS OTHERWISE NOTED
☒ CALC. CORNER
○ SHL
OIL & GAS LEASE
HORIZONTAL SPACING UNIT

0' 1500' 3000'
SCALE: 1" = 1500'

NOTES

1. ALL COORDINATES, BEARINGS, AND DISTANCES CONTAINED HEREIN ARE GRID, BASED UPON THE NEW MEXICO STATE PLANE COORDINATES SYSTEM, NORTH AMERICAN DATUM 83, NEW MEXICO EAST (3001), NAVD 88.

2. THIS DOCUMENT IS BASED UPON AN ON THE GROUND SURVEY PERFORMED DURING MAY, 2023. CERTIFICATION OF THIS DOCUMENT IS ONLY TO THE LOCATION OF THIS EASEMENT IN RELATION TO RECORDED MONUMENT OF DEEDS PROVIDED BY THE CLIENT.

3. ELEVATIONS MSL, DERIVED FROM G.N.S.S. OBSERVATION AND DERIVED FROM SAID ON-THE-GROUND SURVEY.

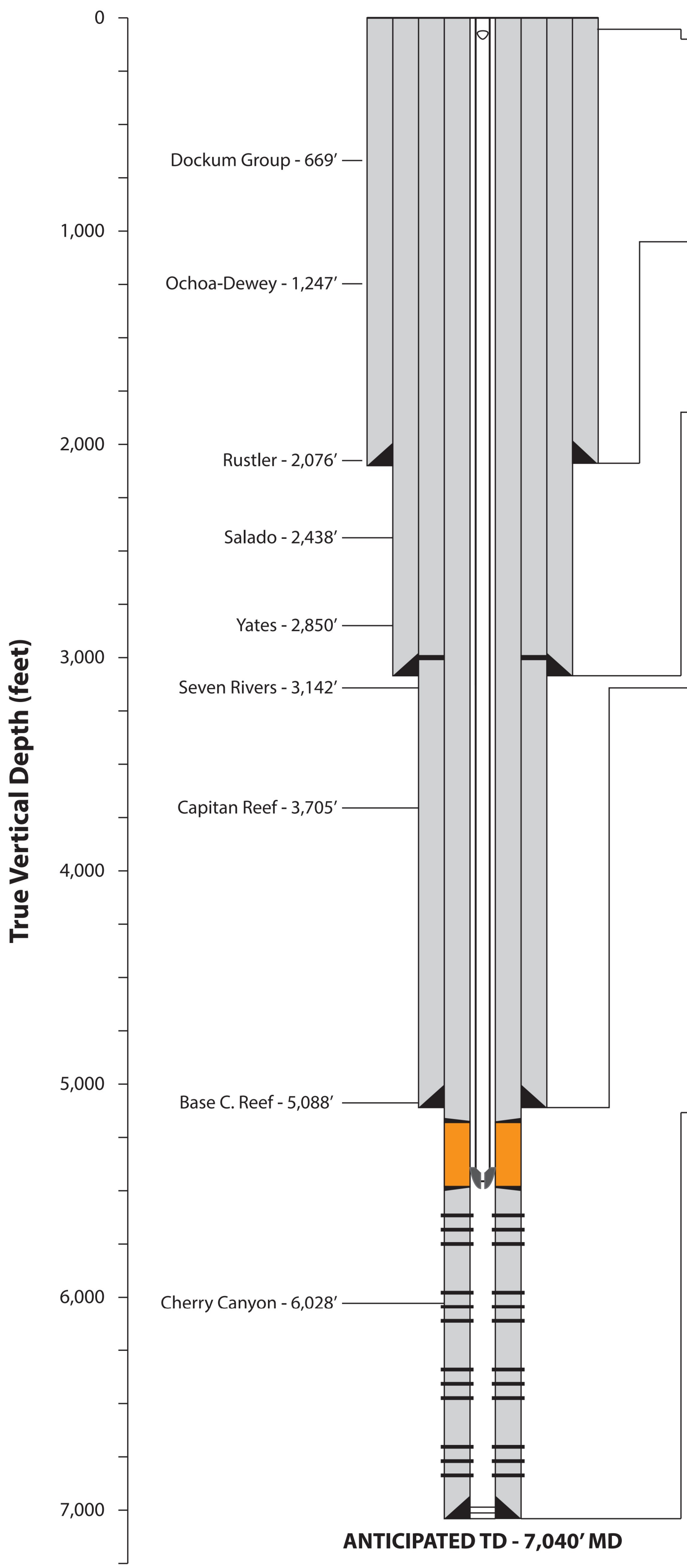
ATTACHMENT A

PROPOSED WELL BORE DIAGRAM
SALT CREEK AGI #3

SALT CREEK MIDSTREAM

SALT CREEK AGI #3
REVISED WELL SCHEMATIC

GEOLEX INCORPORATED



ANTICIPATED TD - 7,040' MD

30" CONDUCTOR PIPE to 80 ft.

20" SURFACE CASING to 2,100 ft. 26" OH

20", 133 #/ft., K55, BTC from 0' to 2,100'

Cement to Surface

Lead: 1,750 sks 12.9 ppg EconoCem
Tail: 1,100 sks 14.8 ppg HalCem

SSSV @ 100'

13 3/8" SURFACE CASING to 3,100 ft. 17.5" OH

13 3/8", 54.5 #/ft., HPL80, BTC from 0' to 3,100'

Cement to Surface

Lead: 1,185 sks EconoCem HLC 12.9 ppg
Tail: 495 sks HalCem C 14.8 ppg

9 5/8" INTERMEDIATE CASING to 5,110 ft. 12.25" OH

9 5/8", 40#/ft., L80, BTC from 0' to 5,110'

Cement to Surface

Stage 1
Lead: 135.5 bbl NeoCem™ 11.0 ppg
Tail: 195 sks VersaCem™ 14.5 ppg

Stage 2
Lead: 189.4 bbl NeoCem™ 11.5 ppg
Tail: 195 sks Halcem C™ 14.8 ppg

DV Tool @ approx. 3,000'

7" PRODUCTION CASING to 7,040 ft. 8.75" OH

7", HP-P110, Rattler from 0' to 5,180'
7", 26 #/ft., SM2535, VAMTOP, CRA from 5,180' to 5,480'
7", HP-P110, Rattler from 5,480' to 7,040'

Cement to Surface

Stage 1
Lead: 54.9 bbl NeoCem™ 13.2 ppg

Stage 2
Lead: 10 bbl WellLock™ Resin 9.28 ppg

Stage 3
Lead: 149 bbl NeoCem™ 11.0 ppg
Tail: 50 sks Halcem C™ 14.8 ppg

DV Tool @ approx. 5,180' and 5,480'

TUBING AND EQUIPMENT

3-1/2", 9.3 #/ft., L80 BENOIT BTS-8 from 0' to 5,180'
3-1/2", 9.3 #/ft., G3, VAMTOP from 5,180' to 5,480'

Halliburton Retrievable SSSV set @ 100'
Halliburton ROC P-T Gauge set above packer
Halliburton BWD Nickel-Alloy Permanent Packer @ approx. 5,480'

Annulus Fluid: Diesel with corrosion inhibitors and biocide

PERFORATIONS (six radial shots per foot)

PRIMARY TARGET:

Delaware Sands (Bell Canyon and Cherry Canyon formations)
5,580' (uppermost allowable perforation point) to 7,040'

Final perforation plan will be determined based on the results of geophysical log and sidewall core analyses.

*All depths are approximate and subject to change based off of the geology encountered

Date prepared: 01/20/2023

Redesign wellbore schematic for Salt Creek AGI #3

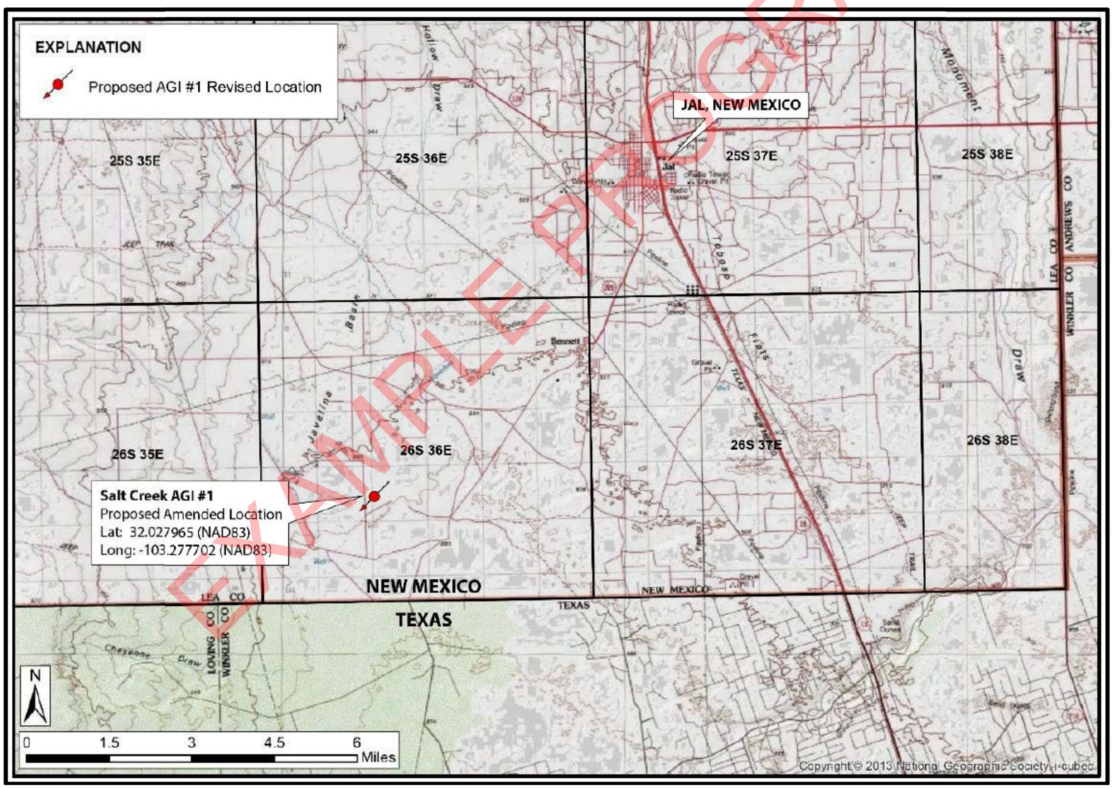
ATTACHMENT B

EXAMPLE DRILLING PROGRAM
SALT CREEK AGI #3

PRELIMINARY DRILLING PROGRAM
SALT CREEK AGI #3

Location: Section 21
Township 26 South, Range 36 East
2,329' FSL & 278'FWL
Lea County, New Mexico

Directions: From Jal, New Mexico, drive south on 3rd Street (a.k.a Frying Pan Road) for approximately 8 miles. Turn right on lease road marked with Salt Creek Midstream signage and continue for approximately 1.5 miles to the end of road. Turn right (north) at T-intersection of lease road and continue for approximate 500 feet. Turn right at lease road marked with Salt Creek Midstream signage and continue 0.25 mile to east plant entrance.



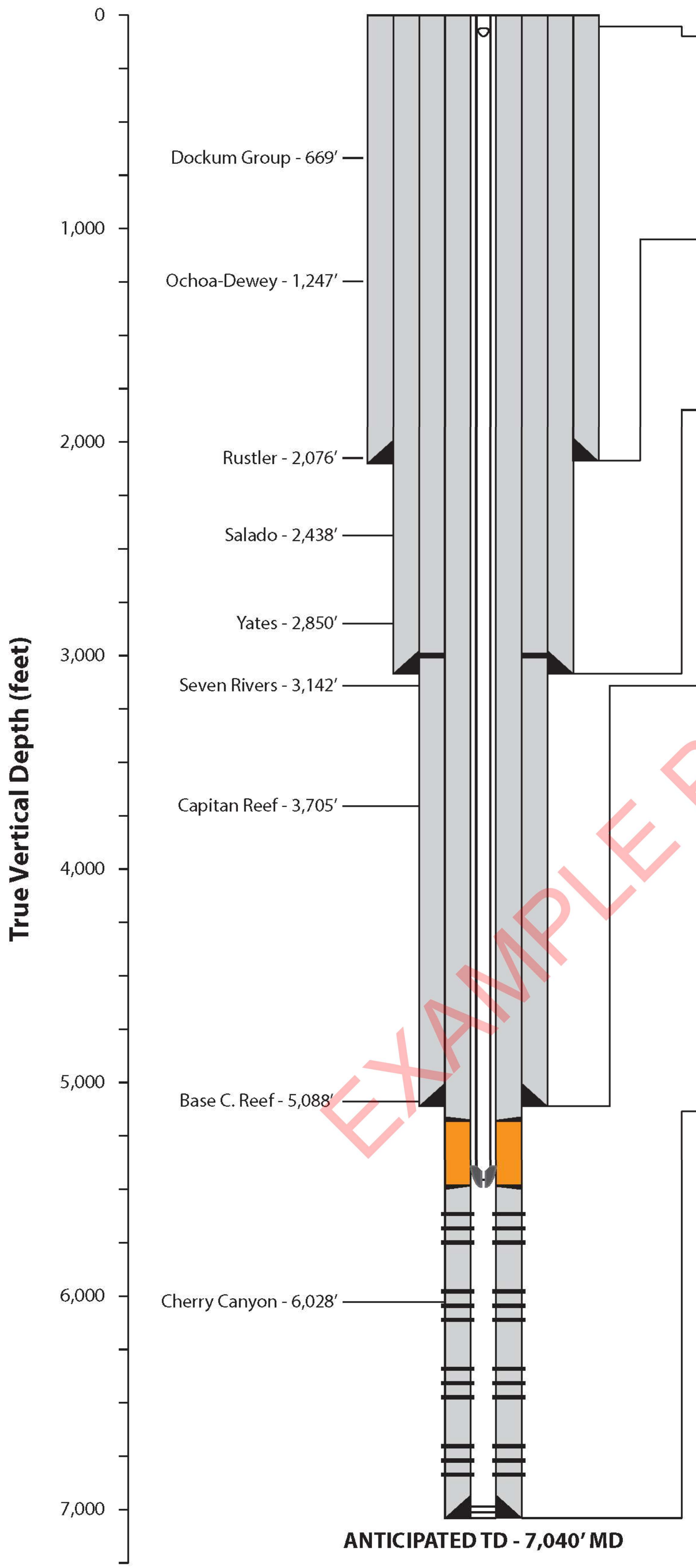
WELL SUMMARY DATA

County:	Lea	**Field**	Delaware
API:	TBD	**NMOCC Order No.**	R-20913-F
AFE Number:	TBD	**Drilling Rig:**	TBD
Elevation:	2926'	**KB Elevation:**	-
NAD83 Coordinates:	32.027965 -103.277702	**Location:**	2329' FSL, 278' FWL T26S, R36E, Sec. 21

SALT CREEK MIDSTREAM

SALT CREEK AGI #3
REVISED WELL SCHEMATIC

GEOLEX INCORPORATED



30" CONDUCTOR PIPE to 80 ft.

20" SURFACE CASING to 2,100 ft. 26" OH

20", 133 #/ft., K55, BTC from 0' to 2,100'

Cement to Surface

Lead: 1,750 sks 12.9 ppg EconoCem
Tail: 1,100 sks 14.8 ppg HalCem

SSSV @ 100'

13 3/8" SURFACE CASING to 3,100 ft. 17.5" OH

13 3/8", 54.5 #/ft., HPL80, BTC from 0' to 3,100'

Cement to Surface

Lead: 1,185 sks EconoCem HLC 12.9 ppg
Tail: 495 sks HalCem C 14.8 ppg

9 5/8" INTERMEDIATE CASING to 5,110 ft. 12.25" OH

9 5/8", 40#/ft., L80, BTC from 0' to 5,110'

Cement to Surface

Stage 1
Lead: 135.5 bbl NeoCem™ 11.0 ppg
Tail: 195 sks VersaCem™ 14.5 ppg

Stage 2
Lead: 189.4 bbl NeoCem™ 11.5 ppg
Tail: 195 sks Halcem C™ 14.8 ppg

DV Tool @ approx. 3,000'

7" PRODUCTION CASING to 7,040 ft. 8.75" OH

7", HP-P110, Rattler from 0' to 5,180'
7", 26 #/ft., SM2535, VAMTOP, CRA from 5,180' to 5,480'
7", HP-P110, Rattler from 5,480' to 7,040'

Cement to Surface

Stage 1
Lead: 54.9 bbl NeoCem™ 13.2 ppg

Stage 2
Lead: 10 bbl WellLock™ Resin 9.28 ppg

Stage 3
Lead: 149 bbl NeoCem™ 11.0 ppg
Tail: 50 sks Halcem C™ 14.8 ppg

DV Tool @ approx. 5,180' and 5,480'

TUBING AND EQUIPMENT

3-1/2", 9.3 #/ft., L80 BENOIT BTS-8 from 0' to 5,180'
3-1/2", 9.3 #/ft., G3, VAMTOP from 5,180' to 5,480'

Halliburton Retrievable SSSV set @ 100'
Halliburton ROC P-T Gauge set above packer
Halliburton BWD Nickel-Alloy Permanent Packer @ approx. 5,480'

Annulus Fluid: Diesel with corrosion inhibitors and biocide

PERFORATIONS (six radial shots per foot)

PRIMARY TARGET:

Delaware Sands (Bell Canyon and Cherry Canyon formations)
5,580' (uppermost allowable perforation point) to 7,040'

Final perforation plan will be determined based on the results of geophysical log and sidewall core analyses.

*All depths are approximate and subject to change based off of the geology encountered

Date prepared: 01/20/2023

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

HOLE SECTION SUMMARY

Hole Section	Hole Size	Depth Interval (hole section	Depth Criteria
Surface	26”	0’ – 2,100’	Set at ± 2,100’ Casing and Cement to Surface
Intermediate (1st)	17.5”	2,100’ – 3,100’	Below Rustler Fm. Instability Casing and Cement to Surface
Intermediate (2nd)	12.25”	3,100’ – 5,110’	Isolation of Capitan Rf. Casing and Cement to Surface
Production	8.75”	5,110’ – 7,040’	Casing and Cement to Surface

CASING PROGRAM

String	Casing Size (in)	Weight (lb/ft)	Grade	Thread	Top (ft., MD)	Base (ft., MD)	Length
Surface Casing	20	133	K55	BTC	0	2,100	2,100
Intermediate (1st)	13.325	54.5	HPL-80	BTC	0	3,100	3,100
Intermediate (2nd)	9.625	40	L80	BTC	0	5,110	5,110
Production	7	29	HP-P110	Rattler	0	5,180	5,180
Production (CRA)	7	26	SM2535	VAMTOP	5,180	5,480	300
Production (Inj. Zone)	7	29	HP-P110	Rattler	5,480	7,040	1560

CEMENT PROGRAM

String	Lead/Tail	Type	Density (ppg)	# Sacks	Estimated TOC
Surface	Lead	EconoCem HLC (or equivalent)	12.9	2850	Surface
	Tail	Halcem C	14.8		
Intermediate (1st)	Lead	EconoCem HLC	12.9	1680	Surface
	Tail	HalCem C	14.8		
2nd Int. (Stage 1)	Lead	NeoCem	11.0	135.5 bbls	Surface
	Tail	VersaCem	14.5	195 sks	
2nd Int. (Stage 2)	Lead	NeoCem	11.5	189.4 bbls	Surface
	Tail	Halcem C	14.8	195 sks	
Prod. (Stage 1)	-	NeoCem	13.2	54.9 bbls	5,480’
Prod. (Stage 2)	-	WellLock Resin	9.28	10 bbls	5,180’
Prod. (Stage 3)	Lead	NeoCem	11.0	149 bbls	Surface
	Tail	Halcem C	14.8	50 sks	

***NOTE:** DV Tools at 3,000’, 5180’, and 5480’

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

PRE SPUD

Notify regulatory agency (NMOCD – Hobbs District) 24 hours prior to spud. Document notification on IADC and morning report

1. Level and grade the location with caliche or comparable material, as required
2. Install a corrugated steel cellar around well site
3. Auger a 36-inch hole to approximately 80 feet and set 30-inch conductor pipe
4. Cement conductor pipe to the surface using sufficient volume of Redi-mix cement
5. Install a 4-inch outlet for draining the conductor pipe after cementing the surface casing
6. Drill a mouse hole per drilling contractor. Ensure rat hole contractor is using correct layout.
7. Prior to moving rig, drive to location and note any road hazards and/or power lines
8. Move in and rig up drilling rig and associated equipment
    a. Move in and rig up a closed-loop system for handling drill cuttings and drilling fluid
    b. Inspect drill collars and drill pipe (or use most recent if supplied as per IADC contract) and circulate inspection report to drilling superintendent
    c. Make sure all drill pipe has been inspected with paperwork in hand before spud and all pipe on location is counted prior to spud. Keep an up-to-date and correct account (OD, ID, length) of all tubulars on location at all times, including 3rd-party equipment.
    d. Perform a pre-spud rig inspection prior to accepting the rig on daywork.

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

26" SURFACE INTERVAL: 0' – 2,100'

Objective: Drill a 26" hole to approximately 2,100' and set 20" casing to protect usable water intervals and to isolate potentially problematic intervals of flowing sand. Casing string will be cemented to surface.

Notes: Notify NMOCD – Hobbs District Office 24 hours prior to running and cementing surface casing string.

Procedure:

1. Weld a flange to the 30-inch conductor pipe and install an annular blowout preventer (BOP)
2. Install riser pipe with bell nipple and flowline to the BOP
3. Mix a spud mud for the surface hole
4. Make up a bottom-hole assembly (BHA) with a 26" bit (TBD, based on availability)
5. Drill ahead to 2,100' (top of Rustler Formation) taking deviation surveys at approximately 250' intervals and maintaining deviation below 2°.
6. Monitor cellar to ensure ground is not washing out
7. Vary RPM, differential psi, and WOB to optimize ROP. Ream each stand 2-3 on surface hole.
8. Monitor pickup, slack off, torque, returns, and standpipe pressure to evaluate hole cleaning
9. Sweep the hole with paper/MF-55 sweeps and drop a soap stick every connection.
10. Circulate and condition mud for running casing
11. Sweep the hole with a high-viscosity, fresh gel sweep at surface casing TD and spot a high-viscosity sweep at TD
12. Run fluid caliper
13. TOOH to run surface casing
14. Move in and rig up casing crew and run centralized 20", 133 #/ft., K55, BTC surface casing to approximately 2,100'. Run two bow spring centralizers on the float joint (1 in center of joint on a stop ring and 1 on collar) and one centralizer per every third joint at the collars back to surface
15. Dimensional data and minimum performance properties (TBD) of the surface casing are presented on page 7.
16. Move in and rig up cementing equipment. Cement the surface casing as follows:
    a. Pump a freshwater spacer followed by a tuned spacer designed for the rheology of the drilling fluid and lead cement.

b. Pump 1750 sks of ECONOCEM with additives (density – 12.9 ppg) followed by 1100 sks HALCEM with additives (density – 14.8 ppg) according to the current cement program

c. Drop wiper plug and displace with drilling fluid according to the cementing program

d. Bump wiper plug and pressurize over final circulating pressure

e. Monitor pressure for five (5) minutes and bleed off to cement unit to ensure floats are holding

f. Wait on cement at least eight (8) hours (cement volumes are based on bit size, plus 100% excess for open-hole section. Actual cement volumes will be based on fluid caliper hole volume, plus 25% excess)

g. If cement was not circulated to surface, additional cement bond logging may be required and it may be necessary to perform a top out operation using a 1" pipe to place up to 200 sks of standard cement.

17. After waiting at least 8 hours for cement to set, release the 20" surface casing and lift the stack to make a rough cut on the 20" surface casing. Nipple down the bell nipple, flow line, and BOP. Cut the conductor and make a final cut on the 20" casing. Weld a temporary flange to the 20" casing. Re-install the BOP. Nipple up the bell nipple with flow line and riser pipe to the top of the BOP and test. Pressure test and function test the BOP.

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

Casing and Cementing – 20" Section

CASING						
Hole Size	**Wt./ft.**	**Grade**	**Connection**	**Top Set**	**Bottom Set**	**Length**
26	133	K55	BTC	0'	2,100'	2,100'

CASING DETAILS			
ID:	18.73 inches	**Internal Yield Pressure:**	3,060
Drift:	18.54 inches	**Pipe Body Strength:**	2,125,000 lbs
Coupling OD:	21 inches	**Joint Strength:**	1,453,000 lbs.
Collapse:	1,500	**Capacity:**	0.3408 bbl/ft

Float Equipment & Accessories				
Item	**Model**	**Depth**	**Qty**	**Remarks**
Float Collar	HOWCO	2,060	1	
Shoe	HOWCO	2,100'	1	
Centralizers	HOWCO		15	2 on float joint, and 1 every 3rd joint to surface
Stop ring		2,059'	1	

Cement	
Spacer:	20 bbl gel spacer with red dye
Type:	EconoCem HLC & Halcem C (2850 sks total)

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

17.5" FIRST INTERMEDIATE INTERVAL: 2,100' – 3,100'

Objective: Drill a 17.5" hole to planned TD of 3,100' and set 13.375" intermediate casing. Casing will be set to cover interval of anticipated wellbore instability within the Rustler Formation geologic strata.

Notes: Notify NMOCD – Hobbs District Office 24 hours prior to running and cementing production-casing string.

Procedure:

1. RU mud loggers
2. Make up suitable BHA and trip in the hole to the float collar. Drill out the float collar and approximately 30' of cement in the shoe track joint.
3. Trip in hole with a 17.5" bit and BHA which includes a straight-hole motor. Pressure test the 20" surface casing to 1,000 psi for at least 30 minutes and record the test on a chart recorder. Drill the remainder of the shoe track cement and float shoe. Drill 10 feet of formation and perform a Formation Integrity Test (FIT) to 100 psi for 30 minutes.
4. Continue drilling an 17.5" hole to approximately 3,100', maintaining a low fluid loss mud system as the developed mud program.
5. Move in and rig up casing crew and run centralized 13.375", 54.5 #/ft. casing to 3,100' from 0' to 3,100'
6. Run two bow spring centralizers on the float joint (1 in center of joint on a stop ring and 1 on collar) and one centralizer per every third joint at the collars back to surface. The float joint will consist of a float shoe, one joint of casing, and a float collar. Circulate and condition the mud for cementing in three stages.
7. Dimensional data and minimum performance properties of the production casing are presented on page 10.
8. Cement the 13.375" intermediate casing back to the surface in the following three stages:
   a. Establish circulation and conditions the mud for optimum cementing conditions. Pump a freshwater spacer followed by a 20 bbl gel spacer w/ red dye designed for the rheology of the drilling fluid and lead cement. Pump 1185 sks EconoCem and 495 sks HalCem C and flush with 2% KCl water according to the final cementing plan.
   b. If cement was not circulated to surface, additional cement bond logging may be required and it may be necessary to perform a top out operation using a 1" pipe to place up to 200 sks of standard cement.
9. After waiting at least 8 hours for cement to set, release the 13.375" casing and lift the stack to make a rough cut on the intermediate casing. Nipple down the bell nipple, flow line, and BOP. If necessary, perform a top out operation using a 1" pipe to place up to 200 sks of standard cement. Cut the conductor and make a final cut on the casing. Weld a temporary flange to the 13.375" casing. Re-install the BOP. Nipple up the bell nipple with flow line and riser pipe to the top of the BOP and test. Pressure test and function test the BOP.

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

Casing and Cementing – 13.375" Section

CASING						
Hole Size	**Wt./ft.**	**Grade**	**Connection**	**Top Set**	**Bottom Set**	**Length**
17.5	54.5	HPL80	BTC	0'	3,100'	3,100'

CASING DETAILS			
ID:	TBD	**Internal Yield Pressure:**	TBD
Drift:	TBD	**Pipe Body Strength:**	TBD
Coupling OD:	TBD	**Joint Strength:**	TBD
Collapse:	TBD	**Capacity:**	TBD

Float Equipment & Accessories				
Item	**Model**	**Depth**	**Qty**	**Remarks**
Float Collar	HOWCO	3,060'	1	
Float Shoe	HOWCO	3,100'	1	
Centralizers	HOWCO		-	2 on float joint and 1 every 3rd joint to surface
Stop ring	HOWCO	3,059	1	

Cement	
Spacer:	20 bbls gel spacer with red dye
Type:	EconoCem (1185 sks) & HalCem C (495 sks)

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

9.625" SECOND INTERMEDIATE INTERVAL: 3,100' – 5,110'

Objective: Drill a 12.25" hole to planned TD of 5,110' and set 9.625" casing. Note that open-hole geophysical logs, from original SCM AGI #1 location, are available and are to be reviewed prior to drilling intermediate interval. Primary objective is to isolate, via casing, the interval of the Capitan Reef.

Notes: Notify NMOCD – Hobbs District Office 24 hours prior to running and cementing production-casing string.

Procedure:

1. RU mud loggers

2. Make up 12.25" PDC drill bit and trip in the hole to the float collar. Drill out the float collar and approximately 30' of cement in the shoe track joint.

3. Trip in hole with a 12.25" bit and BHA which includes a straight-hole motor. Pressure test the 13.375" intermediate casing to 1,000 psi for at least 30 minutes and record the test on a chart recorder. Drill the remainder of the shoe track cement and float shoe. Drill 10 feet of formation and perform a Formation Integrity Test (FIT) to 100 psi for 30 minutes.

4. Continue drilling an 12.25" hole to approximately 5,110', maintaining a low fluid loss mud system as per developed mud program.

5. Move in and rig up casing crew and run centralized 9.625", 40 #/ft. casing to 5,110' as follows:

   a. 9.625", 40 #/ft., L80, BTC from 0' to 5,110'
   b. DV Tool will be installed at approximately 3,000'

6. Run two bow spring centralizers on the float joint (1 in center of joint on a stop ring and 1 on collar) and one centralizer per every third joint at the collars back to surface. The float joint will consist of a float shoe, one joint of casing, and a float collar. A DV tool will be positioned in the casing string at approximately 3,000' for the first stage. Circulate and condition the mud for cementing in two stages.

7. Dimensional data and minimum performance properties of the production casing are presented on page 10.

8. Cement the 9.625" casing back to the surface in the following three stages:

   a. **Stage 1** – Establish circulation and conditions the mud for optimum cementing conditions. Pump a freshwater spacer followed by a 20 bbl gel spacer w/ red dye designed for the rheology of the drilling fluid and lead cement. Pump 135.5 bbls Halliburton NeoCem (11.0 ppg) and 195 sks VersaCem (14.5 ppg) and flush with 2% KCl water according to the final cementing plan.

b. **Stage 2** – Drop stage collar opening plug and wait for it to reach stage collar. Pressure casing to open stage collar. Establish circulation through the stage collar and continue circulating for four (4) hours. Pump a gel spacer with red dye followed by approximately 189.4 bbls of NeoCem (11.5 ppg) and 195 sks HalCem C (14.8 ppg).

c. If cement was not circulated to surface, additional cement bond logging may be required and it may be necessary to perform a top out operation using a 1" pipe to place up to 200 sks of standard cement.

9. After waiting at least 8 hours for cement to set, release the 9.625" casing and lift the stack to make a rough cut on the intermediate casing. Nipple down the bell nipple, flow line, and BOP. If necessary, perform a top out operation using a 1" pipe to place up to 200 sks of standard cement. Cut the conductor and make a final cut on the casing. Weld a temporary flange to the casing. Re-install the BOP. Nipple up the bell nipple with flow line and riser pipe to the top of the BOP and test. Pressure test and function test the BOP.

SALT CREEK MIDSTREAM

GEOLEX INCORPORATED

Casing and Cementing – 9.625" Section

CASING						
Hole Size	**Wt./ft.**	**Grade**	**Connection**	**Top Set**	**Bottom Set**	**Length**
12.25	40	L80	BTC	0'	5,110'	5,110'
CASING DETAILS						
ID:	9.625 inches			**Internal Yield Pressure:**	5,750	
Drift:	8.679 inches			**Pipe Body Strength:**	916,000 lbs	
Coupling OD:	-			**Joint Strength:**	-	
Collapse:	3,090			**Capacity:**	0.0758 bbls/ft.	

Float Equipment & Accessories				
Item	**Model**	**Depth**	**Qty**	**Remarks**
Float Collar	HOWCO	5,070'	1	
Float Shoe	HOWCO	5,110'	1	
Centralizers	HOWCO		-	2 on float joint and 1 every 3rd joint to surface
Stop ring	HOWCO	5,069'	1	
DV Tool	-	3,000'	1	

Cement – Stage 1	
Spacer:	20 bbls gel spacer with red dye
Type:	NeoCem (135.5 bbls) and VersaCem (195 sks)
Cement – Stage 2	
Spacer:	20 bbls gel spacer with red dye
Type:	NeoCem (189.4 bbls) and HalCem C (195 sks)

8.75" PRODUCTION INTERVAL: 5,110' – 7,040'

Objective: Drill a 8-3/4" hole to planned TD of 7,040' and set 7" casing. Open-hole geophysical logs are currently available from prior AGI #1 location. Collect sidewall cores on cap rock, top of injection interval, and various sections of the open-hole interval.

Notes: Notify NMOCD – Hobbs District Office 24 hours prior to running and cementing production-casing string.

Procedure:

1. RU mud loggers

2. Make up 8.75" PDC drill bit and trip in the hole to the float collar. Drill out the float collar and approximately 30' of cement in the shoe track joint.

3. Trip in hole with a 8.75" bit and BHA which includes a straight-hole motor. Pressure test the 9.625" surface casing to 1,000 psi for at least 30 minutes and record the test on a chart recorder. Drill the remainder of the shoe track cement and float shoe. Drill 10 feet of formation and perform a Formation Integrity Test (FIT) to 100 psi for 30 minutes.

4. Continue drilling an 8.75" hole to approximately 7,040', maintaining a low fluid loss mud system as per attached mud program.

5. Move in and rig up casing crew and run centralized 7", 26 #/ft. casing to 7,040' as follows:

    a. 7", 26 #/ft., HP-P110, Rattler, from 5,480' – 7,040'
    b. 7", 26 #/ft., SM2535 (CRA), VAMTOP, from 5,180' – 5,480'
    c. 7", 26 #/ft., HP-P110, Rattler from 0' – 5,180'

6. Run two bow spring centralizers on the float joint (1 in center of joint on a stop ring and 1 on collar) and one centralizer per every third joint at the collars back to surface. The float joint will consist of a float shoe, one joint of casing, and a float collar. A DV tool will be positioned in the casing string at approximately 5,480' for the first stage and another DV tool at 5,180' for the second stage cement. Circulate and condition the mud for cementing in three stages.

7. Dimensional data and minimum performance properties of the production casing are presented on page 10.

8. Cement the 7" casing back to the surface in the following three stages:

    a. **Stage 1** – Establish circulation and conditions the mud for optimum cementing conditions. Pump a freshwater spacer followed by a 20 bbl gel spacer w/ red dye designed for the rheology of the drilling fluid and lead cement. Pump 54.9 bbls Halliburton NeoCem (13.2 ppg) and flush with 2% KCl water according to the final cementing plan.

    b. **Stage 2** – Drop stage collar opening plug and wait for it to reach stage collar. Pressure casing to open stage collar. Establish circulation through the stage collar and continue circulating for four (4) hours. Pump a gel spacer with red dye followed by approximately 10 bbls of Halliburton WellLock Resin and two (2) bbls solvent cleanup. Drop stage collar wiper/closing plug and displace with 2% KCl water. Bump wiper/closing plug and close stage collar with required pressure over final circulating pressure. Release pressure and assure that stage collar is holding.

c. **Stage 3** – Drop stage collar opening plug and wait for it to reach stage collar. Pressure casing to open stage tool and continue circulating for four (4) hours. Pump 20 bbl Gel spacer with red dye. Pump 149 bbls NeoCem (11.0 ppg) followed by 50 sks HALCEM "C" (14.8 ppg) according to the final cementing plan. Drop stage collar wiper/closing plug and flush with 2% KCl water.

d. If cement was not circulated to surface, additional cement bond logging may be required and it may be necessary to perform a top out operation using a 1" pipe to place up to 200 sks of standard cement.

9. After waiting on cement, ND BOP and cut off 7" casing. NU wellhead.

10. RD and release drilling rig and all associated equipment.

SALT CREEK MIDSTREAM

GEOLEX® INCORPORATED

Casing and Cementing – 7” Section

CASING						
Hole Size	**Wt./ft.**	**Grade**	**Connection**	**Top Set**	**Bottom Set**	**Length**
7”	26.0	HP-P110	Rattler	0'	5,110’	5,110’
7”	26.0	SM2535	VAMTOP	5,180’	5,480’	300’
7”	26.0	HP-P110	Rattler	5,480’	7,040’	1,560’

CASING DETAILS			
ID:	TBD	**Internal Yield Pressure:**	TBD
Drift:	TBD	**Pipe Body Strength:**	TBD
Coupling OD:	TBD	**Joint Strength:**	TBD
Collapse:	TBD	**Capacity:**	TBD

Float Equipment & Accessories				
Item	**Model**	**Depth**	**Qty**	**Remarks**
Float Collar	HOWCO	-	1	
Float Shoe	HOWCO	7,040’	1	
Centralizers	HOWCO	-	-	2 on float joint and 1 every 3rd joint to surface
Stop ring	HOWCO	-	1	
DV Tool #1	HOWCO	5,180’	1	
DV Tool #2	HOWCO	5,480’	1	

Cement – Stage 1	
Spacer:	20 bbls gel spacer with red dye
Type:	NeoCem (54.9 bbls) – 13.2 ppg
Cement – Stage 2	
Spacer:	20 bbls gel spacer with red dye
Type:	Halliburton WellLock Resin (10 bbls)
Cement – Stage 3	
Spacer:	20 bbls gel spacer with red dye
Type:	NeoCem (149 bbls) & HalCem C (50 sks)

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 240347

CONDITIONS

Operator:	
Salt Creek Midstream, LLC 5775 N Sam Houston Pkwy W Houston, TX 77086	OGRID: 373554
	Action Number: 240347
	Action Type: [C-101] Drilling Non-Federal/Indian (APD)

CONDITIONS

Created By	Condition	Condition Date
pkautz	Notify OCD 24 hours prior to casing & cement	8/17/2023
pkautz	Once the well is spud, to prevent ground water contamination through whole or partial conduits from the surface, the operator shall drill without interruption through the fresh water zone or zones and shall immediately set in cement the water protection string	8/17/2023
pkautz	Oil base muds are not to be used until fresh water zones are cased and cemented providing isolation from the oil or diesel. This includes synthetic oils. Oil based mud, drilling fluids and solids must be contained in a steel closed loop system	8/17/2023
pkautz	CEMENT MUST CIRCULATE ON ALL STRINGS	8/17/2023
pkautz	In addition to the requirements of the APD, operator shall complete the conditions contained in the UIC permit including logging (CBL for liner; mud logging, etc.), well testing, and reporting as stipulated.	8/17/2023
pkautz	IF ON ANY STRING CEMENT DOES NOT CIRCULATE, A RCBL MUST BE RUN ON THAT STRING OF CASING.	8/17/2023

Submit To Appropriate District Office
Two Copies
District I
1625 N. French Dr., Hobbs, NM 88240
District II
811 S. First St., Artesia, NM 88210
District III
1000 Rio Brazos Rd., Aztec, NM 87410
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-105
Revised April 3, 2017

1. WELL API NO. 30-025-51865

2. Type of Lease ☐ STATE ■ FEE ☐ FED/INDIAN

3. State Oil & Gas Lease No.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG

4. Reason for filing:

■ **COMPLETION REPORT** (Fill in boxes #1 through #31 for State and Fee wells only)

☐ **C-144 CLOSURE ATTACHMENT** (Fill in boxes #1 through #9, #15 Date Rig Released and #32 and/or #33; attach this and the plat to the C-144 closure report in accordance with 19.15.17.13.K NMAC)

5. Lease Name or Unit Agreement Name SALT CREEK AGI

6. Well Number 3

7. Type of Completion:
■ NEW WELL ☐ WORKOVER ☐ DEEPENING ☐ PLUGBACK ☐ DIFFERENT RESERVOIR ☐ OTHER

8. Name of Operator Northwind Midstream Partners, LLC

9. OGRID 331501

10. Address of Operator 825 Town and Country Ln; Bldg. 5, Suite 700
Houston, TX 77024

11. Pool name or Wildcat AGI; Delaware

12. Location	Unit Ltr	Section	Township	Range	Lot	Feet from the	N/S Line	Feet from the	E/W Line	County
Surface:	L	21	26S	36E		2,329	SOUTH	278	WEST	LEA
BH:	L	21	26S	36E		2,329	SOUTH	278	WEST	LEA

13. Date Spudded 9/12/23
14. Date T.D. Reached 10/11/23
15. Date Rig Released 10/26/23
16. Date Completed (Ready to Produce) 11/13/23
17. Elevations (DF and RKB, RT, GR, etc.) 2,926′ (GR)

18. Total Measured Depth of Well 7,050′
19. Plug Back Measured Depth
20. Was Directional Survey Made? YES
21. Type Electric and Other Logs Run GR, TCOM, SONIC, XRMI

22. Producing Interval(s), of this completion - Top, Bottom, Name
Perforated injection interval from 5,610 ft. to 7,000 ft. (MD) -- Bell Canyon, Cherry Canyon

23. **CASING RECORD** (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20″	133	1,277′	26″	1,565 sks	
16″	75	2,550′	18.5″	2,610 sks	
13.375″	61, 68	3,163′	17.5″	940 sks	
9.625″	40	5,100′	12.25″	1,320 sks	
7″	29	7,050′	8.75″	938 sks & 16.1 bbls WellLock	

24. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

25. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
3.5″	5,601′	5,567′

26. Perforation record (interval, size, and number)
Multiple from 5,610′ to 7,000′
(See attached well schematic)

27. ACID, SHOT, FRACTURE, CEMENT, SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
5,610′-7,000′	40,000 gal HCl with 5,280 diverter pods

28. **PRODUCTION**

Date First Production	Production Method *(Flowing, gas lift, pumping - Size and type pump)*	Well Status *(Prod. or Shut-in)*

Date of Test	Hours Tested	Choke Size	Prod'n For Test Period	Oil - Bbl	Gas - MCF	Water - Bbl.	Gas - Oil Ratio

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate	Oil - Bbl.	Gas - MCF	Water - Bbl.	Oil Gravity - API - *(Corr.)*

29. Disposition of Gas *(Sold, used for fuel, vented, etc.)*
30. Test Witnessed By

31. List Attachments
As-built well schematic, directional survey

32. If a temporary pit was used at the well, attach a plat with the location of the temporary pit.
33. Rig Release Date: 10/26/2023

34. If an on-site burial was used at the well, report the exact location of the on-site burial:
Latitude Longitude NAD83

I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief

Signature
Printed Name David A. White
Title Consultant to Northwind
Date 11/30/23
E-mail Address dwhite@geolex.com

INSTRUCTIONS

This form is to be filed with the appropriate District Office of the Division not later than 20 days after the completion of any newly-drilled or deepened well and not later than 60 days after completion of closure. When submitted as a completion report, this shall be accompanied by one copy of all electrical and radio-activity logs run on the well and a summary of all special tests conducted, including drill stem tests. All depths reported shall be measured depths. In the case of directionally drilled wells, true vertical depths shall also be reported. For multiple completions, items 11, 12 and 26-31 shall be reported for each zone.

INDICATE FORMATION TOPS IN CONFORMANCE WITH GEOGRAPHICAL SECTION OF STATE

Southeastern New Mexico		Northwestern New Mexico	
T. Anhy	T. Canyon	T. Ojo Alamo	T. Penn A"
T. Salt 2,524′	T. Strawn	T. Kirtland	T. Penn. "B"
B. Salt	T. Atoka	T. Fruitland	T. Penn. "C"
T. Yates 2,860′	T. Miss	T. Pictured Cliffs	T. Penn. "D"
T. 7 Rivers 3,139′	T. Devonian	T. Cliff House	T. Leadville
T. Queen	T. Silurian	T. Menefee	T. Madison
T. Grayburg	T. Montoya	T. Point Lookout	T. Elbert
T. San Andres	T. Simpson	T. Mancos	T. McCracken
T. Glorieta	T. McKee	T. Gallup	T. Ignacio Otzte
T. Paddock	T. Ellenburger	Base Greenhorn	T.Granite
T. Blinebry	T. Gr. Wash	T. Dakota	
T.Tubb	T. Delaware Sand 5,510′	T. Morrison	
T. Drinkard	T. Bone Springs	T.Todilto	
T. Abo	T.	T. Entrada	
T. Wolfcamp	T.	T. Wingate	
T. Penn	T.	T. Chinle	
T. Cisco (Bough C)	T.	T. Permian	

OIL OR GAS SANDS OR ZONES

No. 1, from……………………to…………………………. No. 3, from……………………to……………………….
No. 2, from……………………to………………………… No. 4, from……………………to……………………….

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from………………………………to……………………………………feet…………………………………
No. 2, from………………………………to……………………………………feet…………………………………
No. 3, from………………………………to……………………………………feet…………………………………

LITHOLOGY RECORD (Attach additional sheet if necessary)

From	To	Thickness In Feet	Lithology	From	To	Thickness In Feet	Lithology
0′	790′	790′	SAND, SILT				
790′	2,090′	1,300′	SILT, ANHYDRITE, DOLOMITE				
2090′	2524′	434′	SILT, SAND, ANHYDRITE				
2524	2860	336′	ANHYDRITE, DOLOMITE, SALT				
2860′	3139′	279′	ANHYDRITE, DOLOMITE, SAND				
3139′	3764′	625′	LIME, DOLOMITE, SAND				
3764′	5510	1746′	LIME, DOLOMITE				
5510′	6012′	502′	SAND, LIME				
6012′	7000′	502′	SAND, SILT, SHALE, LIME				

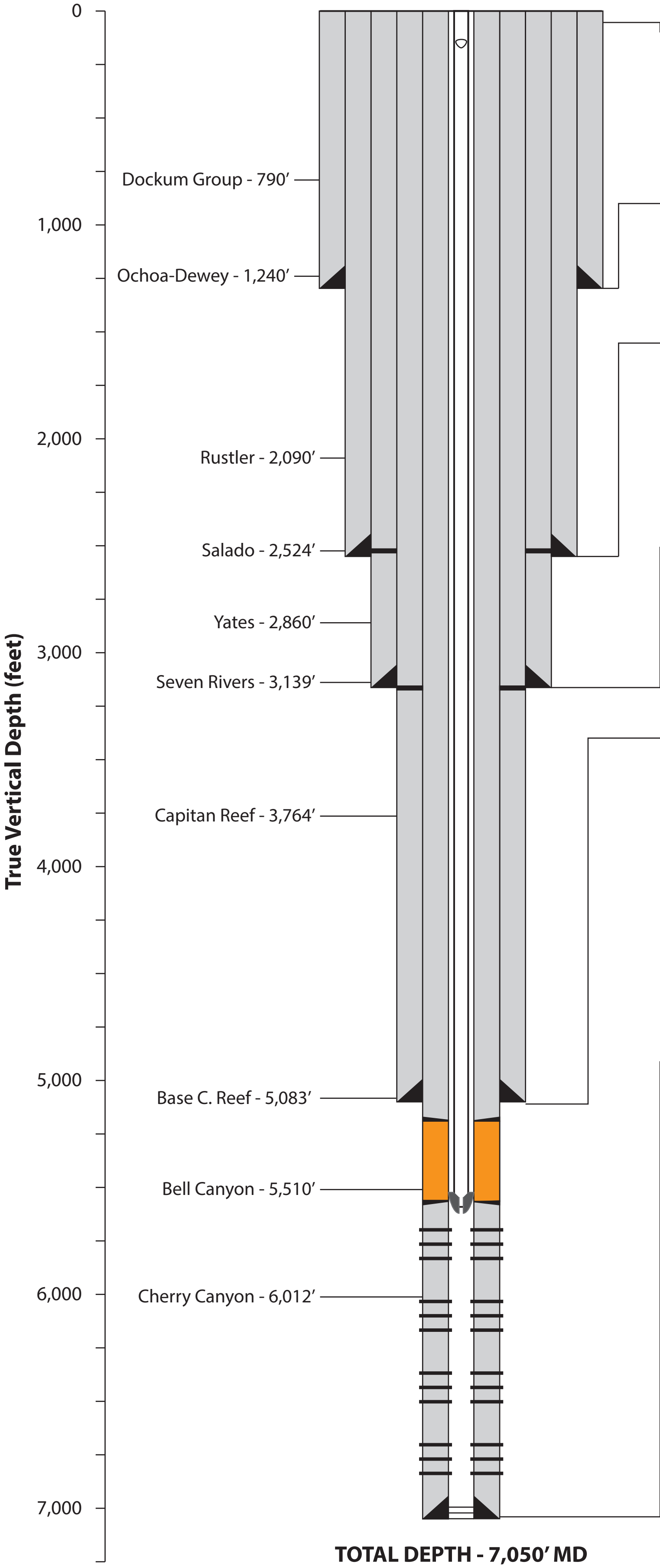
ATTACHMENT 1

SALT CREEK AGI #3
AS-BUILT WELL SCHEMATIC

SALT CREEK AGI #3
AS-BUILT WELL SCHEMATIC

NORTHWIND MIDSTREAM

GEOLEX INCORPORATED



TOTAL DEPTH - 7,050' MD

30" CONDUCTOR PIPE to 80 ft.

20" SURFACE CASING to 1,277 ft. — 26" OH

20", 133 #/ft., K55, BTC from 0' to 1,277'

Cement to Surface

Lead: 465 sks 13.5 ppg ExtendaCem
Tail: 1,100 sks 14.8 ppg HalCem

SSSV @ 172'

16" INTERMEDIATE CASING to 2,550 ft. — 18.5" OH

16", 75 #/ft., J55, BTC from 0' to 2,550'

Cement to Surface

Lead: 310 sks 12.5 ppg EconoCem
Tail: 2,300 sks 13.5 ppg ExtendaCem

13 3/8" INTERMEDIATE CASING to 3,163 ft. — 17.5" OH

13 3/8", 61 #/ft., J55, BTC from 0' to 164'
13 3/8", 68 #/ft., L80, BTC from 164' to 205'
13 3/8", 61 #/ft., J55, BTC from 205' to 3,163'

Cement to Surface

Lead: 410 sks 12.9 ppg EconoCem
Tail: 530 sks 14.8 ppg HalCem Neat

DV Tool @ 2,533'

9 5/8" INTERMEDIATE CASING to 5,100 ft. — 12.25" OH

9 5/8", 40#/ft., HCL80, BTC from 0' to 5,100'

Cement to Surface

Stage 1
Lead: 420 sks 12.5 ppg NeoCem
Tail: 200 sks 14.5 ppg VersaCem

Stage 2
Lead: 550 sks 12.5 ppg NeoCem
Tail: 150 sks 14.5 ppg Halcem

ECP/DV Tool @ 3,174'

7" PRODUCTION CASING to 7,050 ft. — 8.75" OH

7", 29 #/ft., HP-P110, Rattler from 0' to 5,190'
7", 29 #/ft., VM28110 VAMTOP from 5,190' to 5,379'
7", 29 #/ft., SM2535, VAMTOP from 5,379' to 5,582'
7", 29 #/ft., HP-P110, Rattler from 5,582' to 7,050'

Cement to Surface

Stage 1
Lead: 210 sks 13.2 ppg EconoCem

Stage 2
Lead: 16.1 bbl 10.0 ppg WellLock™ Resin

Stage 3
Lead: 375 sks 14.8 ppg HalCem
Tail: 353 sks 12.5 ppg NeoCem

DV Tool @ approx. 5,190' and 5,581'

TUBING AND EQUIPMENT

3-1/2", 9.3 #/ft., L80 BENOIT BTS-8 from 0' to 5,227'
3-1/2", 9.3 #/ft., G3/SM2535, VAMTOP from 5,227' to 5,601'

Halliburton Retrievable SSSV set @ 172'
Halliburton ROC P-T Gauge set above packer @ 5,554'
Halliburton BWD Nickel-Alloy Permanent Packer @ approx. 5,567'

Annulus Fluid: Diesel with corrosion inhibitors and biocide

PERFORATIONS (six radial shots per foot)

5610-5650	6010-6030	6325-6365	6715-6735
5660-5680	6045-6085	6390-6410	6750-6790
5690-5710	6085-6125	6412-6452	6840-6880
5730-5750	6125-6165	6455-6495	6880-6920
5750-5790	6165-6205	6495-6535	6920-6960
5795-5815	6205-6245	6585-6605	6960-7000
5845-5865	6245-6285	6605-6625	
5865-5905	6285-6325	6640-6680	

Date prepared: 11/29/23

ATTACHMENT 2

SALT CREEK AGI #3
DIRECTIONAL SURVEY

INVICTUS

Job:	SALT CREEK AGI No. 003 (Job #20026)
Total Correction:	6.16°, This value was ADDED to the magnetic azimuth values sent by the tool to arrive at the Survey Azimuth values shown below.
Job Notes:	Akita 518 SALT CREEK AGI No. 003 Corrected to ground level and true north
Created On:	10 Sep 2023 at 18:34:10
File Contents:	121 Total Surveys in File. 59 are tagged as Accepted

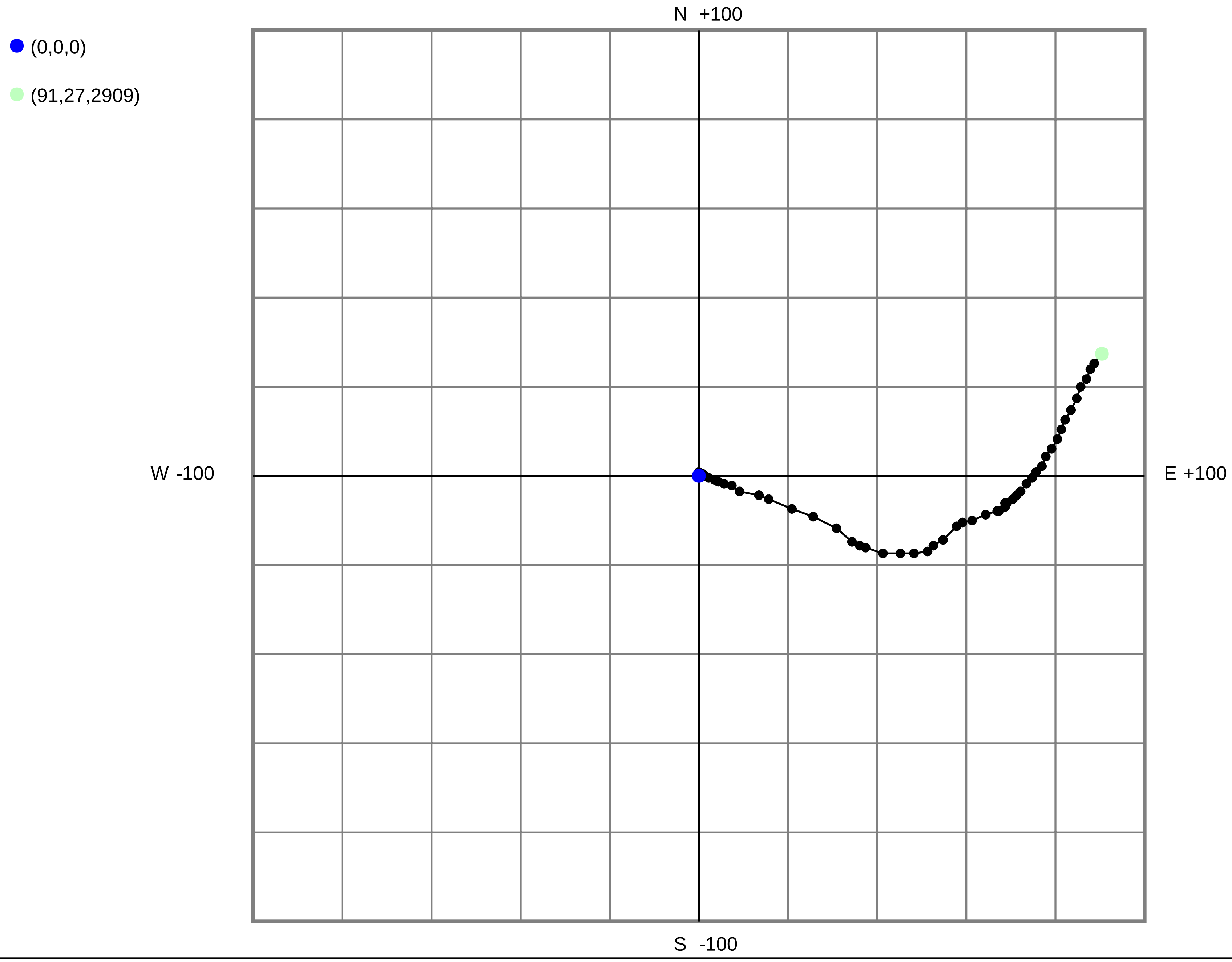
The Vertical Depth and Departure values below were calculated using the Minimum Curvature Model. This information is intended for reference purposes ONLY.It is NOT intended to replace professional oversight or sound judgement. For more detail on the data and algorithms used to compute this information, contact INVICTUS TOOLS.

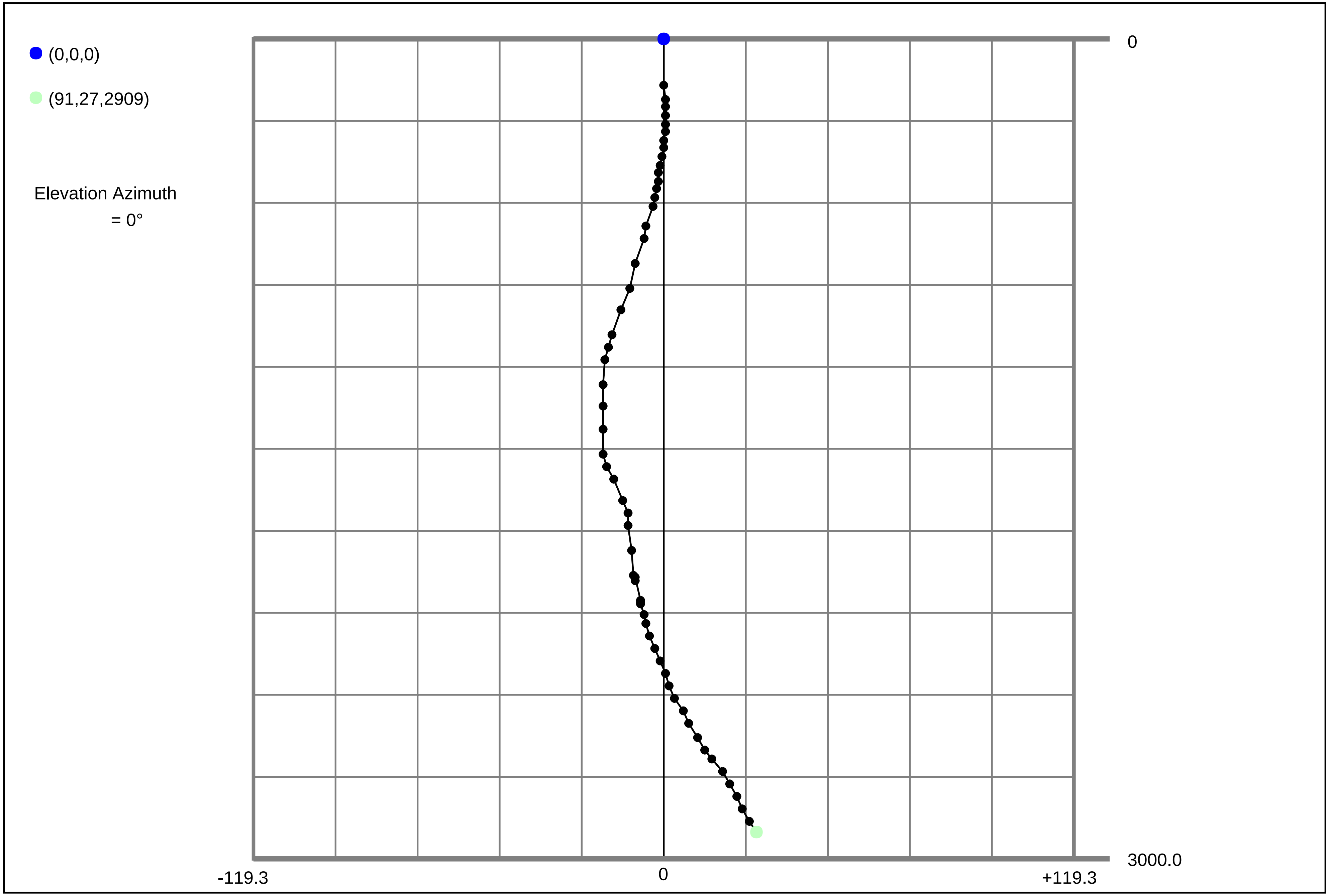
REPORT OF ALL ACCEPTED SURVEYS SORTED BY SURVEY DEPTH

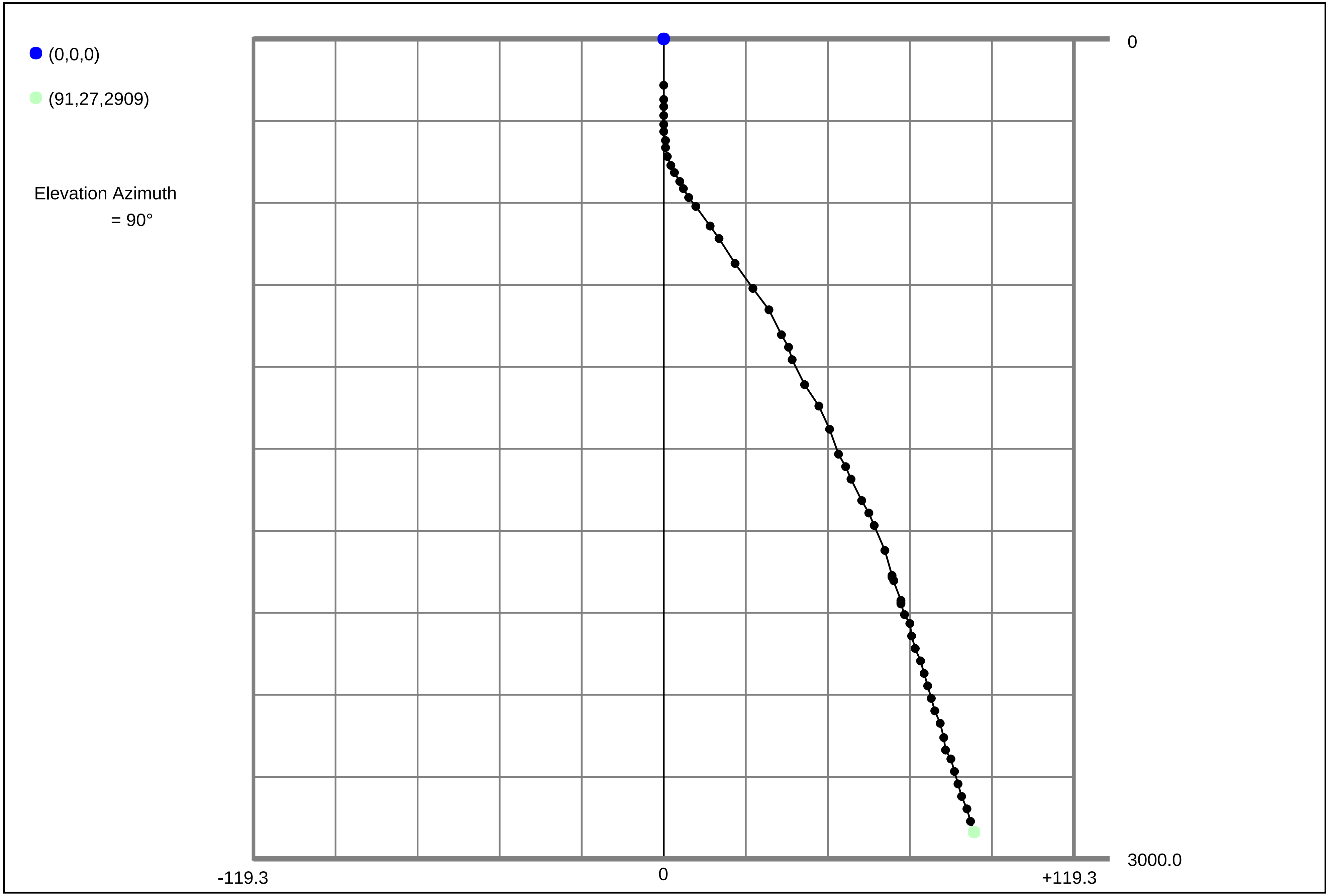
SURVEY DEPTH	SURVEY ANGLE	SURVEY AZIMUTH	VERT DEPTH	N-S DEPART	E-W DEPART	#	SURVEY TYPE	SURVEY DATE & TIME
0.0	0.00	0.00	0.00	0.0	0.0	0	Tie-In	10 Sep 2023 18:34
170.0	0.30	6.16	170.00	0.4	0.0	2	Survey	12 Sep 2023 23:39
222.0	0.20	24.16	222.00	0.7	0.1	3	Survey	13 Sep 2023 00:32
255.0	0.10	233.16	255.00	0.7	0.1	4	Survey	13 Sep 2023 01:23
284.0	0.00	267.16	284.00	0.7	0.1	5	Survey	13 Sep 2023 02:00
314.0	0.20	70.16	314.00	0.7	0.1	6	Survey	13 Sep 2023 02:30
344.0	0.80	115.16	344.00	0.6	0.4	7	Survey	13 Sep 2023 02:56
374.0	0.80	113.16	373.99	0.5	0.7	8	Survey	13 Sep 2023 03:24
404.0	1.10	135.16	403.99	0.2	1.1	9	Survey	13 Sep 2023 03:51

SURVEY DEPTH	SURVEY ANGLE	SURVEY AZIMUTH	VERT DEPTH	N-S DEPART	E-W DEPART	#	SURVEY TYPE	SURVEY DATE & TIME
434.0	1.60	134.16	433.98	-0.3	1.6	10	Survey	13 Sep 2023 04:32
464.0	2.30	110.16	463.96	-0.8	2.5	11	Survey	13 Sep 2023 05:04
494.0	2.50	110.16	493.94	-1.3	3.7	13	Survey	13 Sep 2023 06:02
524.0	2.60	114.16	523.91	-1.8	4.9	14	Survey	13 Sep 2023 06:46
554.0	2.90	110.16	553.87	-2.3	6.3	15	Survey	13 Sep 2023 07:21
583.0	3.60	110.16	582.83	-2.9	7.8	16	Survey	13 Sep 2023 08:01
614.0	3.50	109.16	613.77	-3.5	9.6	17	Survey	13 Sep 2023 09:17
690.0	3.10	106.16	689.64	-4.8	13.8	18	Survey	13 Sep 2023 10:30
734.0	3.70	113.16	733.56	-5.7	16.2	19	Survey	13 Sep 2023 11:31
821.0	3.40	114.16	820.40	-7.9	21.2	21	Survey	13 Sep 2023 15:03
909.0	3.80	107.16	908.22	-9.8	26.3	22	Survey	13 Sep 2023 18:07
998.0	3.30	131.16	997.06	-12.4	31.1	26	Survey	14 Sep 2023 08:16
1087.0	2.90	118.16	1085.93	-15.1	35.0	28	Survey	14 Sep 2023 11:07
1131.0	2.10	122.16	1129.89	-16.1	36.7	29	Survey	14 Sep 2023 12:25
1175.0	1.60	112.16	1173.86	-16.7	37.9	30	Survey	14 Sep 2023 12:56
1263.0	3.40	97.16	1261.78	-17.5	41.6	34	Survey	14 Sep 2023 19:42
1351.0	1.90	81.16	1349.68	-17.6	45.7	37	Survey	15 Sep 2023 00:09
1430.0	2.40	104.16	1428.63	-17.8	48.6	42	Survey	15 Sep 2023 04:09
1527.0	1.90	54.16	1525.57	-17.4	51.8	44	Survey	15 Sep 2023 06:05
1571.0	3.00	52.16	1569.53	-16.3	53.3	45	Survey	15 Sep 2023 08:56
1616.0	3.10	44.16	1614.46	-14.7	55.1	46	Survey	15 Sep 2023 10:38
1704.0	2.40	47.16	1702.36	-11.7	58.1	48	Survey	15 Sep 2023 13:37
1748.0	2.60	68.16	1746.32	-10.7	59.7	49	Survey	15 Sep 2023 14:52
1792.0	2.60	80.16	1790.27	-10.2	61.6	50	Survey	15 Sep 2023 16:35
1878.0	1.60	73.16	1876.22	-9.5	64.7	52	Survey	15 Sep 2023 20:17
1970.0	1.70	63.16	1968.18	-8.5	67.1	55	Survey	16 Sep 2023 00:29

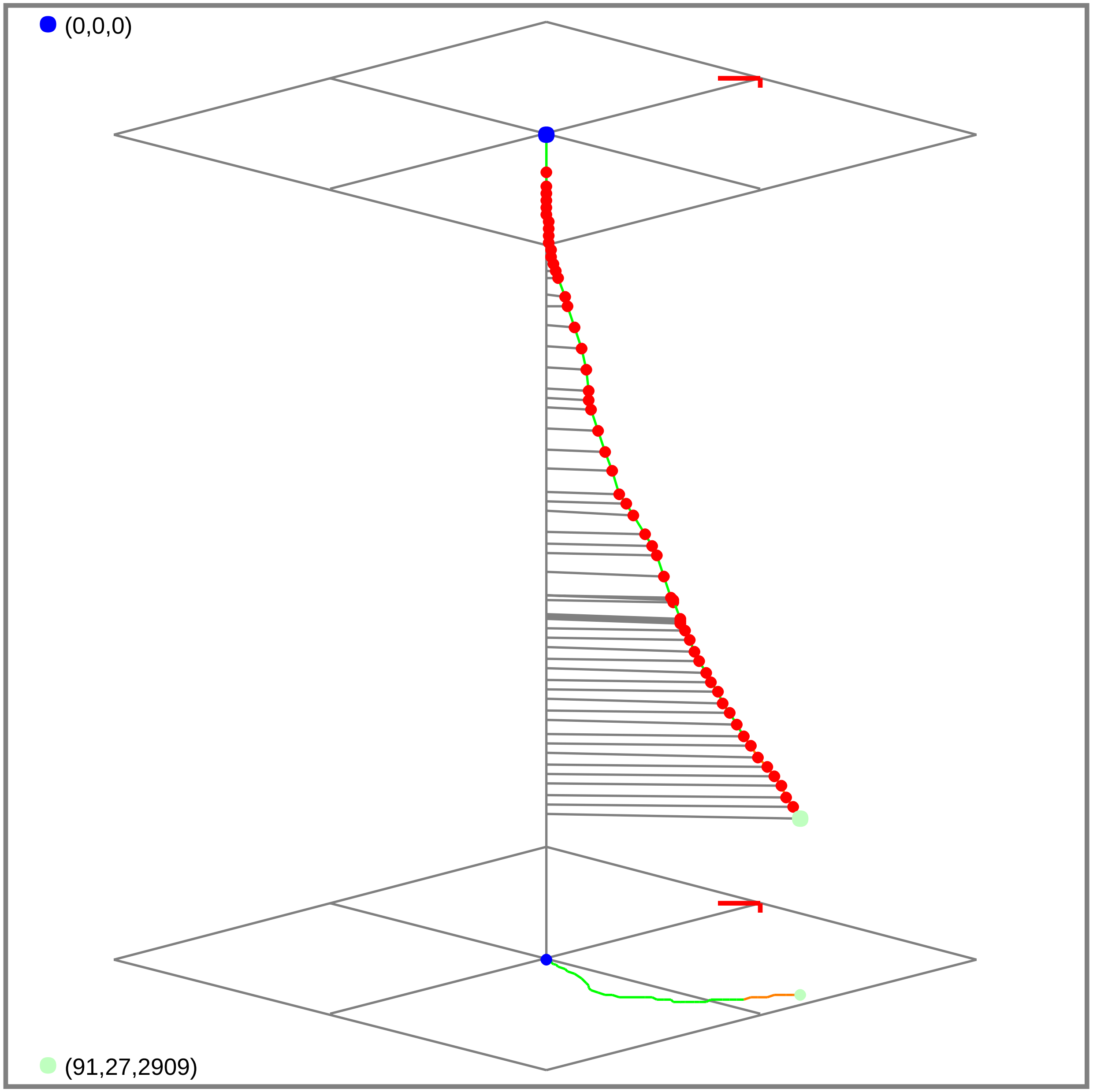
SURVEY DEPTH	SURVEY ANGLE	SURVEY AZIMUTH	VERT DEPTH	N-S DEPART	E-W DEPART	#	SURVEY TYPE	SURVEY DATE & TIME
1994.0	1.70	57.00	1992.17	-8.1	67.8	56	Manual	16 Sep 2023 00:31
1977.0	1.30	77.16	1975.17	-8.3	67.4	75	Survey	22 Sep 2023 07:26
2058.0	1.90	43.16	2056.14	-7.1	69.2	58	Survey	16 Sep 2023 04:33
2066.0	2.30	46.16	2064.14	-6.9	69.4	76	Survey	22 Sep 2023 08:27
2076.0	2.10	43.16	2074.13	-6.7	69.7	59	Survey	16 Sep 2023 05:40
2110.0	1.80	52.16	2108.11	-5.9	70.5	78	Survey	22 Sep 2023 10:57
2154.0	2.00	47.16	2152.09	-4.9	71.6	81	Survey	22 Sep 2023 14:11
2198.0	2.10	42.16	2196.06	-3.8	72.7	82	Survey	22 Sep 2023 17:52
2242.0	2.70	39.16	2240.02	-2.4	73.9	83	Survey	22 Sep 2023 20:48
2287.0	2.40	37.16	2284.97	-0.8	75.2	84	Survey	22 Sep 2023 23:11
2331.0	2.40	31.16	2328.94	0.7	76.2	85	Survey	23 Sep 2023 01:25
2375.0	2.60	33.16	2372.89	2.3	77.2	87	Survey	23 Sep 2023 03:58
2420.0	3.00	31.16	2417.84	4.2	78.4	89	Survey	23 Sep 2023 08:39
2463.0	3.10	31.16	2460.78	6.1	79.6	90	Survey	23 Sep 2023 12:34
2508.0	2.60	32.16	2505.72	8.0	80.7	91	Survey	23 Sep 2023 15:00
2561.0	3.10	22.16	2558.66	10.4	81.9	99	Survey	01 Oct 2023 11:38
2606.0	2.80	23.16	2603.60	12.5	82.8	104	Survey	01 Oct 2023 16:45
2649.0	3.60	25.16	2646.53	14.7	83.8	105	Survey	01 Oct 2023 18:18
2693.0	4.00	24.16	2690.43	17.4	85.0	108	Survey	01 Oct 2023 22:58
2736.0	3.20	25.16	2733.35	19.8	86.1	112	Survey	02 Oct 2023 03:57
2780.0	2.80	31.16	2777.29	21.8	87.2	113	Survey	02 Oct 2023 08:35
2824.0	2.60	31.16	2821.24	23.6	88.3	115	Survey	02 Oct 2023 13:44
2868.0	3.10	34.16	2865.19	25.5	89.5	116	Survey	02 Oct 2023 16:28
2912.0	3.20	33.16	2909.12	27.5	90.8	120	Survey	02 Oct 2023 22:43


(0,0,0)
(91,27,2909)
N +100
W -100
E +100
S -100

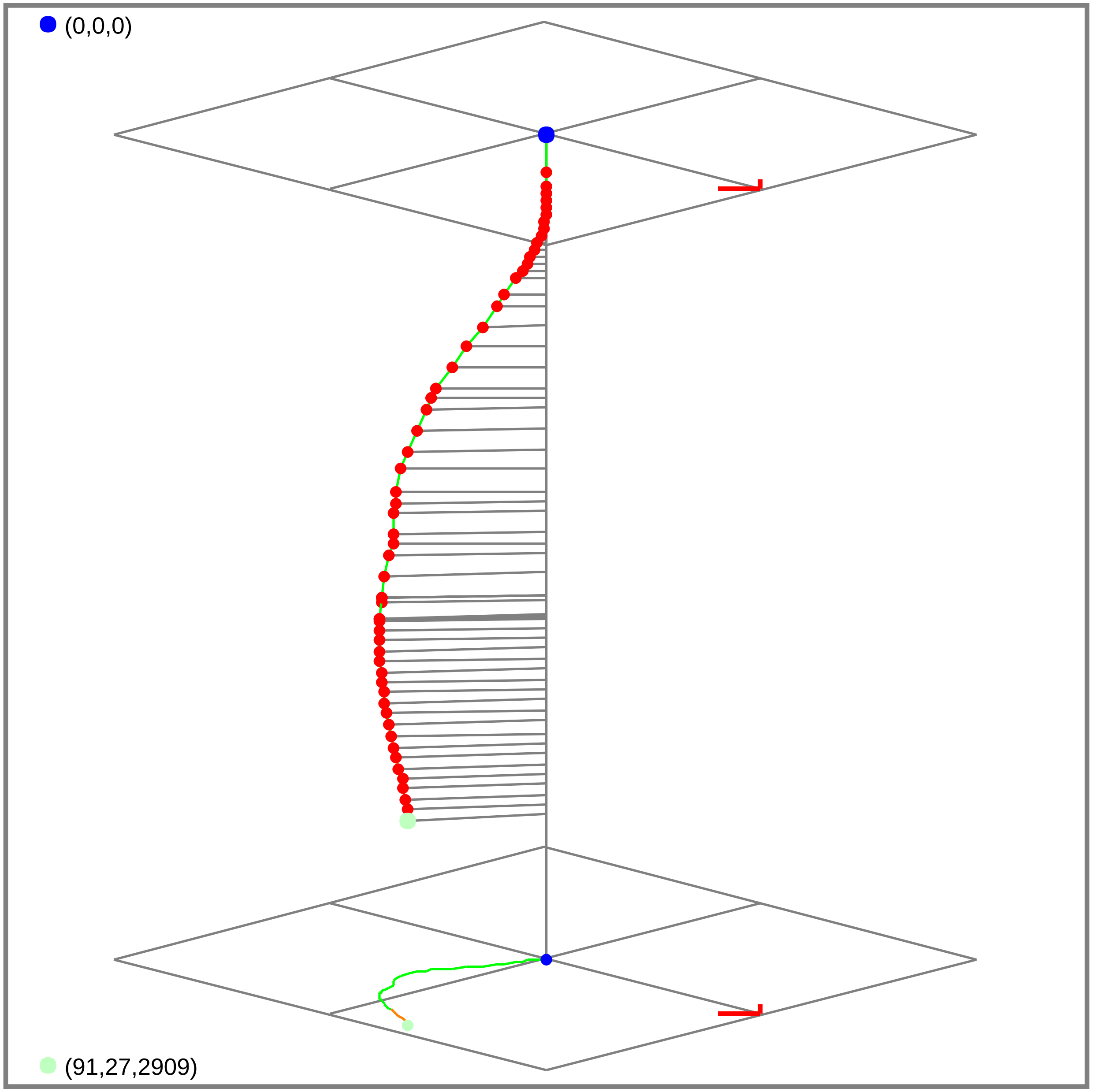

(0,0,0)
(91,27,2909)
Elevation Azimuth
= 0°
0
3000.0
-119.3
0
+119.3

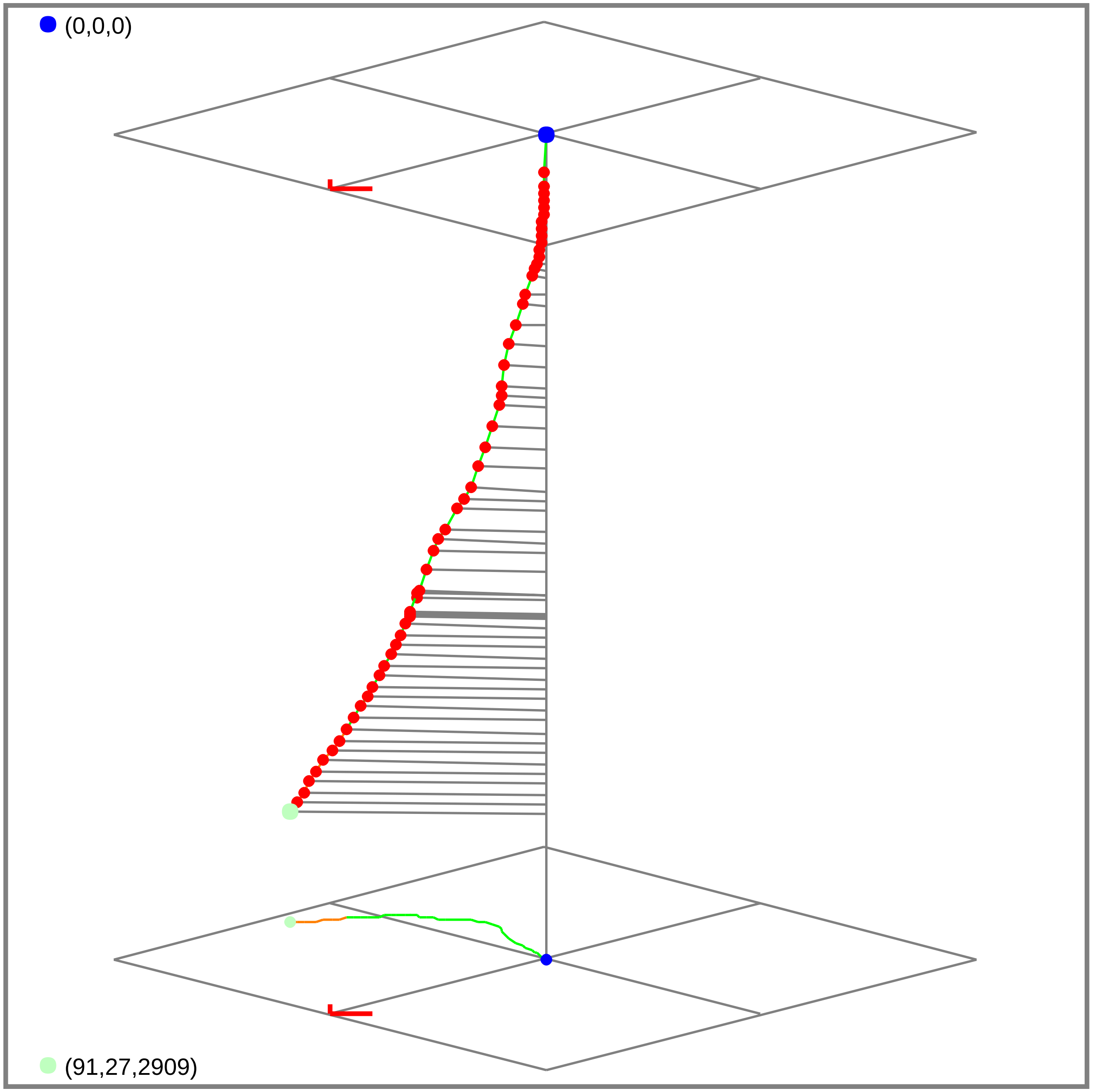


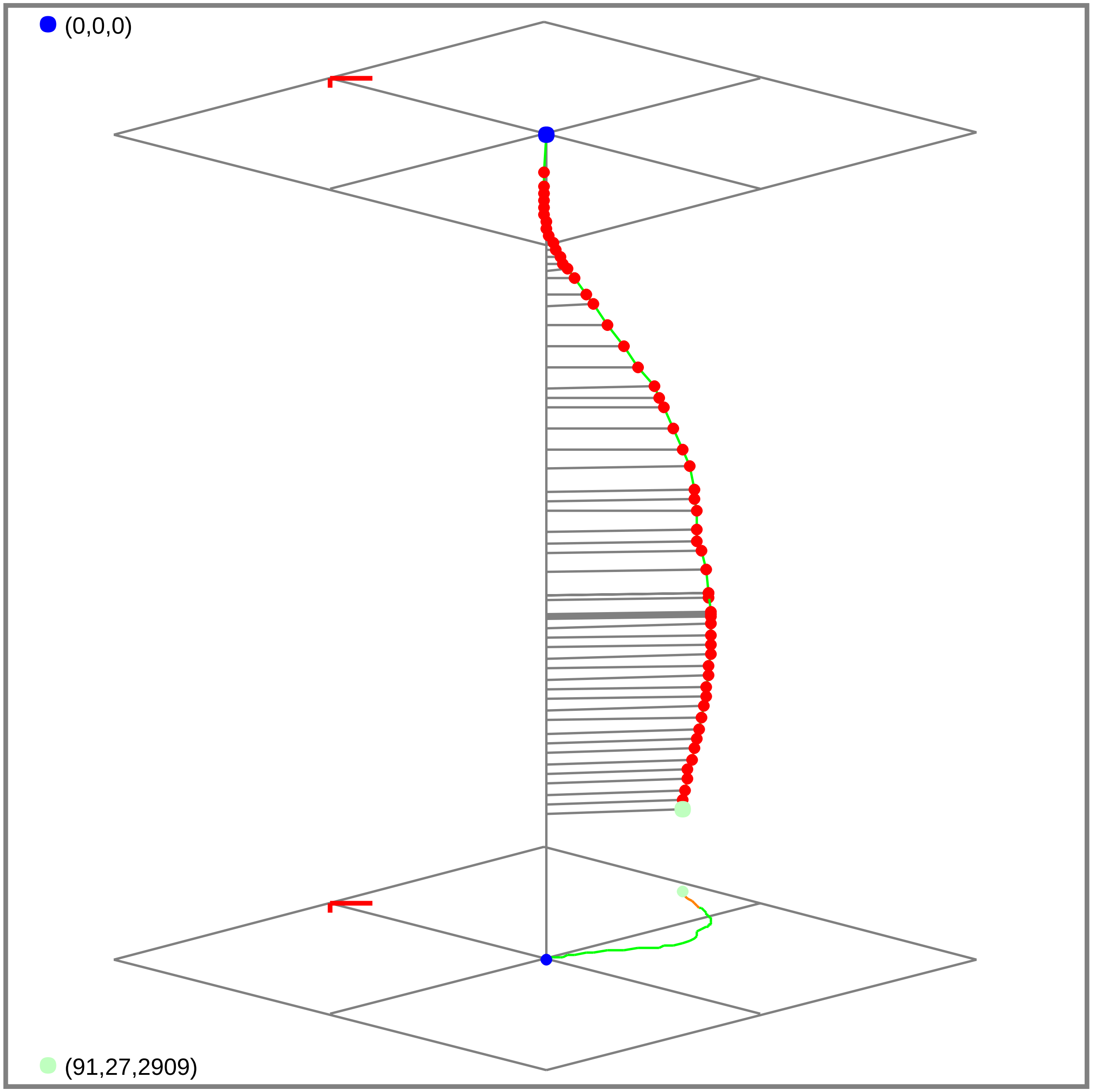
(0,0,0)
(91,27,2909)
Elevation Azimuth
= 90°
0
3000.0
-119.3
0
+119.3



(0,0,0)
(91,27,2909)


(0,0,0)
(91,27,2909)


(0,0,0)
(91,27,2909)


(0,0,0)
(91,27,2909)

APPENDIX B – SITE SAFETY AND FACILITY LAYOUT

Appendix B-1 – Titan Plant Safety Location Plans

Appendix B-2 – Salt Creek AGI No. 2 Piping and Instrumentation Diagram

Appendix B-3 – Salt Creek AGI No. 3 Piping and Instrumentation Diagram

Appendix B-4 – Titan Safety Layout Schematic

NOTES:

GENERAL NOTES FOR NEW DEVICES

1. THE PREVAILING WIND DIRECTION IS NORTHEAST.
2. LEL DETECTOR – METHANE GAS – LIGHTER THAN AIR, MOUNT 48" ABOVE DECK ELEVATION.
3. H2S DETECTOR – HEAVIER THAN AIR, MOUNT 18" ABOVE GRADE.
4. FLAME DETECTOR W/ FIELD OF VIEW LIMITER – INSTALL 12' MIN. ABOVE GRADE ON STEEL STRUCTURE OR LIGHT POLE. TILT ANGLE TO AVOID REFLECTION AND DISTANT UV SOURCES. WHERE POSSIBLE POINT CAMERAS AWAY FROM FLARE. SEE DETAILS BELOW FOR FIELD OF VIEW DISTANCES.
5. DETECTOR TO BE INSTALLED DURING FUTURE CONSTRUCTION PHASE.

AGI #3 flow meter

STAMP & SEAL

REFERENCE DRAWINGS	
NO.	TITLE

SAULSBURY
ENGINEERING SERVICES
SAULSBURY.COM
TEXAS REGISTERED ENGINEERING FIRM F-518

REVISIONS

NO.	FIRM	DATE	DESCRIPTION	BY	CHK.	APP.
0	SI	04/24/2024	ISSURED FOR CONSTRUCTION - PHASE 0, 0.5, 1 AND 2	RAD	GV	PAM

ENGINEERING RECORD

PROJ. MANAGER:	MF	SI JOB NUMBER:	10991
PROJ. ENGR:	DW		
PROJ. DESIGN:	SAB		

NORTHWIND MIDSTREAM

AGI #2

NOTES:

1. (F) FURNISHED BY FLARE VENDOR.

STAMP & SEAL

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	FIRM	DATE	DESCRIPTION	BY	CHK.	APP.
B1	SI	02/19/24	ISSUED FOR APPROVAL PHASE 1	CLM	APL	SSR

SAULSBURY
ENGINEERING SERVICES
SAULSBURY.COM
TEXAS REGISTERED ENGINEERING FIRM F-518

ENGINEERING RECORD

PROJ. MANAGER:	-	SI JOB NUMBER:	10991
PROJ. ENGR:	-	AFE NUMBER:	
PROJ. DESIGN:	-	WELD CODE:	

NORTHWIND MIDSTREAM

TITAN TREATER KO
GAS TREATING FACILITY
PIPING & INSTRUMENTATION DIAGRAM
ACID GAS INJECTION WELL #2
LEA COUNTY, NM

PLOT SCALE:	NONE	DWG. NO.	REV
FILE NAME:	P04-1512	D-10991-P04-1512	B1

J:\Northwind Midstream (EVX)\10991-01 Northwind Titan Treater\03 ENGINEERING, DESIGN\3.1 Process\3.1.4 Drawings - P&IDs\P04-1512 (2/21/2024 1:52:54 PM)

NOTES:

1. (F) FURNISHED BY FLARE VENDOR.

STAMP & SEAL

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	FIRM	DATE	DESCRIPTION	BY	CHK.	APP.
B1	SI	02/19/24	ISSUED FOR APPROVAL PHASE 1	CLM	APL	SSR

SAULSBURY
ENGINEERING SERVICES
SAULSBURY.COM
TEXAS REGISTERED ENGINEERING FIRM F-518

ENGINEERING RECORD

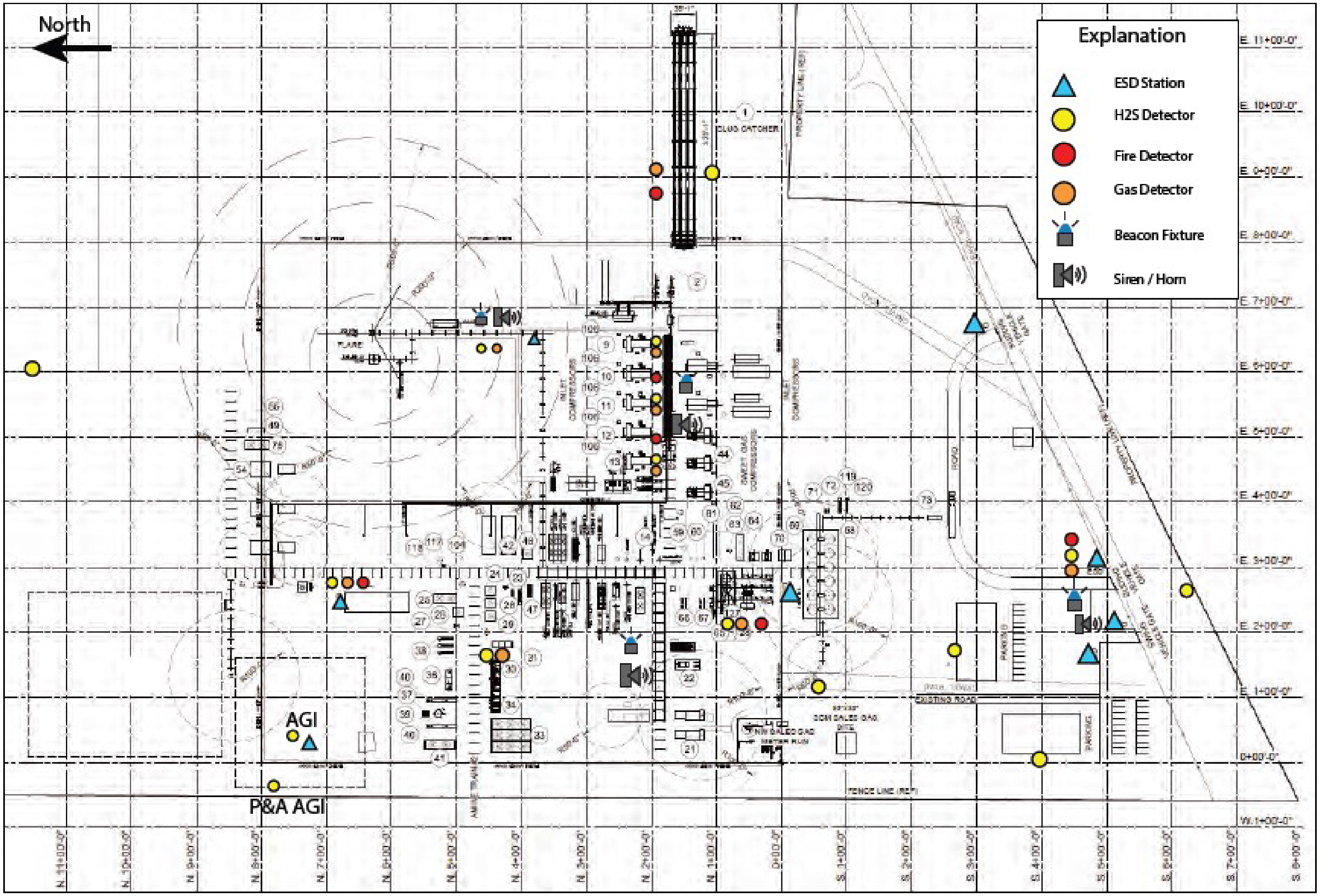
PROJ. MANAGER:	-	SI JOB NUMBER:	10991
PROJ. ENGR:	-	AFE NUMBER:	
PROJ. DESIGN:	-	WELD CODE:	

NORTHWIND MIDSTREAM

TITAN TREATER KO
GAS TREATING FACILITY
PIPING & INSTRUMENTATION DIAGRAM
ACID GAS INJECTION WELL #3
LEA COUNTY, NM

PLOT SCALE: NONE	DWG. NO.		REV
FILE NAME: P04-1513	D-10991-P04-1513		B1

J:\Northwind Midstream (EVX)\10991-01 Northwind Titan Treater\03 ENGINEERING, DESIGN\3.1 Process\3.1.4 Drawings - P&IDs\P04-1513 (2/23/2024 1:35:01 PM)



North
Explanation
ESD Station
H2S Detector
Fire Detector
Gas Detector
Beacon Fixture
Siren / Horn
AGI
P&A AGI
SLUG CATCHER
FENCE LINE (REF)
EXISTING ROAD
PARKING
ROAD

APPENDIX C – AREA OF REVIEW

Salt Creek AGI No. 2 & No. 3

Maximum Monitoring Area

Northwind Midstream Partners LLC

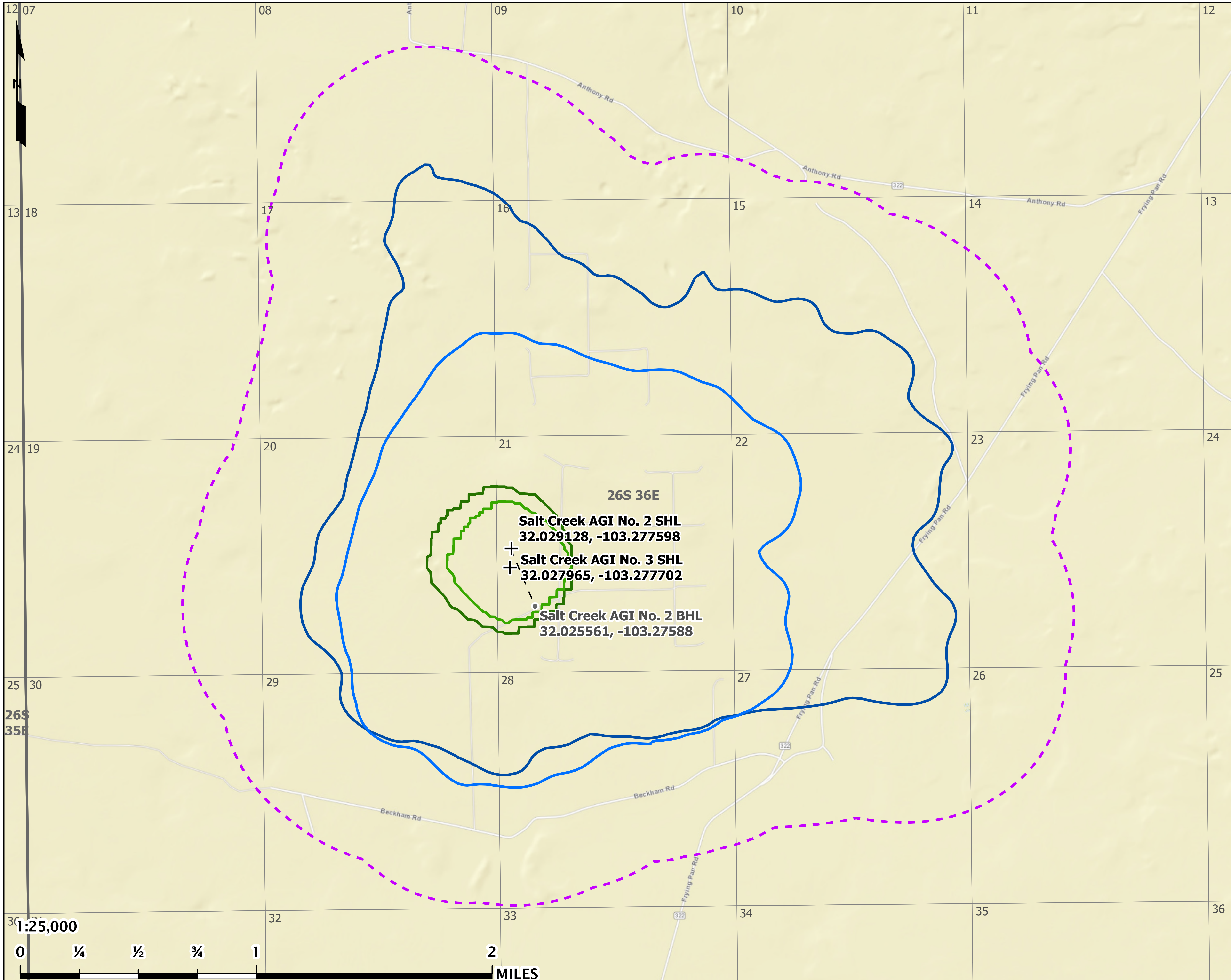
Lea County, NM

Drawn by: SJL	Date: 7/1/2024	Approved by: SLP

PCS: NAD 1983 State Plane NM-E FIPS 3001 (US Ft.)

LONQUIST & CO. LLC

PETROLEUM ENGINEERS | ENERGY ADVISORS



Salt Creek AGI No. 2 SHL (Devonian)

Salt Creek AGI No. 2 BHL (Devonian)

Salt Creek AGI No. 2 Proposed Directional

Salt Creek AGI No. 3 SHL (DMG)

DMG Plume Extent (Salt Creek AGI No. 3, End of 30-Year Injection)

DMG Plume Extent (Salt Creek AGI No. 3, 50 Years Post-Injection)

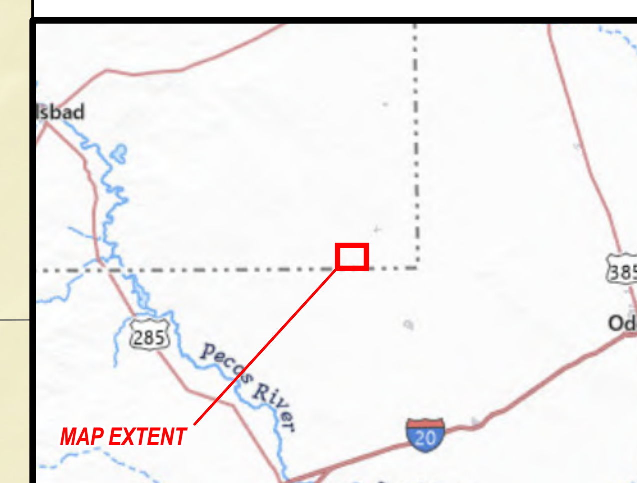
Devonian Plume Extent (Salt Creek AGI No. 2, End of 30-Year Injection)

Devonian Plume Extent (Salt Creek AGI No. 2, 50 Years Post-Injection)

Maximum Monitoring Area (1/2-Mile Buffer from Maximum Devonian Plume Extent)

Township/Range (NM-PLSS)

Sections (NM-PLSS)



Salt Creek AGI No. 2 & No. 3

Active Monitoring Area

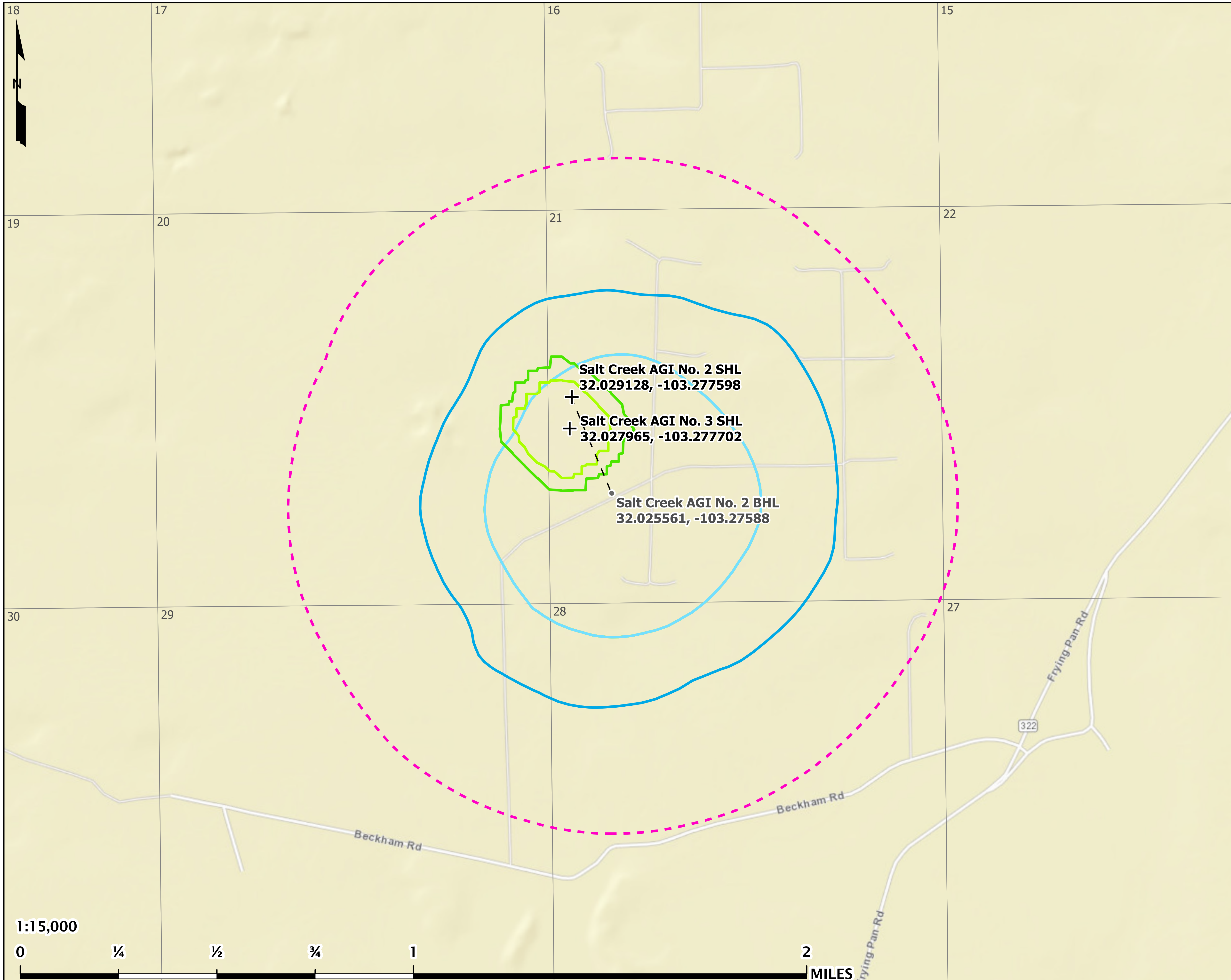
Northwind Midstream Partners LLC

Lea County, NM

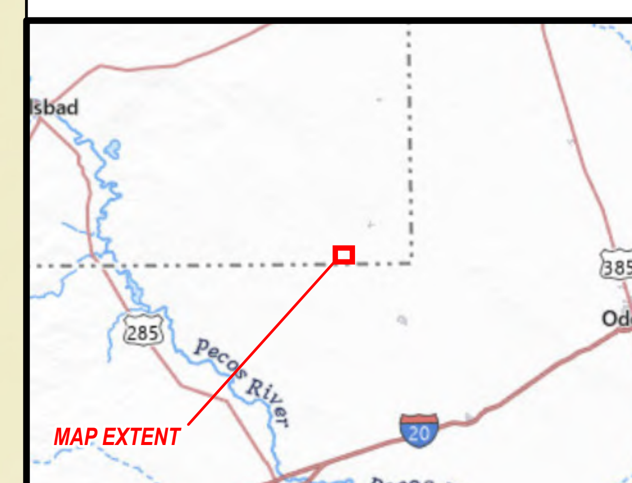
Drawn by: SJL	Date: 7/1/2024	Approved by: SLP

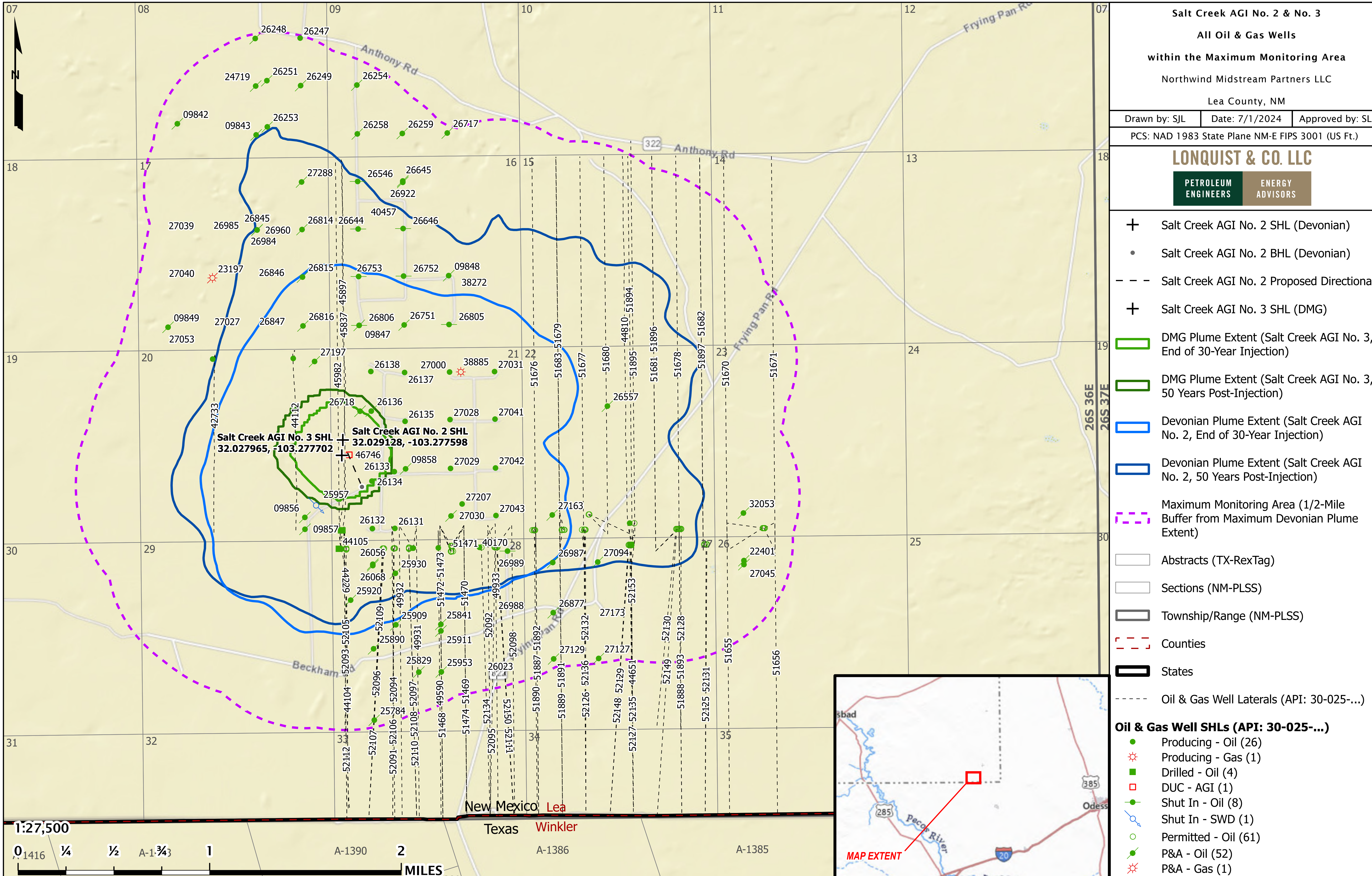
PCS: NAD 1983 State Plane NM-E FIPS 3001 (US Ft.)

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS



- Salt Creek AGI No. 2 SHL (Devonian)
- Salt Creek AGI No. 2 BHL (Devonian)
- Salt Creek AGI No. 2 Proposed Directional
- Salt Creek AGI No. 3 SHL (DMG)
- DMG Plume Extent (Salt Creek AGI No. 3, 5 Years Injection)
- DMG Plume Extent (Salt Creek AGI No. 3, 10 Years Injection)
- Devonian Plume Extent (Salt Creek AGI No. 2, 5 Years Injection)
- Devonian Plume Extent (Salt Creek AGI No. 2, 10 Years Injection)
- Active Monitoring Area (1/2-Mile Buffer from Combined 5-Year Plume Extent)
- Sections (NM-PLSS)





Salt Creek AGI No. 2 & No. 3
All Oil & Gas Wells
within the Maximum Monitoring Area
Northwind Midstream Partners LLC
Lea County, NM
Drawn by: SJL
Date: 7/1/2024
Approved by: SLP
PCS: NAD 1983 State Plane NM-E FIPS 3001 (US Ft.)
LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
Salt Creek AGI No. 2 SHL (Devonian)
Salt Creek AGI No. 2 BHL (Devonian)
Salt Creek AGI No. 2 Proposed Directional
Salt Creek AGI No. 3 SHL (DMG)
DMG Plume Extent (Salt Creek AGI No. 3, End of 30-Year Injection)
DMG Plume Extent (Salt Creek AGI No. 3, 50 Years Post-Injection)
Devonian Plume Extent (Salt Creek AGI No. 2, End of 30-Year Injection)
Devonian Plume Extent (Salt Creek AGI No. 2, 50 Years Post-Injection)
Maximum Monitoring Area (1/2-Mile Buffer from Maximum Devonian Plume Extent)
Abstracts (TX-RexTag)
Sections (NM-PLSS)
Township/Range (NM-PLSS)
Counties
States
Oil & Gas Well Laterals (API: 30-025-...)
Oil & Gas Well SHLs (API: 30-025-...)
Producing - Oil (26)
Producing - Gas (1)
Drilled - Oil (4)
DUC - AGI (1)
Shut In - Oil (8)
Shut In - SWD (1)
Permitted - Oil (61)
P&A - Oil (52)
P&A - Gas (1)
Salt Creek AGI No. 3 SHL
32.027965, -103.277702
Salt Creek AGI No. 2 SHL
32.029128, -103.277598
Anthony Rd
Frying Pan Rd
Beckham Rd
322
26S 36E
26S 37E
New Mexico
Texas
Lea
Winkler
A-1390
A-1386
A-1385
A-1389
1:27,500
0
¼
½
1
2
MILES
MAP EXTENT
Pecos River
285
385
20

Area of Review: Oil & Gas Wells List													
API	WELL NAME	WELL NO.	CURRENT OPERATOR	TOWNSHIP	RANGE	SECTION	LATITUDE (NAD83)	LONGITUDE (NAD83)	WELL STATUS	WELL TYPE	TOTAL DEPTH (TVD FT.)	PERFORATED INTERVAL (MD FT.)	SPUD DATE
30-025-09842	SAND HILLS UNIT	008	CITIES SERVICES OIL CO	26S	36E	8	32.053249	-103.29245	P & A	OIL	3348	-	1/27/1960
30-025-09843	SAND HILLS UNIT	003	SINCLAIR OIL & GAS COMPANY	26S	36E	8	32.052341	-103.284996	P & A	OIL	5500	-	7/16/1957
30-025-09847	MARALO SV 16 STATE	006	MARALO LLC	26S	36E	16	32.037827	-103.276459	P & A	OIL	11492	-	
30-025-09848	MARALO 16 STATE	005	DRACO ENERGY, INC.	26S	36E	16	32.041451	-103.267929	P & A	OIL	4149	-	
30-025-09849	G L ERWIN B FEDERAL NCT 2	005	CITGO	26S	36E	17	32.037827	-103.293465	P & A	OIL	3471	-	
30-025-09856	W A RAMSAY NCT C	002	PRE-ONGARD WELL OPERATOR	26S	36E	20	32.0233040	-103.2806930	P & A	OIL	1247	-	
30-025-09857	W A RAMSAY NCT C	004	PRE-ONGARD WELL OPERATOR	26S	36E	20	32.0224	-103.280693	P & A	OIL	3349	-	
30-025-09858	FEDERAL	001	HUMBLE OIL & REFINING	26S	36E	21	32.026932	-103.272179	P & A	OIL	3940	-	
30-025-22401	REESE	001	STOLTZ & COMPANY & CLARK OIL & REFINING CORPORATIO	26S	36E	26	32.0196690	-103.2423860	P & A	OIL	3502	-	
30-025-23197	SOUTH LEA FEDERAL	001	DIAMONDBACK	26S	36E	17	32.041458	-103.289215	P & A	GAS	21252	17755-17898	7/15/1969
30-025-24719	DOGIE DRAW FEDERAL	001	PRE-ONGARD WELL OPERATOR	26S	36E	8	32.0559690	-103.2850040	P & A	OIL	20971	-	
30-025-25784	LEA 7406 JV-S	003	PRE-ONGARD WELL OPERATOR	26S	36E	28	32.0078890	-103.2753520	P & A	OIL	887	-	
30-025-25829	LEA 7406 JV-S	004	BTA OIL PRODUCERS	26S	36E	28	32.011517	-103.271103	P & A	OIL	3268	-	
30-025-25841	QUANAH PARKER	002	PRE-ONGARD WELL OPERATOR	26S	36E	28	32.015148	-103.268967	P & A	OIL	284	-	
30-025-25890	LEA 7406 JV-S	005	BTA OIL PRODUCERS	26S	36E	28	32.013332	-103.27536	P & A	OIL	3266	-	

LONQUIST SEQUESTRATION LLC

30-025-25909	LEA 7406 JV-S	006	BTA OIL PRODUCERS	26S	36E	28	32.015141	-103.273231	P & A	OIL	3250	-	
30-025-25911	QUANAH PARKER	002Y	CELERO ENERGY	26S	36E	28	32.014599	-103.268883	P & A	OIL	3258	3159-3248	
30-025-25920	LEA 7406 JV-S	007	BTA OIL PRODUCERS	26S	36E	28	32.0169530	-103.2774960	P & A	OIL	3270	-	
30-025-25930	LEA 7406 JV-S	8	BTA OIL PRODUCERS	26S	36E	28	32.019013	-103.273239	P & A	OIL	3270	-	
30-025-25953	NEW MEXICO CV STATE	1	CHORD ENERGY	26S	36E	28	32.011501	-103.268967	P & A	OIL	3239	3128-3235	6/23/1978
30-025-25957	LEA 20	1	CHANCE PROPERTIES CO.	26S	36E	20	32.0242120	-103.2796330	TA	SWD	3420	3323-3420	5/21/1978
30-025-26056	LEA 7406 JV-S	9	BTA OIL PRODUCERS	26S	36E	28	32.0196760	-103.2753680	P & A	OIL	1406	-	
30-025-26068	LEA 7406 JV-S	009Y	BTA OIL PRODUCERS	26S	36E	28	32.019566	-103.275368	P & A	OIL	3270	-	
30-025-26131	WILSON 21 FEDERAL	1	FULFER OIL & CATTLE	26S	36E	21	32.022396	-103.273239	PRODUCING	OIL	3340	-	
30-025-26132	WILSON 21 FEDERAL	2	FULFER OIL & CATTLE	26S	36E	21	32.022396	-103.275368	PRODUCING	OIL	3500	-	
30-025-26133	WILSON 21 FEDERAL	3	FULFER OIL & CATTLE	26S	36E	21	32.026741	-103.272758	PRODUCING	OIL	3797	-	
30-025-26134	WILSON 21 FEDERAL	4	FULFER OIL & CATTLE	26S	36E	21	32.026024	-103.275375	PRODUCING	OIL	3575	-	
30-025-26135	WILSON 21 FEDERAL	5	FULFER OIL & CATTLE	26S	36E	21	32.030514	-103.272186	PRODUCING	OIL	3800	-	
30-025-26136	WILSON 21 FEDERAL	6	PRE-ONGARD WELL OPERATOR	26S	36E	21	32.031338	-103.275383	P & A	OIL	1682	-	
30-025-26137	WILSON 21 FEDERAL	7	FULFER OIL & CATTLE	26S	36E	21	32.034195	-103.272125	PRODUCING	OIL	3700	-	
30-025-26138	WILSON 21 FEDERAL	8	FULFER OIL & CATTLE	26S	36E	21	32.034279	-103.275383	PRODUCING	OIL	3700	-	
30-025-26247	WILSON 8 FEDERAL	1	FULFER OIL & CATTLE	26S	36E	08	32.059601	-103.280747	PRODUCING	OIL	3606	-	3/27/1979

LONQUIST SEQUESTRATION LLC

30-025-26248	WILSON 8 FEDERAL	2	PRE-ONGARD WELL OPERATOR	26S	36E	08	32.059605	-103.285011	P & A	OIL	3850	-	
30-025-26249	WILSON 8 FEDERAL	3	LYCO ENERGY CORPORATION	26S	36E	08	32.055969	-103.280747	P & A	OIL	3795	-	
30-025-26251	WILSON 8 FEDERAL	5	PRE-ONGARD WELL OPERATOR	26S	36E	08	32.056412	-103.284386	P & A	OIL	3700	-	
30-025-26253	WILSON 8 FEDERAL	7	PRE-ONGARD WELL OPERATOR	26S	36E	08	32.052872	-103.284378	P & A	OIL	3700	-	
30-025-26254	WILSON 9 FEDERAL	1	PRE-ONGARD WELL OPERATOR	26S	36E	09	32.055969	-103.276482	P & A	OIL	3730	-	
30-025-26258	WILSON 9 FEDERAL	2	PRE-ONGARD WELL OPERATOR	26S	36E	09	32.052341	-103.276482	P & A	OIL	3800	-	
30-025-26259	WILSON 9 FEDERAL	3	PRE-ONGARD WELL OPERATOR	26S	36E	09	32.052341	-103.272217	P & A	OIL	3684	-	
30-025-26546	MARALO 16 STATE	1	RMR OPERATING, LLC	26S	36E	16	32.048714	-103.276474	TA	OIL	3800	-	11/21/1979
30-025-26557	PAWNEE DEEP UNIT	1	HERITAGE RESOURCES INC	26S	36E	22	32.031467	-103.254074	P & A	OIL	18577	12505-13196	11/25/1979
30-025-26644	MARALO 16 STATE	2	RMR OPERATING, LLC	26S	36E	16	32.045086	-103.276466	TA	OIL	3770	3291-3692	
30-025-26645	MARALO SV 16 STATE	3	MARALO	26S	36E	16	32.048714	-103.272209	P & A	OIL	1576	-	
30-025-26646	MARALO 16 STATE	4	RMR OPERATING, LLC	26S	36E	16	32.045086	-103.272209	TA	OIL	3780	3232-3744	6/2/1980
30-025-26717	WILSON 9 FEDERAL	6	PRE-ONGARD WELL OPERATOR	26S	36E	09	32.052341	-103.267937	P & A	OIL	3650	-	
30-025-26718	WILSON 21 FEDERAL	006-Y	PRE-ONGARD WELL OPERATOR	26S	36E	21	32.031338	-103.275703	P & A	OIL	3750	-	
30-025-26751	MARALO 16 STATE	7	DRACO ENERGY, INC.	26S	36E	16	32.037827	-103.272194	P & A	OIL	3800	-	
30-025-26752	MARALO 16 STATE	8	RMR OPERATING, LLC	26S	36E	16	32.041454	-103.272201	TA	OIL	3750	-	
30-025-26753	MARALO 16 STATE	9	RMR OPERATING, LLC	26S	36E	16	32.041454	-103.276459	TA	OIL	3800	3284-3744	

LONQUIST SEQUESTRATION LLC

30-025-26805	MARALO 16 STATE	10	NORTHERN PACIFIC OIL AND GAS INCORPORATED	26S	36E	16	32.037823	-103.267921	INACTIVE PRODUCER	OIL	3800	3540-3742	
30-025-26806	MARALO 16 STATE	006Y	RMR OPERATING, LLC	26S	36E	16	32.037827	-103.276131	TA	OIL	3800	-	7/3/1980
30-025-26814	WILSON 17 FEDERAL	1	PRE-ONGARD WELL OPERATOR	26S	36E	17	32.045086	-103.280731	P & A	OIL	3800	-	
30-025-26815	WILSON 17 FEDERAL	2	PRE-ONGARD WELL OPERATOR	26S	36E	17	32.041454	-103.280724	P & A	OIL	3700	-	
30-025-26816	WILSON 17 FEDERAL	3	PRE-ONGARD WELL OPERATOR	26S	36E	17	32.037827	-103.280716	P & A	OIL	3700	-	
30-025-26845	WILSON 17 FEDERAL	4	PRE-ONGARD WELL OPERATOR	26S	36E	17	32.045086	-103.284988	P & A	OIL	1950	-	
30-025-26877	BUFFALO HUMP	1	CELERO ENERGY	26S	36E	27	32.015911	-103.259384	P & A	OIL	3585	-	
30-025-26922	MARALO 16 STATE	003Y	DRACO ENERGY, INC.	26S	36E	16	32.048576	-103.272209	P & A	OIL	3800	-	
30-025-26960	WILSON 17 FEDERAL	004-Y	PRE-ONGARD WELL OPERATOR	26S	36E	17	32.045086	-103.284828	P & A	OIL	1331	-	
30-025-26984	WILSON 17 FEDERAL	004-Z	PRE-ONGARD WELL OPERATOR	26S	36E	17	32.045086	-103.284668	P & A	OIL	3603	-	
30-025-26987	BUFFALO HUMP	2	CELERO ENERGY	26S	36E	27	32.019676	-103.259384	P & A	OIL	3545	-	
30-025-27000	LEA 21, 7406 JV-S	1	FULFER OIL & CATTLE	26S	36E	21	32.034195	-103.267921	PRODUCING	OIL	3668	-	9/6/1980
30-025-27028	LEA 21, 7406 JV-S	2	FULFER OIL & CATTLE	26S	36E	21	32.030567	-103.267914	PRODUCING	OIL	3658	3208-3415	
30-025-27029	LEA 21, 7406 JV-S	3	FULFER OIL & CATTLE	26S	36E	21	32.026932	-103.267914	PRODUCING	OIL	3574	3231-3431	10/12/1980
30-025-27030	LEA 7406 JV-S	4	PRE-ONGARD WELL OPERATOR	26S	36E	21	32.023304	-103.267906	P & A	OIL	1060	-	
30-025-27031	LEA 21, 7406 JV-S	5	FULFER OIL & CATTLE	26S	36E	21	32.034195	-103.263657	PRODUCING	OIL	3660	3194-3383	
30-025-27041	LEA 21, 7406 JV-S	6	FULFER OIL & CATTLE	26S	36E	21	32.030563	-103.263657	PRODUCING	OIL	3495	-	11/21/1980

LONQUIST SEQUESTRATION LLC

Salt Creek AGI No. 2 and No. 3

30-025-27042	LEA 21, 7406 JV-S	7	FULFER OIL & CATTLE	26S	36E	21	32.026936	-103.263649	PRODUCING	OIL	3525	3218-3416	
30-025-27043	LEA 21, 7406 JV-S	8	FULFER OIL & CATTLE	26S	36E	21	32.023304	-103.263649	PRODUCING	OIL	3570	3227-3414	
30-025-27045	LEA 26 7406 JV-S	1	BTA OIL PRODUCERS	26S	36E	26	32.01939	-103.242386	P & A	OIL	3660	-	
30-025-27094	BUFFALO HUMP	3	GIFFED MITCHELL & WISENBANKER	26S	36E	27	32.019672	-103.254646	P & A	OIL	3608	-	
30-025-27127	BUFFALO HUMP	5	CELERO ENERGY	26S	36E	27	32.012421	-103.255119	P & A	OIL	3554	-	
30-025-27129	BUFFALO HUMP	8	CELERO ENERGY	26S	36E	27	32.012425	-103.259384	P & A	OIL	3606	-	
30-025-27163	AMERICAN EAGLE	1	CELERO ENERGY	26S	36E	22	32.023304	-103.259392	P & A	OIL	3550	3166-3232	1/23/1981
30-025-27197	LEA 20 7426 JV-S	2	BTA OIL PRODUCERS	26S	36E	20	32.035107	-103.279648	P & A	OIL	3670	-	
30-025-27207	LEA 21, 7406 JV-S	004Y	FULFER OIL & CATTLE	26S	36E	21	32.024212	-103.266846	PRODUCING	OIL	3550	-	1/26/1981
30-025-27288	LEA 17 7426 JV-S	1	PRE-ONGARD WELL OPERATOR	26S	36E	17	32.048714	-103.280731	P & A	OIL	2879	-	
30-025-32053	BEARTOOTH STATE UNIT	1	EOG	26S	36E	23	32.023296	-103.242386	P & A	OIL	7725	-	7/22/1993
30-025-38885	EAGLE FEATHER FEDERAL	2	AMEREDEV II	26S	36E	21	32.034195	-103.266792	PRODUCING	GAS	13179	12444-12718	7/20/2008
30-025-40170	GOOD CHIEF STATE	1	RMR OPERATING, LLC	26S	36E	28	32.020584	-103.262581	TA	OIL	3873	3215-3575	7/13/2011
30-025-42733	WILDHOG BWX STATE COM	001H	AMEREDEV II	26S	36E	20	32.035356	-103.289055	PRODUCING	OIL	12517	12583-17150	9/1/2015
30-025-44104	AZALEA 26 36 28 STATE	111H	AMEREDEV II	26S	36E	28	32.020883	-103.277753	PRODUCING	OIL	12200	12170-18987	12/15/2017
30-025-44105	AZALEA 26 36 28 STATE	121	AMEREDEV II	26S	36E	28	32.020883	-103.277688	DRILLED	OIL	994	-	11/24/2017
30-025-44112	WILDHOG BWX STATE COM	002H	AMEREDEV II	26S	36E	20	32.035345	-103.28189	PRODUCING	OIL	12010	12007-16560	1/21/2018

Salt Creek AGI No. 2 and No. 3

30-025-44229	AZALEA 26 36 28 STATE	121Y	AMEREDEV II	26S	36E	28	32.020883	-103.277817	PRODUCING	OIL	12437	12669-19467	11/30/2017
30-025-44651	AMEN CORNER 26 36 27 STATE COM	115C	AMEREDEV II	26S	36E	27	32.020974	-103.252022	DRILLED	OIL	11894	-	2/27/2019
30-025-44810	MAGNOLIA 26 36 22 STATE COM	125H	AMEREDEV II	26S	36E	22	32.022621	-103.252118	PRODUCING	OIL	11714	11878-22033	3/2/2019
30-025-45837	CAMELLIA FEDERAL COM 26 36 21	111H	AMEREDEV II	26S	36E	21	32.022296	-103.277785	DRILLED	OIL	12150	-	5/9/2019
30-025-45897	CAMELLIA FEDERAL COM 26 36 21	121H	AMEREDEV II	26S	36E	21	32.022296	-103.277721	PRODUCING	OIL	12367	13408-22584	5/11/2019
30-025-45982	CAMELLIA FEDERAL COM 26 36 21	081C	AMEREDEV II	26S	36E	21	32.022296	-103.277656	DRILLED	OIL	10500	-	6/3/2019
30-025-46746	SALT CREEK AGI	1	SALT CREEK MIDSTREAM	26S	36E	21	32.028016	-103.276681	DUC	GAS	7000	-	10/18/2022
30-025-49590	AZALEA 26 36 28 STATE COM	125H	AMEREDEV II	26S	36E	28	32.020894	-103.269155	PRODUCING	OIL	12483	-	5/12/2022
30-025-49931	AZALEA 26 36 28 STATE COM	104H	AMEREDEV II	26S	36E	28	32.020892	-103.271377	PRODUCING	OIL	11747	-	4/25/2022
30-025-49932	AZALEA 26 36 28 STATE COM	123H	AMEREDEV II	26S	36E	28	32.020891	-103.271442	PRODUCING	OIL	12328	-	4/27/2022
30-025-49933	AZALEA 26 36 28 STATE COM	127H	AMEREDEV II	26S	36E	28	32.020898	-103.265494	PRODUCING	OIL	12262	-	6/5/2022
30-025-51468	AZALEA 26 36 28 STATE COM	063H	AMEREDEV II	26S	36E	28	32.02062	-103.268058	PERMITTED	OIL	8600	-	
30-025-51469	AZALEA 26 36 28 STATE COM	073H	AMEREDEV II	26S	36E	28	32.021033	-103.267897	PERMITTED	OIL	9700	-	
30-025-51470	AZALEA 26 36 28 STATE COM	183H	AMEREDEV II	26S	36E	28	32.021033	-103.267962	PERMITTED	OIL	10300	-	
30-025-51471	AZALEA 26 36 28 STATE COM	195H	AMEREDEV II	26S	36E	28	32.02062	-103.267929	PERMITTED	OIL	11100	-	
30-025-51472	AZALEA 26 36 28 STATE COM	263H	AMEREDEV II	26S	36E	28	32.021033	-103.268026	PERMITTED	OIL	9450	-	
30-025-51473	AZALEA 26 36 28 STATE COM	283H	AMEREDEV II	26S	36E	28	32.02062	-103.267994	PERMITTED	OIL	10700	-	

30-025-51474	AZALEA 26 36 28 STATE COM	383H	AMEREDEV II	26S	36E	28	32.02062	-103.267865	PERMITTED	OIL	10900	-	
30-025-51655	NELSON BRIDGE 26 36 26 STATE COM	121H	AMEREDEV II	26S	36E	23	32.022143	-103.240249	PERMITTED	OIL	11950	-	
30-025-51656	NELSON BRIDGE 26 36 26 STATE COM	123H	AMEREDEV II	26S	36E	23	32.022143	-103.24012	PERMITTED	OIL	11886	-	
30-025-51670	HOGAN BRIDGE 26 36 23 STATE COM	121H	AMEREDEV II	26S	36E	23	32.022143	-103.240314	PERMITTED	OIL	11970	-	
30-025-51671	HOGAN BRIDGE 26 36 23 STATE COM	123H	AMEREDEV II	26S	36E	23	32.022143	-103.240185	PERMITTED	OIL	11887	-	
30-025-51676	MAGNOLIA 26 36 22 STATE COM	061H	AMEREDEV II	26S	36E	22	32.022165	-103.26067	PERMITTED	OIL	8068	-	
30-025-51677	MAGNOLIA 26 36 22 STATE COM	062H	AMEREDEV II	26S	36E	22	32.022161	-103.25638	PERMITTED	OIL	7959	-	
30-025-51678	MAGNOLIA 26 36 22 STATE COM	064H	AMEREDEV II	26S	36E	22	32.022148	-103.247747	PERMITTED	OIL	7714	-	
30-025-51679	MAGNOLIA 26 36 22 STATE COM	071H	AMEREDEV II	26S	36E	22	32.022163	-103.258186	PERMITTED	OIL	9500	-	
30-025-51680	MAGNOLIA 26 36 22 STATE COM	072H	AMEREDEV II	26S	36E	22	32.023314	-103.255773	PERMITTED	OIL	9450	-	
30-025-51681	MAGNOLIA 26 36 22 STATE COM	073H	AMEREDEV II	26S	36E	22	32.022148	-103.247811	PERMITTED	OIL	9351	-	
30-025-51682	MAGNOLIA 26 36 22 STATE COM	074H	AMEREDEV II	26S	36E	27	32.020961	-103.245538	PERMITTED	OIL	9330	-	
30-025-51683	MAGNOLIA 26 36 22 STATE COM	181H	AMEREDEV II	26S	36E	22	32.022163	-103.258122	PERMITTED	OIL	10000	-	
30-025-51887	AMEN CORNER 26 36 27 STATE COM	061H	AMEREDEV II	26S	36E	22	32.022165	-103.2608	PERMITTED	OIL	7970	-	
30-025-51888	AMEN CORNER 26 36 27 STATE COM	064H	AMEREDEV II	26S	36E	22	32.022148	-103.247682	PERMITTED	OIL	7715	-	
30-025-51889	AMEN CORNER 26 36 27 STATE COM	071H	AMEREDEV II	26S	36E	22	32.022163	-103.257993	PERMITTED	OIL	9500	-	
30-025-51890	AMEN CORNER 26 36 27 STATE COM	121H	AMEREDEV II	26S	36E	22	32.022165	-103.260542	PERMITTED	OIL	12153	-	

LONQUIST SEQUESTRATION LLC

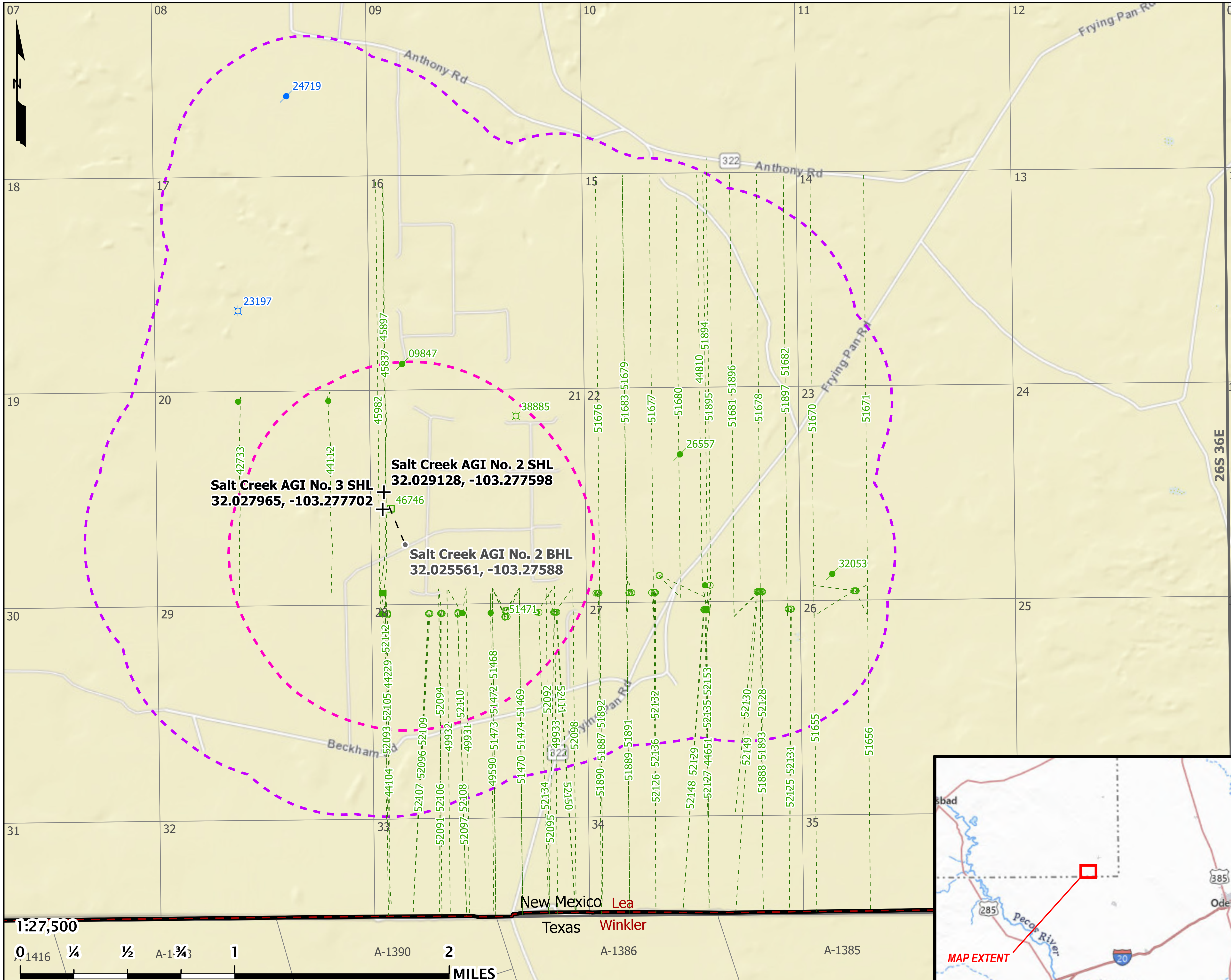
Salt Creek AGI No. 2 and No. 3

30-025-51891	AMEN CORNER 26 36 27 STATE COM	181H	AMEREDEV II	26S	36E	22	32.022163	-103.257928	PERMITTED	OIL	10053	-	
30-025-51892	AMEN CORNER 26 36 27 STATE COM	261H	AMEREDEV II	26S	36E	22	32.022165	-103.260606	PERMITTED	OIL	9323	-	
30-025-51893	AMEN CORNER 26 36 27 STATE COM	264H	AMEREDEV II	26S	36E	22	32.022148	-103.247616	PERMITTED	OIL	9120	-	
30-025-51894	MAGNOLIA 26 36 22 STATE COM	063H	AMEREDEV II	26S	36E	22	32.022619	-103.251715	PERMITTED	OIL	7959	-	
30-025-51895	MAGNOLIA 26 36 22 STATE COM	182H	AMEREDEV II	26S	36E	22	32.023314	-103.255709	PERMITTED	OIL	9830	-	
30-025-51896	MAGNOLIA 26 36 22 STATE COM	183H	AMEREDEV II	26S	36E	22	32.022148	-103.247876	PERMITTED	OIL	9820	-	
30-025-51897	MAGNOLIA 26 36 22 STATE COM	184H	AMEREDEV II	26S	36E	27	32.020961	-103.245473	PERMITTED	OIL	9800	-	
30-025-52091	AZALEA 26 36 28 STATE COM	262H	AMEREDEV II	26S	36E	28	32.02089	-103.273087	PERMITTED	OIL		-	
30-025-52092	AZALEA 26 36 28 STATE COM	264H	AMEREDEV II	26S	36E	28	32.020901	-103.264171	PERMITTED	OIL	9377	-	
30-025-52093	AZALEA 26 36 28 STATE COM	281H	AMEREDEV II	26S	36E	28	32.02083	-103.277349	PERMITTED	OIL	10498	-	
30-025-52094	AZALEA 26 36 28 STATE COM	282H	AMEREDEV II	26S	36E	28	32.02089	-103.273022	PERMITTED	OIL	10480	-	
30-025-52095	AZALEA 26 36 28 STATE COM	284H	AMEREDEV II	26S	36E	28	32.020899	-103.264106	PERMITTED	OIL		-	
30-025-52096	AZALEA 26 36 28 STATE COM	381H	AMEREDEV II	26S	36E	28	32.020889	-103.27399	PERMITTED	OIL		-	
30-025-52097	AZALEA 26 36 28 STATE COM	382H	AMEREDEV II	26S	36E	28	32.020946	-103.27178	PERMITTED	OIL		-	
30-025-52098	AZALEA 26 36 28 STATE COM	384H	AMEREDEV II	26S	36E	28	32.020899	-103.264042	PERMITTED	OIL	10600	-	
30-025-52105	AZALEA 26 36 28 STATE COM	061H	AMEREDEV II	26S	36E	28	32.02094	-103.277349	PERMITTED	OIL		-	
30-025-52106	AZALEA 26 36 28 STATE COM	062H	AMEREDEV II	26S	36E	28	32.02089	-103.273151	PERMITTED	OIL		-	

30-025-52107	AZALEA 26 36 28 STATE COM	071H	AMEREDEV II	26S	36E	28	32.020889	-103.274119	PERMITTED	OIL		-	
30-025-52108	AZALEA 26 36 28 STATE COM	072H	AMEREDEV II	26S	36E	28	32.020836	-103.27178	PERMITTED	OIL		-	
30-025-52109	AZALEA 26 36 28 STATE COM	181H	AMEREDEV II	26S	36E	28	32.020889	-103.274055	PERMITTED	OIL		-	
30-025-52110	AZALEA 26 36 28 STATE COM	182H	AMEREDEV II	26S	36E	28	32.020891	-103.27178	PERMITTED	OIL		-	
30-025-52111	AZALEA 26 36 28 STATE COM	184H	AMEREDEV II	26S	36E	28	32.020899	-103.263977	PERMITTED	OIL		-	
30-025-52112	AZALEA 26 36 28 STATE COM	261H	AMEREDEV II	26S	36E	28	32.020885	-103.277346	PERMITTED	OIL	9474	-	
30-025-52125	AMEN CORNER 26 36 27 STATE COM	074H	AMEREDEV II	26S	36E	27	32.020961	-103.245344	PERMITTED	OIL		-	
30-025-52126	AMEN CORNER 26 36 27 STATE COM	123H	AMEREDEV II	26S	36E	22	32.02216	-103.256057	PERMITTED	OIL		-	
30-025-52127	AMEN CORNER 26 36 27 STATE COM	125H	AMEREDEV II	26S	36E	27	32.020974	-103.252119	PERMITTED	OIL		-	
30-025-52128	AMEN CORNER 26 36 27 STATE COM	127H	AMEREDEV II	26S	36E	22	32.022147	-103.247553	PERMITTED	OIL		-	
30-025-52129	AMEN CORNER 26 36 27 STATE COM	182H	AMEREDEV II	26S	36E	27	32.020974	-103.252184	PERMITTED	OIL		-	
30-025-52130	AMEN CORNER 26 36 27 STATE COM	183H	AMEREDEV II	26S	36E	22	32.022148	-103.248005	PERMITTED	OIL		-	
30-025-52131	AMEN CORNER 26 36 27 STATE COM	184H	AMEREDEV II	26S	36E	27	32.020961	-103.245279	PERMITTED	OIL		-	
30-025-52132	AMEN CORNER 26 36 27 STATE COM	262H	AMEREDEV II	26S	36E	22	32.022161	-103.256122	PERMITTED	OIL		-	
30-025-52134	AZALEA 26 36 28 STATE COM	064H	AMEREDEV II	26S	36E	28	32.020898	-103.265332	PERMITTED	OIL		-	
30-025-52135	AMEN CORNER 26 36 27 STATE COM	263H	AMEREDEV II	26S	36E	27	32.020974	-103.252055	PERMITTED	OIL		-	
30-025-52136	AMEN CORNER 26 36 27 STATE COM	062H	AMEREDEV II	26S	36E	22	32.022161	-103.256186	PERMITTED	OIL		-	

LONQUIST SEQUESTRATION LLC

30-025-52148	AMEN CORNER 26 36 27 STATE COM	072H	AMEREDEV II	26S	36E	27	32.020975	-103.252248	PERMITTED	OIL		-	
30-025-52149	AMEN CORNER 26 36 27 STATE COM	073H	AMEREDEV II	26S	36E	22	32.022148	-103.24794	PERMITTED	OIL		-	
30-025-52150	AZALEA 26 36 28 STATE COM	074H	AMEREDEV II	26S	36E	28	32.020899	-103.263911	PERMITTED	OIL		-	
30-025-52153	AMEN CORNER 26 36 27 STATE COM	063H	AMEREDEV II	26S	36E	27	32.020974	-103.25199	PERMITTED	OIL		-	



Salt Creek AGI No. 2 & No. 3

Injection Zone-Penetrating Oil & Gas Wells

within the Maximum Monitoring Area

Northwind Midstream Partners LLC

Lea County, NM

Drawn by: SJL	Date: 7/1/2024	Approved by: SLP

PCS: NAD 1983 State Plane NM-E FIPS 3001 (US Ft.)

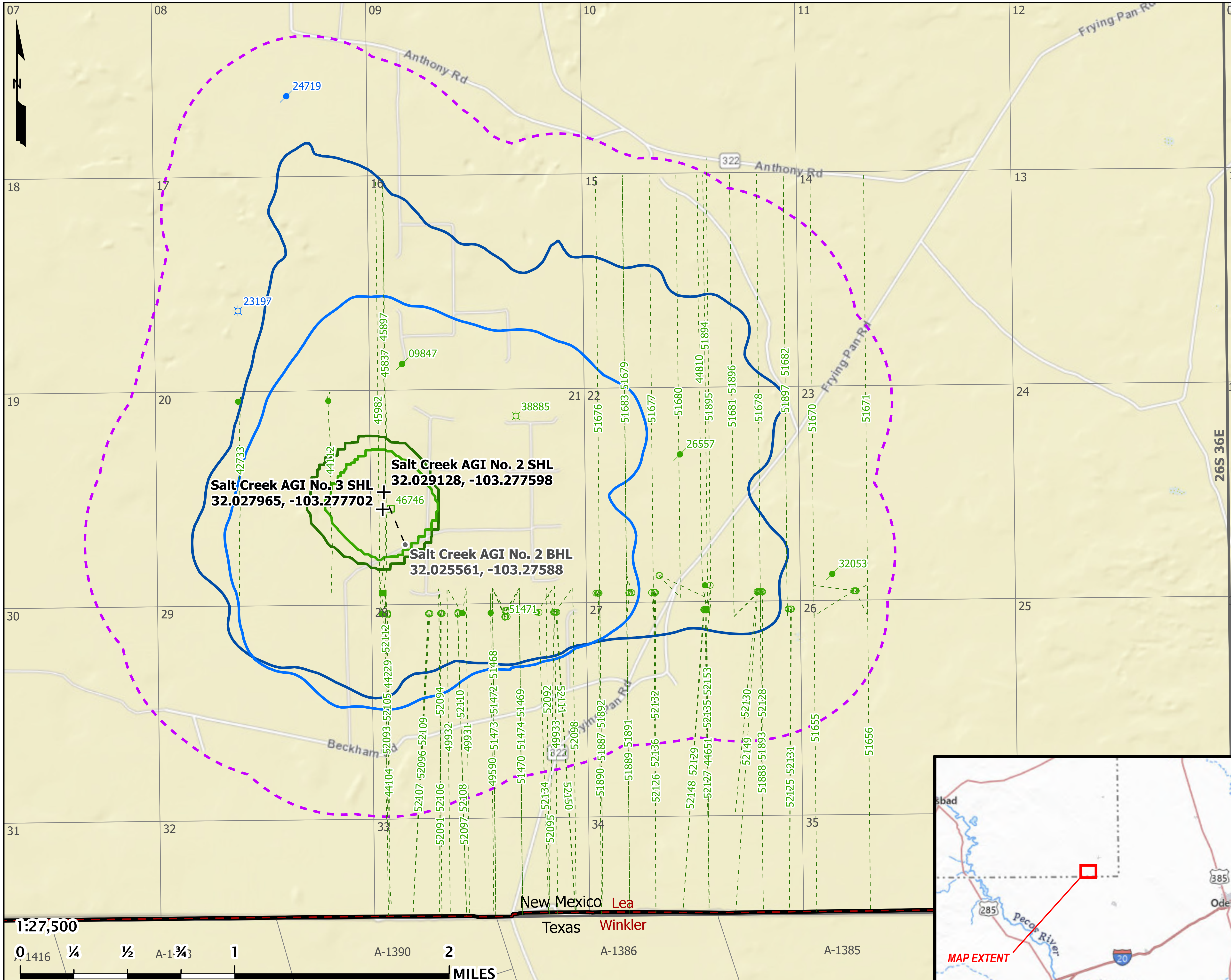
LONQUIST & CO. LLC

PETROLEUM ENGINEERS | ENERGY ADVISORS

- Salt Creek AGI No. 2 SHL (Devonian)
- Salt Creek AGI No. 2 BHL (Devonian)
- Salt Creek AGI No. 2 Proposed Directional
- Salt Creek AGI No. 3 SHL (DMG)
- Active Monitoring Area (1/2-Mile Buffer from Combined 5-Year Plume Extent)
- Maximum Monitoring Area (1/2-Mile Buffer from Maximum Devonian Plume Extent)
- Abstracts (TX-RexTag)
- Sections (NM-PLSS)
- Township/Range (NM-PLSS)
- Counties
- States
- Oil & Gas Well Laterals (API: 30-025-...)

Oil & Gas Well SHLs (API: 30-025-...)

- Producing - Oil [Only penetrates DMG] (10)
- Producing - Gas [Only penetrates DMG] (1)
- Drilled - Oil [Only penetrates DMG] (3)
- DUC - AGI [Only penetrates DMG] (1)
- Permitted - Oil [Only penetrates DMG] (61)
- P&A - Oil [Only penetrates DMG] (3)
- P&A - Oil [Penetrates DMG & Siluro-Devonian] (1)
- P&A - Gas [Penetrates DMG & Siluro-Devonian] (1)



Salt Creek AGI No. 2 & No. 3

Injection Zone-Penetrating Oil & Gas Wells

within the Maximum Monitoring Area

Northwind Midstream Partners LLC

Lea County, NM

Drawn by: SJL	Date: 7/1/2024	Approved by: SLP

PCS: NAD 1983 State Plane NM-E FIPS 3001 (US Ft.)

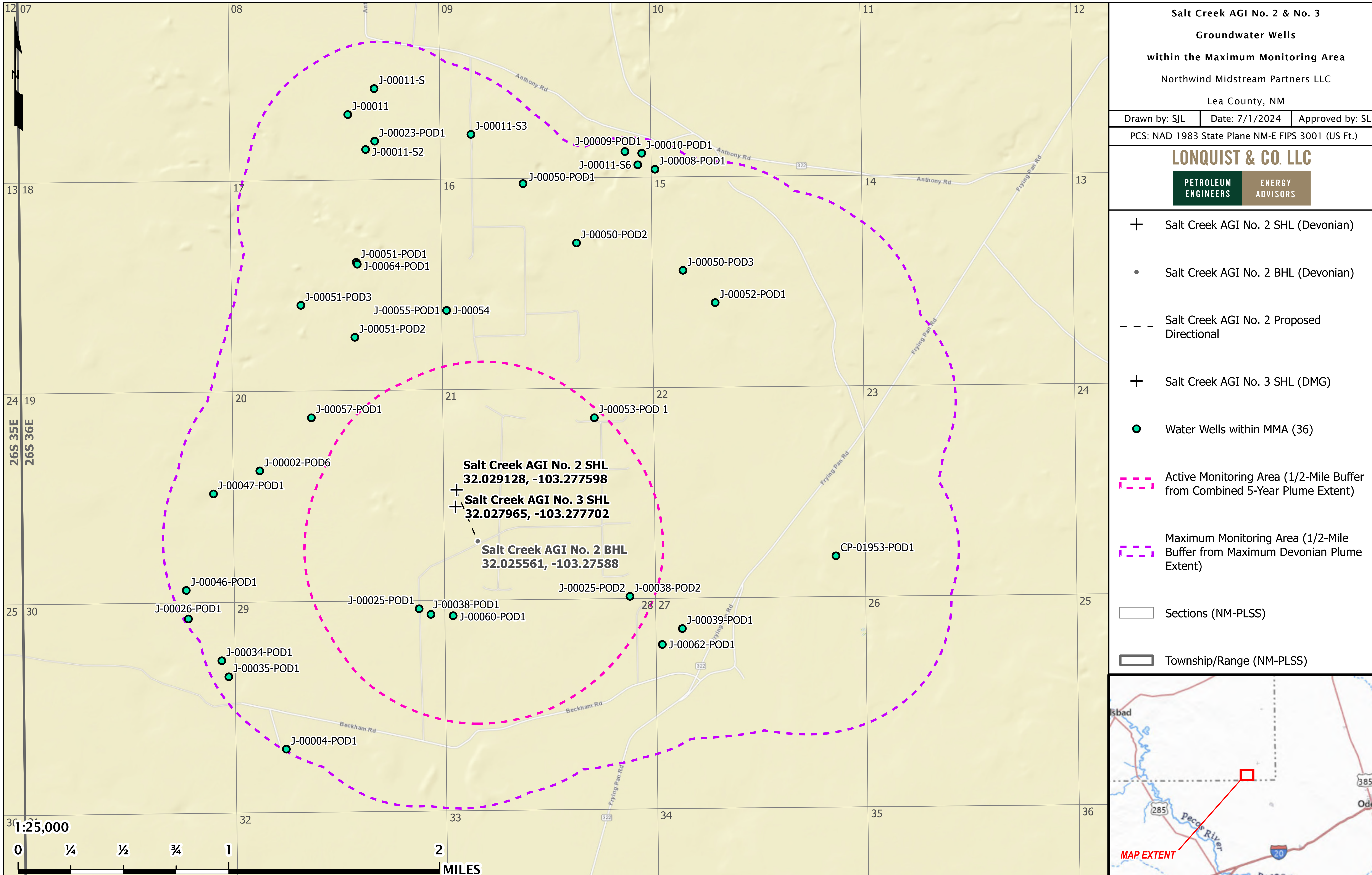
LONQUIST & CO. LLC

PETROLEUM ENGINEERS | ENERGY ADVISORS

- Salt Creek AGI No. 2 SHL (Devonian)
- Salt Creek AGI No. 2 BHL (Devonian)
- Salt Creek AGI No. 2 Proposed Directional
- Salt Creek AGI No. 3 SHL (DMG)
- DMG Plume Extent (Salt Creek AGI No. 3, End of 30-Year Injection)
- DMG Plume Extent (Salt Creek AGI No. 3, 50 Years Post-Injection)
- Devonian Plume Extent (Salt Creek AGI No. 2, End of 30-Year Injection)
- Devonian Plume Extent (Salt Creek AGI No. 2, 50 Years Post-Injection)
- Maximum Monitoring Area (1/2-Mile Buffer from Maximum Devonian Plume Extent)
- Abstracts (TX-RexTag)
- Sections (NM-PLSS)
- Township/Range (NM-PLSS)
- Counties
- States
- Oil & Gas Well Laterals (API: 30-025-...)

Oil & Gas Well SHLs (API: 30-025-...)

- Producing - Oil [Only penetrates DMG] (10)
- Producing - Gas [Only penetrates DMG] (1)
- Drilled - Oil [Only penetrates DMG] (3)
- DUC - AGI [Only penetrates DMG] (1)
- Permitted - Oil [Only penetrates DMG] (61)
- P&A - Oil [Only penetrates DMG] (3)
- P&A - Oil [Penetrates DMG & Siluro-Devonian] (1)
- P&A - Gas [Penetrates DMG & Siluro-Devonian] (1)



Salt Creek AGI No. 2 & No. 3
Groundwater Wells
within the Maximum Monitoring Area
Northwind Midstream Partners LLC
Lea County, NM
Drawn by: SJL
Date: 7/1/2024
Approved by: SLP
PCS: NAD 1983 State Plane NM-E FIPS 3001 (US Ft.)
LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
Salt Creek AGI No. 2 SHL (Devonian)
Salt Creek AGI No. 2 BHL (Devonian)
Salt Creek AGI No. 2 Proposed Directional
Salt Creek AGI No. 3 SHL (DMG)
Water Wells within MMA (36)
Active Monitoring Area (1/2-Mile Buffer from Combined 5-Year Plume Extent)
Maximum Monitoring Area (1/2-Mile Buffer from Maximum Devonian Plume Extent)
Sections (NM-PLSS)
Township/Range (NM-PLSS)
Salt Creek AGI No. 2 SHL
32.029128, -103.277598
Salt Creek AGI No. 3 SHL
32.027965, -103.277702
Salt Creek AGI No. 2 BHL
32.025561, -103.27588
J-00011-S
J-00011
J-00023-POD1
J-00011-S2
J-00011-S3
J-00009-POD1
J-00010-POD1
J-00011-S6
J-00008-POD1
J-00050-POD1
J-00050-POD2
J-00050-POD3
J-00051-POD1
J-00064-POD1
J-00051-POD3
J-00055-POD1
J-00054
J-00052-POD1
J-00051-POD2
J-00057-POD1
J-00053-POD 1
J-00002-POD6
J-00047-POD1
CP-01953-POD1
J-00046-POD1
J-00025-POD2
J-00038-POD2
J-00026-POD1
J-00025-POD1
J-00038-POD1
J-00060-POD1
J-00039-POD1
J-00062-POD1
J-00034-POD1
J-00035-POD1
J-00004-POD1
Anthony Rd
Frying Pan Rd
Beckham Rd
26S 35E
26S 36E
N
1:25,000
0
¼
½
¾
1
2
MILES
MAP EXTENT
Pecos River
Odess
lsbad

Area of Review: Groundwater Wells List

POD FILE NO.	OWNER'S NAME	OWNER ADDRESS	CITY/STATE/ZIP	LAT. NAD 83	LONG. Nad 83	WELL USE	WATER LEVEL (FT.)	TOTAL DEPTH (FT.)	DATE DRILLED
CP-01953-POD1	AMEREDEV OPERATING LLC	2901 VIA FORTUNA SUITE 600	AUSTIN, TX 78746	32.024316	-103.246919	EXPLORATION	0	101	5/23/2023
J-00002-POD6	CITY OF JAL	PO DRAWER 340	JAL, NM 88252	32.030559	-103.293448	MUNICIPAL	216	710	9/4/1980
J-00004-POD1	NGL SOUTH RANCH INC	3773 CHERRY CREEK NORTH DRIVE	DENVER, CO 80209	32.011364	-103.291517	COMMERCIAL	510	510	1/16/2018
J-00008-POD1	INTREPID POTASH NEW MEXICO LLC	1001 17TH STREET SUITE 1050	DENVER, CO 80202	32.051084	-103.26125	LIVESTOCK	0	175	NR
J-00009-POD1	INTREPID POTASH NEW MEXICO LLC	1001 17TH STREET SUITE 1050	DENVER, CO 80202	32.052325	-103.263665	LIVESTOCK	0	175	NR
J-00010-POD1	INTREPID POTASH NEW MEXICO LLC	1001 17TH STREET SUITE 1050	DENVER, CO 80202	32.052195	-103.262305	DOMESTIC & LIVESTOCK	0	NR	NR
J-00011	INTREPID POTASH NEW MEXICO LLC	1001 17TH STREET SUITE 1050	DENVER, CO 80202	32.055057	-103.286056	IRRIGATION	410	563	5/18/2011
J-00011-S	DINWIDDIE CATTLE COMPANY LLC	PO BOX 195	JAL, NM 88252	32.056831	-103.283904	COMMERCIAL	225	757	4/30/2013
J-00011-S2	INTREPID POTASH NEW MEXICO LLC	1001 17TH STREET SUITE 1050	DENVER, CO 80202	32.052639	-103.284639	IRRIGATION	209	835	4/17/2013
J-00011-S3	DINWIDDIE CATTLE COMPANY LLC	PO BOX 195	JAL, NM 88252	32.053611	-103.276111	COMMERCIAL	135	546	2/13/2012
J-00011-S6	INTREPID POTASH NEW MEXICO LLC	1001 17TH STREET SUITE 1050	DENVER, CO 80202	32.0514	-103.262634	IRRIGATION	0	NR	NR
J-00023-POD1	JAY ANTHONY	PO BOX 398	JAL, NM 88252	32.053205	-103.283898	EXPLORATION	0	NR	NR
J-00025-POD1	NGL SOUTH RANCH INC	3773 CHERRY CREEK NORTH DRIVE SUITE 1000	DENVER, CO 80209	32.020951	-103.280668	COMMERCIAL	0	NR	NR
J-00025-POD2	NGL SOUTH RANCH INC	3773 CHERRY CREEK NORTH DRIVE SUITE 1000	DENVER, CO 80209	32.021667	-103.263611	COMMERCIAL	0	800	3/16/2017
J-00026-POD1	NGL SOUTH RANCH INC	3773 CHERRY CREEK NORTH DRIVE SUITE 1000	DENVER, CO 80209	32.020403	-103.299333	COMMERCIAL	285	571	7/4/2013

LONQUIST SEQUESTRATION LLC

J-00034-POD1	NGL SOUTH RANCH INC	3773 CHERRY CREEK NORTH DRIVE SUITE 1000	DENVER, CO 80209	32.0175	-103.296667	LIVESTOCK	250	506	10/14/2014
J-00035-POD1	NGL SOUTH RANCH INC	3773 CHERRY CREEK NORTH DRIVE SUITE 1000	DENVER, CO 80209	32.016389	-103.296112	LIVESTOCK	250	506	10/20/2014
J-00038-POD1	BRAD BECKHAM	PO BOX 1203	JAL, NM 88252	32.020556	-103.279723	EXPLORATION	0	NR	NR
J-00038-POD2	JOEL STEWART	PO BOX 2067	MILAN, NM 87021	32.021667	-103.263611	EXPLORATION	0	NR	NR
J-00039-POD1	R T HICKS CONSULTANTS	901 RIO GRANDE BLVD NW SUITE F-142	ALBUQUERQUE, NM 87104	32.019408	-103.2594	SANITARY W/ COMMERCIAL	0	NR	NR
J-00046-POD1	CITY OF JAL	PO DRAWER 340	JAL, NM 88252	32.022369	-103.299486	EXPLORATION	0	NR	NR
J-00047-POD1	CITY OF JAL	PO DRAWER 340	JAL, NM 88252	32.029003	-103.297211	EXPLORATION	0	171	10/20/2020
J-00050-POD1	CITY OF JAL	PO BOX 340	JAL, NM 88252	32.050183	-103.271933	EXPLORATION	0	997	1/23/2023
J-00050-POD2	GLORIETA GEOSCIENCE INC	PO BOX 5727	SANTA FE, NM 87502	32.046055	-103.26765	EXPLORATION	0	1005	1/27/2023
J-00050-POD3	CITY OF JAL	PO BOX 340	JAL, NM 88252	32.044097	-103.259064	EXPLORATION	0	NR	NR
J-00051-POD1	CITY OF JAL	PO DRAWER 340	JAL, NM 88252	32.044867	-103.285483	EXPLORATION	0	901	1/6/2023
J-00051-POD2	GLORIETA GEOSCIENCE INC	PO BOX 5727	SANTA FE, NM 87502	32.039703	-103.285658	EXPLORATION	0	1005	1/12/2023
J-00051-POD3	GLORIETA GEOSCIENCE INC	PO BOX 5727	SANTA FE, NM 87502	32.041942	-103.29	EXPLORATION	0	1119	1/18/2023
J-00052-POD1	CITY OF JAL	PO BOX 340	JAL, NM 88252	32.04185	-103.25648	EXPLORATION	0	1000	1/23/2023
J-00053-POD 1	AMEREDEV OPERATING LLC	2901 VIA FORTUNA SUITE 600	AUSTIN, TX 78746	32.033998	-103.266348	EXPLORATION	0	101	9/27/2022
J-00054	AMEREDEV OPERATING,LLC	2901 VIA FORTUNA STE 600	AUSTIN, TX 78746	32.041494	-103.278214	MONITORING	0	101	5/22/2023
J-00055-POD1	AMEREDEV OPERATING, LLC	2901 VIA FORTUNA STE 600	AUSTIN, TX 78746	32.041494	-103.278211	MONITORING	0	101	5/11/2023

LONQUIST SEQUESTRATION LLC

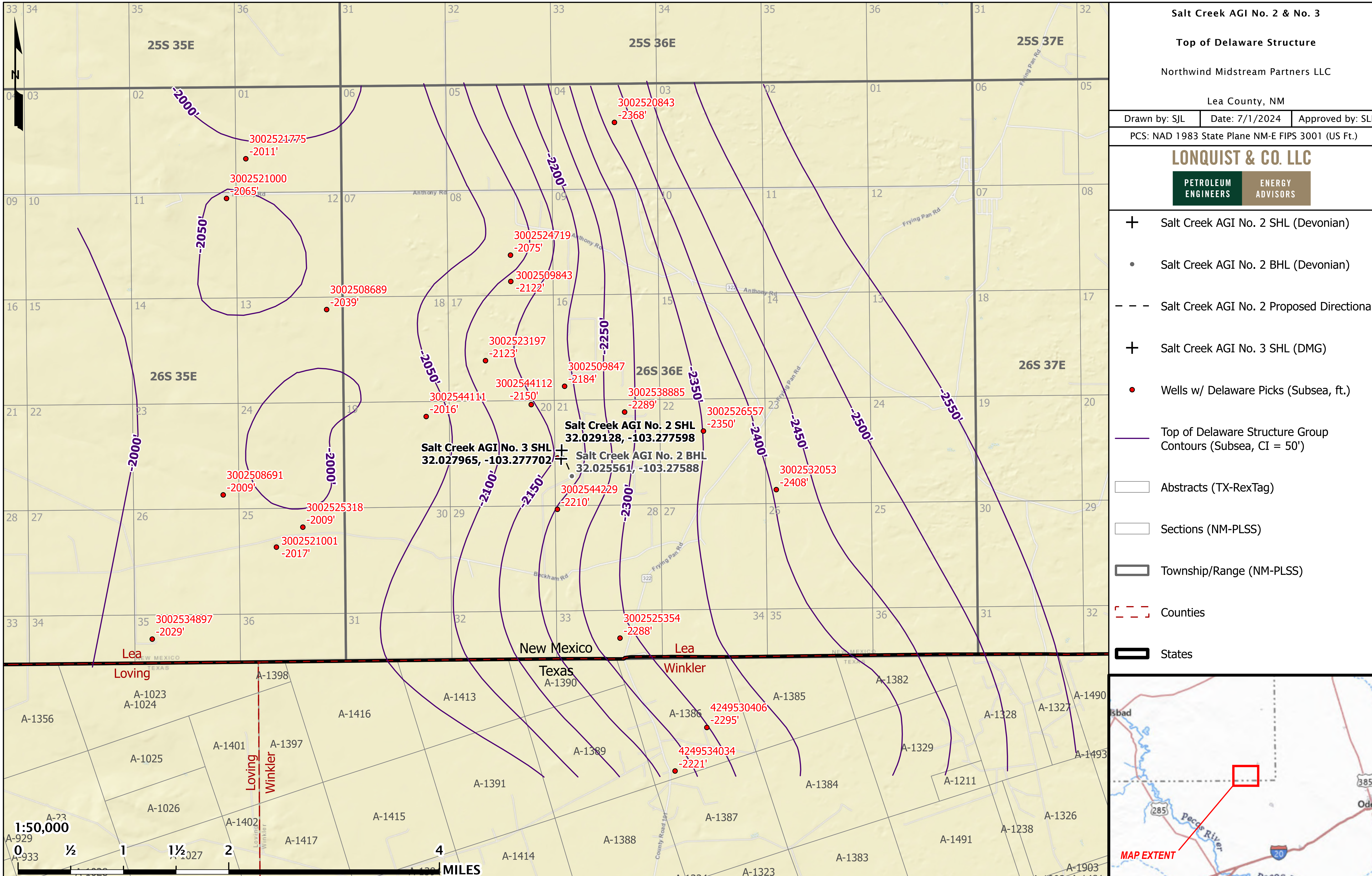
J-00057-POD1	AMEREDEV OPERATING LLC	2901 VIA FORTUNA STE 600	AUSTIN, TX 78746	32.034183	-103.289233	MONITORING	0	101	5/12/2023
J-00060-POD1	AMEREDEV OPERATING LLC	2901 VIA FORTUNA SUITE 600	AUSTIN, TX 78746	32.02045	-103.277923	EXPLORATION	0	101	5/2/2023
J-00062-POD1	AMEREDEV OPERATING LLC	2901 VIA FORTUNA SUITE 600	AUSTIN, TX 78746	32.018327	-103.261031	EXPLORATION	0	101	2/21/2023
J-00064-POD1	PAUL DRAKOS	PO BOX 5727	SANTA FE, NM 87502	32.044739	-103.285403	EXPLORATION	0	NR	NR

APPENDIX D – GEOLOGY

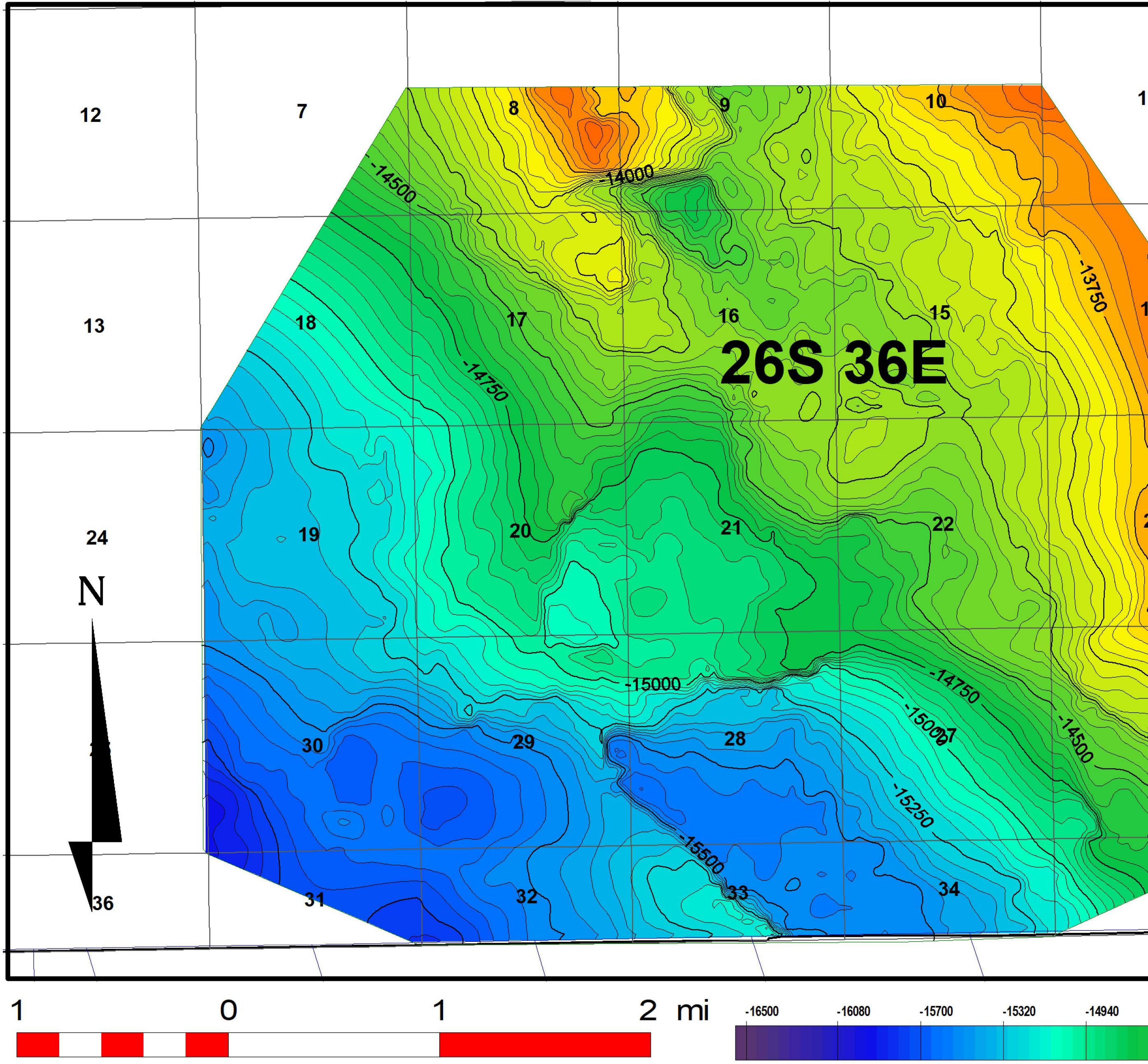
Appendix D-1 – Structure map of top of the Delaware Mountain Group

Appendix D-2 – Structure map of top of the Siluro-Devonian

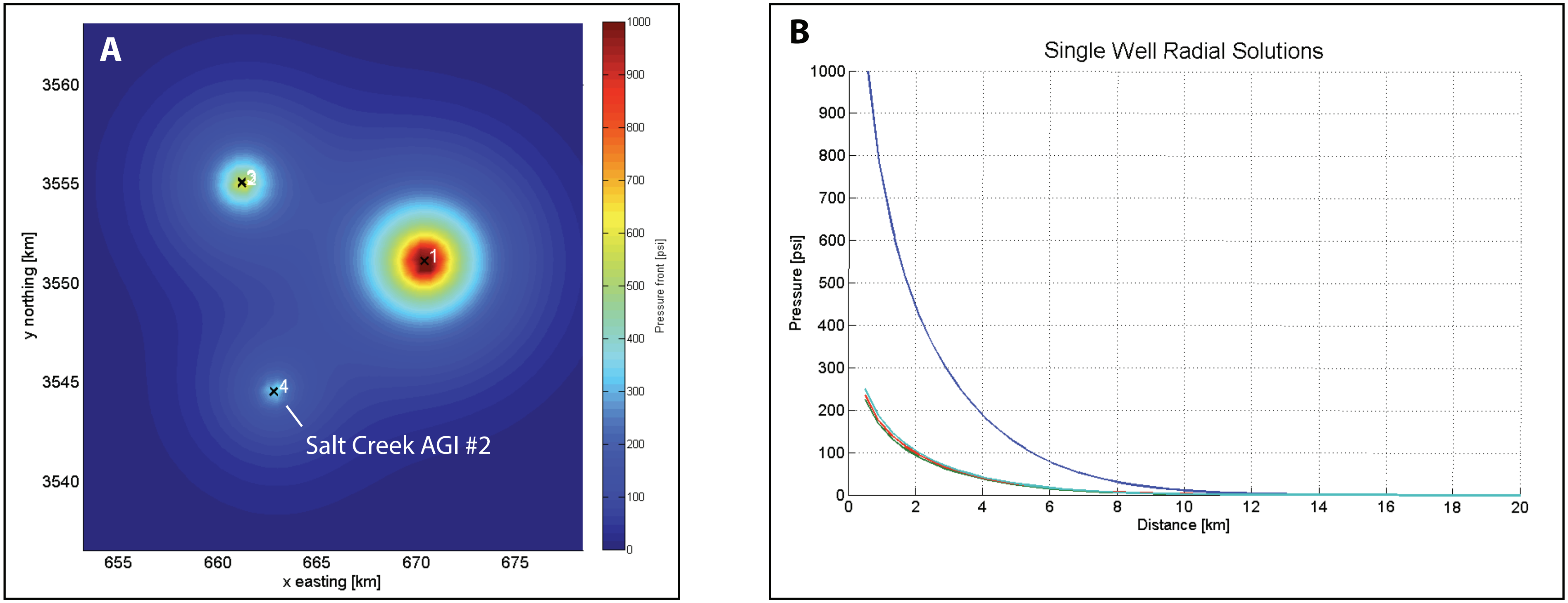
Appendix D-3 – Fault Slip potential model results



Salt Creek AGI No. 2 & No. 3
Top of Delaware Structure
Northwind Midstream Partners LLC
Lea County, NM
Drawn by: SJL
Date: 7/1/2024
Approved by: SLP
PCS: NAD 1983 State Plane NM-E FIPS 3001 (US Ft.)
LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
Salt Creek AGI No. 2 SHL (Devonian)
Salt Creek AGI No. 2 BHL (Devonian)
Salt Creek AGI No. 2 Proposed Directional
Salt Creek AGI No. 3 SHL (DMG)
Wells w/ Delaware Picks (Subsea, ft.)
Top of Delaware Structure Group Contours (Subsea, CI = 50')
Abstracts (TX-RexTag)
Sections (NM-PLSS)
Township/Range (NM-PLSS)
Counties
States
MAP EXTENT
25S 35E
25S 36E
25S 37E
26S 35E
26S 36E
26S 37E
Salt Creek AGI No. 2 SHL
32.029128, -103.277598
Salt Creek AGI No. 3 SHL
32.027965, -103.277702
Salt Creek AGI No. 2 BHL
32.025561, -103.27588
3002520843
-2368'
3002521775
-2011'
3002521000
-2065'
3002524719
-2075'
3002509843
-2122'
3002508689
-2039'
3002523197
-2123'
3002509847
-2184'
3002544112
-2150'
3002544111
-2016'
3002538885
-2289'
3002526557
-2350'
3002532053
-2408'
3002544229
-2210'
3002508691
-2009'
3002525318
-2009'
3002521001
-2017'
3002534897
-2029'
3002525354
-2288'
4249530406
-2295'
4249534034
-2221'
New Mexico
Texas
Lea
Loving
Winkler
1:50,000
MILES



Schlumberger BlueView :



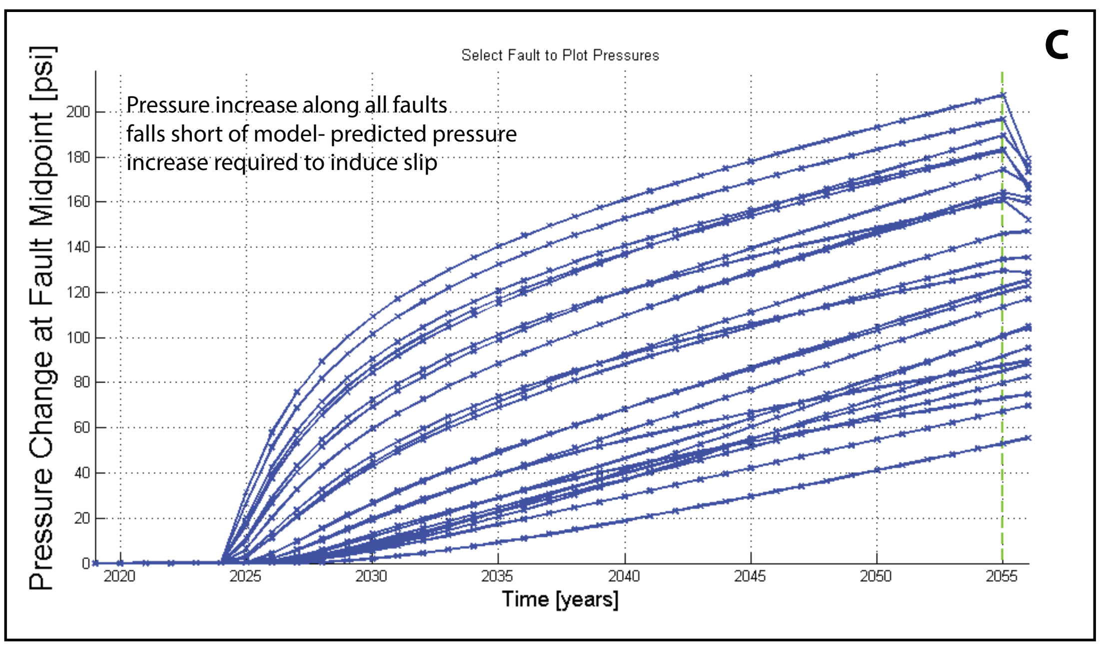
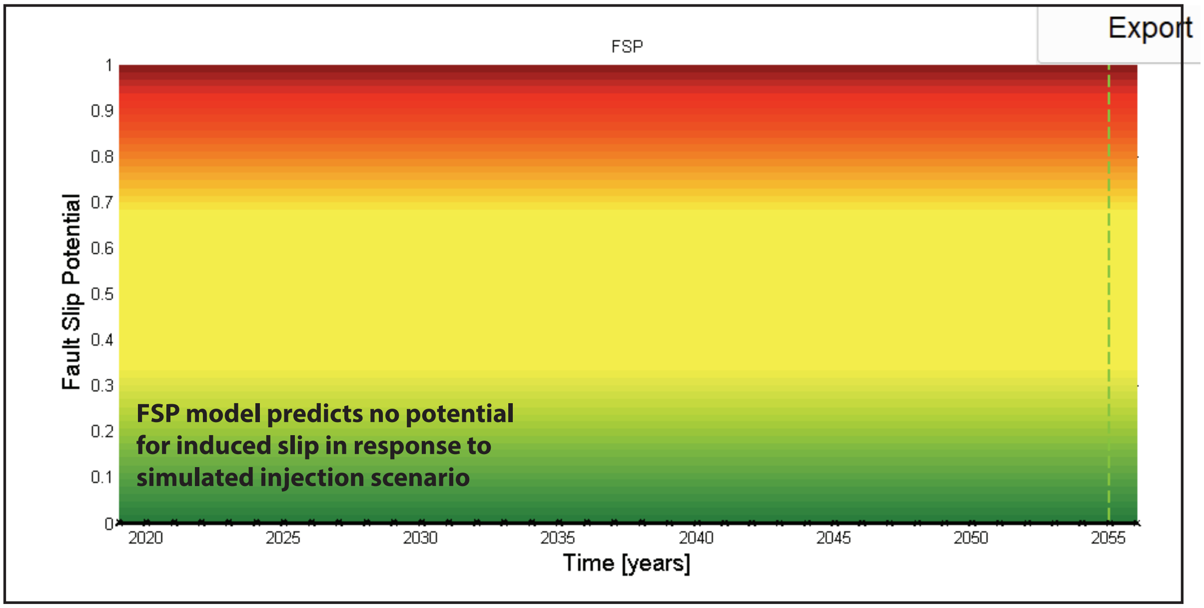


Figure 8. Summary of FSP model-predicted pressure front effects in the year 2055, from injection wells near the permitted Salt Creek AGI #2 (shown in Panel A as Well #4) that are actively injecting within the Siluro-Devonian formations.



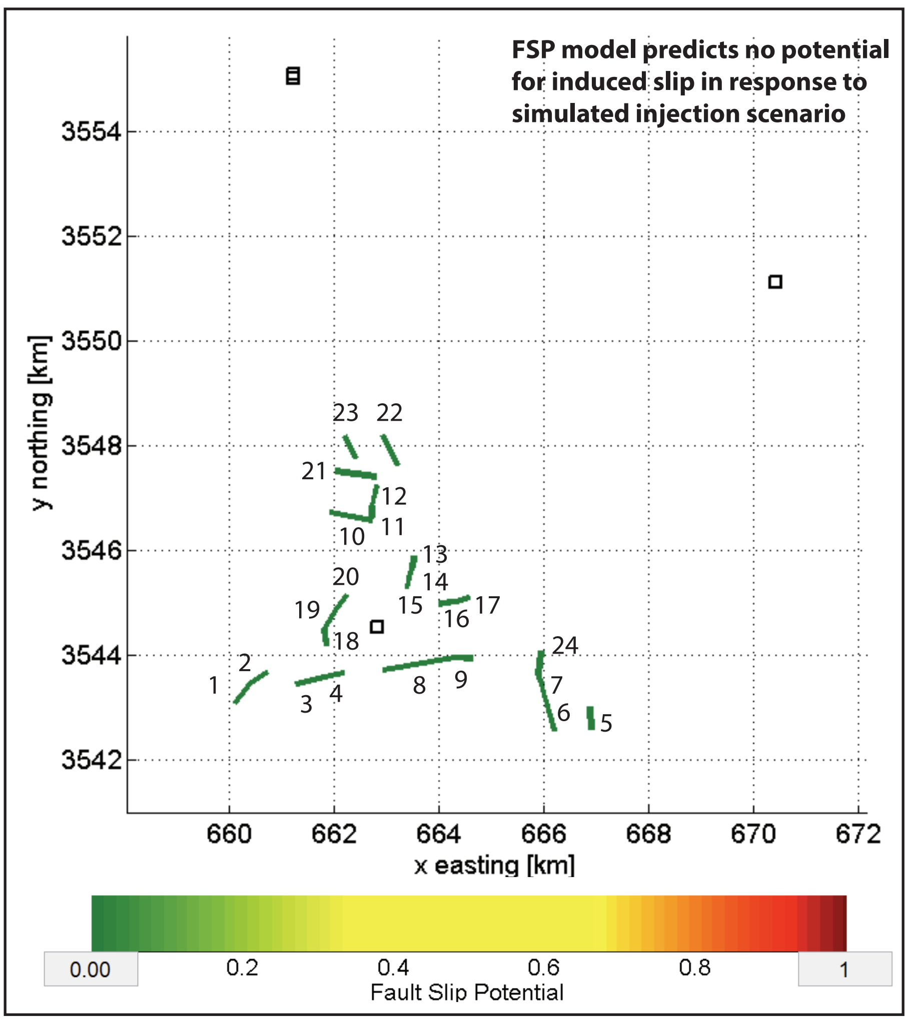


Figure 9. Model-predicted fault-slip potential after 30 years (Panel A) of injection operations at maximum daily volume conditions. Injection operations proposed for Salt Creek AGI #2 will have little impact on faults in the area and indicate no risk of increasing the likelihood of induced seismicity in the region (Panel B).