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**Subpart RR Monitoring, Reporting, and
Verification Plan
Libby AGI No. 1 and Libby AGI No. 2**

Lea County, New Mexico

Prepared for DKL Delaware Operating - NM, LLC
Hobbs, New Mexico

By

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Revised
September 2025



INTRODUCTION

DKL Delaware Operating - NM, LLC (Delek) has submitted a C-101 Application for Permit to Drill to the New Mexico Oil Conservation Division (NMOCD) for the Libby AGI (acid gas injection) No. 1 Class II well. The Libby AGI No. 1 (Libby No. 1) well will provide Delek with the needed oil and gas waste disposal capacity for the DKL Libby Gas Plant. The Libby AGI No. 2 (Libby No. 2) well will provide the redundant disposal capacity required by the New Mexico Oil Conservation Division.

Additionally, Delek has received the approved C-108 Application for Authorization to Inject (Order No. R-20694) to support the disposal of oil and gas waste from the nearby DKL Libby Gas Plant located in Lea County, New Mexico. As shown in Figure 1, the DKL Libby Gas Plant is located approximately 23 miles southwest of Hobbs, New Mexico, in a sparsely populated area of Lea County. The Libby No. 1 well is scheduled to begin construction in the first Quarter of 2026 and be in operation by the second Quarter of 2026. Delek is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the United States Environmental Protection Agency (EPA) for approval under 40 CFR **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). An approved MRV Plan enables Delek to sequester significant amounts of carbon dioxide (CO₂), thereby reducing carbon emissions in the region.

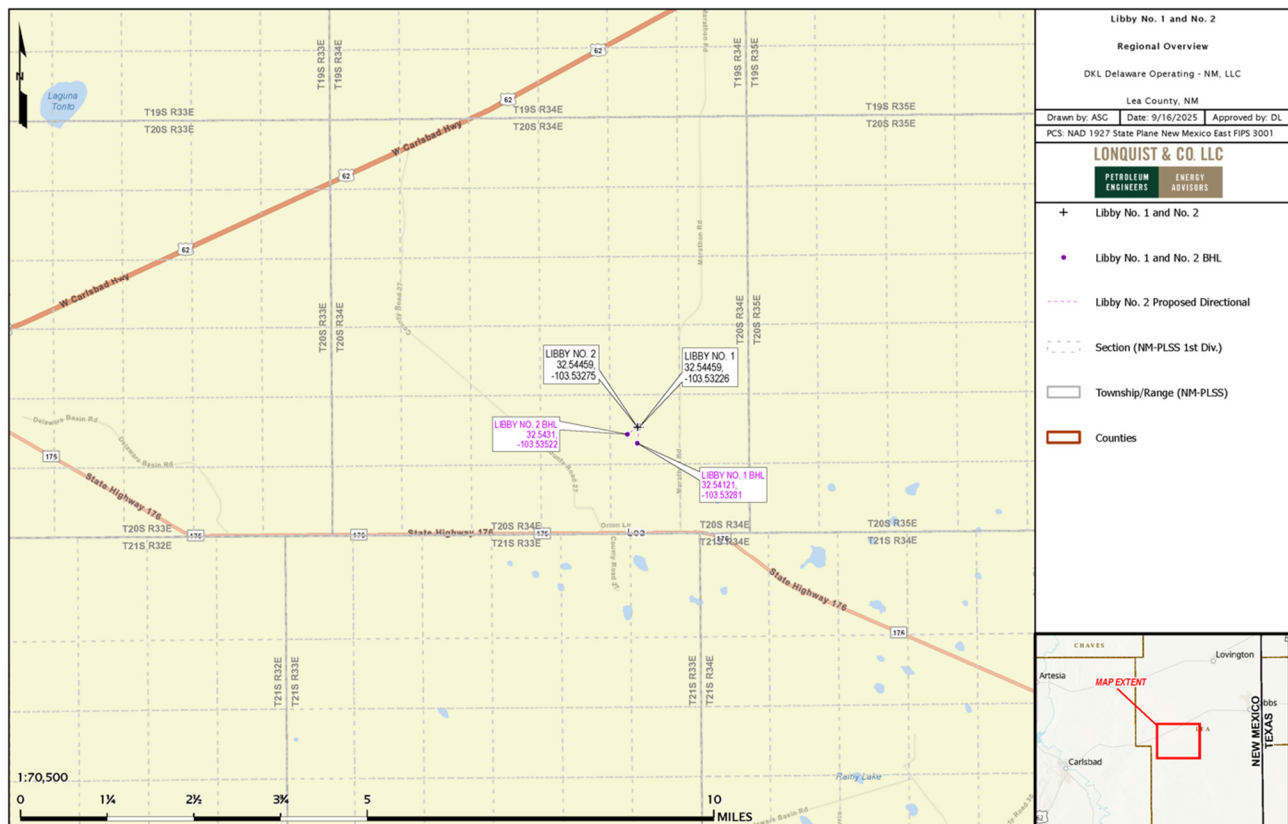


Figure 1 – Location of the Libby No. 1 and No. 2 Wells and the DKL Libby Gas Plant.

ACRONYMS AND ABBREVIATIONS

40 CFR	Title 40, U.S. Code of Federal Regulations
AAPG	American Association of Petroleum Geologists
AGI	acid gas injection
AMA	active monitoring area
API	American Petroleum Institute
BHP	bottomhole pressure
BUQW	Base of Usable Quality Water
CFR	U.S. Code of Federal Regulations
DCSM	Distribution Control System Monitoring
EOS	equation of state
EPA	U.S. Environmental Protection Agency
ESD	emergency shutdown (valve)
FG	fracture gradient
Ft	foot/feet
GHG	greenhouse gas (emissions)
GHGRP	Greenhouse Gas Reporting Program
ILD	deep induction log
Ma	million years ago
mD	millidarcy
mg/L	milligrams per liter
MIT	mechanical integrity test
MMA	maximum monitoring area
MMscf/d	million standard cubic feet per day
MMT	million metric tons
MRV	Monitoring, Reporting, and Verification
NAD	North American Datum
NIST	National Institute of Standards and Technology
NMOCD	New Mexico Oil Conservation Division

NMTSO	New Mexico Tech Seismological Observatory
NSHM	National Seismic Hazard Model
OBG	overburden gradient
OSE	Office of the State Engineer
OSHA	Occupational Safety and Health Administration
ppm	parts per million
psi/ft	pounds per square inch per foot
QA/QC	quality assurance/quality control
RSC	residual sodium carbonate
SAR	sodium-adsorption ratio
SWD	Saltwater disposal
SCADA	Supervisory Control and Data Acquisition
SP	spontaneous potential
TDS	total dissolved solids
TEC	tubing encapsulated conductor
TVD	true vertical depth
TVDSS	true vertical depth subsea
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey

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SECTION 1 – FACILITY INFORMATION

Key information regarding the CO₂ & H₂S injection facilities is described in this section.

1.1 Reporter Number:

- Greenhouse Gas Facility Name: DKL Libby Gas Plant
- Greenhouse Gas Reporting Program ID: 573821
- Operator: DKL Delaware Operating - NM, LLC
- Location:
 - Latitude: 32° 32.44' N
 - Longitude: 103° 31.34' W

1.2 Underground Injection Control Permit Class: Class II

The NMOCD regulates oil and gas activities in New Mexico and has primacy over implementing the Underground Injection Control (UIC) Class II Program. On July 18, 2019, the NMOCD approved a Class II oil and gas waste permit for the Libby No. 1 and No. 2 wells.

1.3 UIC Well Identification Number:

Libby No. 1 (Devonian):

American Petroleum Institute (API) No. 30-025-54599
Order No.: R-20694
Surface Location: 32.54459, -103.53226 (North America Datum [NAD] 83)

Libby No. 2 (Devonian):

API No. TBD
Order No. R-20694
Location: 32.54459, -103.53275 (NAD 83)

API Numbers are assigned upon issuance of the C-101 Permit to Drill.

1.4 Facility Address

674 Marathon Road
Hobbs, New Mexico 88240

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection volumes, and reservoir modeling prepared by Lonquist Sequestration, LLC, for the Libby No. 1 and No. 2 wells. The Libby No. 1 and No. 2 wells will inject an acid gas stream consisting of both hydrogen sulfide (H₂S) and CO₂ into the Siluro-Devonian. The DKL Libby Gas Plant and the Libby No. 1 and No. 2 wells are designed to protect against leakage from the mechanical components and out of the injection interval to protect against contaminating other formations and prevent surface releases.

The Libby No. 1 and No. 2 well locations and facilities construction are engineered to protect against CO₂ migration into productive oil and gas formations and Underground Sources of Drinking Water (USDWs). The Siluro-Devonian injection zone for these wells is overlain by the regionally extensive Woodford Shale to act as a barrier and safeguard subsurface resources from undesired contamination. Lower confinement is to be provided by tight limestone and claystone interbeds of the underlying Montoya Formation and Simpson Group.

2.1 Sources of CO₂

The acid gas stream to be injected into the Libby No. 1 and No.2 wells originates from the amine unit at the DKL Libby Gas Plant. From the amine unit, the acid gas stream will be measured, sampled, pumped to the nearby Libby No. 1 and No. 2 wells, and injected into the Siluro-Devonian disposal formation. The acid gas stream from the DKL Libby Gas Plant is currently the only source of CO₂ to be injected into the Libby No. 1 and No. 2 wells.

The DKL Libby Gas Plant only processes hydrocarbons and associated CO₂ produced from formations shallower than the Siluro-Devonian. Hydrocarbons and other components of the inlet stream for the DKL Libby Gas Plant are from formations shallower than the Siluro-Devonian, such as the Yates, Bone Spring, and Wolfcamp. There are no producing wells or production from the Siluro-Devonian Formation within the maximum monitoring area (MMA), where the CO₂ is injected and sequestered.

2.2 Regional Geology

The Libby No.1 and No.2 wells (sited adjacent to the DKL Libby Gas Plant) are situated in the northeastern portion of the Delaware Basin, within the larger Permian Basin, as seen in Figure 2. The Delaware Basin is the major Western structural subbasin of the Permian Basin and is contained by the Diablo Platform to the west, the Central Basin Platform to the east, the Northwest Shelf to the north, and the Marathon-Ouachita Fold Belt to the south.

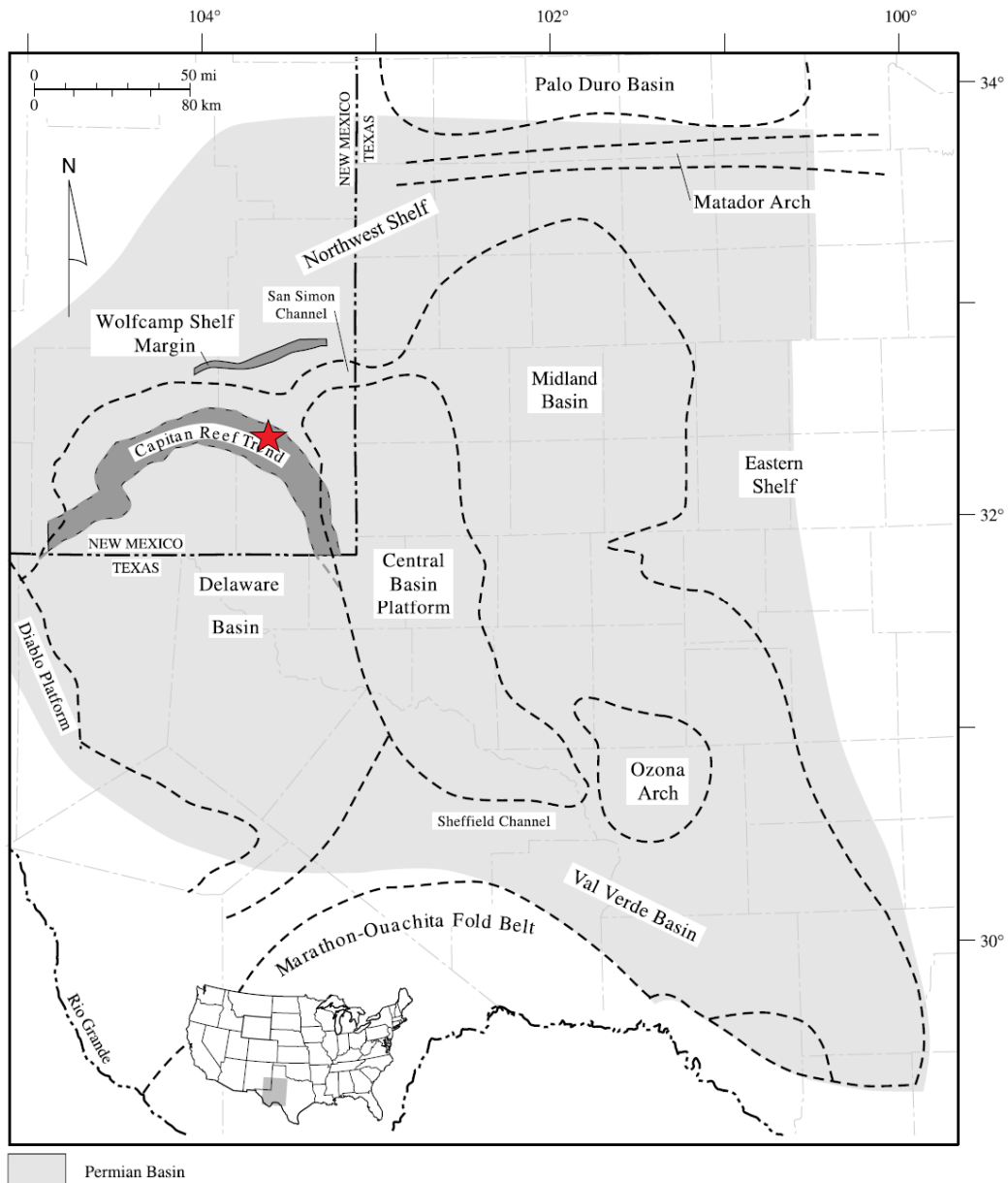


Figure 2 – Regional Map of the Permian Basin. The red star is the approximate location of the DKL Libby Gas Plant (modified from Dutton, et al., 2005).

Figure 3 depicts the stratigraphic column as found in the area of the DKL Libby Gas Plant, noted with red stars referencing the injection formations, purple stars referencing confining zones, and black stars indicating productive intervals in the maximum monitoring area (MMA).

The injection interval for the Libby No. 1 and No.2 wells is found within the gross “Silurian-Devonian” (or “Siluro-Devonian”) geologic section. The Siluro-Devonian includes the Thirtyone Formation, Wristen Group, and Fusselman Formation, as clarified by the detailed stratigraphic column presented in Figure 4. For this permit application, the nomenclature of the targeted formations is simply referred to as the Woodford Shale, Siluro-Devonian, and Simpson Group.

System	Epoch/ Series/ Stage	Time (Ma)	Delaware basin	NW Shelf New Mexico	NW Shelf Texas	Central Basin Platform	Midland basin			
PERMIAN	Ochoan	251	Delaware basin	NW Shelf New Mexico	NW Shelf Texas	Central Basin Platform	Midland basin			
			Dewey Lake	Dewey Lake	Dewey Lake	Dewey Lake	Dewey Lake			
			Rustler	Rustler	Rustler	Rustler	Rustler			
			Salado	Salado	Salado	Salado	Salado			
	Guadalupian			Castile	Castile	Castile				
				Delaware Mountain Group	Tansill	Tansill	Tansill	Tansill	Tansill	
					Bell Canyon	Yates	Yates	Yates	Yates	
					Cherry Canyon	Seven Rivers	Seven Rivers	Seven Rivers	Seven Rivers	
						Queen	Queen	Queen	Queen	
				Grayburg	Grayburg	Grayburg	Grayburg	Grayburg		
				Upper San Andres	Upper San Andres	Upper San Andres	Upper San Andres	Upper San Andres		
				Brushy Canyon						Brushy Canyon
				Leonardian			Bone Spring	Glorieta	Glorieta	Glorieta
	Paddock	Upper Clear Fork	Upper Clear Fork					Upper Clear Fork		
	Blinberry	Middle Clear Fork	Middle Clear Fork					Middle Clear Fork		
	Tabb	Lower Clear Fork	Lower Clear Fork					Lower Clear Fork		
	Wolfcampian			Wolfcamp	Abo	Abo	Abo/Wichita	Abo		
PENNSYLVANIAN	Virgilian	302	Cisco	Cisco	Cisco	Cisco	Cisco			
	Missourian		Canyon	Canyon	Canyon	Canyon	Canyon			
	Desmoinesian		Strawn	Strawn	Strawn	Strawn	Strawn			
	Atokan		Atoka	Atoka	Atoka	Atoka	Atoka/Bend			
MISSISSIPPIAN	Chesterian	323	Morrow	Morrow	Morrow					
	Meramecian		Barnett	Barnett	Barnett	Barnett	Barnett			
	Osagean		Mississippian	Mississippian	Mississippian	Mississippian	Mississippian			
DEVONIAN	Kinderhookian	363	Woodford	Woodford	Woodford	Woodford	Woodford			
	Famennian									
	Frasnian									
	Givetian									
	Eifelian									
	Pragian									
SILURIAN	Lochkovian	417	Thirtyone		Thirtyone	Thirtyone	Thirtyone			
	Pridolian		Wristen Group	Wristen Group	Wristen Group	Wristen Group	Wristen Group			
	Ludlovian									
	Wenlockian									
ORDOVICIAN	Llandoveryan	443	Fusselman	Fusselman	Fusselman	Fusselman	Fusselman			
	Ashgillian		Montoya	Montoya	Montoya	Montoya	Montoya			
	Caradocian									
	Llandeilian		Bromide			Bromide	Bromide			
	Llanvirnian		Tulip Creek			Tulip Creek	Tulip Creek			
	Arenigian		McLish			McLish	McLish			
Tremadocian	Oil Creek			Oil Creek	Oil Creek					
CAMBRIAN		495	Ellenburger	Ellenburger	Ellenburger	Ellenburger	Ellenburger			
			Bliss	Bliss	Bliss	Cambrian	Cambrian			

Figure 3 – Regional stratigraphic column of the Permian Basin. Red stars indicate injection zone, purple stars indicate confining zones, and black stars indicate productive intervals (modified from Dutton, et al., 2005).

System	Series	Lithostratigraphic unit	
Mississippian	Chesterian	undivided	
	Meramecian		
	Osagian		
	Kinderhookian		
Devonian	Upper	★ Woodford Shale	
	Middle		
	Lower	★ Thirtyone Fm.	
Silurian	Pridolian	★ Wristen Gp.	Frame Fm.
	Ludlovian		Fasken Fm.
	Wenlockian		Wink Fm.
	Llandoveryan		
		★ Fusselman Fm.	
Ordovician	Upper	★ Montoya Fm.	
	Middle	★ Simpson Gp.	
	Lower	Ellenburger Fm.	

Figure 4 – Stratigraphic column clarifying Siluro-Devonian strata of southeastern New Mexico and underlying and overlying formations. Red stars represent the injection zone, and purple stars represent confining zones (modified from Broadhead, 2005)

2.2.1 Regional Geologic Setting and Stratigraphy

The geologic section of the Permian Basin is underlain by Precambrian basement rock previously exposed to a series of orogenic events approximately ~1.7 to ~1.0 billion years ago. Reactivation of these pre-existing structures over geologic time influenced the development of younger structures, sedimentation, and resulting accumulations within the region (Merrill, et al., 2015).

The ancestral Tabosa Basin, which predates the Permian Basin, began to develop after the Precambrian within a broad cratonic sag in the general vicinity of the present-day Permian Basin (Figure 5). Sedimentation of the Tabosa Basin consisted of Upper Cambrian to Lower Ordovician siliciclastic rocks that were deposited unconformably over the Precambrian crystalline basement (Merrill, et al., 2015; Robinson, 1988). Deposition of Cambrian sediments was highly erratic and resulted in variable distribution patterns, typically less than 100 feet (ft) thick (Robinson, 1988).

Sedimentation during the Ordovician and Devonian time was substantial and primarily consisted of carbonate deposition, but still had occasional secondary input from siliciclastic sediments (Merrill, et al., 2015). This geologic time period includes the deposition of the Montoya and Fusselman Formations, Wristen Group, and Devonian Thirtyone Formation, which are the injection zones of the Libby No. 1 and No. 2 wells. The Siluro-Devonian was influenced by periods of increased tectonic and eustatic activity that resulted in significant erosion, regional unconformities, and extensive paleokarsting, as well as the development of secondary porosity and enhanced permeability. The regional unconformities and lithologic changes made for complicated naming conventions and nomenclatures but are clarified by the stratigraphic column presented in Figure 4. Intervals that underwent longer durations of paleokarsting contain enhanced petrophysical properties and are also more likely to be preserved over time (Merrill, et al., 2015). These are the intervals evaluated for injection. The same section was also selected by the U.S. Geological Survey (USGS) as part of a composite reservoir in their 2012 National Assessment of CO₂ Storage Resources report, attributed to their storage potential and the presence of regionally extensive sealing rocks over the section (Merrill, et al., 2015).

Thirtyone Formation:

The Thirtyone Formation was deposited in an outer platform to basin setting, rich in chert, carbonate sediment, and carbonate debris (Ruppel and Holtz, 1994). The extents and thickness of the Thirtyone Formation are displayed in Figure 6, generally limited to the north by the Wristen platform margin and a Middle Devonian erosion event that truncated a significant portion of the Devonian. The Libby No. 1 and No. 2 injection wells are located beyond the published northern boundary of the Thirtyone Formation and are not anticipated to be present. This is demonstrated in Figure 6, as well as the regional schematic cross section provided in Figure 10 (Ruppel and Holtz, 1994). However, the Thirtyone Formation is included in the gross geologic section since the top of Devonian is referenced in offset wells and nearby “Lea Field” reports production from carbonate underlying the Woodford Shale as “Devonian.” Therefore, injection takes place into the Wristen Group and Fusselman Formation.

Wristen Group:

The Wristen Group is Silurian in age and consists of the Wink, Frame, and Fasken Formations, as clarified by the stratigraphic column in Figure 4. Deposition of the Wristen Group occurred along a broad, shallow-water carbonate platform that extended east-west through central Andrews County. The resulting facies distribution of the group is characterized by grain-rich skeletal carbonates of the Fasken Formation that transition southward into mud-dominated carbonates of the Wink and Frame Formations (Ruppel and Holtz, 1994). The gross thickness of the Wristen Group and the distribution

of incorporated formations are presented in Figure 7. The map suggests the Wristen Group solely consists of the Fasken Formation in the area of the DKL Libby Gas Plant , with an approximate thickness of 1,000 ft. According to Ruppel and Holtz (1994), the Frame Formation is comprised of a “highly diverse assemblage of carbonate lithofacies” that can be generalized into two facies complexes: “platform-margin skeletal wackestones to grainstones and boundstones and inner platform mudstones to pellet and skeletal wackestones to grainstones.”

Fusselman Formation:

The Fusselman Formation consists of a diverse series of shallow-water carbonate facies deposited along a widespread, open-marine, shallow-water carbonate platform. The thickest and most prevalent facies within the Fusselman Formation are gray to pink pelmatozoan grainstones and packstones. Deposition of these facies was occasionally interrupted by periods of increased energy and shoaling, resulting in the deposition of thin ooid grainstone deposits, typically less than 10 ft thick (Ruppel and Holtz, 1994). Regional gross thickness of the Fusselman Formation is presented in Figure 8 along with generalized facies distributions. The map suggests the Fusselman Formation is primarily dolostone in the area of the Libby No. 1 and No. 2 well locations, with an approximate thickness of 600 ft. Dolomitization boundaries of the Fusselman are widespread and suggest the presence of highly cyclic sea levels during deposition. Similar diagenetic features present in the overlying Fasken Formation indicate sea level cyclicity continued through the end of the Silurian and into the Devonian (Ruppel and Holtz, 1994). This is substantiated by regional unconformities observed at the top of Fusselman as well as in the Devonian at the base of the Woodford Shale.

Montoya Formation:

The Montoya Formation underlies the Fusselman Formation and represents earlier development of the same carbonate platform (Ruppel and Holtz, 1994). The Montoya Formation is Ordovician in age but was grouped with the Siluro-Devonian zone because of shared lithology, depositional environment, and stratigraphic positioning above the Simpson Group lower confining zone. The Montoya Formation primarily consists of interbedded limestone, dolostone, and gravel conglomerates with minor amounts of chert and evaporites (Merrill, et al., 2015). The Montoya Formation was deposited in carbonate ramp successions with primary reservoir development occurring in dolomitized facies and poor reservoir development in limestone facies.

Alteration of the Siluro-Devonian in the region includes the development of diagenetic features, such as dolomitization, silica replacement, karsting, and vugular porosity. These features enhanced reservoir development in portions of the Siluro-Devonian by forming secondary porosity and natural fractures while enhancing pore connection and permeability (Ruppel and Holtz, 1994). A thickness and distribution map of the Silurian system is provided in Figure 9 to illustrate the gross thickness of the injection interval. The Silurian system includes both the Wristen Group and the Fusselman Formations, which the map suggests are approximately 1,800 ft thick in the area of the DKL Libby Gas Plant. A regional schematic cross section is provided in Figure 10 to demonstrate the distribution of carbonate rock types introduced above and the regional continuity of the thick Woodford Shale overlying the Siluro-Devonian. A reference line for the cross section can be found in Figure 6, represented by B-B.’

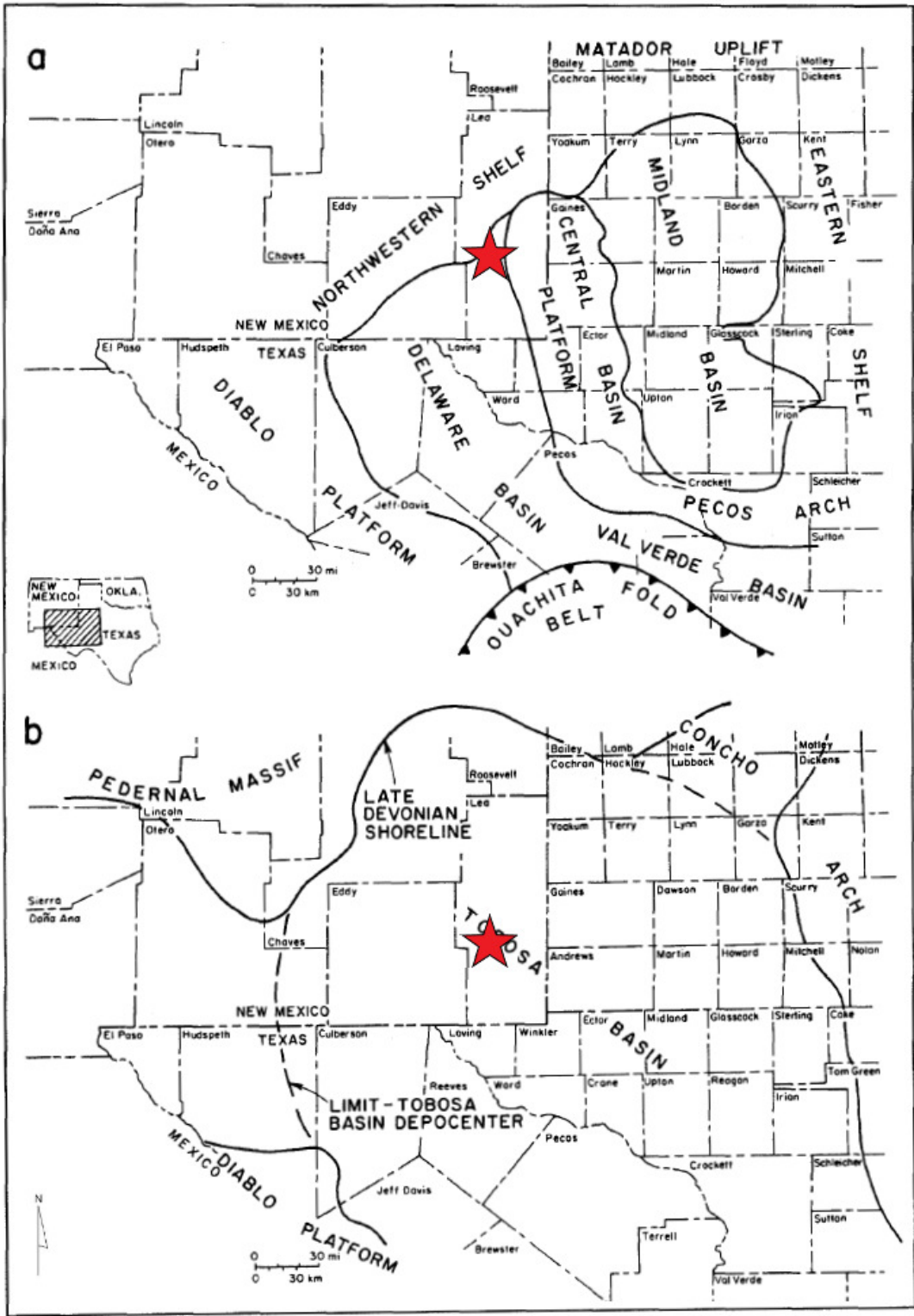


Figure 5 – Paleogeographic map comparison during (a) Late Paleozoic to recent time and (b) Late Devonian. The red star is the approximate location of the DKL Libby Gas Plant (modified from Comer, 1991).

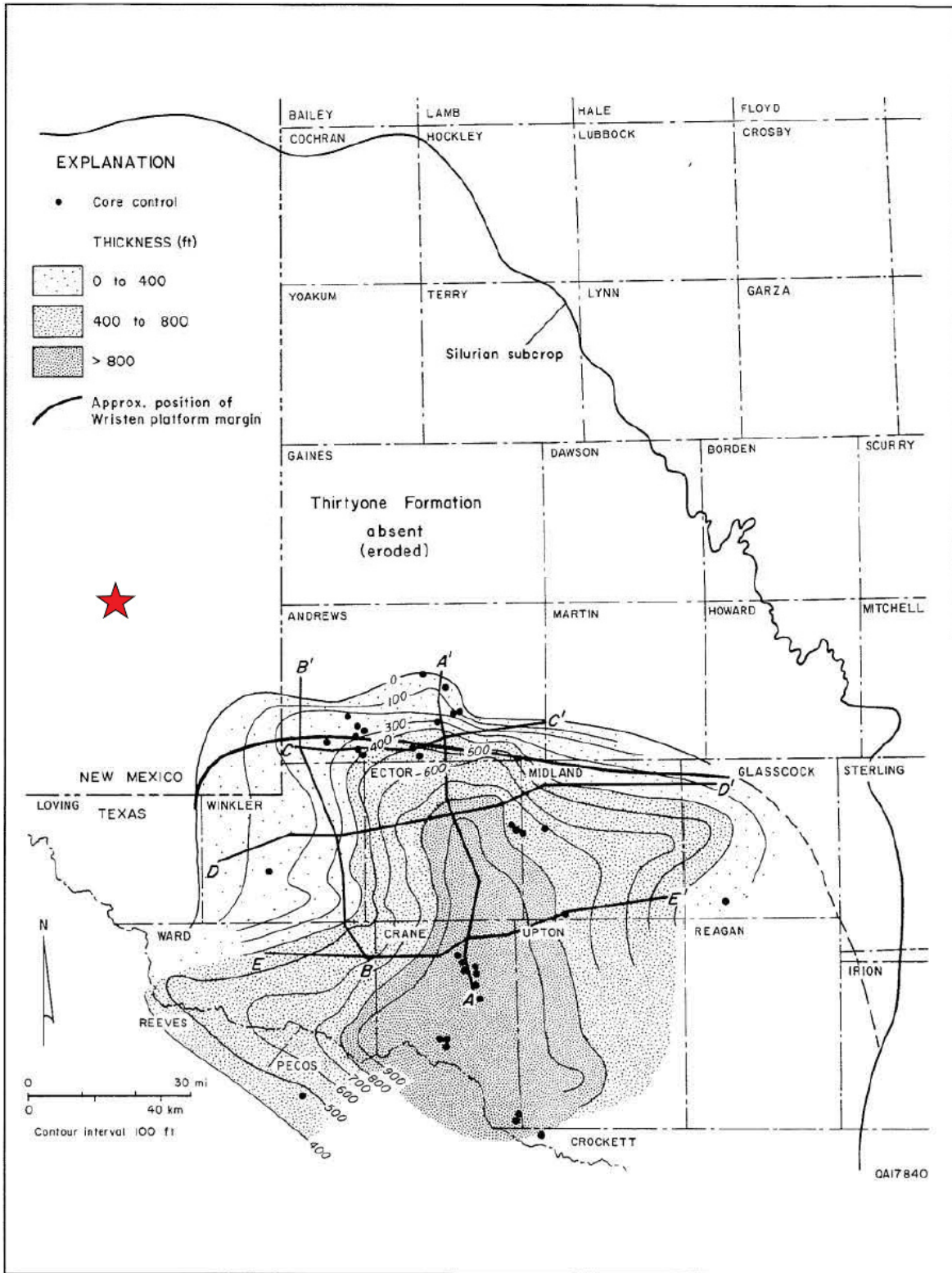


Figure 6 – Thickness and distribution map of the Devonian Thirtyone Formation. Red star indicates approximate location of DKL Libby Gas Plant (modified from Ruppel and Holtz, 1994).

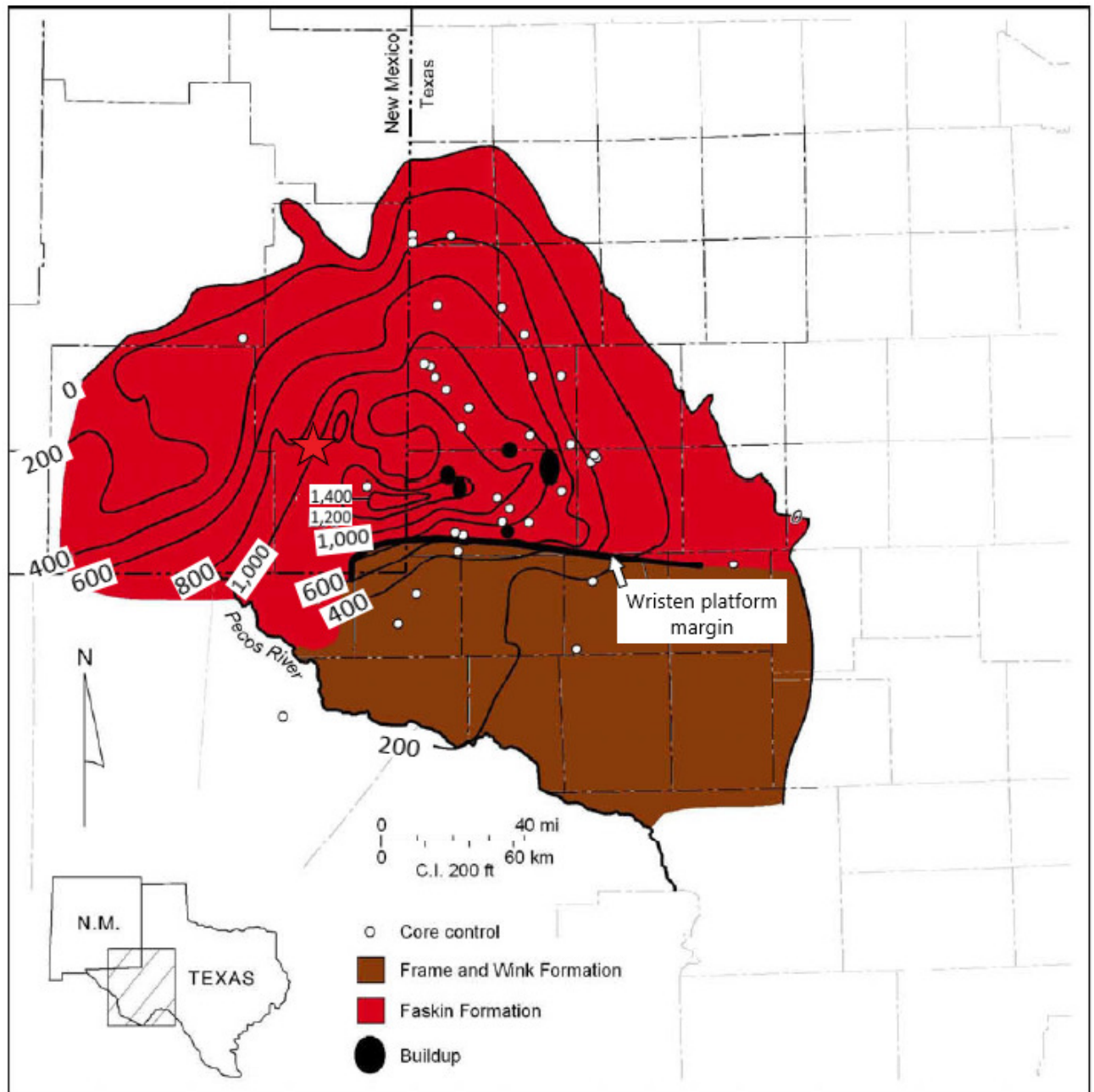


Figure 7 – Thickness and distribution map of the Fasken Formation of Wristen Group. The red star indicates the approximate location of the DKL Libby Gas Plant (modified from Ruppel S.C., 2006).

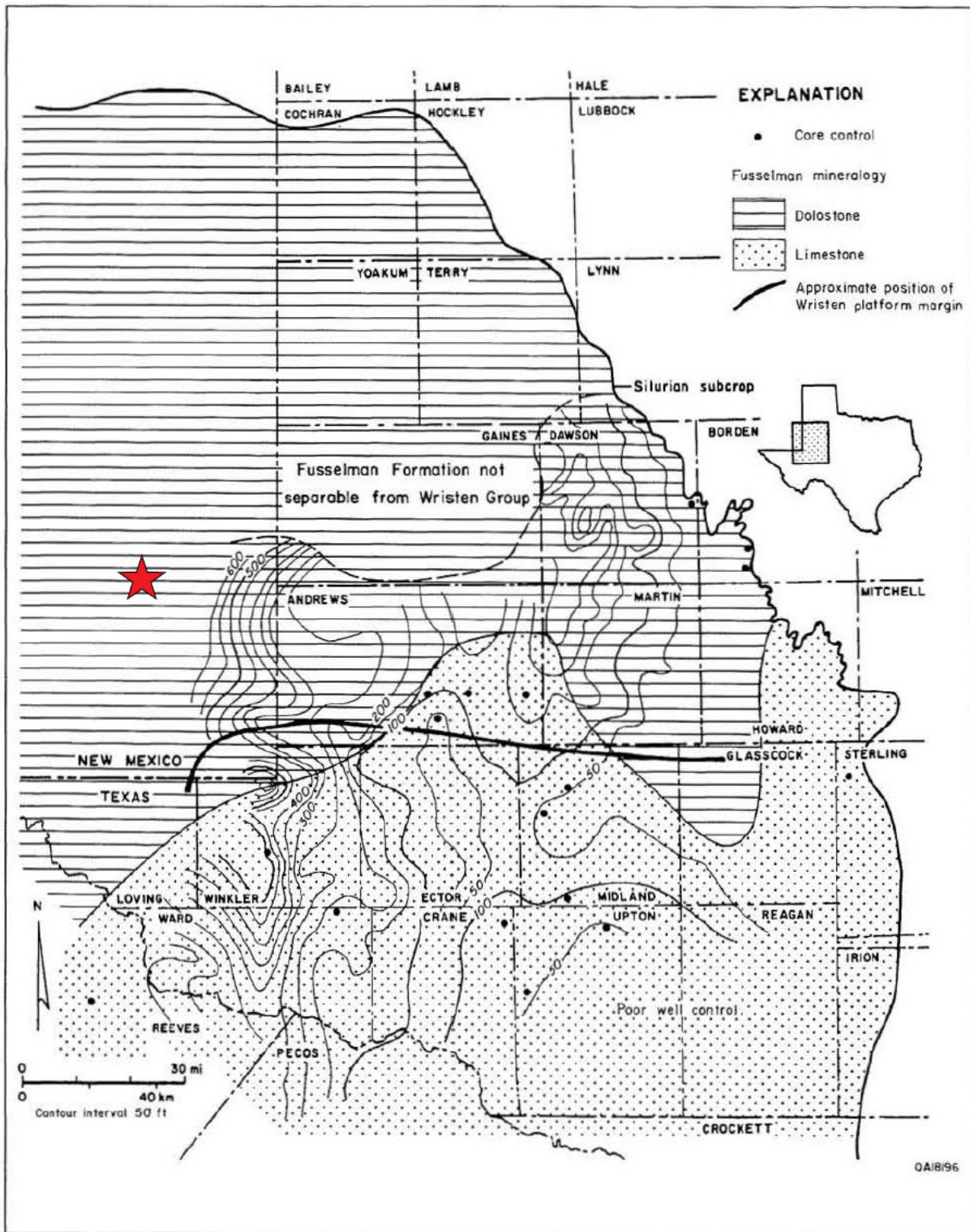


Figure 8 – Thickness and facies distribution map of the Fusselman Formation. The red star indicates the approximate location of the DKL Libby Gas Plant (Ruppel and Holtz, 1994).

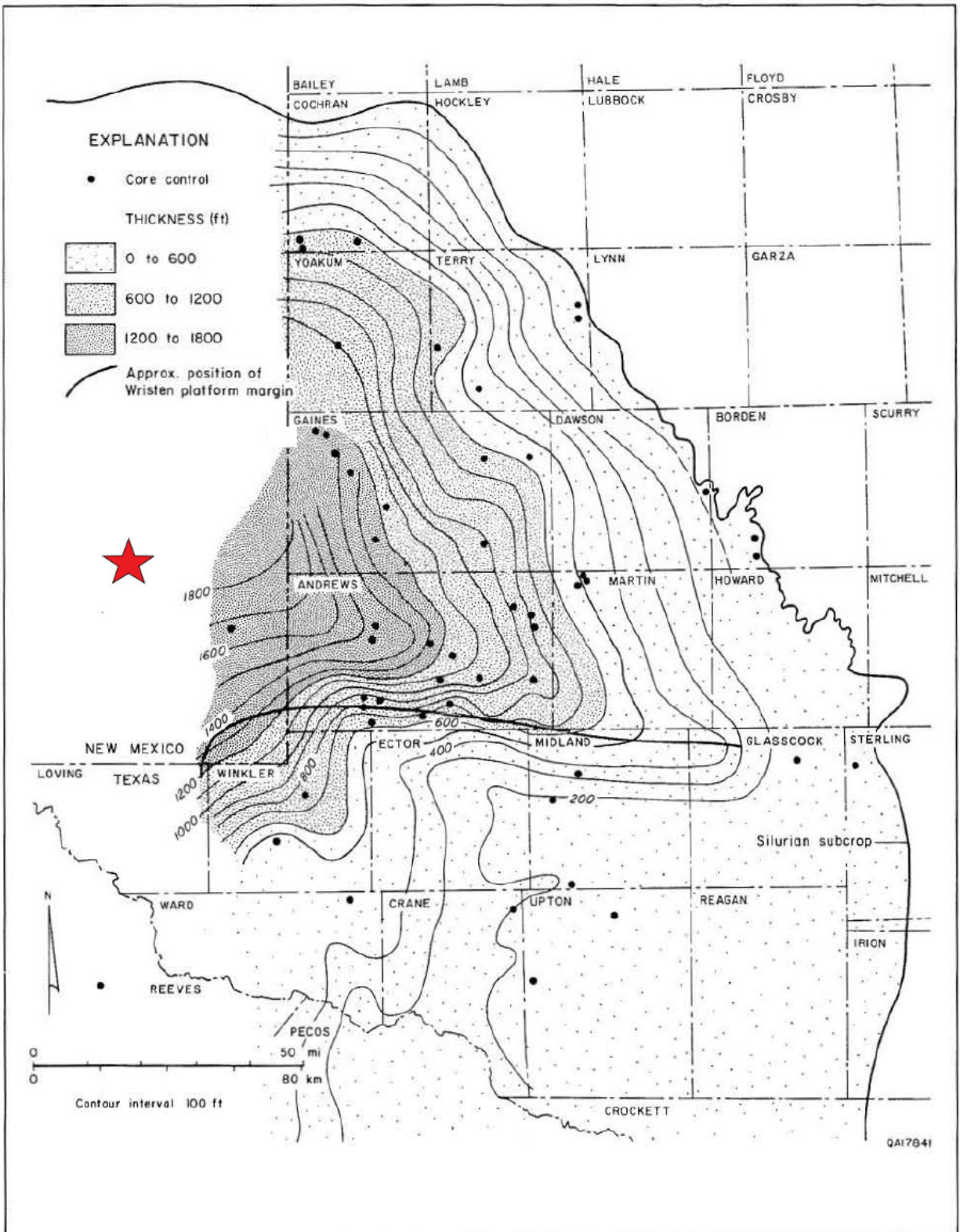


Figure 9 – Thickness and distribution map of the Silurian System. The red star indicates the approximate location of the DKL Libby Gas Plant (modified from Ruppel and Holtz, 1994).

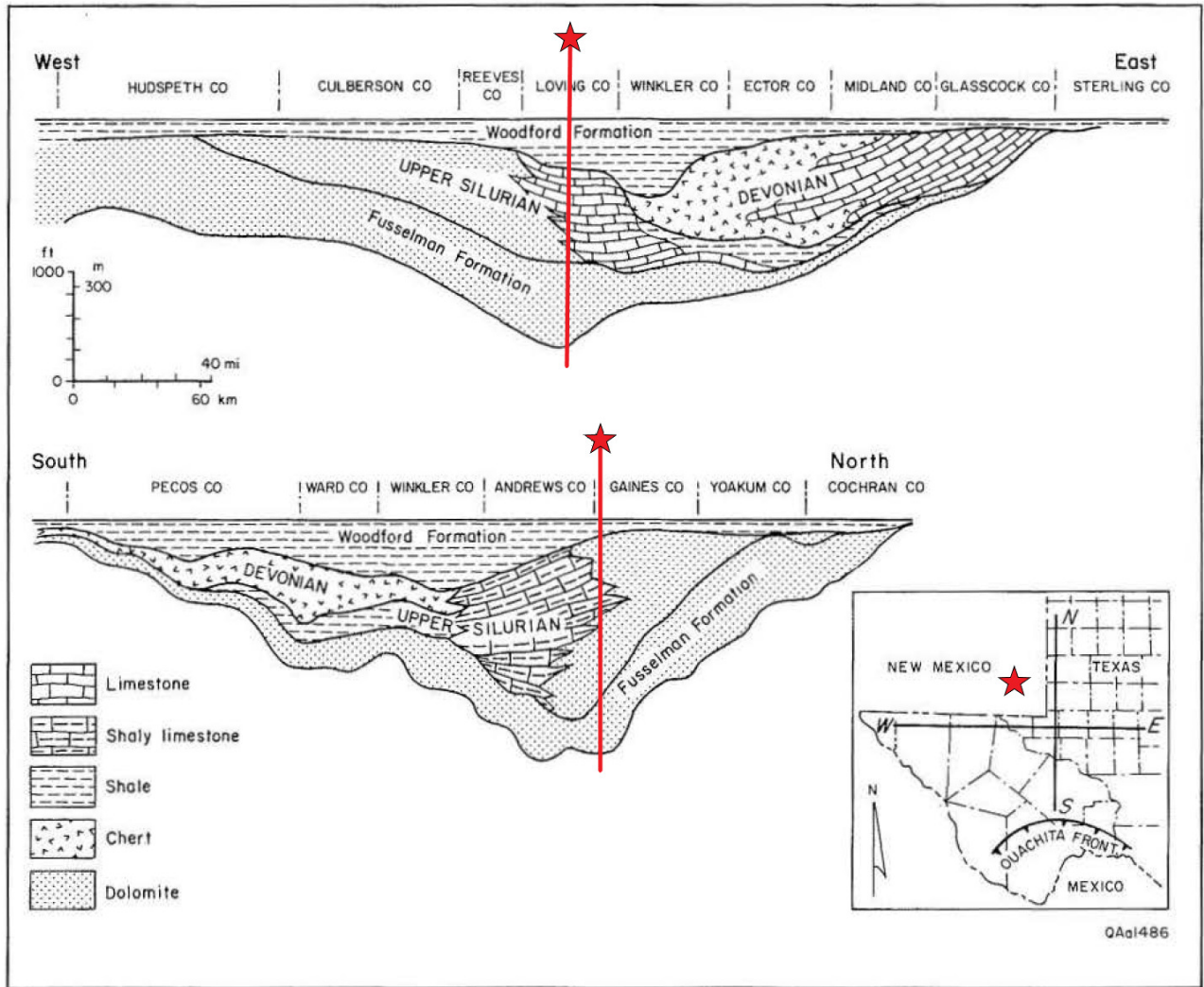


Figure 10 – Regional Schematic Cross Section of the Siluro-Devonian Injection Interval. The red star indicates the approximate location of the DKL Libby Gas Plant (modified from Ruppel and Holtz, 1994).

2.2.2 Regional Faulting

During the Late Mississippian to Late Permian periods, the ancestral Tabosa Basin experienced significant basin subsidence accompanied by large-scale, high-angle thrust faulting. The structural deformation resulted in the breakup of the Tabosa Basin into the Permian Basin, which consists of the Delaware Basin, Central Basin Platform, and Midland Basin. The Libby No. 1 and No. 2 wells are located in the Delaware Basin, west of the Central Basin Platform, as clarified in Figures 2 and 5.

Regional structure and faulting surrounding the DKL Libby Gas Plant were heavily influenced by the development of the Central Basin Platform (CBP) to the east. Uplift of the CBP began during the Middle Pennsylvanian period and ceased by the Middle Permian period, resulting in a series of high-angle reverse faults with a general north-northwest to south-southeast orientation (Horne,

Hennings, and Zahm, 2021). Figure 11 depicts Horne, Hennings, and Zahm (2021) structural interpretation of the Delaware Basin and CBP and clarifies the location of the Libby No. 1 and No. 2 wells relative to basin-rooted faulting. The nearest fault identified on the map is located approximated 2.65 miles northeast of the DKL Libby Gas Plant. These faults are located outside the maximum monitoring area (MMA) and are anticipated to die within the Pennsylvanian strata; thus, there is a very low likelihood of injected fluids transmitting into shallow freshwater aquifers. Additional discussion of offset structure and faulting is provided in *Section 2.4.5, Local Structure*, including the review of three-dimensional (3D) seismic in the area of the DKL Libby Gas Plant.

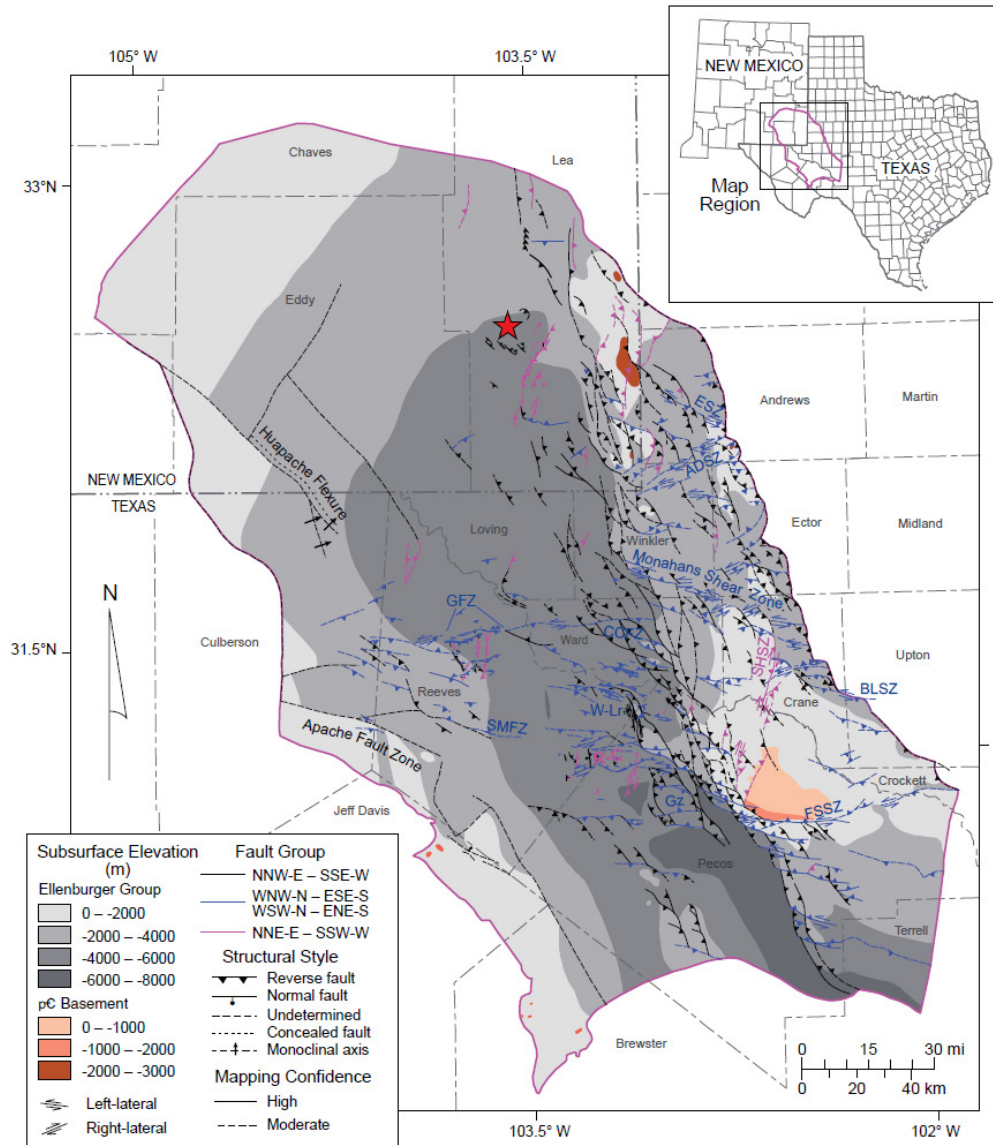


Figure 11 – Basement-rooted fault map of the Delaware Basin and Central Basin Platform (Horne, Hennings, and Zahm, 2021). ADSZ = Andector shear zone; BLSZ = Big Lake shear zone; CCFZ = Coyanosa complex fault zone; ESZ = Eunice shear zone; FSSZ = Fort Stockton shear zone; GFZ =Grisham fault zone; Gz = Gomez field; R-C = Rojo-Caballlos fault zone; SHSZ = Sand Hills shear zone; SMFZ =San Martin fault zone; W-Lr = Waha-Lockridge fault zone.

2.3 Site Characterization

The Libby No. 1 and No.2 wells are located in Section 26, T20S, T34E, in Lea County, New Mexico. Delek controls approximately 120 acres of surface where the DKL Libby Gas Plant, the Libby No. 1 and No. 2, and SWDs are located. The following section discusses the geological characteristics of this site.

2.3.1 Stratigraphy and Lithologic Characteristics

Figure 12 depicts an openhole log from the Lea Unit Deep No. 12 offset well (API No. 30-025-26365), located approximately 2.7 miles northeast of the DKL Libby Gas Plant. The openhole log includes gamma ray and neutron curves with interpreted formation tops to clarify the injection zone, the upper confining zone (UCZ), and the lower confining zone (LCZ). The well penetrated the entirety of the geologic section and encountered the top of Precambrian basement at approximately 16,490 ft.

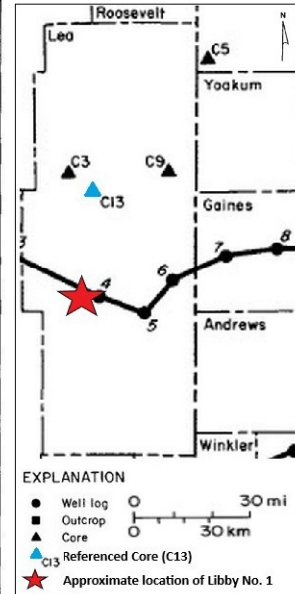
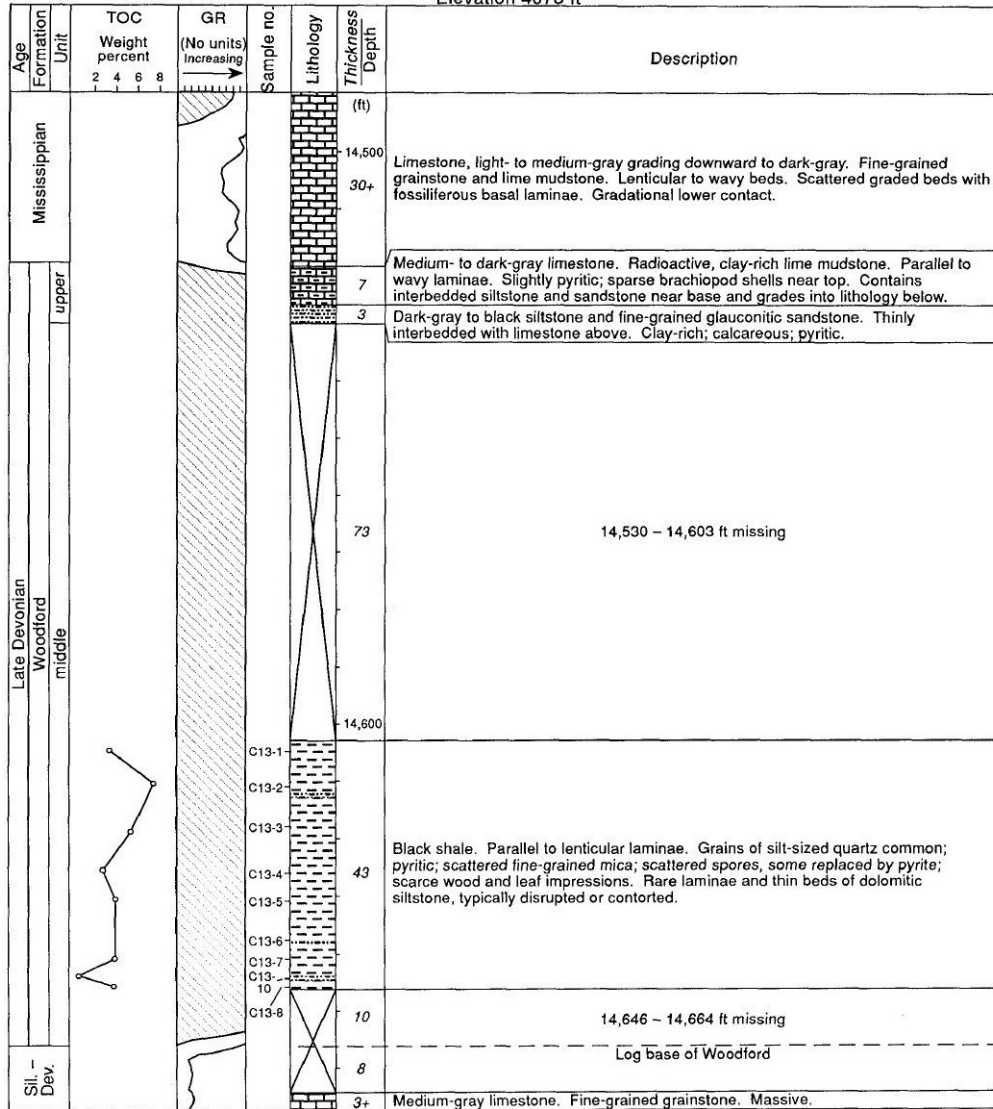
2.3.2 Upper Confining Zone – Woodford Shale

The Upper Confining Zone (UCZ) for the Libby No.1 and No. 2 wells is to be provided by the regionally extensive Woodford Shale. The Woodford Shale is late Devonian in age and primarily consists of organic-rich shale deposited during a period of widespread marine transgression. The flooding was extensive and blanketed the Siluro-Devonian of the Permian Basin with relatively uniform lithology (Comer, 1991). Comer (1991) reported that black shale and siltstone are the two dominant lithofacies present within the Woodford Shale. Black shales contain “parallel laminae, abundant pyrite, very high radioactivity, and a high concentration of marine organic matter.” The relative increase in radioactivity of Woodford Shales creates a gamma ray response well above 150 API, allowing for easy identification on openhole logs. This response can be observed in the type log presented in Figure 15, where the gamma ray readings go off scale.

The Comer (1991) study also evaluated core samples of the Woodford Shale to improve understanding of lithologic features within the Permian Basin. The closest core sample to the Libby No. 1 and No. 2 wells, is from a well in northern Lea County. A locator map and core description from the study is included in Figure 13. The core covered the entirety of the Woodford Shale and notes high clay content, pyrite, and parallel to lenticular laminae; suggesting excellent sealing capabilities to contain injected fluids within the injection interval.

The Woodford Shale is encountered at approximately 14,638 ft at the Libby No. 1 well location with a gross thickness of approximately 191 ft. Modeling suggests the thick, regionally extensive shales of the Woodford Shale can provide sufficient containment of injection into the underlying Siluro-Devonian. Additionally, there is a significant amount of geologic section between the top of the Woodford Shale and any freshwater-bearing intervals because of its deep occurrence near the base of the regional stratigraphic column.

▲ C13
 Humble No. 1 Federal Elliott
 Lea County, New Mexico
 Section 1, T 16 S – R 34 E
 Elevation 4078 ft



QA 14582c

Figure 13 – Core description of the Woodford Shale with sample locator map (modified from Comer, 1991).

2.3.3 Injection Zone – Siluro-Devonian

The injection zone of the Libby No. 1 and No.2 wells is comprised of the gross Siluro-Devonian, as introduced in *Section 2.2, Regional Geology*. The top of the Siluro-Devonian is anticipated to occur at a depth of approximately 14,829 ft in the Libby No. 1 well with a gross thickness of approximately 1,600 ft, and at a depth of approximately 14,835 ft true vertical depth (TVD) at the Libby No. 2 location with a similar gross thickness. Carbonates within the Siluro-Devonian experienced significant leaching and diagenetic alteration that developed secondary porosity and permeability within portions of the gross section. The Siluro-Devonian was selected as the injection zone because of the enhanced reservoir quality associated with karsting, development of vugs, and microfractures.

Porosity and Permeability Development

Porosity within the Wristen Group near the DKL Libby Gas Plant is typically found within intergranular pores of basal ooid grainstones, as well as moldic and intercrystalline features associated with leaching of allochem-rich intervals. While porosity within the Fusselman Formation tends to occur in 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).

A summary of Siluro-Devonian reservoir properties derived from the Permian Basin core is provided in Figure 14. The dataset presents averages and ranges of petrophysical properties collected from Silurian and Devonian reservoir plays. The table highlights the two primary intervals evaluated for injection, the Fusselman Shallow Platform Carbonate play and the Wristen Buildup/Platform Carbonate play. The data suggests porosity within the injection reservoir formations ranges from 1% to 33%, with an average of 7.10% to 7.93%. Corresponding permeabilities range from 0.6 millidarcies (mD) to 400 (mD) and average between 11.61 mD to 45.28 mD, with the Wristen Group representing the higher end of the range. Ranges within the Montoya Formation are anticipated to be similar to those of the Fusselman Formation, based on the shared depositional environment and lithologies.

The range of petrophysical properties from the dataset was analyzed along with an openhole log from a nearby well, the Lea Unit Deep No. 12 offset well (API No. 30-025-26365), located approximately 2.7 miles northeast of the DKL Libby Gas Plant. The datasets were used to estimate a porosity-permeability relationship for the Siluro-Devonian and generate an estimated permeability curve from porosity data collected in the Lea Unit Deep No. 12. The resulting porosity and permeability curves are presented in Figure 15, in Tracks 2 and 3, respectively. The figure illustrates the elevated porosities and permeability modeled within the Siluro-Devonian injection zone. The model incorporates partial to complete porosity coverage of the Siluro-Devonian from 17 wells to extrapolate reservoir characteristics for plume modeling.

	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	657

Figure 14 – Reservoir Properties of the Siluro-Devonian (Ruppel and Holtz, 1994).

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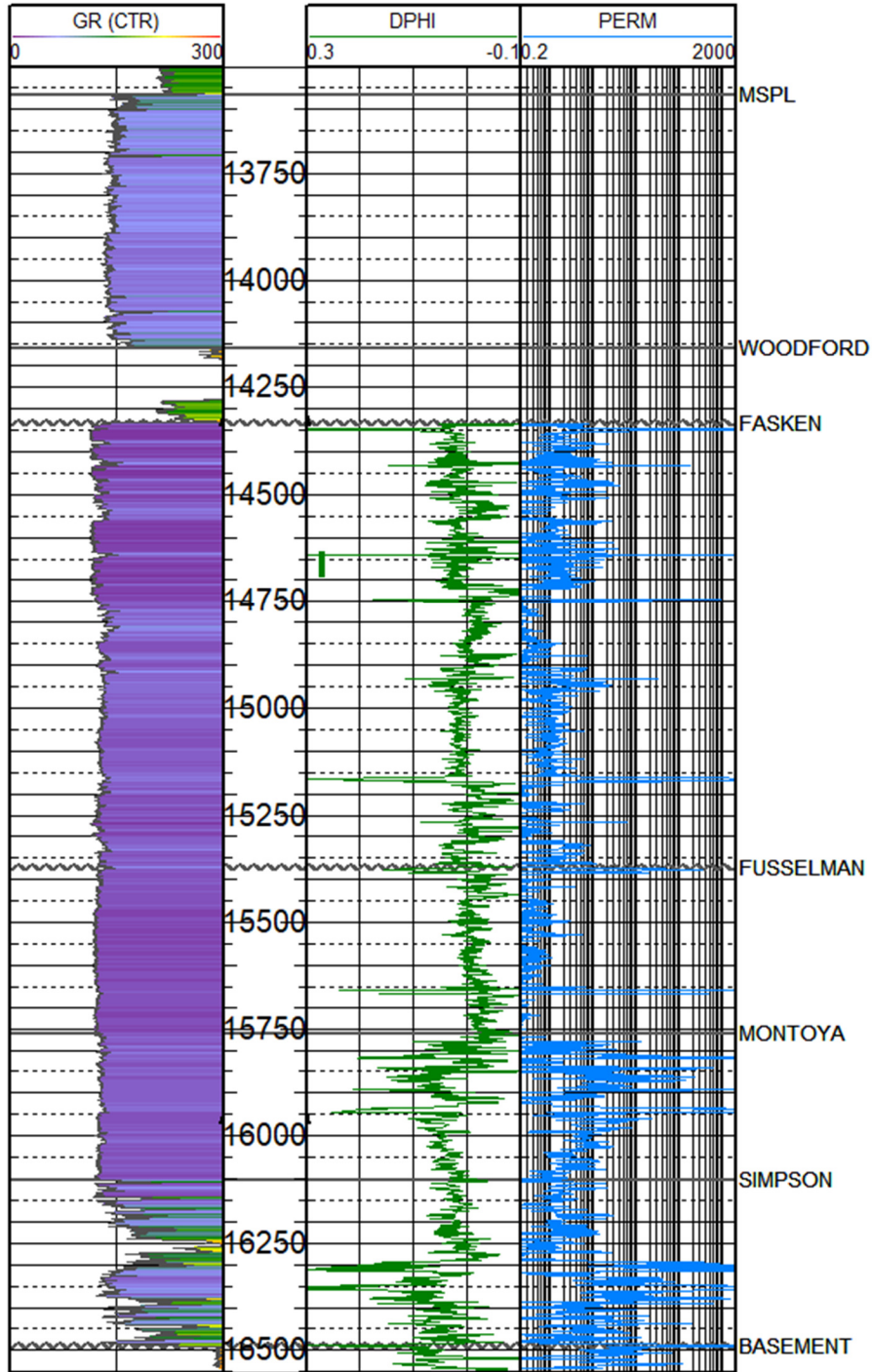


Figure 15 – Offset openhole log (API No. 30-025-26365) showing the following curves: gamma ray (GR), density porosity (DPHI), and permeability (PERM).

Siluro-Devonian Formation Fluid

A review of chemical analyses of oilfield brines from the USGS National Produced Waters Geochemical Database version 3.0 (Blondes et al., 2018) identified four wells with fluid analysis from the Devonian Formation within 5 miles of the Libby No. 1 and No. 2 wells. The location of these wells is presented in Figure 16, and the corresponding data is provided in Table 1. All fluid samples contain total dissolved solids (TDS) that exceed 10,000 parts per million (ppm), and the average salinity among the dataset is calculated at 38,734 ppm, thereby classifying the reservoir as saline (Table 1). The analysis indicates in situ reservoir fluid of the Siluro-Devonian and underlying Fusselman and Montoya Formations are compatible with the injection fluids of the Libby No. 1 and No. 2 wells. The graph in Figure 17 plots sample TDS vs. depth, illustrating a linear relationship.

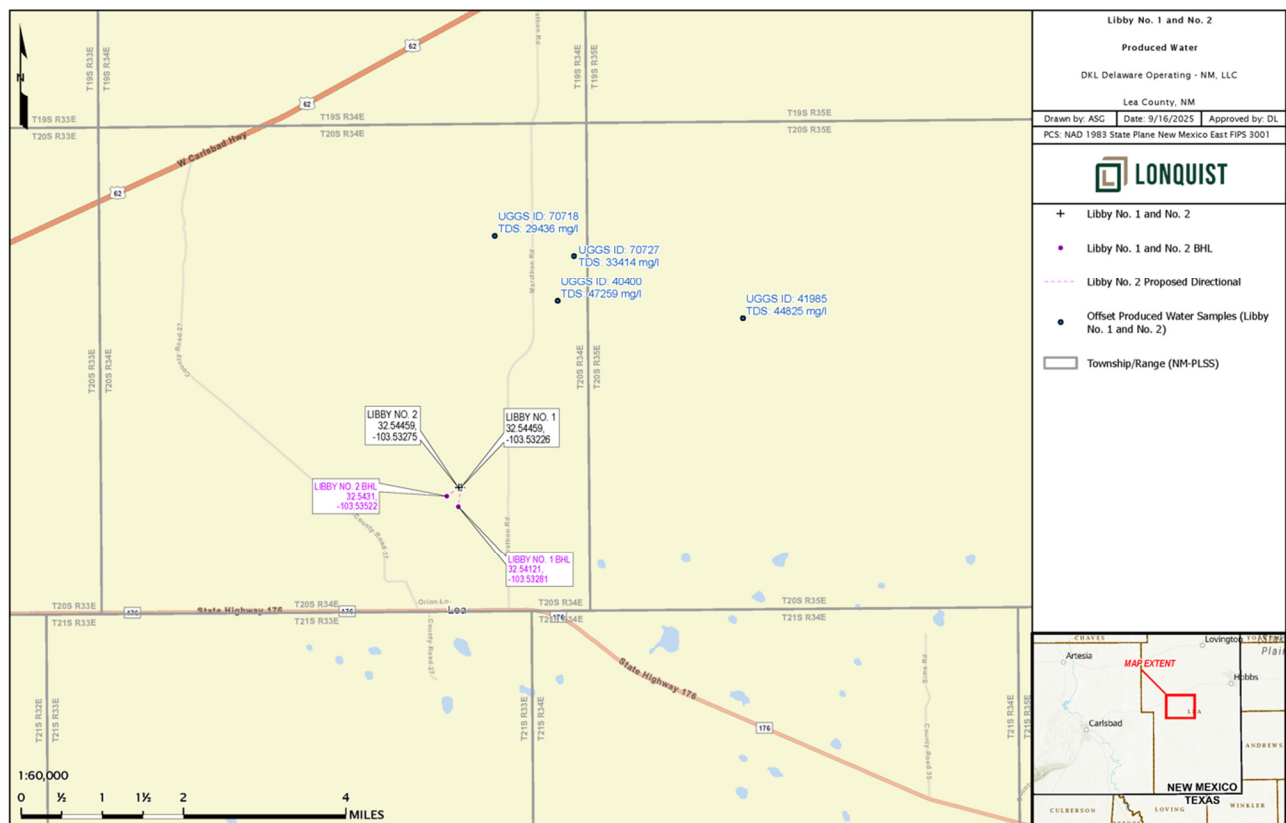


Figure 16 – Produced Water Samples for Devonian Formation Fluid Characterization.

Table 1 – Analysis of Devonian Formation Fluids from Gulf Coast Oil-Field Brine Samples. Data sourced from the USGS National Produced Waters Geochemical Database v3.0 (Blondes et al., 2018).

API	Concentration, in parts per million (ppm)						
	TDS	HCO ₃	Ca	Cl	Na	Mg	SO ₄
30-025-02424	29,436	634	1,550	16,720	8,894	496	1,142
30-025-02431	33,414	227	1,775	18,570	10,730	151	1,961
30-025-02432	47,259	-	-	-	-	-	-
30-025-20377	44,825	761	2,590	27,970	11,080	2,424	-
Average	38,734	541	1,972	21,087	10,235	1,024	1,552

HCO₃ bicarbonate
 Ca calcium
 Cl chlorine
 Na sodium
 Mg magnesium
 SO₄ sulfate

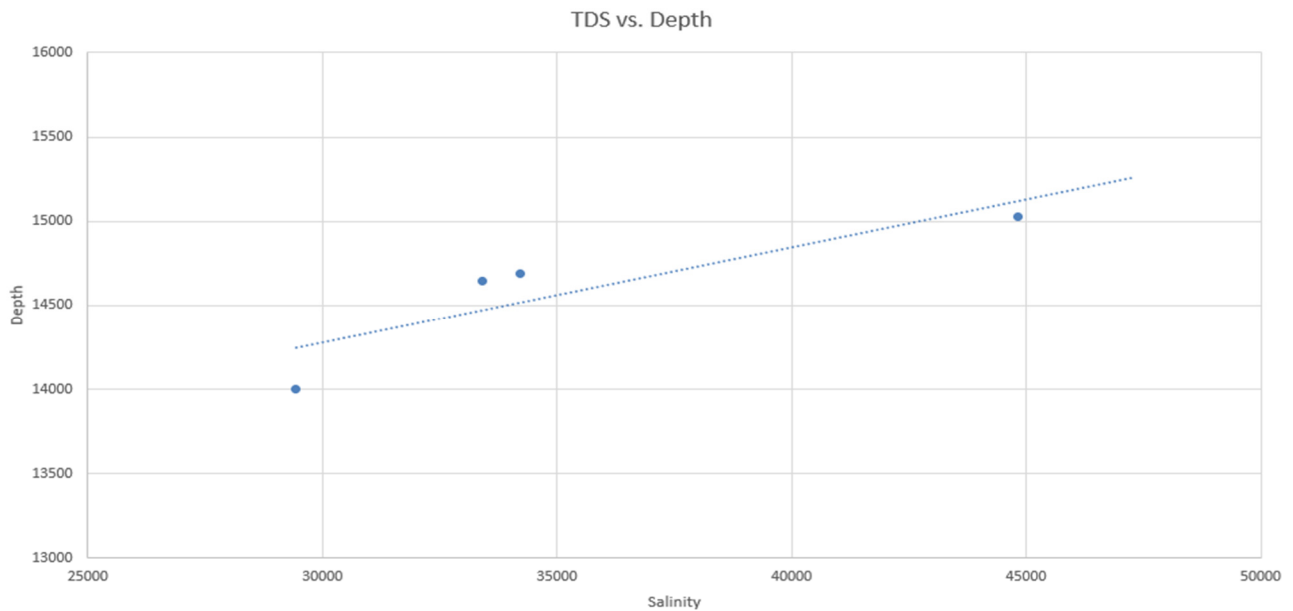


Figure 17 – Devonian salinity data relative to collected depth. Data sourced from the USGS National Produced Waters Geochemical Database v3.0 (Blondes et al., 2018).

2.3.4 Lower Confining Zone – Simpson Group

Lower confinement of the Libby No. 1 and No. 2 wells is to be provided by the underlying Simpson Group. The Simpson Group is composed of a complex series of interbedded stratigraphic sequences, including interfingering shale, tight limestone, and silt with limited reservoir development. Reservoir quality in the Simpson Group is restricted to coalescent shoreline sands present along the

Central Basin Platform. These sands are thin, local in areal extent, and behave as independent reservoirs. Deposition occurred during a period of marine transgression over the undulated surface of the underlying Ellenburger Formation, where present (Merrill, et al., 2015; Wright, 1965). However, offset openhole logs suggest the underlying Ellenburger Formation was completely truncated and is absent from the geologic section in the area, as evidenced by the interpretation presented in Figures 15 and 20.

The Simpson Group, as a whole, is anticipated to provide sufficient sealing characteristics to keep injected fluids contained within the Siluro-Devonian injection interval. The Simpson Group is anticipated to be encountered at approximately 16,600 ft in the Libby No. 1 and No. 2 wells, overlying the crystalline Precambrian basement with a gross thickness of approximately 385 ft. Porosity and permeability reductions present within lower portions of the Montoya Formation are anticipated to provide additional lower confinement to the Simpson Group.

2.3.5 Local Structure

The Libby No. 1 and No.2 wells are located west of the CBP, generally beyond the extent of regional faulting. The faults to the east are thrust faults associated with the uplift of the CBP and tend to be oriented in a north-south direction, as previously presented in Figure 11 of *Section 2.2.2, Regional Faulting*. A local structure map on top of the Siluro-Devonian injection interval is provided in Figure 18 with a red star representing the location of the DKL Libby Gas Plant. The map references the modeled plumes, pressure front, regional fault interpretations published by Horne, Hennings, and Zahm (2021), seismically identified faulting, and the cross section lines for Figures 19 and 20. The Libby No. 1 and No. 2 wells are located down-dip, along the southwestern edge of a four-way closure. Production occurred from the Siluro-Devonian section along the top of the structure, with water saturation increasing down-dip towards the Libby No. 1 and No. 2 wells, located below the initial oil-water contact.

The nearest fault identified from a 3D seismic is located approximately 1.9 miles east-northeast of the Libby No. 1 and No. 2 wells, and approximately 1.1 miles beyond the extent of the modeled MMA. The nearest basement fault identified in published regional literature occurs approximately 2.65 miles northeast of the site, and approximately 1.8 miles beyond the extent of the modeled MMA. Therefore, no faulting of the Siluro-Devonian has been published or identified within 1 mile of the MMA.

The north-south and northeast-southwest structural cross sections are provided in Figures 19 and 20, respectively, and illustrate structural dips surrounding the Libby No. 1 and No. 2 locations. The cross sections also illustrate the lateral continuity of the Woodford Shale UCZ that immediately overlies the injection interval, approximately 175 ft to 205 ft thick.

Larger versions of Figures 19 and 20 are provided in *Appendix A*.

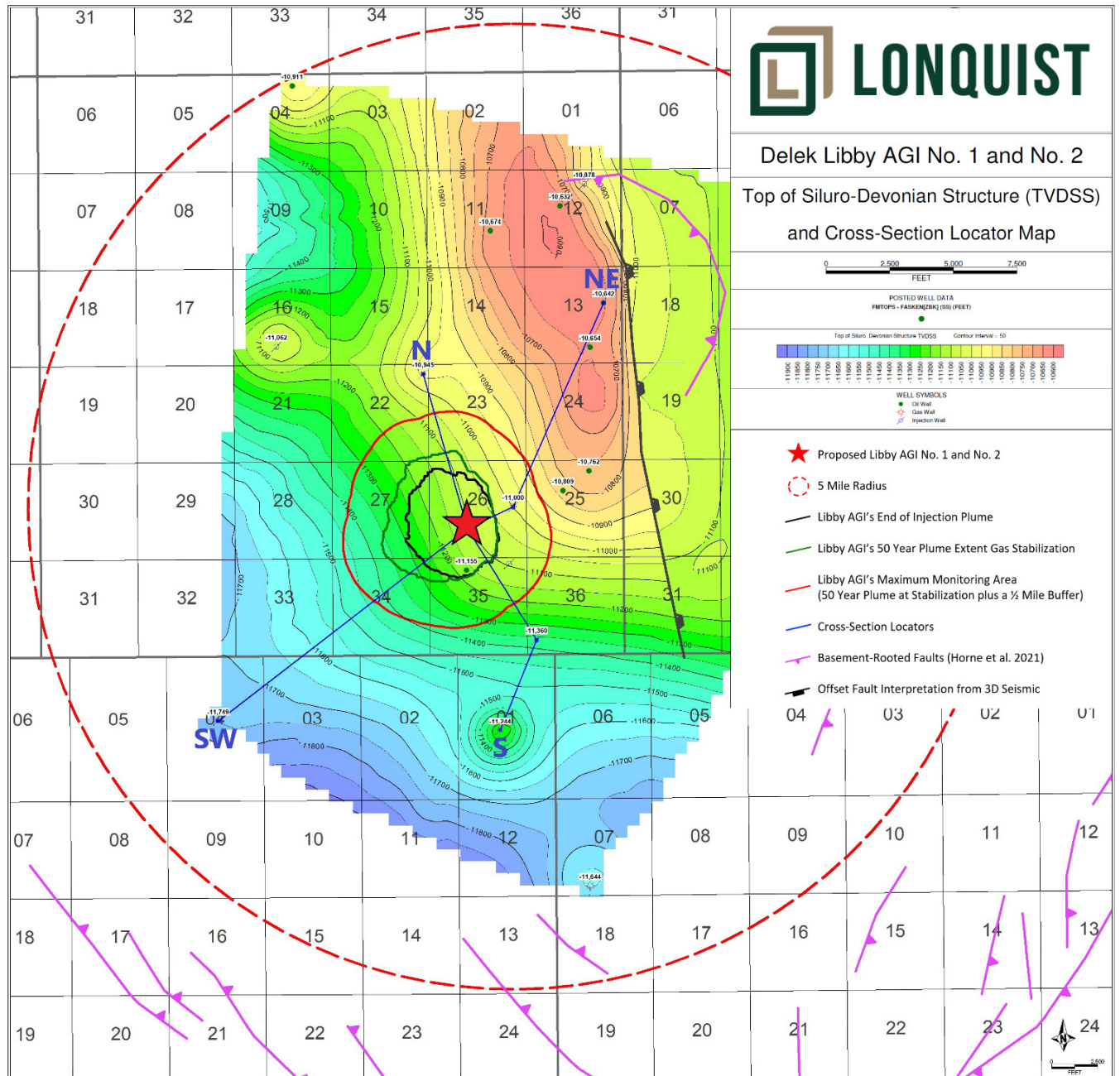


Figure 18 – Top of Siluro-Devonian Structure Map. The red star represents the approximate location of the Libby No. 1 and No. 2 locations.

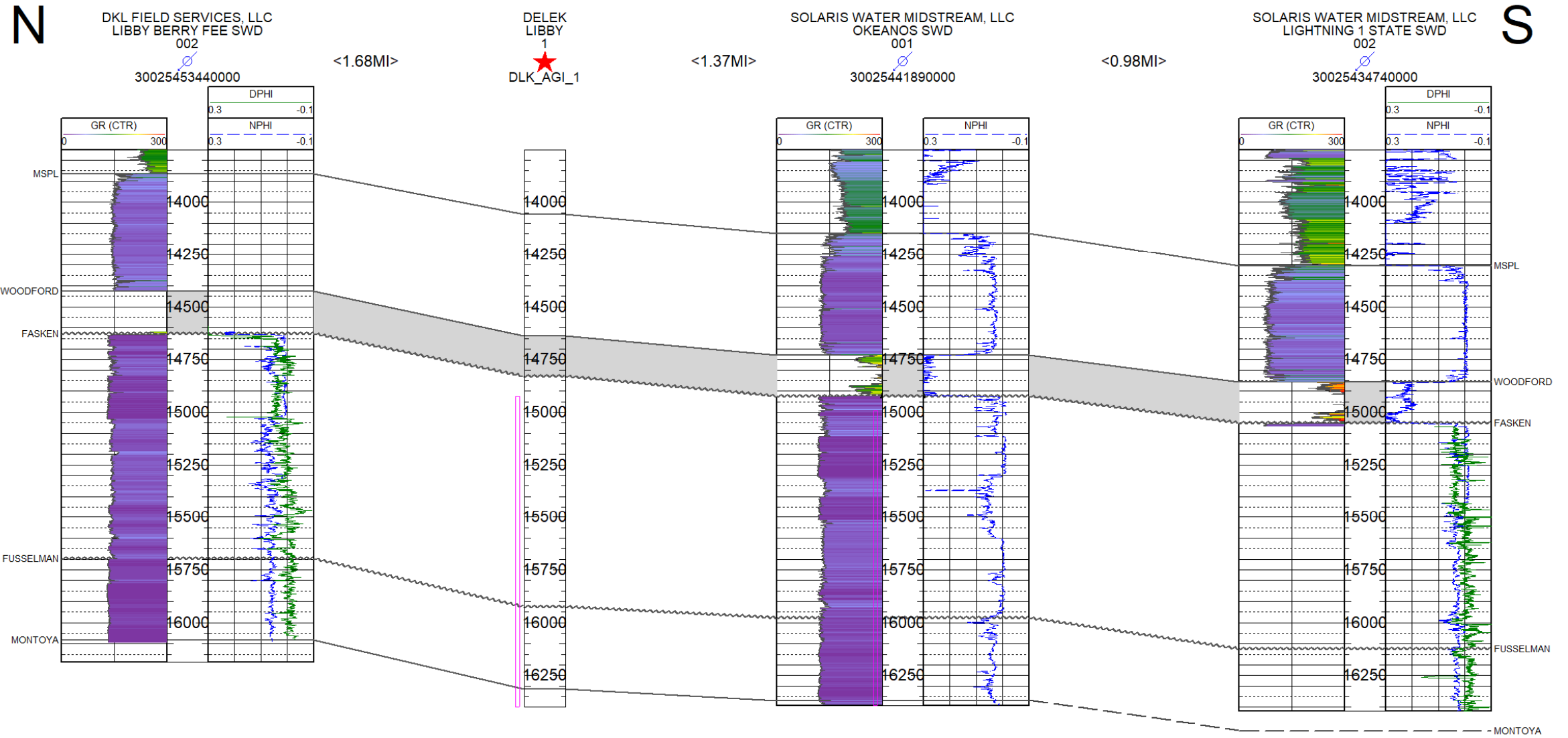


Figure 19 – Structural North-South Cross Section.

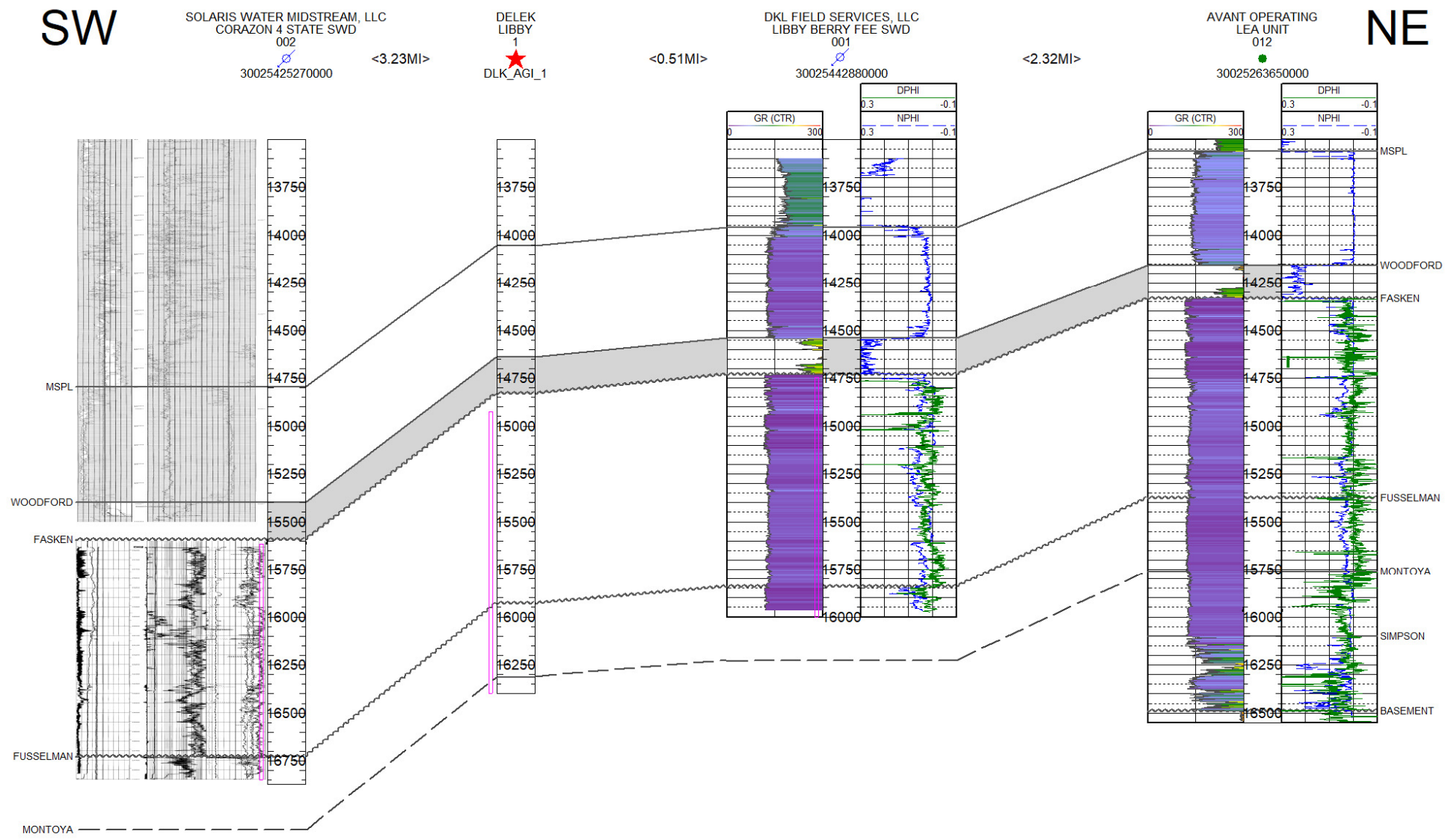


Figure 20 – Structural Southwest-Northeast Cross Section

2.3.6 Geomechanics

The fracture pressure gradient for the Siluro-Devonian through the Montoya section 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 fracture pressure gradient of the confining zone. The anticipated fracture gradient was derived from site-specific data, literature reviews, and industry standard practices.

For the Siluro-Devonian formation, a PG of 0.465 pounds per square inch/foot (feet) (psi/ft) was used. The OBG was chosen to be 1.0 psi/ft based on industry best practices when site—specific data is unavailable. A Poisson’s ratio of 0.28 was used based on literature (Molina et al, 2017) for carbonate formations. Using the variable values listed previously, an FG of 0.67 psi/ft was calculated, based on the equation shown subsequently. A 10% safety factor was implemented, thereby resulting in a maximum allowed BHP of 0.603 psi/ft. This safety factor was set to ensure that the injection pressure never exceeds the fracture pressure of the injection zone.

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).

Table 2 provides the inputs and results of the FG calculations for the Libby No. 1 and No. 2 wells.

Table 2 – Fracture Gradient for Upper Injection Interval

Parameter	Injection Interval
Overburden Gradient (psi/ft)	1.0
Pore Pressure Gradient (psi/ft)	0.465
Poisson’s Ratio	0.28
Fracture Gradient (psi/ft)	0.67
Fracture Gradient with 10% Safety Factor (psi/ft)	0.603

The following steps were taken to calculate the fracture gradient:

$$FG = \frac{\nu}{1 - \nu} (OBG - p_p) + p_p$$
$$FG = \frac{0.28}{1 - 0.28} (1.0 - 0.465) + 0.465 = 0.67$$
$$FG \text{ with } SF = 0.67 \times (1 - 0.1) = \mathbf{0.603}$$

2.3.7 Injection and Confinement Summary

The modeled lithologic and petrophysical characteristics of the Siluro-Devonian at the Libby No. 1 and No. 2 locations agree with regionally published literature, which suggests the injection zone provides the pore space required to effectively store modeled and injection fluids. The tight petrophysical properties and thick, regional nature of the overlying Woodford Shale indicate that the formation is sufficient to serve as the upper confining zone. Beneath the injection interval, low-permeability and low-porosity intervals of the lower Montoya Formation and Simpson Group are unsuitable for fluid migration and serve as the lower confining interval.

2.4 Hydrology

Lea County, New Mexico, has more than 70,000 residents, with the county seat located in the City of Lovington. Lea County covers approximately 4,400 square miles (sq mi) and is contained within the Lea Soil and Water Conservation District. Groundwater resources represent the primary source of irrigation and public water supply because surface water resources within the county are limited to relatively small bodies of water, such as streams and small lakes.

2.4.1 Groundwater Resources

All potable groundwater use in the southern area of Lea County comes from three principal units: the Dockum Group, Ogallala Formation, and Quaternary alluvium (Nicholson and Clebsch, 1961). The top of the Rustler anhydrite is generally recognized as the lowest limit of potable water in the region because “virtually all the water wells in the area bottom in Triassic or younger rocks” (Nicholson and Clebsch, 1961). However, it should be mentioned that the Capitan Reef Complex is also present in Lea County. Stratigraphic descriptions of anticipated formations in southern Lea County are provided in Figure 21, as published by Nicholson and Clebsch (1961). The Figure clarifies the general characteristics of local aquifers and their water-bearing properties.

Quaternary Alluvium

Quaternary sediment accumulations in Lea County form a series of alluvial deposits, likely composed of both Pleistocene and recent-age material. The alluvium tends to gather in topographical lows where portions of the underlying Ogallala Formation have eroded and truncated from the geologic section (Nicholson and Clebsch, 1961). Based on reported depths and water levels of offset water wells, the Quaternary alluvium likely represents the principal aquifer in the vicinity of the Libby No. 1 and No. 2 wells.

Ogallala Formation

The Ogallala Formation is Tertiary in age and primarily composed of unconsolidated calcareous sand but includes minor amounts of silt, clay, and gravel. Gross thickness of the Ogallala Formation ranges from only a few inches to nearly 300 ft; but, according to Nicholson and Clebsch (1961), the formation “was completely removed, except for a few isolated remnants, and

Quaternary deposits derived from Ogallala were laid down on the Mesozoic rocks” at the Libby No. 1 and No. 2 locations (Nicholson and Clebsch, 1961).

Dockum Group

The Dockum Group is Triassic in age and primarily consists of red beds throughout the region. Water production from the Dockum Group tends to occur from the Santa Rosa and Chinle sandstones, which are similar in lithology and difficult to differentiate. The Santa Rosa primarily consists of fine to coarse-grained sandstone and is approximately 160 ft to 300 ft thick in Lea County. The Chinle primarily consists of red and green claystone with interbeds of fine-grained sandstone and siltstone, and ranges from 0 ft to 1,300 ft thick in Lea County. The Chinle is thicker in the eastern portion of the county and not anticipated to be present at the Libby No. 1 and No. 2 wells (Nicholson and Clebsch, 1961). A potentiometric surface map of Lea County is provided in Figure 22.

Recharge of the aquifer occurs from precipitation onto overlying sand dunes; precipitation and associated runoff where outcropped, and potentially from hydraulic communication with the Ogallala Formation and alluvium, where present (Nicholson and Clebsch, 1961). The map provided in Figure 23 illustrates average annual rainfall of southern Lea County, New Mexico, from 1949 to 1955, in inches. The map suggests average rainfall ranged from 7 inches to 14 inches per year in the county, with approximately 9 inches per year at the DKL Libby Gas Plant (Nicholson and Clebsch, 1961). As of 1997, precipitation in Lea County was approximately 15 inches per year, and Lea County received approximately 16 inches of precipitation in 2023. A TDS map of the Dockum Group is provided in Figure 24 to illustrate salinities of the aquifers in the region. The map suggests the Libby No. 1 and No. 2 wells are located near the edge extents of the Dockum Group, with estimated TDS below 1,000 milligrams per liter (mg/L). The map also indicates a TDS band greater than 20,000 mg/L in northern Lea County that moves east into Texas.

Capitan Reef Complex

The Capitan Reef Complex overlies the Delaware Mountain Group and underlies the Salado Formation. The complex extends from the Glass Mountains into Texas, moving north into Lea and Eddy Counties in New Mexico, then back south to the Apache and Davis Mountains in Culberson and Jeff Davis Counties in Texas. The reef complex is generally characterized by a group of Permian carbonate reef deposits that include the Goat Seep, Capitan, and Carlsbad limestones. Large-scale erosion during the Upper Guadalupian and Ochoan epochs was followed by deposition of the Artesian Group, resulting in a complex depositional regime with variable distribution patterns of individual facies (Standen et al., 2009).

The Artesian Group consists of Tansill (the youngest), Yates, Seven Rivers, Queen, and Grayburg (the oldest) Formations that grade into the Capitan Reef Complex; with Grayburg and Queens Formations grading to the Goat Seep Limestone, and the Tansil, Yates, and Seven Rivers Formations grading into the Capitan Limestone. Thus, the Capitan Reef Complex represents an amalgamation of several reef deposits interconnected by hydraulic communication. Figure 25 shows the Capitan Reef Complex system relative to the Rustler Formation, the base of fresh

groundwater, and overlying groundwater resources discussed herein for additional context. Total thickness of the reef complex can reach up to 2,000 ft (Standen et al., 2009).

		GEOLOGIC AGE	GEOLOGIC UNIT	THICKNESS (ft)	GENERAL CHARACTER	WATER-BEARING PROPERTIES
Cenozoic Quaternary	Recent		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 rain-water.
	and Pleistocene		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 21 – Stratigraphic Units in Southern Lea County, New Mexico (modified from Nicholson and Clebsch, 1961).

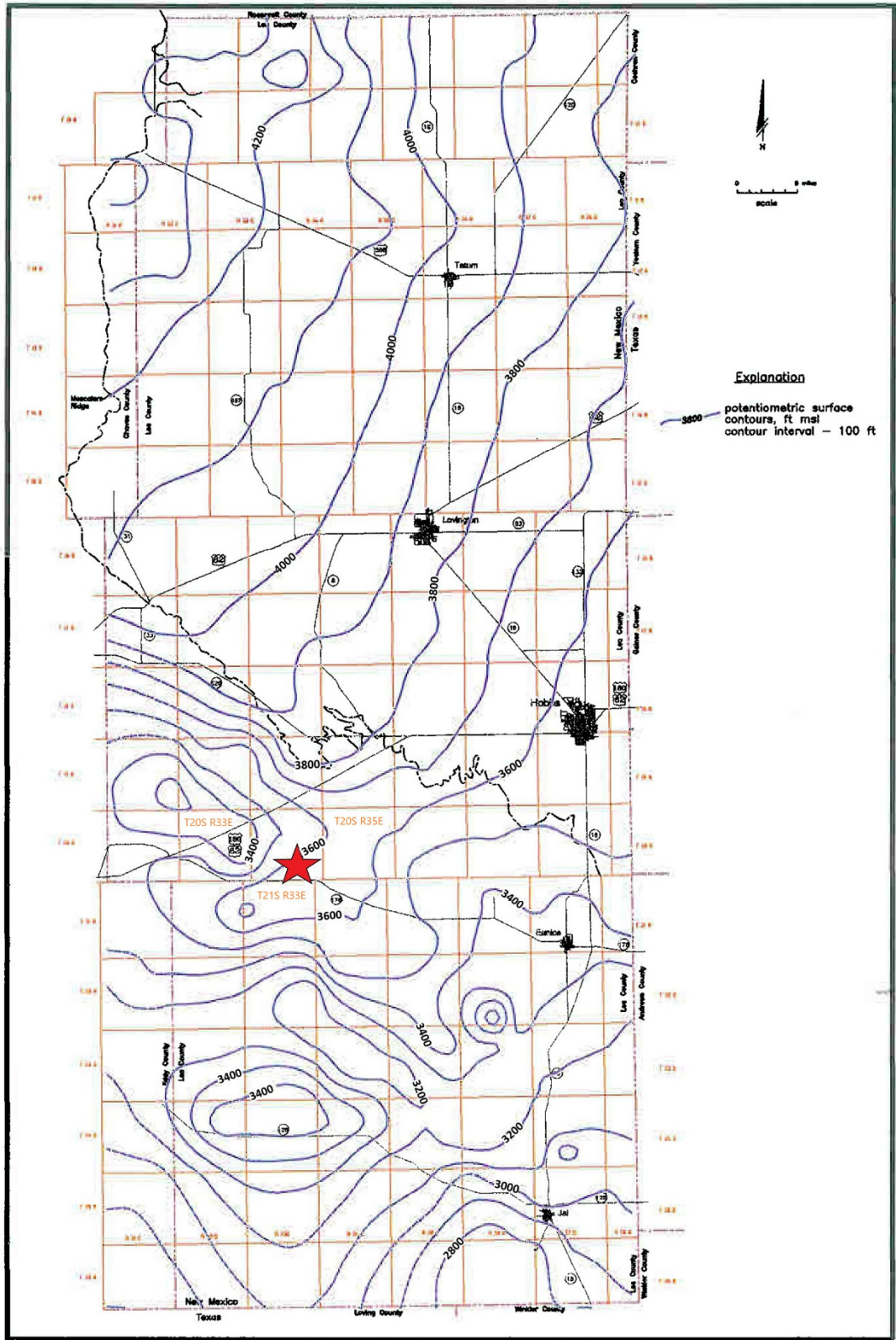


Figure 22 – Potentiometric map of Lea County, New Mexico from 1995 to 1998 (Leedshill-Herkenhoff, Inc. et al., 2000). The red star is the approximate location of the DKL Libby Gas Plant.

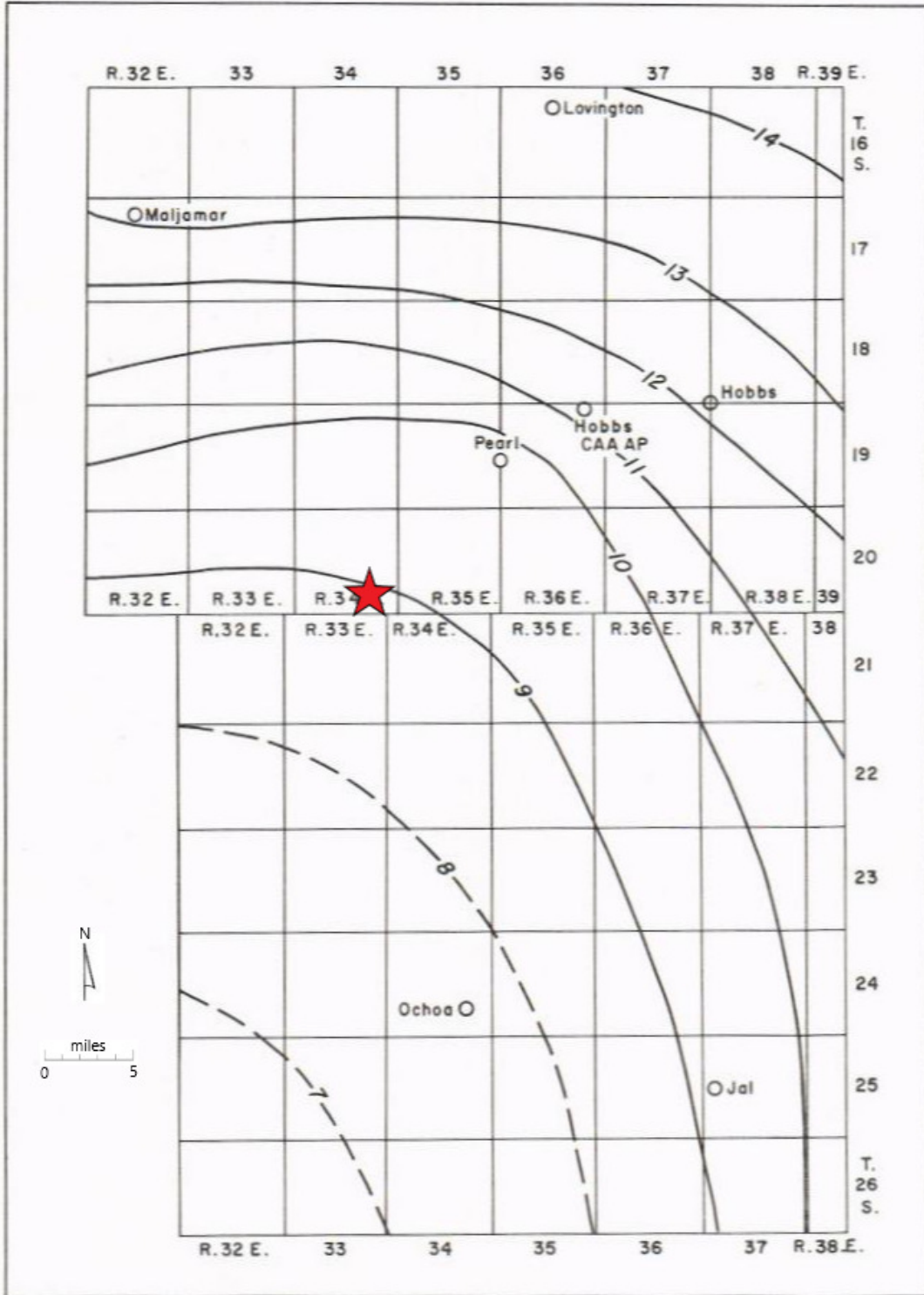


Figure 23 – Average Annual Rainfall in Southern Lea County, New Mexico in inches; 1949 to 1955 (modified from Nicholson and Clebsch, 1961). The red star is the approximate location of DKL Libby Gas Plant.

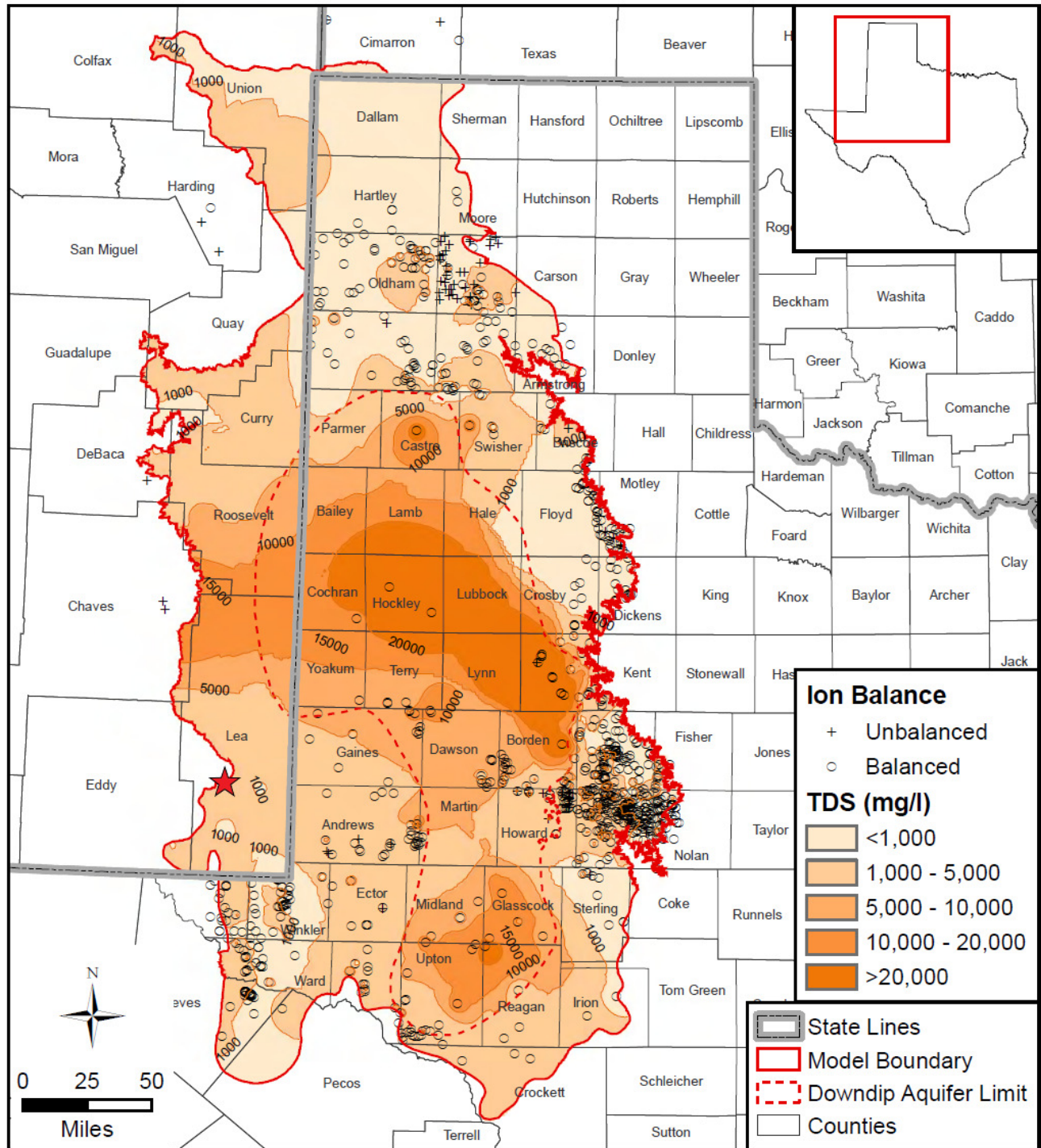


Figure 24 – Total dissolved solids in groundwater from the Dockum Aquifer (Ewing et al., 2008). The red star is the approximate location of the DKL Libby Gas Plant.

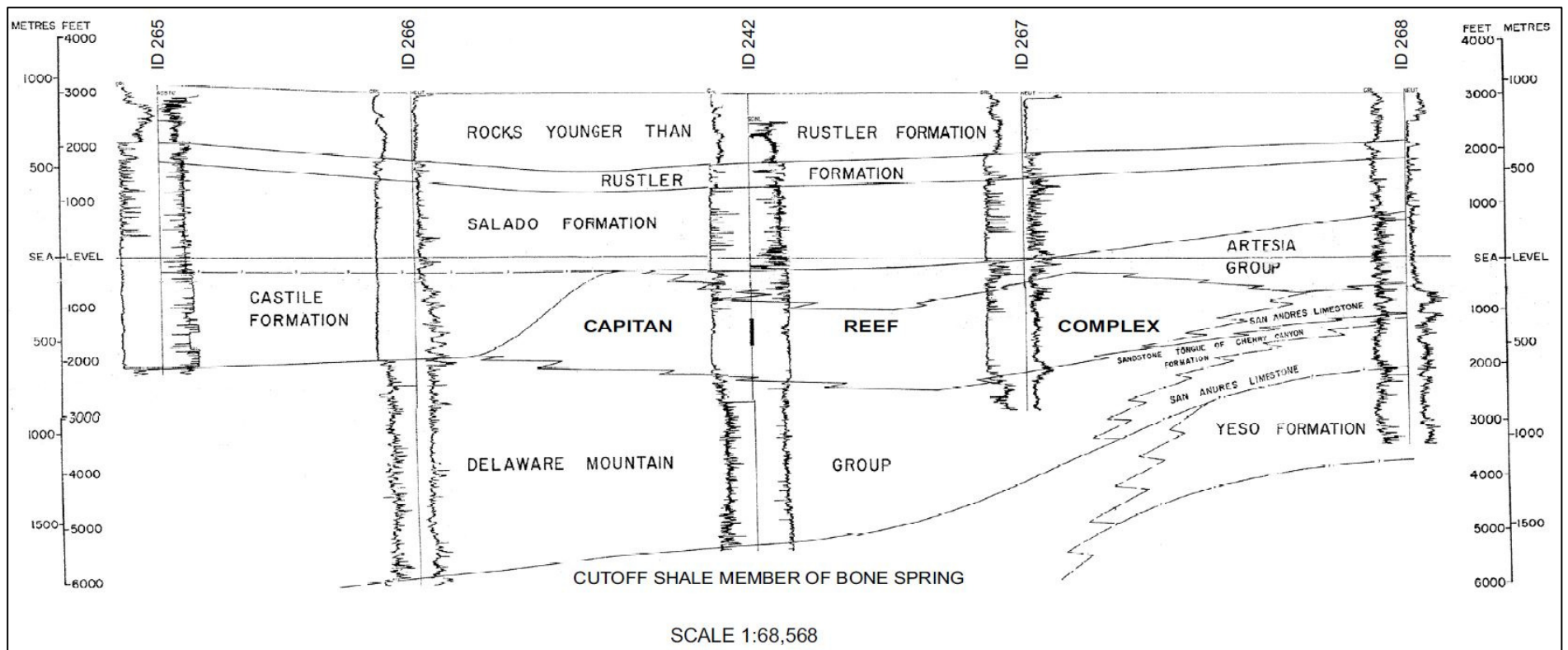


Figure 25 – Capitan Reef Complex in Southern Lea County, New Mexico from West to East (modified from Standen et al., 2009).

2.4.2 Surface Water Resources

As stated previously, surface water resources surrounding the Libby No. 1 and No. 2 wells are limited to intermittent streams and small lakes. There are more than a dozen small lakes in Lea County, New Mexico, the closest of which is Dagger Lake, located approximately 9 miles south-southwest of the Libby No. 1 and No. 2 well locations.

2.5 Reservoir Characterization Modeling

Rock Flow Dynamic's tNavigator version 24.4 simulator was used to simulate the injection of acid gas into the Siluro-Devonian Formation. Formation tops, net thickness maps, and formation extents were created with the Kingdom software suite to support the permitting of the Libby No. 1 and No. 2 wells for oil and gas waste. The dynamic model is an advanced modeling and simulation platform used for understanding reservoir dynamics, flow patterns, and risks associated with acid gas injection. The target injection zone for oil and gas waste storage is located at a depth between approximately 14,832 ft and 16,515 ft TVD.

The tNavigator software stands out as one of the most technically sophisticated tools for simulating conventional, unconventional, and secondary recovery scenarios. The dynamic model uses equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for acid gas injection and storage. The tNavigator model is used to delineate the active monitoring area (AMA) and maximum monitoring area (MMA).

A numeric simulation was performed on this formation to predict the maximum extent of the gas plume. The model predicted that the bottomhole pressure (BHP) does not exceed 90% "frac" pressure of the uppermost perforation (i.e., 9,935 pounds per square inch [psi]). The maximum BHP calculated in the model was 7,649 psi. The plume boundary was delineated using operational assumptions of a 20-year injection period at an injection rate of 8 million standard cubic feet per day (MMscf/d). In total, 58.4 billion cubic feet (bcf) of gas was injected into the Siluro-Devonian Formation resulting in a maximum build-up pressure of 1,169 psi.

The gas injectate is composed primarily of CO₂ and H₂S. The anticipated area composition and reservoir modeled percentages for the 20-year injection period are presented in Table 3.

The composition of the injectate may change slightly if additional sources are added.

Table 3 – Expected/Modeled Initial Gas Composition.

Component	tNavigator Modeled Composition (mol %)
Carbon Dioxide (CO ₂)	80%
Hydrogen Sulfide (H ₂ S)	20%

The Siluro-Devonian is the target zone for the Libby No. 1 and No. 2 wells. The Kingdom and Petra software suite was utilized to determine the subsurface structure of the Siluro-Devonian geologic model. The resulting map is provided in Figure 26.

The Libby No. 1 and No. 2 wells are located along the southwestern edge of a four-way closure, just west of regional development of the CBP, and generally beyond the extents of associated faulting. The nearest fault identified from 3D seismic is located approximately 1.9 miles east-northeast of the DKL Libby Gas Plant, and approximately 1.1 miles beyond the extent of the modeled MMA. The nearest basement fault identified in published regional literature occurs approximately 2.65 miles northeast of the site, and approximately 1.8 miles beyond the extent of the modeled MMA. Additional discussion of structure and faulting of the Siluro-Devonian section is available in *Sections 2.2.2 and 2.3.5, Regional Faulting and Local Structure*.

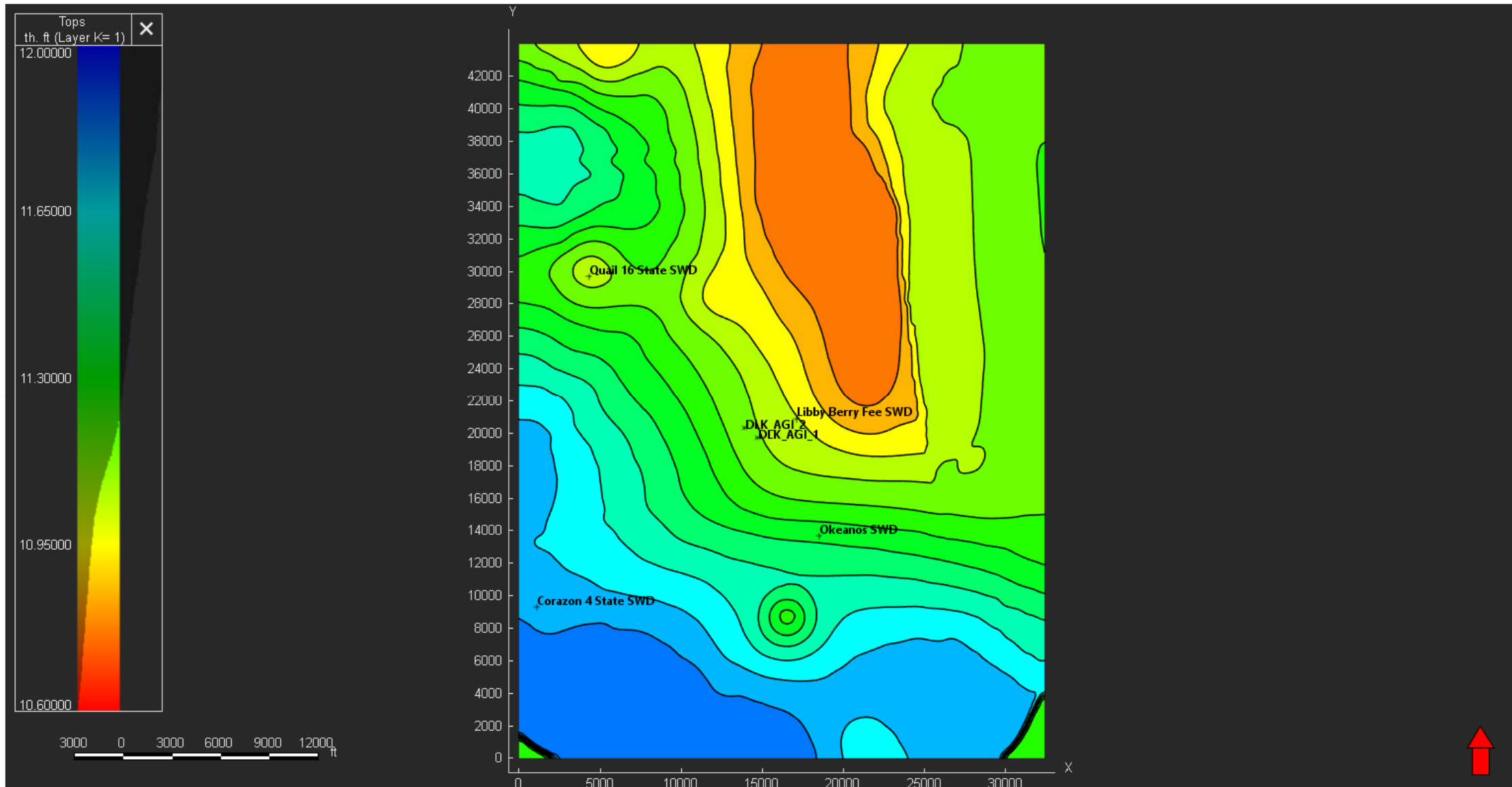


Figure 26 – Siluro-Devonian Structure Contours Map

Porosity distribution across the reservoir zones has been mapped using average porosity values derived from local well data, thereby 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 to ensure accuracy and relevance. Figure 27 provides the pore volume (PV) weighted average of the porosity property in the dynamic model.

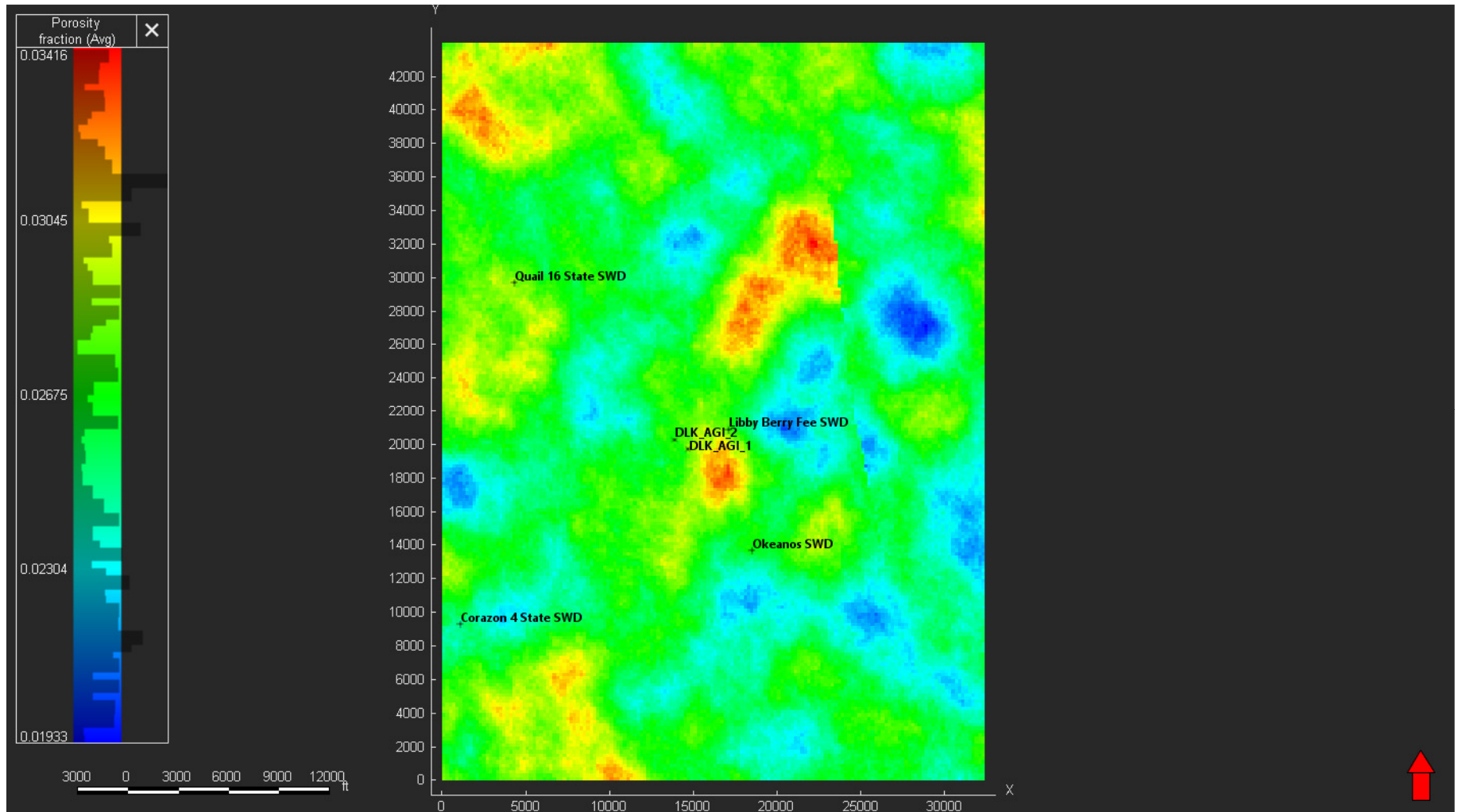


Figure 27 – Pore Volume Weighted Average Porosity Distribution.

Once the porosity property was distributed in the geologic model, a porosity-permeability equation was then applied. This application was done to estimate the permeability across the model. The porosity-permeability was first determined from core data through a

literature review. Model sensitivities were then run to match historical saltwater disposal (SWD) well bottomhole pressures to more realistic values by modifying the equation to more accurately characterize the injection formation. Figure 28 provides the PV weighted average of the permeability property in the dynamic model.

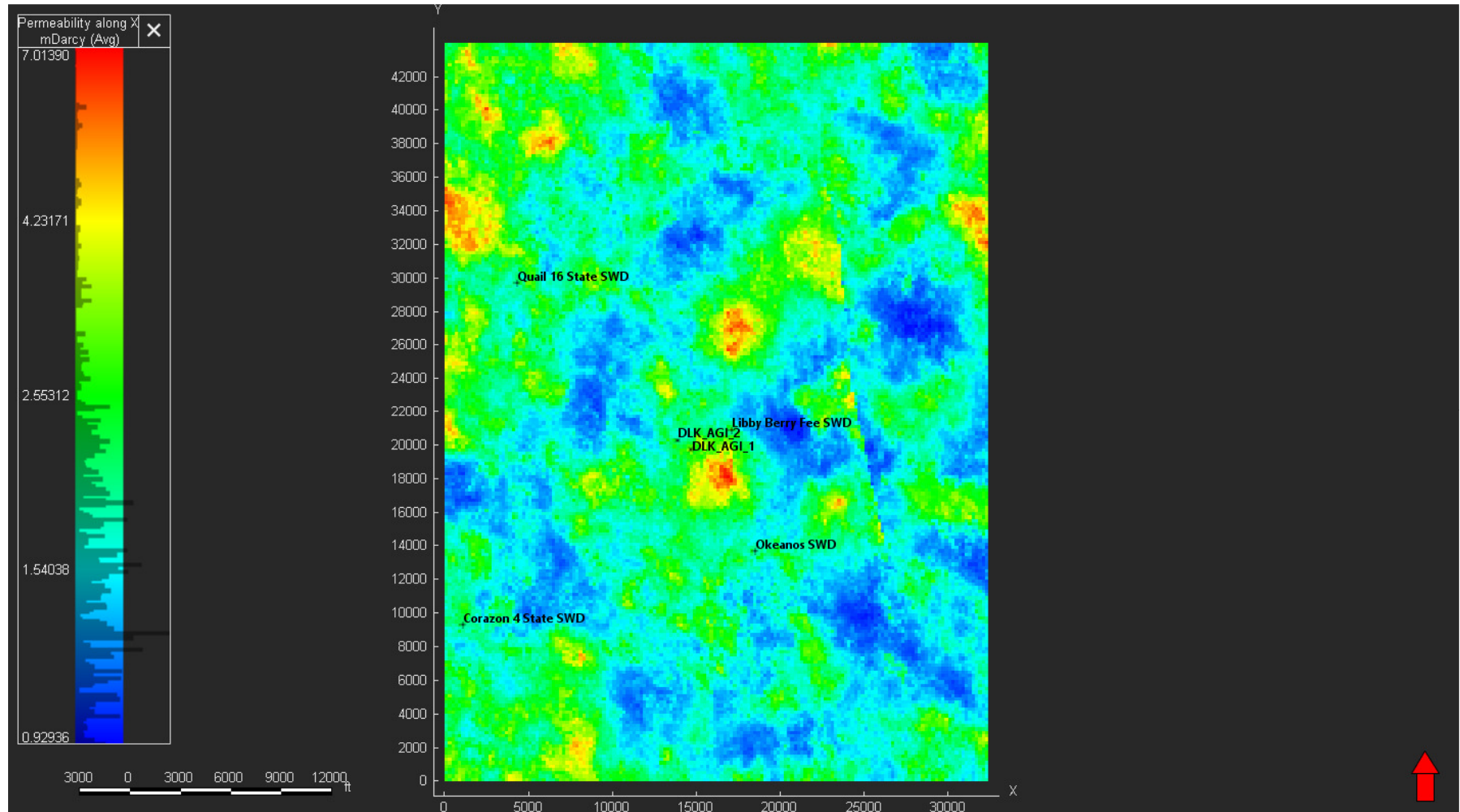


Figure 28 – Pore Volume Weighted Average Permeability Distribution

At the initialization, the reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 35,000 ppm, which is typical for the region and formation. The pore pressure gradient used follows standard industry practices for the region and is presumed to be 0.465 psi/ft. The reservoir temperature is estimated to be 200 degrees Fahrenheit (°F), on average.

An infinite-acting reservoir was created at the edges of the dynamic model to simulate boundary conditions. Core data from a literature review was used to determine residual gas saturation (Ruppel and Holtz, 1994). Core data from the literature review was also used to determine relative permeability curves between CO₂ and the connate brine within analogous carbonate rock formations (Ruppel and Holtz, 1994). The key inputs used in the models include an irreducible water saturation of 40% and a maximum residual gas saturation of 20%.

The grid contains 162 blocks in the x-direction (east-west) and 220 blocks in the y-direction (north-south), resulting in a total of 35,640 grid blocks per layer. Each grid block spans dimensions of 200 ft by 200 ft. This configuration yields a grid size measuring 32,400 ft by 44,000 ft, equating to just under 52 sq mi in area. There are 245 layers in the z-direction, which result in a total model count of 8,731,800 grid blocks (~7.9 million active grid cells after pore volume cutoffs are applied).

2.6 Simulation Modeling

The primary objectives of the model simulations were as follows:

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

Two scenarios were run to delineate the AMA and MMA. The first scenario had acid gas injection into Libby No. 1; whereas the second scenario injected into Libby No. 2. The total combined acid gas plume of both wells was used to determine the AMA and MMA. Each scenario contained the exact same inputs and assumptions.

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 35,000 ppm, typical for the injection zone depth within the region. Though the actual injectate may have trace amounts of other constituents, the gas stream is assumed to be composed of 80% CO₂ and 20% hydrogen sulfide (H₂S), as stated previously. The plume boundary was defined by the maximum gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume for both models. Core data was used to help generate relative permeability curves (Ruppel and Holtz, 1994). Cores that most closely represent the Siluro-Devonian were identified, and the Corey-Brooks equations were used to develop the curves. The initial reservoir pressure gradient was determined to be 0.465 psi/ft based on industry best

practices. The fracture gradient of the injection zone is estimated to be 0.67 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum BHP allowed in the models at 0.603 psi/ft.

The model runs for a total of 80 years, comprised of 10 years of historical SWD well injection, 20 years of active injection through Libby No. 1 and 2 wells, and 50 years of density drift. An injection rate of 8 MMscf/d was implemented during the 20 years of total active injection, after which the wellbore is shut in for the remainder of the simulation. Figures 29 through 32 show the gas plume at the end of injection and the end of the density drift period when the plume stabilizes for Libby No. 1 and No. 2 wells, respectively.

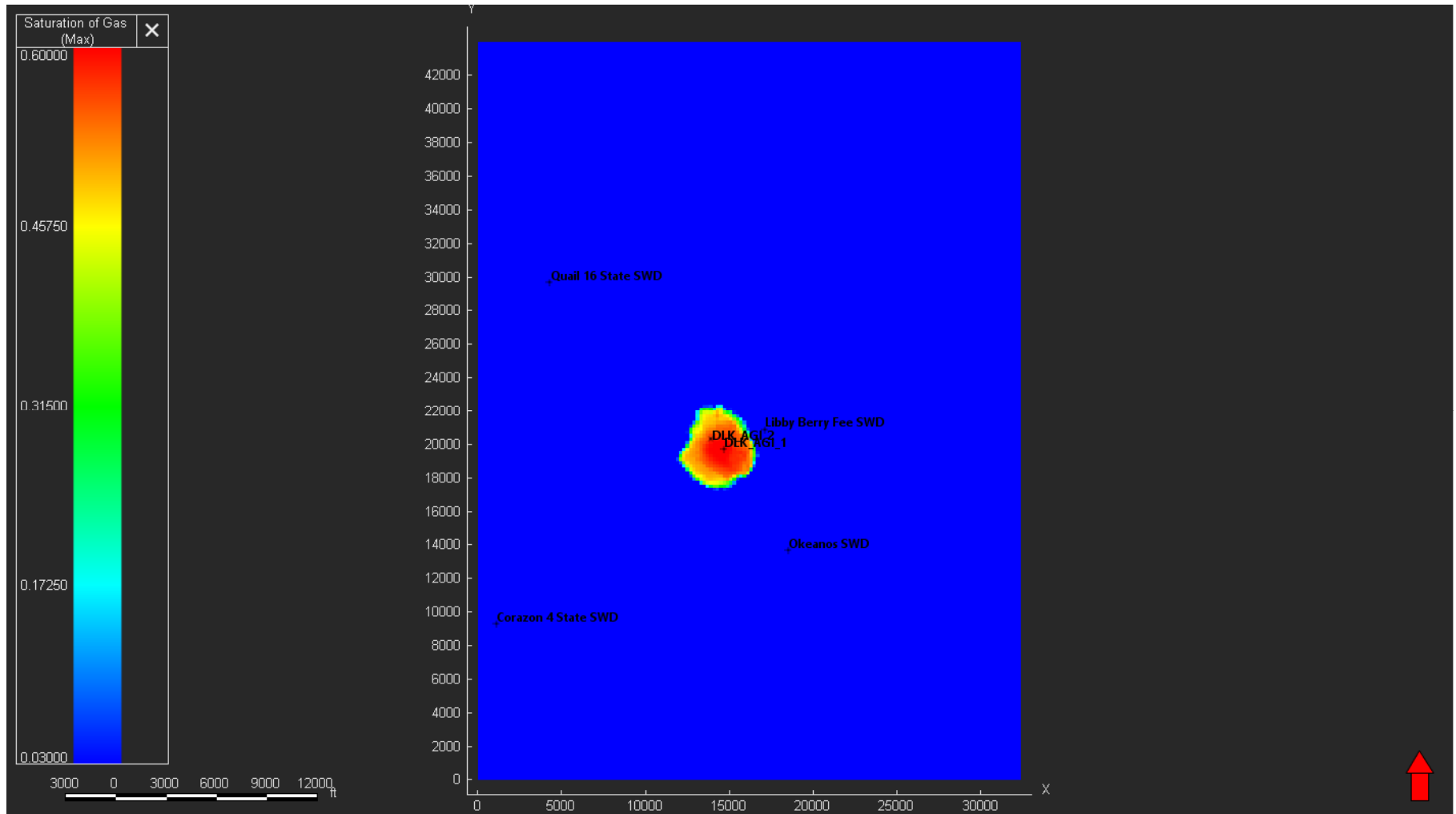


Figure 29 – Libby No. 1 Areal View of Plume at End of Injection.

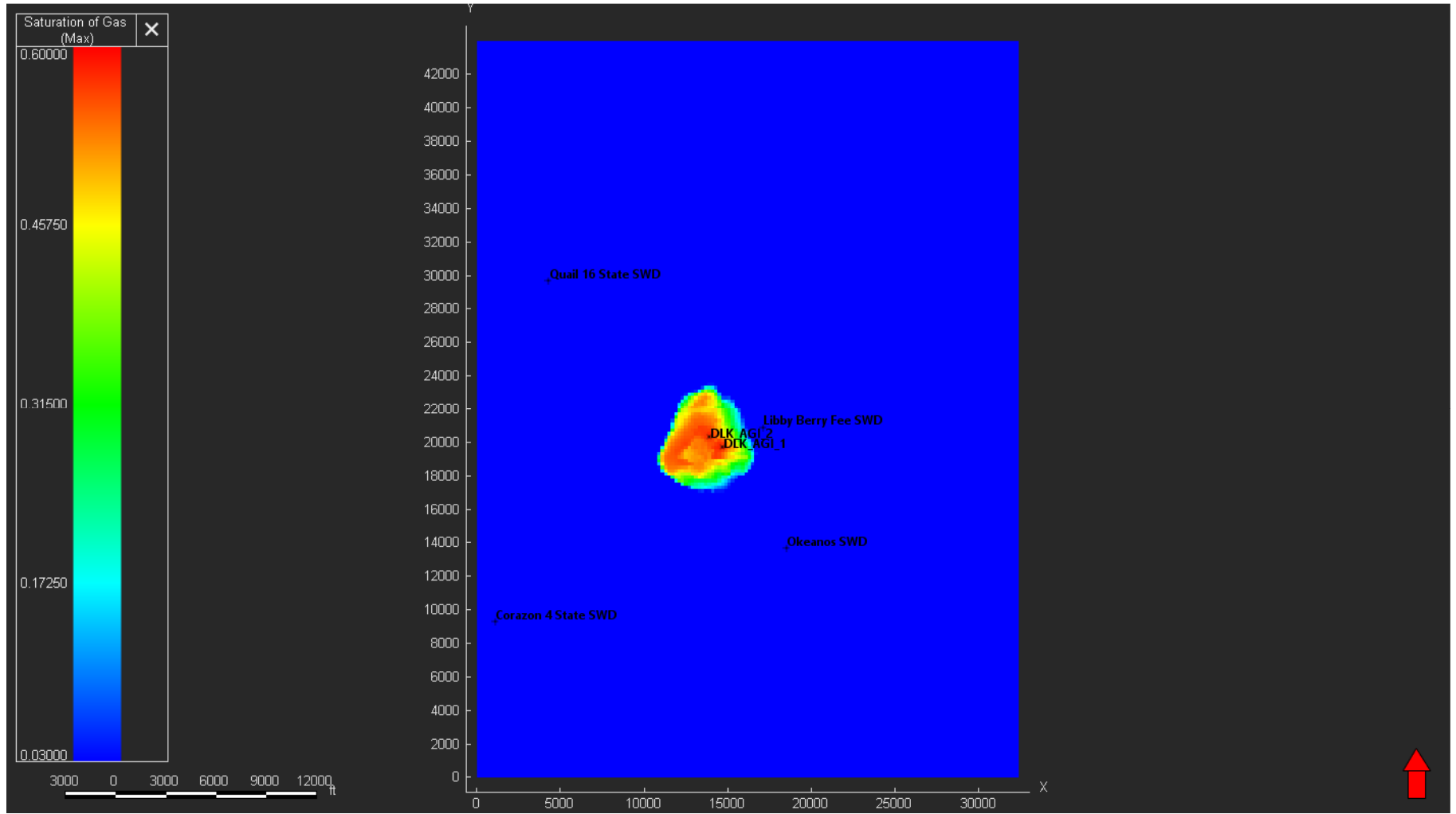


Figure 30 – Libby No. 1 Areal View of Plume at 50 Years After Shut-in.

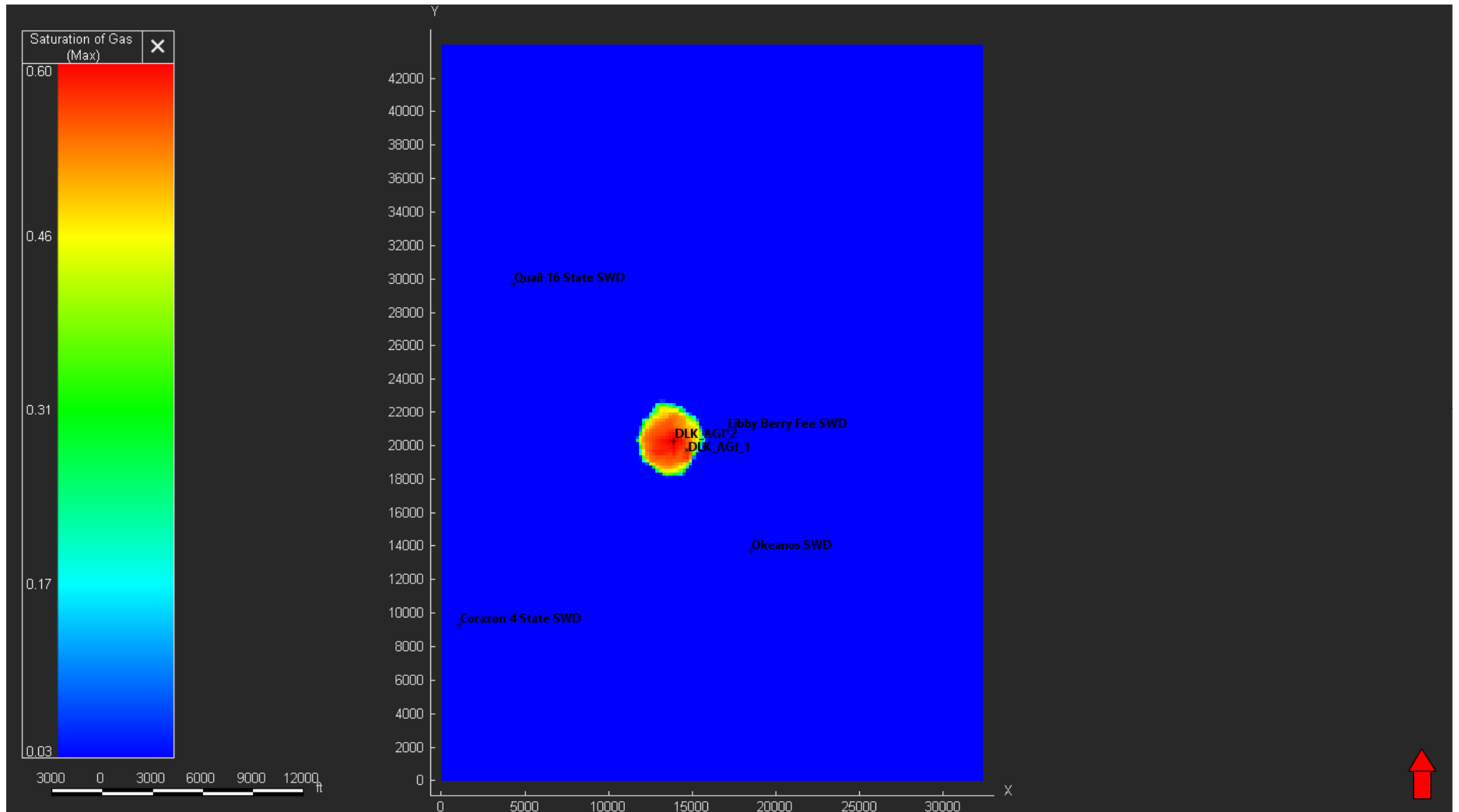


Figure 31 – Libby No. 2 Areal View of Plume at End of Injection.

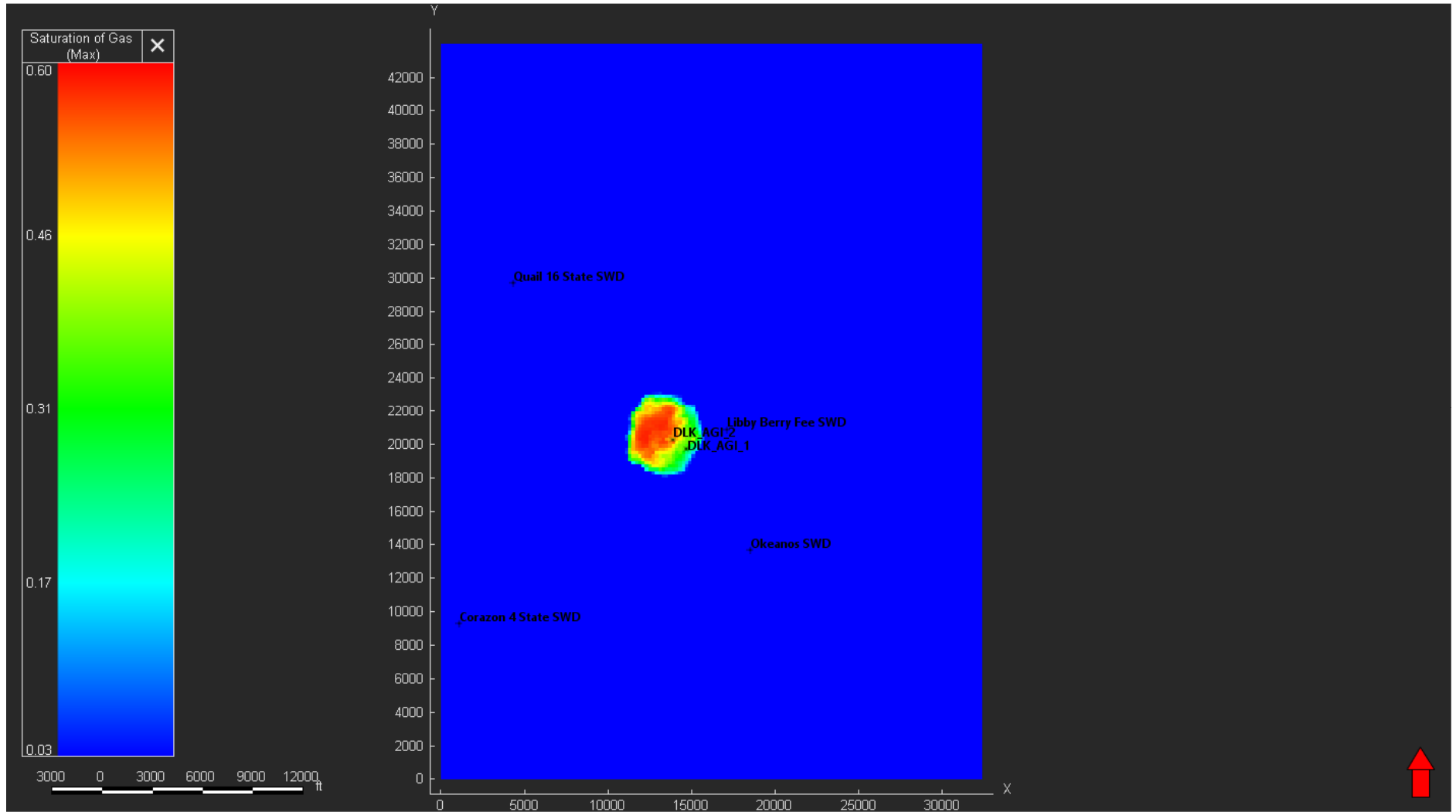


Figure 32 – Libby No. 2 Areal View of Plume at 50 Years After Shut-in.

Figure 33 shows the bottomhole pressure (BHP) during the entire modeled time (i.e., 70 years). Figure 34 shows the surface injection rate during the injection period (i.e., 20 years). The BHP reaches a maximum value of 7,241 psi in Libby No. 1 and 7,649 psi in Libby No. 2. This buildup of 716 psi in Libby No. 1 and 1,169 psi in Libby No. 2 keeps the BHP lower than the fracture pressure of 9,935 psi. The bottomhole pressures during the entire modeled period are displayed in Table 4.

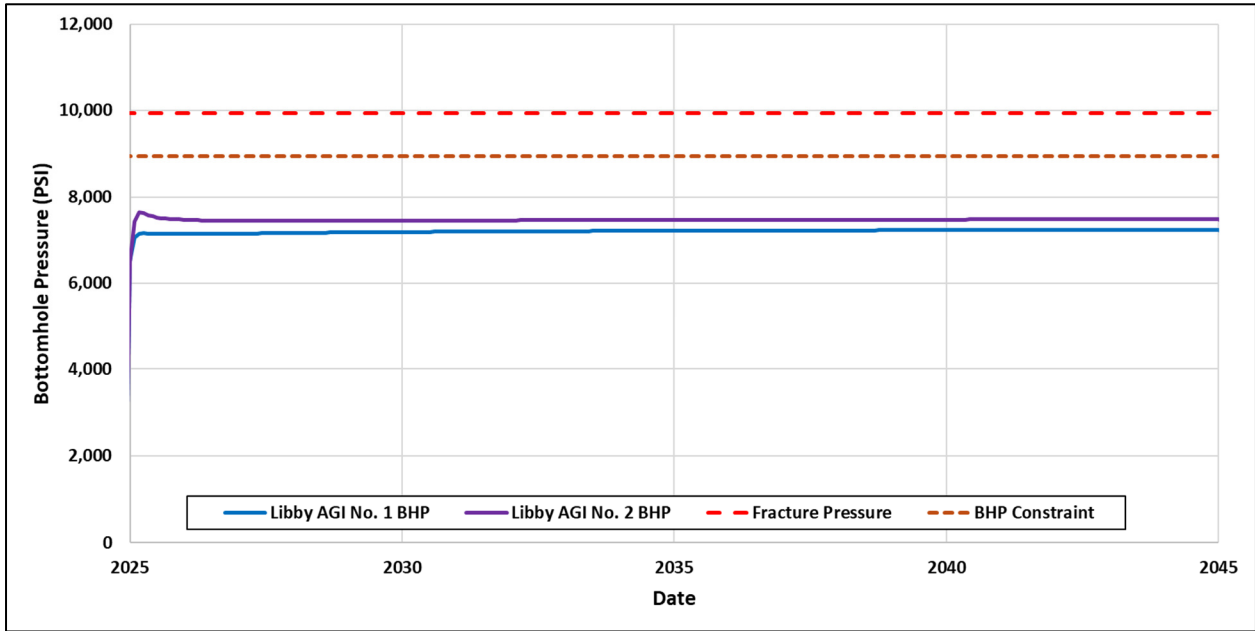


Figure 33 – Bottomhole Pressures During the Entire Modeled Time.

Table 4 – Bottomhole Pressures During the Entire Modeled Time.

Time from Start of Injection (years)	Libby No. 1 BHP (psi)	Libby No. 2 BHP (psi)
0	6,525	6,480
0.1667 (Max BHP of Libby No. 2)	7,138	7,649
5	7,187	7,451
10	7,215	7,466
15	7,230	7,475
20 (End of Injection & Max BHP of Libby No. 1)	7,241	7,483
30	6,589	6,528
40	6,602	6,539
50	6,608	6,547
60	6,611	6,553
70 (End of Model)	6,615	6,557

The linear behavior of the gas rate (MMscf/d) in Figure 34 indicates that the target formation can receive the desired rate of 8 MMscf/d without violating the permitted maximum allowable surface injection pressure (MASIP) of 4,525 pounds per square inch gauge (psig) and fracturing the formation. Of the total 8 MMscf/d of gas that the Libby No. 1 injects, CO₂ accounts for 6.4 MMscf/d, and H₂S accounts for 1.6 MMscf/d of the total rate.

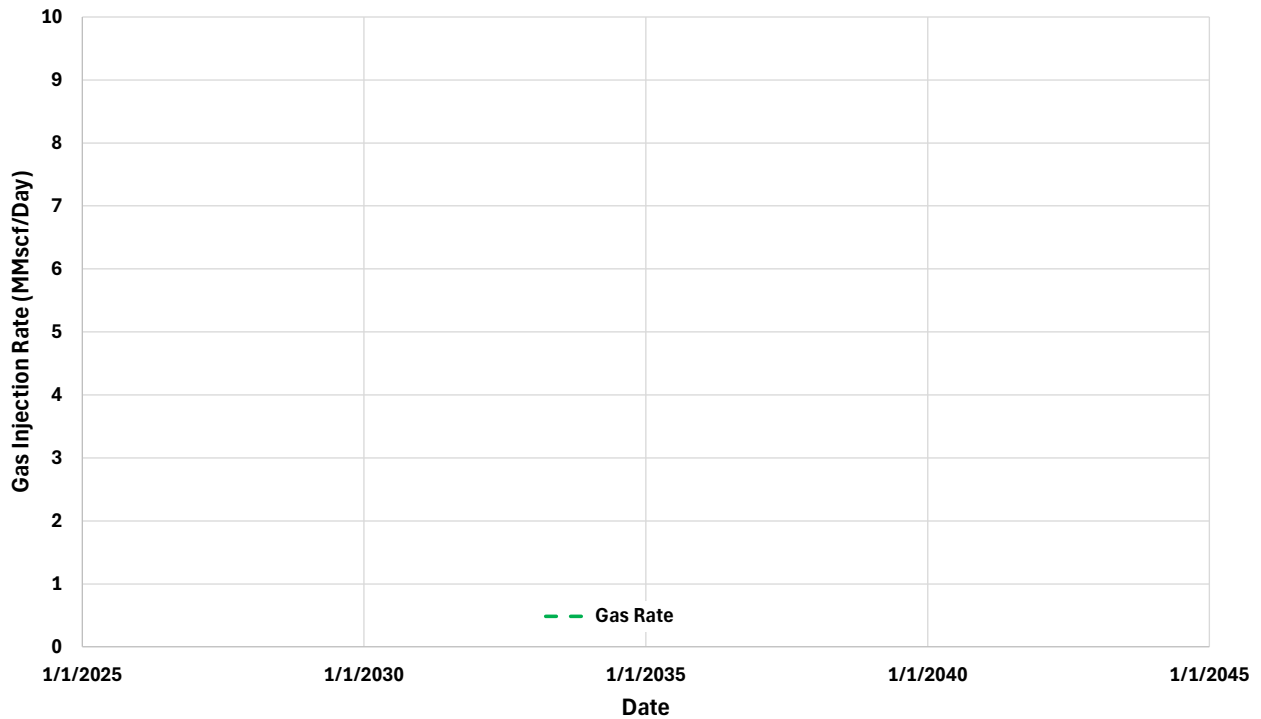


Figure 34 – Combined Gas Injection Rate for Libby No. 1 and No. 2 wells.

SECTION 3 – DELINEATION OF MONITORING AREA

The delineation of the Maximum Monitoring Area (MMA) and the Active Monitoring Area (AMA) as described in the U.S. Environmental Protection Agency (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 CO₂ plume until the plume has stabilized, plus a surrounding buffer zone of at least one-half mile, as shown in Figure 35. 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 2.6*. 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

Stabilization of the plume is deemed to have occurred when the year-over-year growth rate or positional change of the plume size becomes indiscernible. The stabilization of the plume is determined by the simulation model output, when the areal growth rate drops below 0.25% size per year, it is deemed to have stabilized.

3.2 Active Monitoring Area

The AMA is established by superimposing two plume boundaries: (1) the anticipated plume boundary when injection operations cease at the end of year 20 (t), plus a surrounding buffer zone of one-half mi, with (2) the area projected to contain the free-phase CO₂ plume at the end of injection plus 5 years of stabilization (t + 5). The AMA is represented by the dashed green line in Figure 35.

At the end of the injection period in year 20, the areal extent of the plume covers 476 acres. The maximum distance between the wellbore and the edge of the plume is approximately 3,645 ft. After an additional 50 years of density drift, the plume has stabilized, and the areal extent of the plume covers 651 acres. The maximum distance to the edge of the plume at stabilization is approximately 4,303 ft. Figure 35 shows the plume area at the end of 50 years (stabilization) represented by the solid red outline area, plus a one-half mi buffer represented by the dashed red line (MMA). As a result of the small difference between the AMA and the MMA, Delek has elected to set the AMA equal to the MMA.

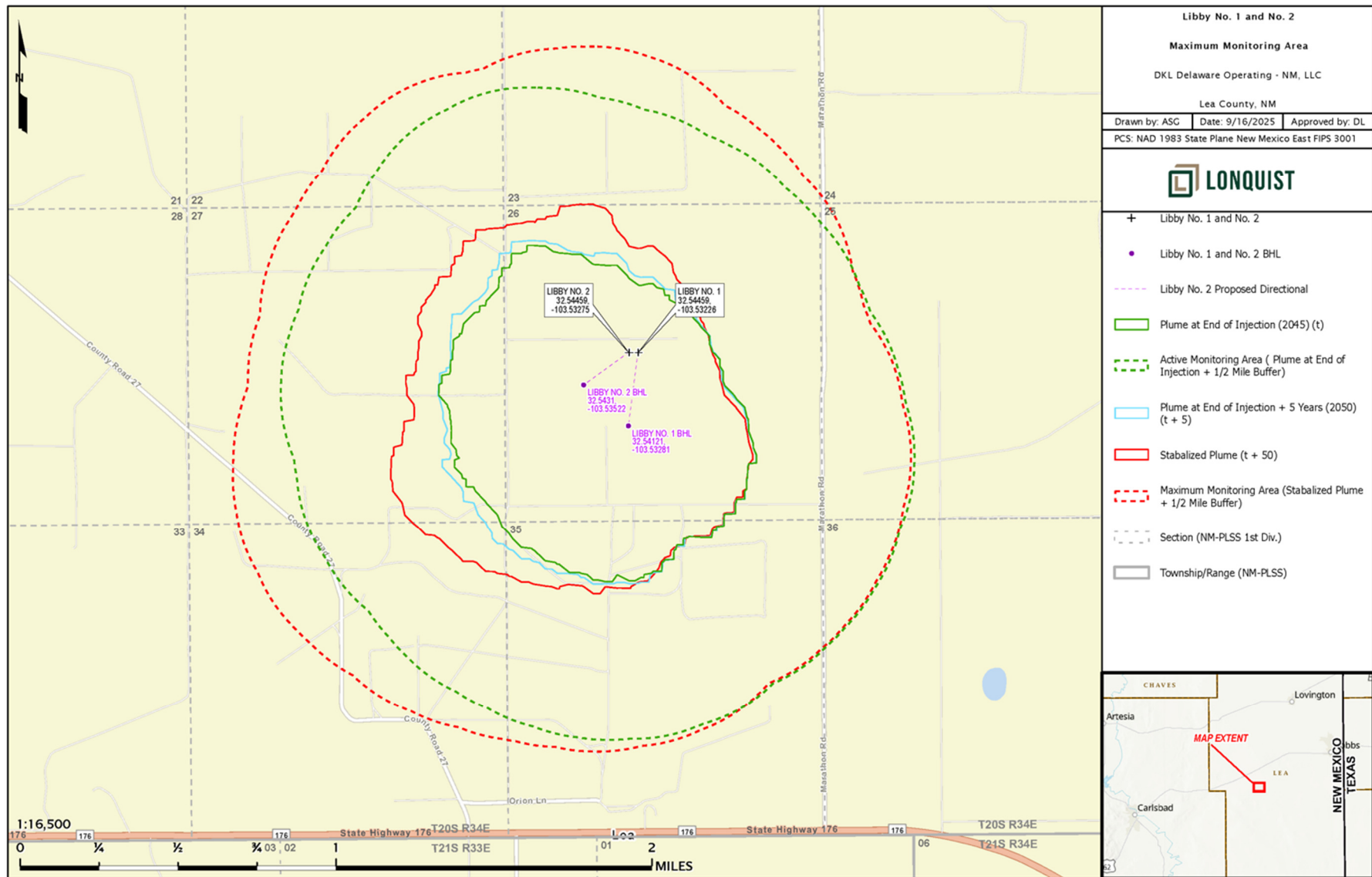


Figure 35 – Delineation of Active and Maximum Monitoring Areas.

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

Potential CO₂ leakage pathways to the surface within the Maximum Monitoring Area (MMA) are identified in this section and evaluated in Table 5 for likelihood, magnitude, and timing. The potential leakage pathways include the following:

- Leakage from surface equipment
- Leakage from existing and plugged & abandoned wells within MMA
- Leakage from future drilling in MMA
- Leakage through faults and fractures
- Leakage through the upper confining zone (UCZ)
- Leakage from natural or induced seismicity

Table 5 – Potential Leakage Pathway Risk Assessment.

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Low. This is possible during injection operations. Delek has extensive monitoring and maintenance programs to properly maintain surface equipment to keep this risk Low.	Low. SCADA systems detect leaks and quickly execute safety shutdown procedures.	During active injection.
Existing and Plugged & Abandoned Wells within the MMA	Low. Three wellbores penetrate the Upper Confinement within the MMA. Only one well is within the stabilized plume. This well has been plugged & abandoned (P&A) to NMOCD regulations.	Low. Two wellbores are new construction and operate as injectors for SWD by Delek, and one well has been plugged and abandoned. There are multiple confining zones above the injection zone to prevent migration to the surface. The P&A well is included in the annual soil gas monitoring program.	During active injection and until the plume stabilizes 50 years after injection ceases.
Future wells within the MMA	Low. Offset Devonian wells are unlikely. NMOCD would require a proper well design to prevent migration of H ₂ S.	Low. The NMOCD would require any new wells penetrating the injection intervals to be constructed to prevent migration of H ₂ S. Multiple confining zones above the injection zone prevent migration of H ₂ S.	During active injection and until the plume stabilizes 50 years after injection ceases.

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Faults and fractures	Low. No faults were identified within the MMA. Siluro-Devonian level faults identified within the area of review do not extend to the surface.	Low. The UCZ should contain any leakage that would migrate through deep offset faults.	During active injection and until the plume stabilizes 50 years after injection ceases.
Upper confining Zone (UCZ)	Low. The UCZ has sufficient thickness, continuity, and confining characteristics.	Low. Leakage out of the Siluro-Devonian injection interval is unlikely to occur because of the extent of the UCZ.	During active injection and until the plume stabilizes 50 years after injection ceases.
Natural or induced seismicity	Low. A review of local seismicity data identified only 4 events of magnitude 2.0 or greater, with the last event being observed in 2023, indicating a low probability of a significant event.	Low. The UCZ, and over 12,000 feet of overburden between the base of USDW and the top of the injection interval, should prevent the migration of fluids out of the injection interval in the case of a seismic event.	During active injection and until the plume stabilizes 50 years after injection ceases.

Magnitude Assessment Description
Low - categorized 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.

These potential leakage pathways have the highest risk of leakage during the injection period. After the injection ceases in 2045, the risk of leakage from the offset wells, fractures, etc., is reduced until the plume fully stabilizes in 2095 based on the plume model. The risks associated with leakage from the surface equipment are eliminated after the injection wells are plugged and the associated surface equipment decommissioned.

4.1 Leakage from Surface Equipment

The DKL Libby Gas Plant and the associated piping to the Libby No. 1 and No. 2 wells are newly constructed facilities that use applicable industry standards for compliance and safety. A pipeline carries the acid gas stream from the exit of the amine treater at the DKL Libby Gas Plant to the Libby No. 1 and No. 2 wells. The pipeline and injection wellheads are potential sources of leakage during injection operations, as the flanged connections and valves are the most likely failure points of the

surface equipment. Also, damage may occur if any of the surface equipment is compromised because of an accident, corrosion, or a natural disaster, resulting in the release of the injectate.

Delek will design, construct, and operate these facilities consistent with internal engineering standards, industry specifications, and practices that meet or exceed these industry codes to ensure potential failure points are limited. Detectors for H₂S are installed at key locations around the facility, as shown in the facility safety plot plan in Figure 36 and in *Appendix B*. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H₂S exposure limits, as recommended by the Occupational Safety and Health Administration (OSHA).

Important safety systems are designed and constructed into the facility to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shut-off settings to isolate the plant, pipeline, and Libby No.1 and No. 2 wells. Delek has also installed a flare stack to safely depressurize the plant and piping during an operating event.

Any release of H₂S/CO₂ is quickly identified because of the real-time monitoring systems in place at the DKL Libby Gas Plant, as listed subsequently in Table 6. The safety systems and protocols implemented minimize the release volume. The acid gas stream can include trace amounts of methane, nitrogen, and other compounds. The CO₂ injected into the Libby No. 1 and No. 2 wells is from the amine treater in the DKL Libby Gas Plant. If any leakage is detected, the volume of CO₂ released is 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). Delek concludes that the leakage of CO₂ through the surface equipment is unlikely.

Table 6 – Leakage Monitoring Equipment at the DKL Libby Gas Plant and Libby No. 1 and No. 2 Wells.

Device	Location	Set Point
H ₂ S detectors	Libby No. 1	10 ppm High Alarm 90 ppm Emergency Shutdown
H ₂ S detectors	Libby No. 2	10 ppm High Alarm 90 ppm Emergency Shutdown
H ₂ S detectors	In-plant detectors	10 ppm High Alarm 90 ppm Emergency Shutdown
Flare stack	Plant site	N/A
Injectate flowmeter	In-plant (downstream of the amine unit)	Calibrated in accordance with API specifications
Emergency shutdown	In-plant detectors	90 ppm Emergency Shutdown
Emergency shutdown	Libby No. 1 and No. 2 well sites	90 ppm Emergency Shutdown

4.2 Leakage from Wells in the MMA

4.2.1 Existing and Plugged & Abandoned Oil and Gas Wells

The Libby No. 1 and No. 2 wells are designed to prevent leakage from the injection interval to the surface through a special casing and cementing designs, as depicted in the schematics provided in Figures 37 and 38. Additionally, each well will be equipped with a pressure-limiting device and a one-way safety valve installed in the tubing string approximately 250 ft below the surface to prevent flow back out of the formation in the event of a failure of the injection equipment. Injection pressure, temperature, rate, and annular pressure will be monitored continuously. The annular space between the injection tubing and the casing will be filled with a biocide and corrosion-inhibited diesel. Annual mechanical integrity tests (MITs), as required under New Mexico

Administrative Code (NMAC) §19.15.26.11 [40 CFR §146.23 (b)(3)], are to be performed to verify that each well and wellhead can contain the appropriate operating pressures. If an MIT indicates a leak, the well is then isolated, and the leak is mitigated to prevent leakage of the injectate to the atmosphere.

A map of oil and gas wells identified within the MMA (one-half mile buffer beyond stabilized plume extent) is provided in Figure 39. The map is also included in *Appendix C* for reference, along with a summary table of the wells identified within the MMA. The table includes the total depth (TD) of the identified wells to clarify productive depth intervals relative to the targeted formations of the Libby No. 1 and No. 2 wells.

The majority of the oil and gas production identified within the MMA is developed in the shallow Yates and Seven Rivers Formations or the deeper Bone Spring and Wolfcamp Formations. Production from the Yates and Seven Rivers Formations within the MMA generally occurred at depths of 3,300 ft to 4,000 ft, and production from the Bone Springs and Wolfcamp Formations generally occurred between depths of 9,500 ft to 11,600 ft.

Only three wells within the MMA were identified to have penetrated the injection zone (API Nos. 30-025-02501, 30-025-23578, and 30-025-44288). The 23578 well is the only well within the stabilized plume, and it has been plugged & abandoned in accordance with NMOCD requirements. Figure 40 identifies the locations of these wells, which represent the only potential conduits identified within the MMA. The Federal C No. 1 zone (API No. 30-025-23578) drilled through the Woodford Shale, the UCZ, and approximately 18 ft into the Siluro-Devonian injection zone, where it reached a total depth of 14,939 ft. The well did not produce from the Siluro-Devonian but did produce a small amount of oil from a comingled completion of the shallow Yates and Seven Rivers Formations. The Neal No. 3 (API No. 30-025-02501) fully penetrated the Woodford Shale UCZ and reached a total depth of 15,000 ft within the Fasken Formation (Wristen Group), while the Libby Berry Fee SWD well (API No. 30-025-44288) fully penetrated the Fasken Formation and reached a total depth of 16,000 ft within the Fusselman Formation; both wells are completed in, and inject into the Siluro-Devonian, like the Libby No. 1 and No. 2 wells. Historical pressure data reported for the Libby Berry Fee SWD well was incorporated into modeling to understand the potential effects on pressure and the resulting plume migration. Pressure influence from the saltwater injections into the 02501 and 44288 wells prevents the plume from reaching these two wells, therefore, they have a low probability of creating leakage pathways.

The Libby No. 1 and No. 2 wells are designed to prevent the migration of fluids from the Siluro-Devonian injection zone. The two Siluro-Devonian penetrators discussed previously (API Nos. 30-025-23578 and 30-025-44288) are the main potential conduits for the potential release of CO₂ through existing wells, unless new wells are drilled within the MMA. Delek will work with other operators and the NMOCD to ensure that any future wells drilled within the MMA are designed to protect against leakage.

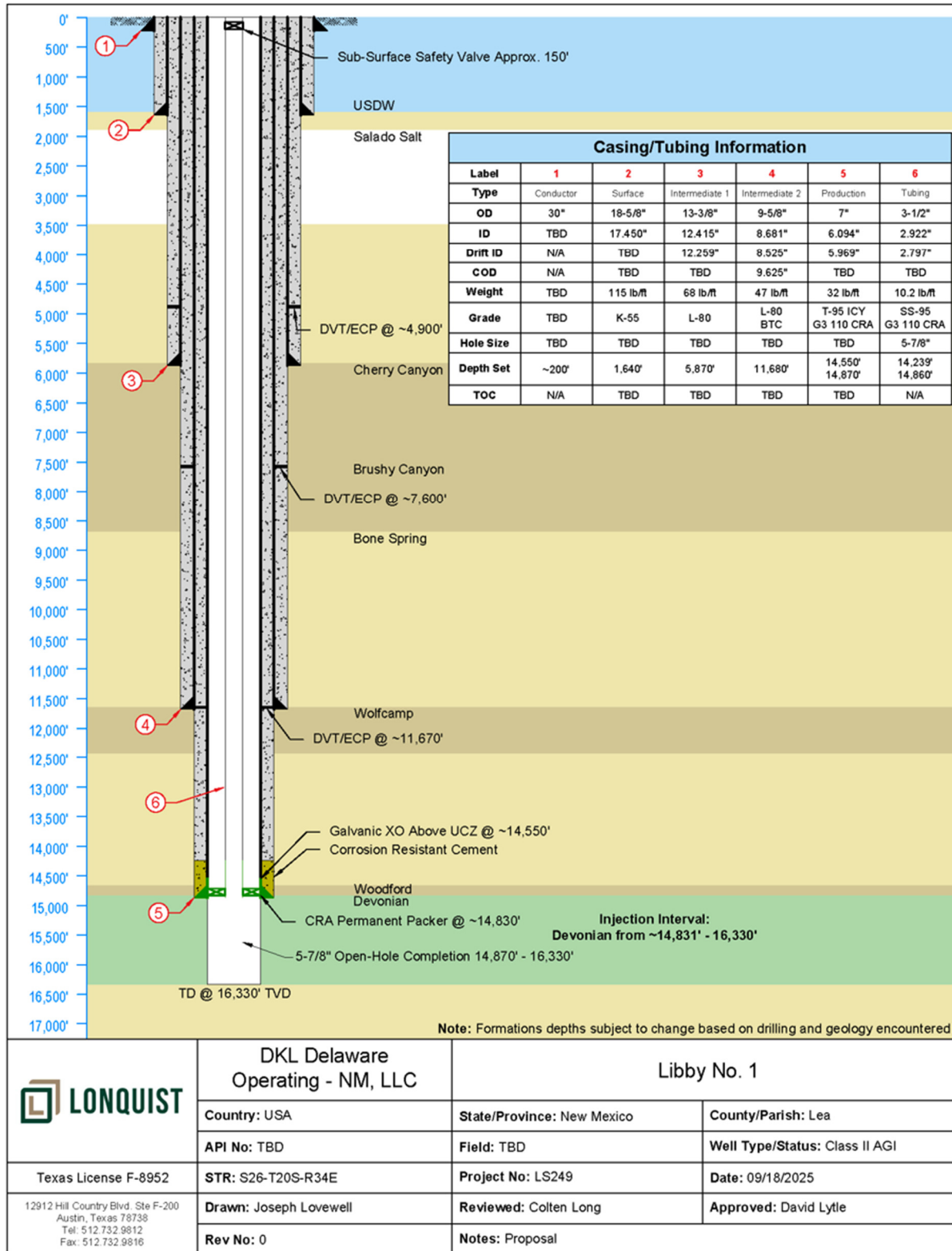


Figure 37 – Libby No. 1 Wellbore Schematic.

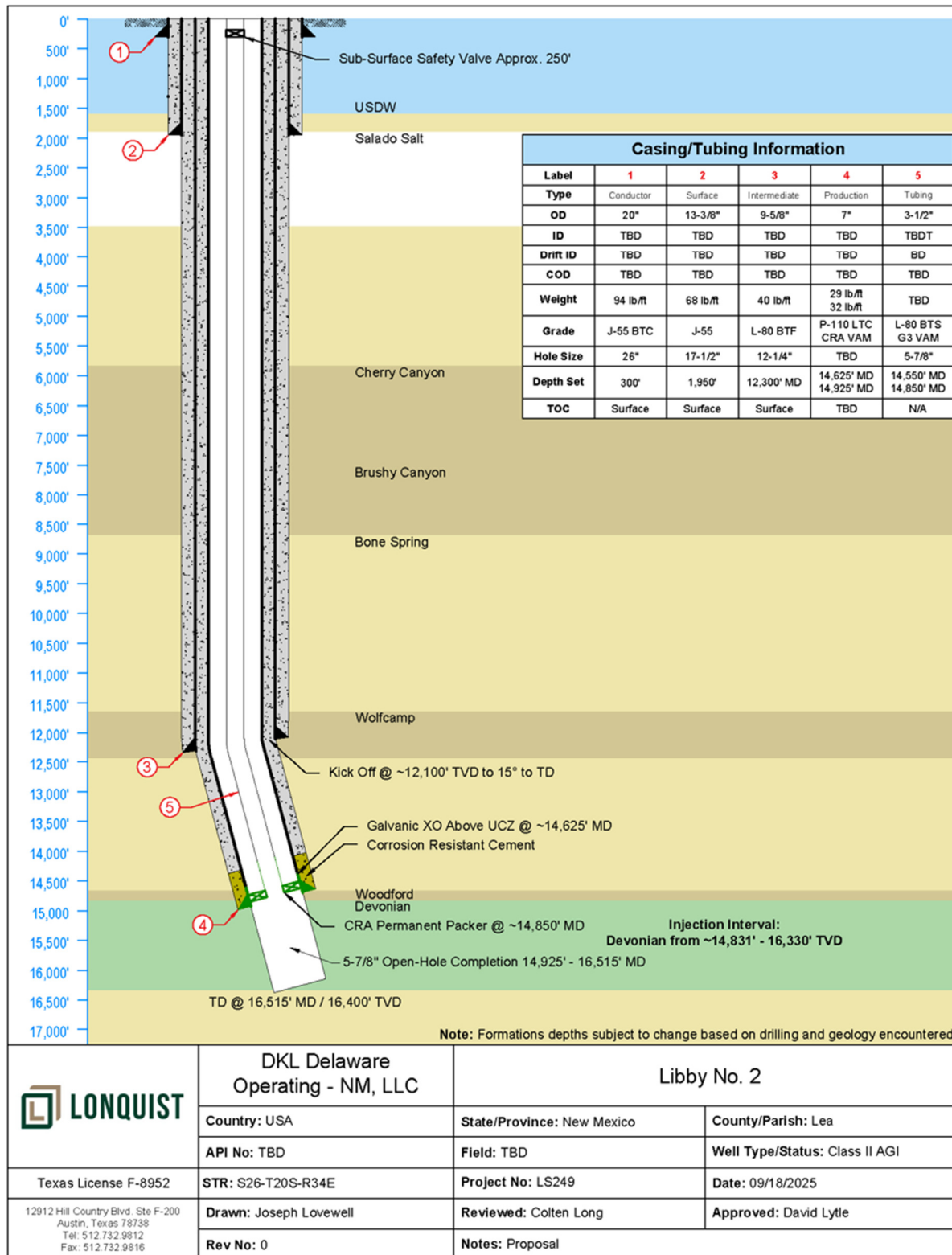


Figure 38 – Libby No. 2 Wellbore Schematic.

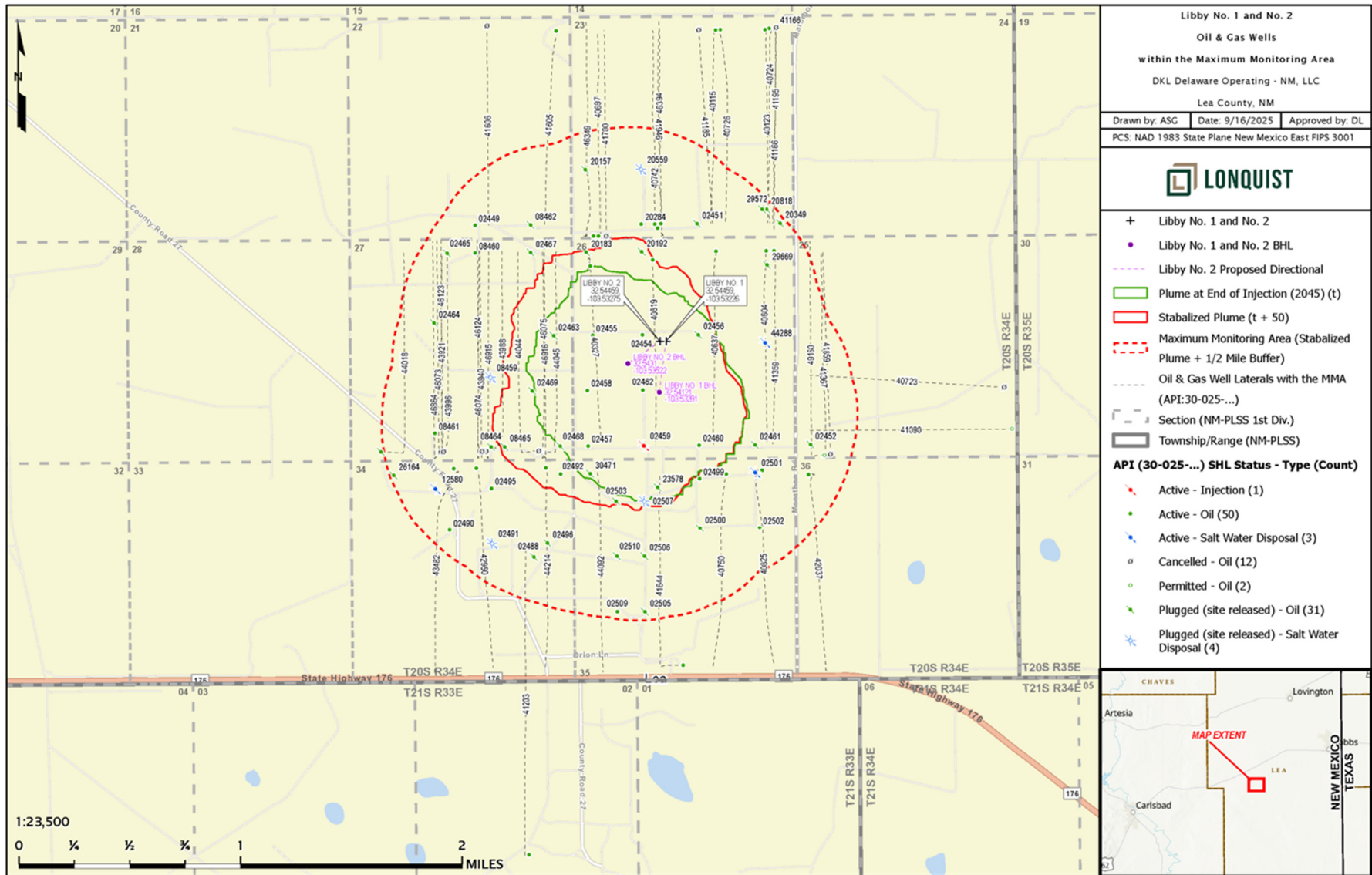


Figure 39 – All Oil and Gas Wells within the Maximum Monitoring Area.

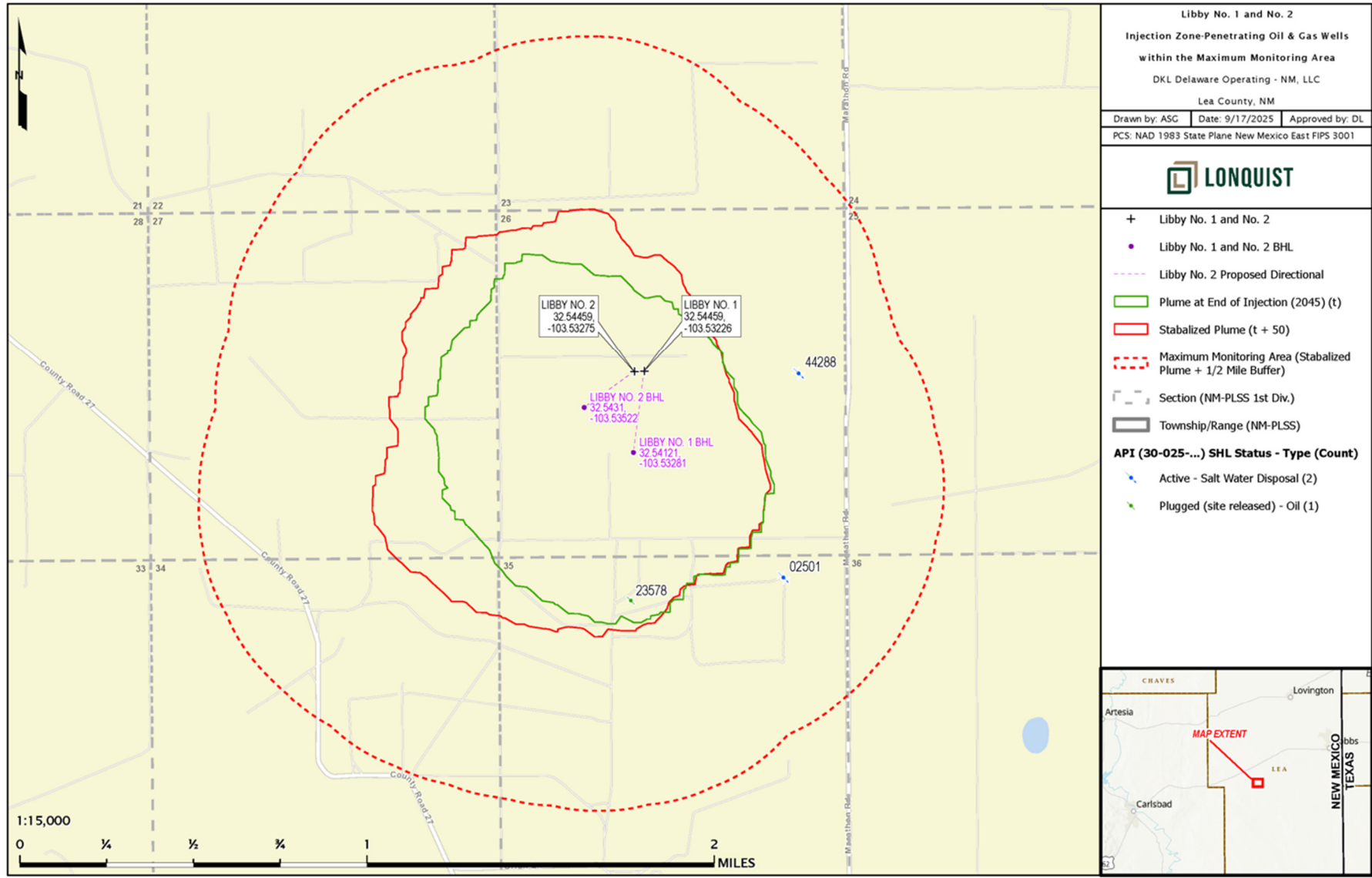


Figure 40 – Oil and Gas Wells Penetrating UCZ within the Maximum Monitoring Area.

4.2.2 Future Drilling

Potential leakage pathways caused by future drilling in the area are possible but not expected to occur. The Siluro-Devonian and deeper formations around the DKL Libby Gas Plant are non-productive and used primarily as Class II disposal wells. Any future drilling to these depths would be for similar Class II acid gas or saltwater disposal wells, for which the permitting is tightly regulated by the NMOCD.

Any drilling permits issued proximal to the Libby No. 1 and No. 2 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 to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluids from the injection zone into another zone or to the surface around the outside of a casing string.”

4.3 Leakage Through Faults or Fractures

As discussed in *Section 2.2.2* and *Section 2.3.5*, regional interpretations published by Horne, Hennings, and Zahm (2021) and seismic evaluation agree that there is no faulting in the targeted formations within the modeled plume extent or MMA of the injectors. Additionally, faults located near the DKL Libby Gas Plant, but outside of the MMA are interpreted by Horne, Hennings, and Zahm (2021) to have a displacement less than the thickness of the UCZ, further reducing the likelihood of injected fluids breaching the UCZ. Any injected fluids breaching the Woodford Shale or transmitting through an unknown fault, have additional confinement to be found within clay-rich, tight-lime, and evaporitic intervals present within the Bone Spring, San Andres, Castile, and Salado Formations.

4.4 Leakage Through Confining Layers

The Woodford Shale is a competent sealing formation that immediately overlies the Siluro-Devonian injection interval with a gross thickness of approximately 190 ft. The Woodford Shale contains ideal properties to prevent the migration and keep the injected fluids isolated to the injection interval. This sealing capability of the Woodford Shale is validated through modeling and demonstrated in the significant amount of injection operations into the Siluro-Devonian in Lea County, New Mexico. The formation also provided the seal for a number of historical oil and gas fields in the Permian Basin, where the formation blanketed over Siluro-Devonian structures. Additional confining intervals are provided by salt, shale, and tight carbonates present between the Woodford Shale and shallow groundwater. These confining intervals alleviate the threat of migration of injected fluids into either the USDW or to the surface.

4.5 Leakage From Natural or Induced Seismicity

The Libby No. 1 and No. 2 wells are situated within the Delaware Basin region, an area that has experienced a number of seismic events in recent history. An evaluation of historic seismic data available from the USGS Advanced National Seismic System and the New Mexico Tech Seismological Observatory (NMTSO) website yielded only 4 seismic events greater than 2.0 magnitude within a 9.08-kilometer (km) (5.4 mi) radius of the Libby No. 1 and No. 2 wells, the search radius suggested by New Mexico for historical seismic investigations. The last recorded event was in July of 2023. During our review, the datasets were found to have duplicate records on certain days. The datasets were scrubbed to filter out duplicate datapoints that occurred in close proximity, on the same day. In such instances, the highest magnitude recorded datapoints were kept, and the lower magnitude datapoints were removed. Figure 41 represents these events of greater than 2.0 magnitude. There were no recorded events of 2.0 or greater from the USGS within the 9.08 km radius.

There are no indications of faulting present within the modeled MMA of the Libby No. 1 and No. 2 wells that could be affected by injection, and the UCZ consists of nearly 200 ft of low-permeability, ductile shale. Consequently, the risks associated with the migration of injected fluids out of the injection interval are deemed to be low. Stringent operating procedures are to be programmed into the SCADA and control systems to ensure operating pressures stay below the maximum allowable surface injection pressure (MASIP) of 4,525 pounds per square inch gauge (psig). Moreover, continuous well monitoring is to be performed in conjunction with monitoring of the USGS and NMTSO online databases to promptly identify any operational irregularities or increases in nearby seismic activity.

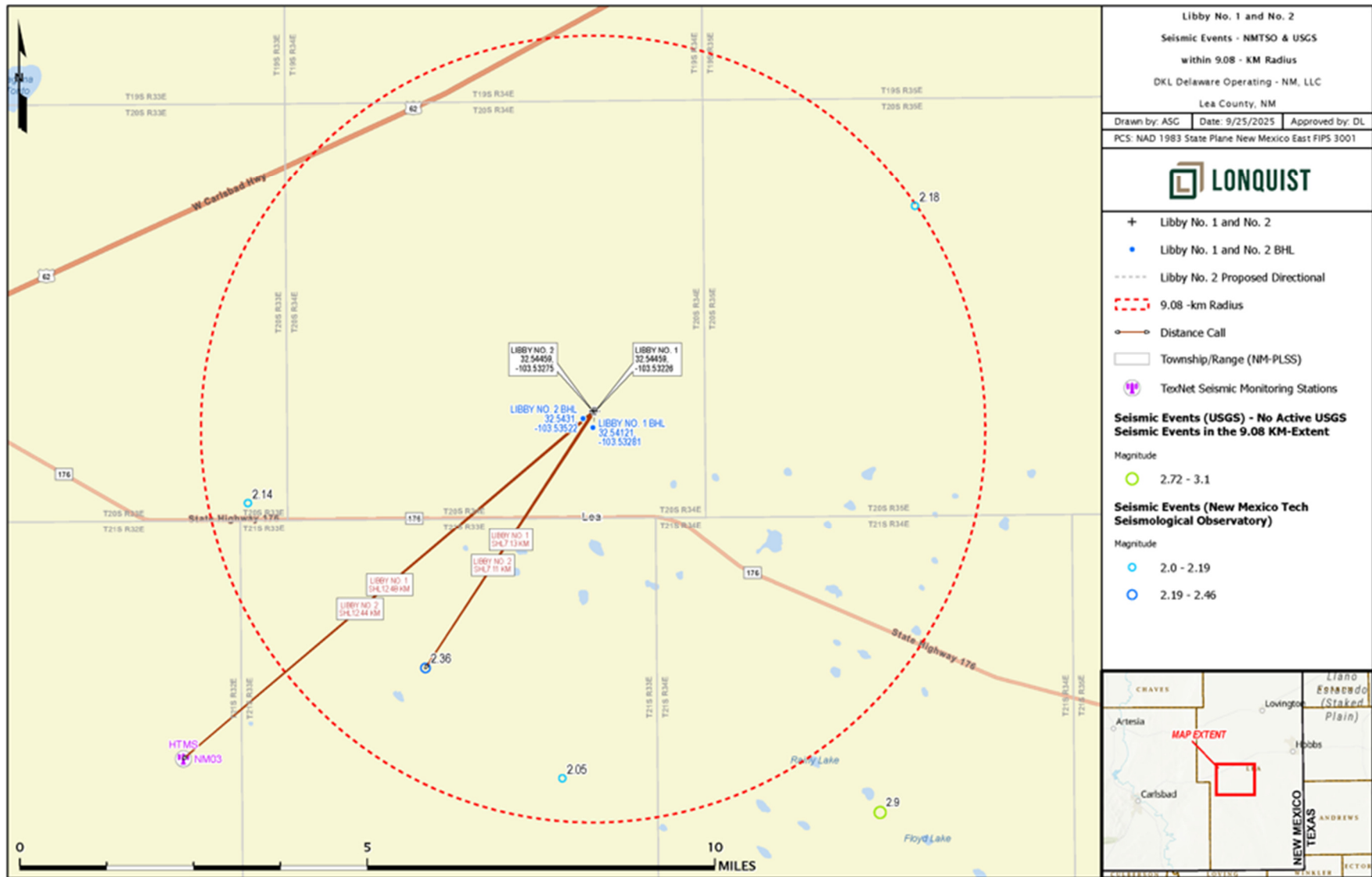


Figure 41 – Local seismicity review map of USGS and New Mexico Tech seismological databases with nearby seismic monitoring stations.

SECTION 5 – MONITORING FOR LEAKAGE

This section outlines Delek's approach to identifying and measuring surface leakage of CO₂ through the pathways described in Section 4, in accordance with 40 CFR §98.448(a)(3). Because the injected stream includes both H₂S and CO₂, H₂S serves as an indicator of CO₂ leakage, meaning the systems designed to monitor H₂S also indicate releases of CO₂. Table 7 provides an overview of the monitoring efforts for potential pathways for surface leakage. Monitoring takes place either during the 20-year injection period or until injection stops, followed by 50 years of the post-injection phase until the plume stabilizes.

Table 7 – Summary of Leakage Monitoring Methods.

Leakage Pathway	Monitoring Method	Frequency
Surface Equipment	Fixed H ₂ S detectors throughout the DKL Libby Gas Plant	Continuous
	Visual inspections	Daily
	SCADA continuous monitoring of the DKL Libby Gas Plant	Continuous
Existing and Plugged and Abandoned Wells	SCADA Continuous Monitoring at the Libby No. 1 and No. 2 Wells	Continuous
	Mechanical Integrity Test of the Libby No. 1 and No. 2 Wells	Annually
	Visual Inspections	As needed
	Annual soil gas sampling at well locations within the MMA	Annually
Drilling through MMA	Compliance with NMOCD regulations	During operations
	Monitor Drilling Activity	During operations
Faults and Fractures	SCADA Monitoring at the Libby No. 1 and No. 2 Wells (volumes and pressures)	Continuous
Upper Confining Zone (UCZ)	SCADA Monitoring at the Libby No. 1 and No. 2 Wells (volumes and pressures)	Continuous
Natural or induced seismicity	Seismic monitoring station	Continuous

5.1 Leakage From Surface Equipment

The DKL Libby Gas Plant and Libby No. 1 and No. 2 wells are designed and constructed to inject CO₂ and H₂S according to industry best practices and standards to minimize the potential leakage points. Critical areas within the facility are constructed with materials that are National Association of Corrosion Engineers (NACE) and API compliant. The DKL Libby Gas Plant operations are monitored and controlled with Distributed Control System (DCS) and Supervisory Control and Data Acquisition (SCADA) systems providing 24/7 operational supervision. Baseline atmospheric H₂S & CO₂ concentrations are to be established during commissioning of the amine unit. Ambient H₂S detectors are located throughout the DKL Libby Gas Plant and near the Libby No. 1 and No. 2 wells with local alarms and are connected to the SCADA system for continuous monitoring.

Field personnel conduct routine field inspections of detectors, gauges, and leak indicators, such as vapor plumes and ice formations. The internal and external corrosion control programs are monitored for effectiveness by way of periodic inspection of surface equipment, analysis of liquids collected directly from the line, and cathodic protection system inspections.

Safety systems include emergency shutdown (ESD) valves that can isolate segments of the facilities and the Libby No. 1 and No. 2 wells. Pressure relief valves are to be located along pipelines to prevent overpressuring, and flares installed are to allow piping and equipment to be vented and depressured under safe and controlled operating conditions. In addition, the fixed infield H₂S specific alarms have setpoints at 10 ppm and alarm at 15 ppm. Delek field personnel are required to wear personal H₂S detectors that trigger an alarm at 10 ppm and CO₂ alarms that trigger at higher than 0.5%. In the event of an alarm, an immediate response to protect personnel and verify properly working detectors is taken. Subsequent actions are taken to secure the facility and mitigate potential leaks. A safety plot plan for the DKL Libby Gas Plant is provided, as shown in Figure 36 and included in *Appendix B*.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO₂ released is quantified based on the operating conditions, including pressure, flow rate, percentage of CO₂ in the acid gas stream, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Delek then quantifies the leak in accordance with the strategies discussed in *Section 7* and with 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

5.2 Leakage From Wells Within MMA

Delek continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems for the Libby No. 1 and No. 2 wells. This data is to be reviewed by qualified personnel and follows response and reporting procedures when the data is outside the normal operating range. A change of injection or annular pressure indicates the presence of a possible leak and is 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, Delek will also establish and operate an infield monitoring program to detect CO₂ leakage within the MMA. This program includes H₂S monitoring as a proxy for CO₂ at the Libby No. 1 and No. 2 well sites and annual soil gas monitoring samples taken near identified wells within the MMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline, and will be performed annually thereafter for comparative results. Delek is scheduled to complete the baseline soil gas testing in the fourth quarter of 2025, before the implementation of the MRV plan. Delek will have these monitoring systems in place through the injection period and through the post-injection site care period.

5.2.1 Leakage From Existing Oil and Gas Wells

There are three wells within the MMA that penetrate the injection interval, thereby creating a potential leakage pathway out of the injection interval. Two of these wells (02501 and 44288) are existing Siluro-Devonian SWD wells that are operated by Delek as SWD injector wells. Neither of these wells is in the stabilized CO₂ plume. The third well (23578) is an oil well that has been plugged and abandoned, consistent with the requirements of the NMOCD. The 23578 well site will be included in the annual soil gas monitoring program. In evaluating the status and location of these wells, the possibility of leakage from these three wells is deemed to be low.

5.2.2 Leakage From Future Wells Within MMA

5.2.2.1 Libby No. 1 and No. 2 Injection Wells

The Libby No. 1 and No. 2 wells are engineered and will be constructed to prevent any fluid migration from the injection interval to the surface. The casing strings for the Libby No. 1 and No. 2 wells are designed in accordance with NMOCD applicable regulations to safeguard shallow freshwater aquifers and the USDW. The construction design includes premium materials such as corrosion-resistant casing and cement, set into the injection interval and in the upper confining zone. The well designs are illustrated in Figures 37 and 38. The likelihood of leakage from the Libby No. 1 and No. 2 wells is deemed to be low.

Delek will ensure the continuous monitoring and collection of data, including injection volumes, temperatures, pressures, and gas composition data for the Libby No. 1 and No. 2 wells. The data will be recorded by the SCADA system and reviewed by qualified personnel. In the instance an event is identified, reporting procedures and corresponding protocols will be followed to evaluate the event and minimize its magnitude. A temperature and pressure gauge is placed at the wellhead in the injection stream, and a pressure gauge is placed on the casing annulus. Changes in annular pressure signal the presence of a possible leak.

The Libby No. 1 and No. 2 wells are to be equipped with an ESD valve and gas monitors, as illustrated in Figure 36. Figure 36 also shows the location of the flow meter to be used to calculate the total mass of CO₂ (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*.

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

Delek will routinely monitor for drilling activities and permits within the MMA and coordinate with the NMOCD and those operators to ensure the well designs 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 deemed to be low.

5.3 Leakage Through Faults, Fractures, or Confining Layer

Delek will operate the Libby No. 1 and No. 2 wells at injection pressures below what would fracture the injection formation, thereby minimizing the potential for induced seismicity. Delek will use SCADA automated systems to continuously monitor operations at the Libby No. 1 and No. 2 wells. Alerts will be triggered if any deviations from normal operating conditions occur that indicate movement into potential pathways, such as faults or breakthrough of the confining seal. Field personnel will review any such alert and, if necessary, take action to shut in the well.

Should CO₂ migrate vertically, the magnitude risk of this event is very low, as the UCZs have adequate confining properties to prevent migration out of the injection interval. In the unlikely event a leak occurs, Delek 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 low, Delek plans to use the nearest TexNet Seismic Monitoring Station (NM03) as the monitoring system check for activity near the Libby No. 1 and No. 2 wells. The closest station (NM03) is approximately 12.2 km south-southwest of the well locations, as shown previously in Figure 42. This distance is sufficient for accurate and detailed monitoring of the seismic activity surrounding the Delek facilities. Delek will monitor for any seismic event of 2.0 magnitude or greater that is detected within the 9.08 km radius of the DKL Libby Gas Plant. Delek will review the injection volumes and pressures to determine if any significant changes occurred that would indicate potential leakage. In the unlikely event a leak occurs, Delek will quantify the leak using the calculation methods discussed in *Section 7*.

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Delek will undertake to establish the expected baselines for monitoring CO₂ surface leakage in accordance with 40 CFR **§98.448(a)(4)**. Delek will use its SCADA monitoring systems to identify changes from the expected performance that may indicate leakage and the corresponding amounts of CO₂.

6.1 Visual Inspections

Regular inspections are to be conducted by field personnel at the DKL Libby Gas Plant and the Libby No. 1 and No. 2 wells. These inspections 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 are to be taken in a prudent and safe manner to address such issues.

6.2 H₂S/CO₂ Detection

Because of the H₂S being injected with the CO₂, Delek has an H₂S contingency plan in place to monitor for any releases. The H₂S detection is to be a proxy for CO₂ releases. Delek installed H₂S monitors throughout the facility, as discussed previously in *Section 5.1*.

In addition to the H₂S monitors, Delek will establish and operate a soil gas monitoring program to detect leakage of CO₂ within the MMA. Soil gas samples are to be collected annually from select artificial penetration locations within the MMA and analyzed by a third-party laboratory to establish baseline values.

6.3 Operational Data

Initial reservoir pressure measurements will be taken before commencing injection operations. Before starting injection operations for the Libby No. 1 and No. 2 wells, baseline measurements of pressures are recorded. Any significant deviations over time are analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

6.4 Continuous Monitoring

The total mass of CO₂ emitted by surface leakage and equipment leaks is not to be measured directly, because 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 H₂S in the gas stream. Continuous monitoring systems are designed to trigger an alarm if there is a release. The mass of the CO₂ released is calculated based on the operating conditions, including pressure, flow rate, percentage of CO₂, 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 depressuring event, the acid gas stream is to be diverted to a flare stack to be safely vented. The event will be documented and reported in compliance with all permit requirements of the Libby No. 1 and No. 2 and the DKL Libby Gas Plant.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

This section presents the calculation methods Delek will utilize to determine the mass of CO₂ injected, emitted, and sequestered. Site-specific variables for calculating CO₂ emissions from equipment leaks and vented emissions of CO₂ between the injection well and injection volumetric flow meter, in accordance with 40 CFR §98.448(a)(5), are also stated.

7.1 Mass of CO₂ Received

The 40 CFR §98.443 requires the mass of CO₂ received to be calculated using the specified CO₂ received equations “unless you follow the procedures in 40 CFR §98.444(a)(4).” According to 40 CFR §98.444(a)(4), “if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received.” The CO₂ received for the Libby No. 1 and No. 2 wells is wholly injected and not combined with any other supply source; the annual mass of CO₂ injected is equal to the amount received. Any additional future streams are to be separately metered before being combined into the calculated injection stream.

7.2 Mass of CO₂ Injected

In accordance with 40 CFR §98.444(b), because a volumetric flow meter is used to measure the flow rate of CO₂ injected, the total annual mass of CO₂, in metric tons, is to be calculated by multiplying the volumetric flow at standard conditions by the CO₂ concentration in the flow and the density of CO₂ 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 CO₂ 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 CO₂ at standard conditions (metric tons per standard cubic meter):
0.0018682

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO₂ Produced

The DKL Libby Gas Plant only processes hydrocarbons and associated CO₂ produced from formations shallower than the Siluro-Devonian. Hydrocarbons and other components of the inlet stream for the DKL Libby Gas Plant are from formations shallower than the Siluro-Devonian, such as the Yates, Bone Spring, and Wolfcamp. There are no producing wells or production from the Siluro-Devonian Formation within the maximum monitoring area (MMA), where the CO₂ is injected and sequestered.

7.4 Mass of CO₂ Emitted by Surface Leakage and Equipment Leaks

The mass of CO₂ emitted by surface leakage is not to be measured directly because of the presence of H₂S in the injection stream and the safety risk that direct leak surveys present for personnel. Because no venting is expected to occur, the calculations are based on an unusual blowdown event, with those emissions being sent to a flare stack and reported as a part of the required greenhouse gas (GHG) reporting for the DKL Libby Gas Plant. Any leakage is to be detected and managed as an upset event. SCADA continuous monitoring systems triggers an alarm upon a release of H₂S and CO₂. The mass of the CO₂ released is to be calculated based on 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)**, and allows the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event CO₂ is released because of a surface leak, the mass emitted is then 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 CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods from Subpart W are to be used to calculate CO₂ emissions from equipment located on the surface between the volumetric flow meter and the Libby No. 1 and No. 2 wellheads. These emissions will be included in the term CO_{2FI} of equation RR-12, and will not be included in RR-10.

Delek believes the potential for leakage from the previously discussed pathways is low. . Given the possibility of uncertainty around the cause of a leakage pathway, Delek believes the most appropriate method to quantify the mass of CO₂ released shall be determined on a case-by-case assessment of the circumstances. Any mass of CO₂ 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 is to be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events are kept and stored, as stated in *Section 10*.

7.5 Mass of CO₂ Sequestered

Delek plans to begin injections in the third quarter of 2025, at which time data collection is to begin for calculating sequestered amounts. The mass of CO₂ sequestered is to be calculated based on Equation RR-12. When injection operations commence, Delek then begins 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 uses the following equation because these wells do not actively produce oil, natural gas, or any other fluids:

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

Where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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.

Because no venting is planned to occur, the calculations for CO_{2FI} are to be made in case of an unusual event in which a blowdown event is required. The emissions sent to the flare stack will be reported in accordance with the requirements of the GHGRP for the DKL Libby Gas Plant. Those emissions quantified as CO_{2FI} will be reported by Delek under the requirements of Subpart W.

Equations from Subpart W – Petroleum and Natural Gas Systems **§98.232** are to be used to calculate CO₂ emissions from equipment located on the surface between the flow meter used to measure injection quantities and the injection wellheads.

7.6 Mass of CO₂ Emitted Caused by Leaks Other Than Surface Equipment

Given the uncertainty of sources other than surface equipment that may create leakage pathways, Delek quantifies the mass of CO₂ released based on specific parameters at the time of release. Any mass of CO₂ detected leaking to the surface is to be quantified by using industry-proven methods, such as engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance. In the rare event a leak occurs, it is to be addressed, quantified, and documented within an appropriate timeline. Records of leakage events are to be kept and retained, as stated in *Section 10*.

SECTION 8 – IMPLEMENTATION AND ANNUAL REPORTING FOR THE MRV PLAN

The Libby No. 1 and No. 2 wells are also subject to reporting injected volumes and pressures under the NMOCD Class II regulations. Delek is submitting this MRV plan application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan is to be implemented upon receiving EPA approval. The Subpart RR Annual Monitoring Report, in accordance with 40 CFR **§98.43(d)** is to be filed on March 31 of the year following the reporting year. Delek will file the Annual Monitoring Report through the e-GGRT portal.

40 CFR **§98.43** outlines the general monitoring, reporting, recordkeeping, and verification requirements for the entire Part 98 (Mandatory Greenhouse Gas Reporting). Subpart RR facilities must comply with these general provisions in addition to the specific requirements of Subpart RR. Key aspects of **§ 98.3** relevant to Subpart RR include:

- In accordance with (**§ 98.3(a)**): Owners and operators of facilities in the United States or on the Outer Continental Shelf that meet the source category requirements (e.g., Subpart RR’s geologic sequestration category) must report GHG emissions.
- Monitoring and QA/QC (**§ 98.3(c)**): Facilities must use standardized methods for monitoring and quality assurance/quality control (QA/QC) as specified in each subpart. For Subpart RR, this includes precise measurement of CO₂ injection and sequestration per **§ 98.444**.
- Reporting Deadlines and Procedures (**§ 98.3(d)**): Annual GHG reports are due by March 31 of the following year (e.g., 2025 data due March 31, 2026).

Recordkeeping (**§ 98.3(g)**): Facilities must retain records for at least three years, including all data used in GHG calculations, aligning with **§ 98.447** requirements for Subpart RR.

A draft of the Annual Subpart RR Report is provided in Appendix D. This draft report provides facility and company information, a summary of monitoring activities, CO₂ volumes (received, injected, and released), and any updates to the MRV plan.

Delek is to perform the baseline surveys for soil gas sampling as discussed in *Section 6*, within the fourth quarter of 2025.

SECTION 9 – QUALITY ASSURANCE

Delek plans to manage quality assurance and quality control (QA/QC) under the requirements of 40 CFR §98.444, using the methods identified in this section.

9.1 Monitoring Quality Assurance and Quality Control

CO₂ Injected

- The flow rate of the acid gas being injected will be measured with a volumetric flow meter, consistent with applicable industry standards in accordance with 40 CFR §98.448. These flow rates are to be compiled quarterly.
- The composition of the acid gas stream is to be measured downstream of the amine unit with either a continuous gas chromatograph or sampled regularly and analyzed by a qualified lab consistent with industry best practices. The analysis of the acid gas will be used with the volumetric flow meter data to calculate the volume of CO₂ in the acid gas stream.
- The composition of the measured acid gas stream is to be averaged quarterly.
- The acid gas measurement equipment is to be calibrated in accordance with the requirements of 40 CFR §98.444(e) and 98.3(i) of the GHGRP in conjunction with manufacturer recommendations.

CO₂ Emissions From Leaks and Vented Emissions

- Gas detectors are to be operated continuously, except for maintenance and calibration.
- Gas detectors are to be calibrated according to manufacturer recommendations and the requirements of 40 CFR §98.444(e) and 98.3(i).
- Calculation methods using equations from Subpart W are to be used to calculate CO₂ emissions caused by any surface leakage between the volumetric flow meter used to measure injection quantities and the Libby No. 1 and No. 2 wells.

Measurement Devices

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

All quantities of CO₂ are to be converted to standard cubic meters at an absolute pressure of 1 atmosphere and a temperature of 60°F.

9.2 Missing Data

In accordance with 40 CFR §98.445, Delek will use the following procedures to estimate missing data if the data needed for the mass balance calculations can not be collected:

- If a quarterly quantity of CO₂ injected is missing, the amount is to be estimated using a representative quantity of CO₂ injected from the nearest previous period at a similar injection pressure.
- Fugitive CO₂ emissions from surface equipment leaks are to 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, Delek then revises and submits an amended MRV plan to the Administrator for approval within 180 days. At least 180 days before the end of the initial 5 years of active injection, an amended MRV plan is to be submitted for this facility with an updated plume extent based on measured conditions in the wells. At that time, the extent of the AMA and MMA is revised.

SECTION 10 – RECORDS RETENTION

In compliance with the requirements of 40 CFR §98.3(g), Delek retains the records listed subsequently for at least 3 years:

- Quarterly records of the CO₂ injected
 - Volumetric flow rates at standard conditions
 - Volumetric flow rates at operating conditions
 - Operating temperatures and pressures
 - Concentrations of the acid gas stream (CO₂, H₂S, and other) stream
- Annual records of the information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate CO₂ quantities emitted from equipment leaks and vented quantities on the surface between the volumetric flow meter and the Libby No. 1 and No. 2 wells.

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