MONITORING, REPORTING, AND VERIFICATION PLAN

Frontier Field Services, LLC (Frontier) Acid Gas Injection Facility

Metropolis, Maljamar AGI #1 and Maljamar AGI #2 Wells

Version Number: 1.0

Version Date: May, 2024

For the purposes of defining a facility as it pertains to acid gas injection (AGI) wells, and specially 40 CFR part 98, Sub Part RR – Geologic Sequestration of Carbon Dioxide, Frontier Field Services LLC (Frontier) owns and operates over 2,000 miles of contiguous inter-connected field gas gathering lines that transport field gas containing carbon dioxide (CO_2) to three gas processing facilities Maljamar Gas Plant, Dagger Draw Gas Plant and Kings Landing Gas Plant (under development with commissioning anticipated by Q2 2024) and three AGI wells (see Map of Frontier Field Services LLC Acid Gas Injection Facility). Frontier plans to include the Kings Landing Gas Plant in the combined facility after its construction is complete. Frontier will submit a revised MRV plan to address any necessary changes and as may be required by 98.448(d).

Frontier continuously adds new supplies of CO_2 laden gas each year by installing new pipelines and field compression to connect new sources of gas from multiple producing fields and transports through multiple pipelines contained in rights of way (ROW) all of which are under the common control and ownership by Frontier. Frontier controls all the contiguous rights of way for the pipelines that connect the gas plants that are being merged into one facility.

The three AGI wells are connected via a super system utilizing contiguous common pipe and are located at two gas treating and processing plants. Two of the AGI wells are located at the Frontier Maljamar Gas Plant (AGI #1 & AGI #2) and the other AGI well is located at the Frontier Dagger Draw Gas Plant (Metropolis Well). Frontier would have the capability of capturing CO_2 produced at the Kings Landing Gas Plant and transporting it to the Maljamar Gas Plant or the Dagger Draw Gas Plant for sequestration. Upon approval of this MRV plan, Frontier will report under 40 CFR Part 98, Subpart RR as a single facility referred to as the Frontier Field Services LLC Acid Gas Injection Facility (see map below).

The Maljamar Gas Plant is currently reporting under GHGRP ID 538285 and operates two acid gas injection wells. The Maljamar Gas Plant reports GHG emissions under sub-parts C, W, and UU. The Dagger Draw Gas Plant (GHGRP ID 1008358) was acquired by Frontier in November of 2011. This plant has been idle for some time and has not reported GHG emissions under any subpart of the Greenhouse Gas Reporting Program under Frontier ownership as emissions have been under reporting thresholds. The Kings Landing Gas Plant is scheduled to commence construction in late calendar year (CY) 2023 or early CY 2024. The goal is to combine reporting under the Maljamar and Dagger Draw Gas Plants.

For clarity, this MRV plan is presented in two parts. Part A is for the Dagger Draw Gas Plant and Part B is for the Maljamar Gas Plant. Each part of the MRV plan references the current Greenhouse Gas Reporting Program ID for each plant. Once the MRV plan is approved Frontier will combine reporting to the GHGRP under one ID.

Table 1 – *Data Reporting Requirement*

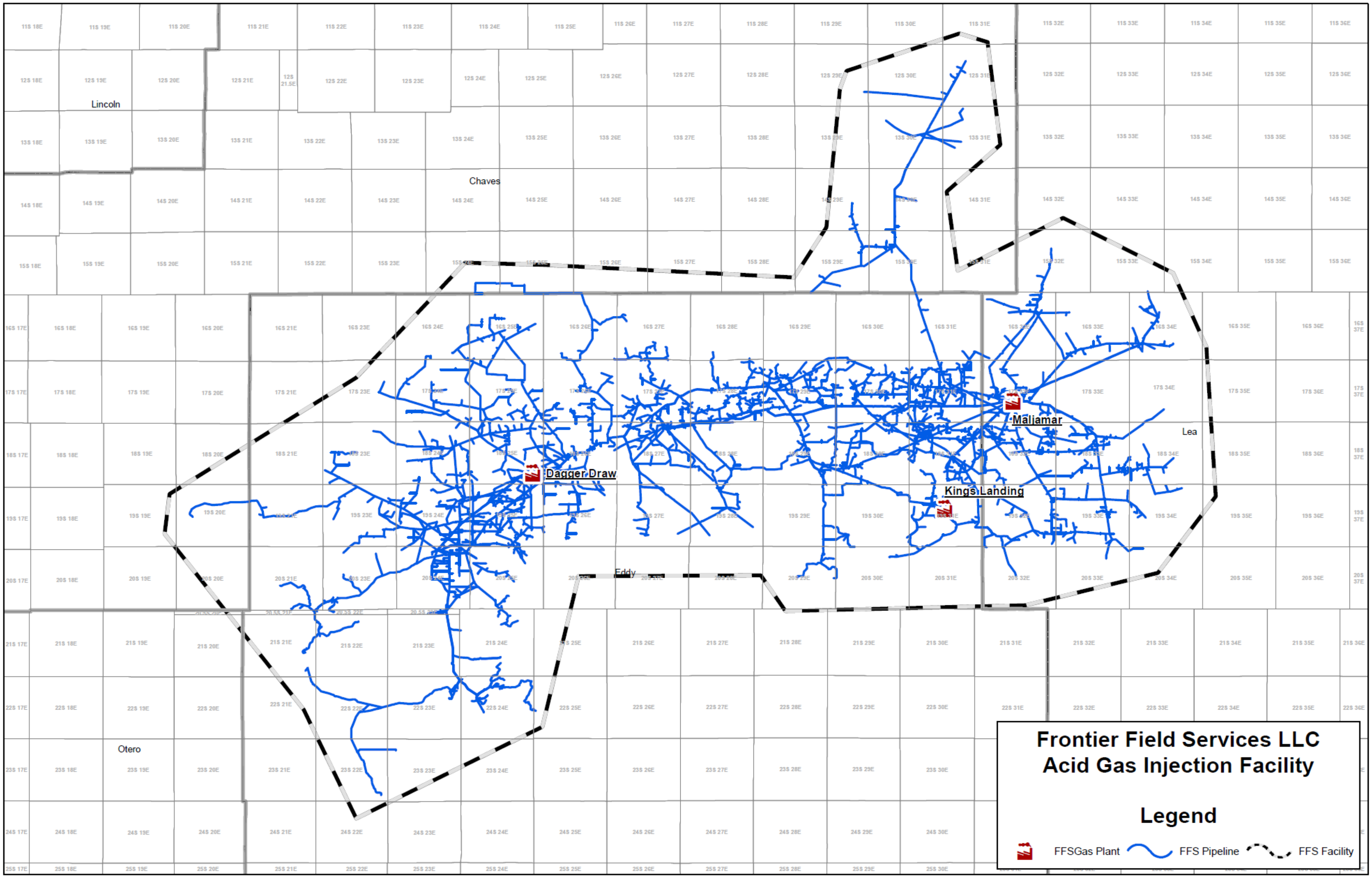
98.446 - Data Reporting Requirement	Dagger Draw Plant	Maljamar Plant	Value to be Reported
98.446 (a) - CO_2 Received through pipeline			
98.446 (a)(1) - total net mass CO_2 received (metric tons) annually	40 CFR 98.444(a)(4) Part A, Section 8.1	40 CFR 98.444(a)(4) Part B, Section 8.1	See 98.446 (a)(4) below
98.446 (a)(2) – receiving volumetric flow meter	NA	NA	

98.446 - Data Reporting Requirement	**Dagger Draw Plant**	**Maljamar Plant**	**Value to be Reported**
98.446 (a)(3) – receiving mass flow meter	NA	NA	
98.446 (a)(4) - CO_2 received is wholly injected	§98.444(a)(4)	§98.444(a)(4)	Annual mass of CO_2 injected Eqn RR-6 where the volumetric flow meters are DDVM and MVM
98.446 (a)(5) – standard or method used	NA	NA	
98.446 (a)(6) – number of times in reporting year substitute data procedures were used	NA	NA	
98.446 (a)(7) – type of receiving flow meter	See 98.446 (f)(1)(vi) below	See 98.446 (f)(1)(vi) below	
98.446 (a)(8) – numerical identifier for flow meter	See 98.446 (f)(1)(v) below	See 98.446 (f)(1)(v) below	
98.446 (b) - CO_2 received in containers	NA	NA	
98.446 (c) - multiple receiving flow meters	NA	NA	
98.446 (d) - source of CO_2	Natural Gas Processing	Natural Gas Processing	Natural Gas Processing
98.446 (e) - date began collecting data for calc tot. CO_2 sequestered	→	→	Will be reported for both plants
98.446 (f) - CO_2 injected			
98.446 (f)(1) - for each injection flow meter, report:			
98.446 (f)(1)(i) - Annual CO_2 mass injected	DDVM: Eqn RR-5	MVM: Eqn RR-5	

98.446 - Data Reporting Requirement	Dagger Draw Plant	Maljamar Plant	Value to be Reported
98.446 (f)(1)(ii) - Quarterly CO_2 conc. (vol. or wt % as decimal fraction)	→	→	Will be reported for both plants
98.446 (f)(1)(iii) - Quarterly volumetric flow rate in standard cubic meters (SCM)	→	→	Will be reported for both plants
98.446 (f)(1)(iv) - mass flow meter	NA	NA	
98.446 (f)(1)(v) - numerical identifier of injection flow meter	DDVM (Part A Figure 3.7-1)	MVM (Part B Figure 3.7-1)	
98.446 (f)(1)(vi) - type of injection flow meter	Volumetric	Volumetric	
98.446 (f)(1)(vii) - standard used to calculate values in ii - iv above	AGA Report #3	AGA Report #3	Will be reported for both plants
98.446 (f)(1)(viii) - number of times annually substitute data used to calculate ii - iv above	→	→	Will be reported for both plants.
98.446 (f)(1)(ix) - location of flow meter	Part A Figure 3.7-1	Part B Figure 3.7-1	Will be reported for both plants.
98.446 (f)(2) - annual mass CO_2 injected	Part A, Section 8.2	Part B, Section 8.2	Eqn RR-6 where the volumetric flow meters are DDVM and MVM
98.446 (f)(3) – emissions from equipment leaks and vented emissions, report the following:			
98.446 (f)(3)(i) – annual mass of CO_2 emitted from equipment leaks between injection flow meter and injection wellhead	Parameter CO_{2FI} of Equation RR-12, Part A, Section 8.5	Parameter CO_{2FI} of Equation RR-12, Part B, Section 8.5	Add values for CO_{2FI} for each plant, report annually

98.446 - Data Reporting Requirement	Dagger Draw Plant	Maljamar Plant	Value to be Reported
98.446 (f)(3)(ii) - annual mass of CO_2 emitted from equipment leaks between production wellhead and flow meter	NA	NA	
98.446 (f)(4) - separator flow meters	NA	NA	
98.446 (f)(5) - entrained CO_2 in produced oil or other fluid	NA	NA	
98.446 (f)(6) -annual produced CO_2	NA	NA	
98.446 (f)(7) - for each leakage pathway, report the following:			
98.446 (f)(7)(i) - numerical identifier for leakage pathway	Will be reported for each leakage pathway at Dagger Draw plant	Will be reported for each leakage pathway at Maljamar plant	Will be reported for both plants
98.446 (f)(7)(ii) - annual CO_2 emitted through each leakage pathway	Will be reported for each leakage pathway at Dagger Draw plant	Will be reported for each leakage pathway at Maljamar plant	Will be reported for both plants
98.446 (f)(8) – annual CO_2 mass emitted by surface leakage – Eqn RR-10	RR-10	RR-10	Sum the results of Eqn RR-10 for Dagger Draw and Maljamar Gas Plants
98.446 (f)(9) – annual CO_2 sequestered	RR-12	RR-12	Sum the results of Eqn RR-12 for Dagger Draw and Maljamar Gas Plants
98.446 (f)(10) – cumulative mass of CO_2 sequestered since all well became subject to reporting	Cumulative sum for Dagger Draw	Cumulative sub for Maljamar plant	Sum of the sums will be reported
98.446 (f)(11) - Date of most recently EPA approved MRV plan and approval number	→	→	Will be reported

98.446 - Data Reporting Requirement	Dagger Draw Plant	Maljamar Plant	Value to be Reported
98.446 (f)(12) - annual monitoring report			
98.446 (f)(12)(i) - narrative history of monitoring efforts	→	→	Narrative history of monitoring efforts at both plants will be included in report
98.446 (f)(12)(ii) - non-material changes to monitoring program	→	→	Description of non-material changes to monitoring program at both plants will be included in report
98.446 (f)(12)(iii) - narrative history of monitoring anomalies	→	→	Description of monitoring anomalies at both plants will be included in report
98.446 (f)(12)(iv) - description of surface leakage of CO_2	→	→	Description of surface leakage at both plants will be included in report
98.446 (f)(13) - UIC well information	Part A, Section 2 and Appendix 1	Part B, Section 2 and Appendix 1	Will be reported
98.446 (f)(14) -	NA	NA	



Map of Frontier Field Services LLC Acid Gas Injection Facility

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Part A – Dagger Draw Gas Plant

1. Introduction

Frontier Field Services, LLC (Frontier) operates the Dagger Draw Gas Plant located in Eddy County, New Mexico. The Metropolis well is located approximately 8 miles southwest of Artesia between the Rio Peñasco and Four Mile Draw, just less than one mile south of the Dagger Draw Gas Plant (**Figures 1-1, 1-2**). Frontier is currently authorized to inject treated acid gas (TAG) consisting of hydrogen sulfide (H2S) and carbon dioxide (CO_2) into the Siluro-Devonian Thirtyone Formation and Wristen Group (hereafter, referred to as Siluro-Devonian units), the Silurian Fusselman Formation, and the Ordovician Montoya Formation, at a depth interval of approximately 9,830 ft to 10,500 ft below the surface, through the Metropolis well (American Petroleum Institute (API) No. 30-015-31905), under the New Mexico Oil Conservation Commission (NMOCC) Order R-13371.

The Siluro-Devonian, the Fusselman, and the Montoya units are sealed by overlying strata consisting of the Mississippian-aged Barnett Shale, and Limestone, and the Devonian Woodford Shale, top to bottom. This thick sequence of low porosity shale and recrystallized limestones are effective barriers above the injection zone. The suitability of the Siluro-Devonian units, Fusselman, and Montoya formations to store the TAG has also been demonstrated by many years of successful injection of produced water by several nearby saltwater disposal wells.

Frontier has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40 Code of Federal Regulations (CFR) 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Frontier intends to inject CO_2 for another 30 years.

Part A of this MRV plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the Dagger Draw Gas Plant and the Metropolis well project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the strategy for detecting and quantifying CO_2 surface leakage from the identified potential sources of leakage.

Section7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV plan as required by 40 CFR 98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 11 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of Part A of this MRV plan.

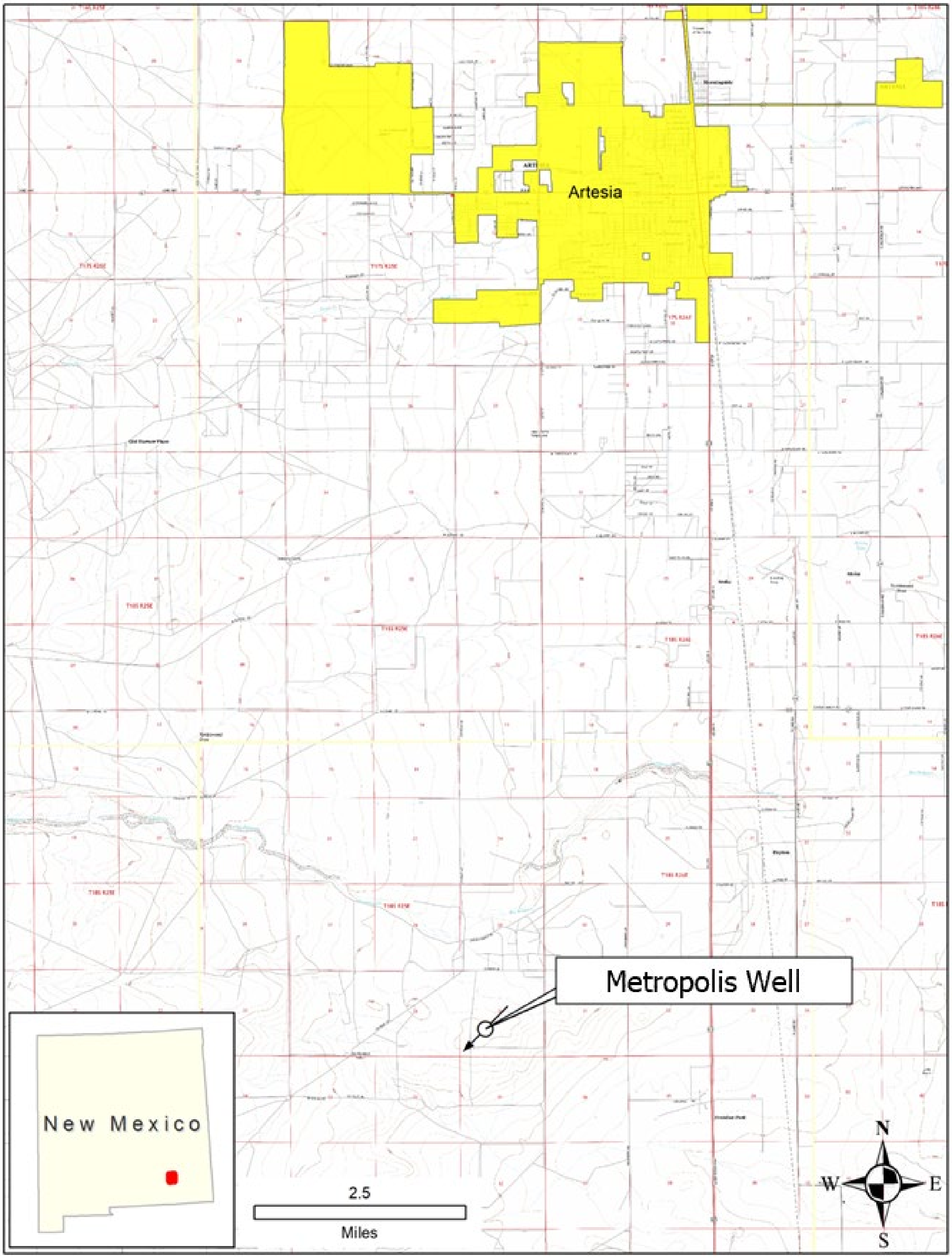


Figure 1-1: Location of the Frontier Metropolis Well

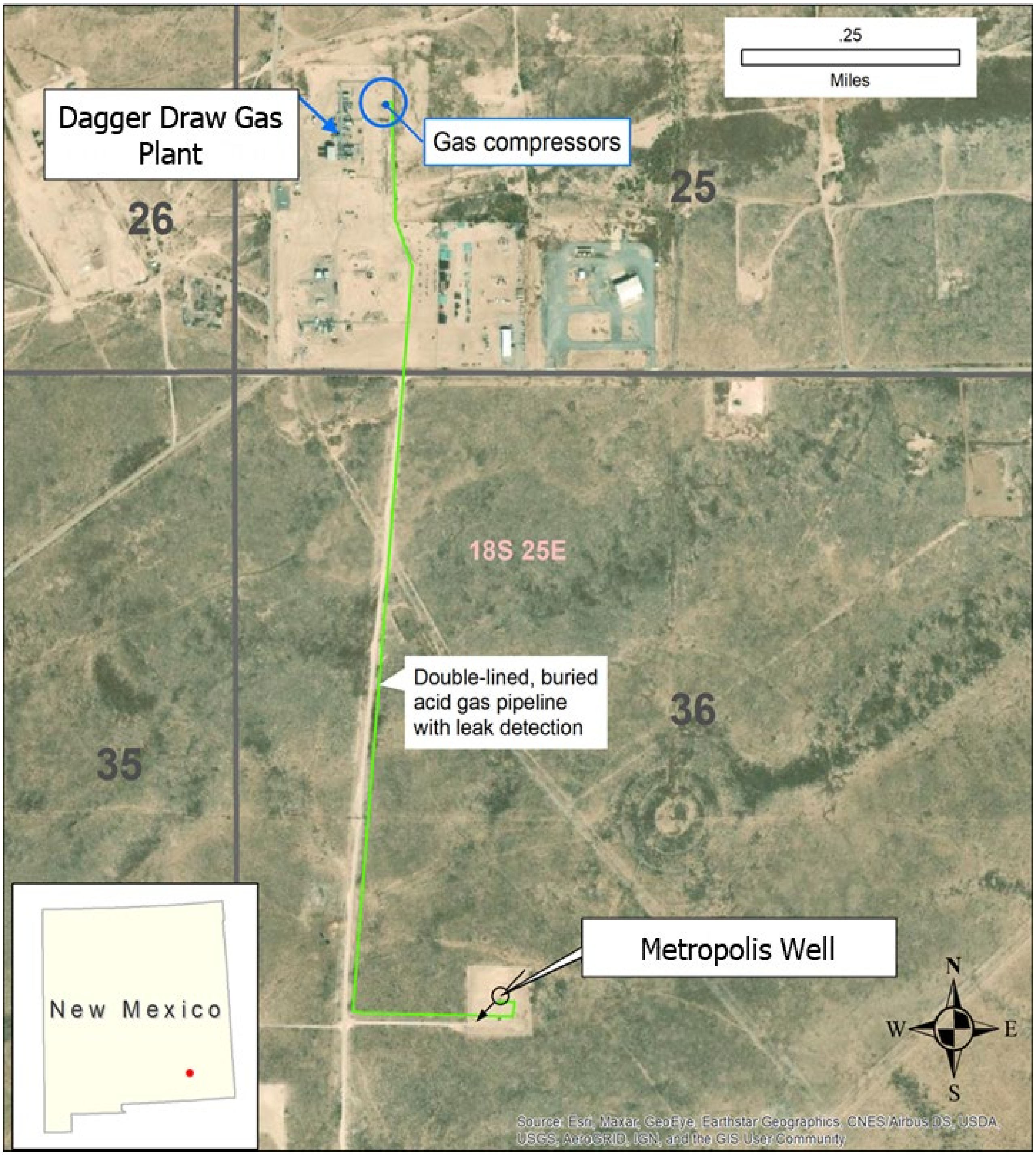


Figure 1-2: *Location of Dagger Draw Gas Plant and the Metropolis Well*

2. Dagger Draw Gas Plant Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID for Dagger Draw Gas Plant is **1008358**. Once the MRV plan is approved, Frontier will seek a new ID under the merged facility.

2.2 UIC injection well identification number

Part A of the MRV plan is for the Dagger Draw Gas Plant and the associated Metropolis well (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC Permit Class

The New Mexico Oil Conservation Division (NMOCD) has issued an Underground Injection Control (UIC) Class II acid gas injection (AGI) permit under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells within a one-mile radius around the Metropolis well, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3. Dagger Draw Gas Plant/Metropolis Well Project Description

The following project description has been developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT). The H_2S Contingency Plan, dated April 2022, was prepared by Geolex, Inc. for Durango Midstream, LLC.

3.1 General Geologic Setting / Surficial Geology

The area surrounding the Dagger Draw Gas Plant and the Metropolis well is covered by alluvial sediments from the Rio Peñasco, and the nearby Pecos River. These two rivers and their tributary systems dominate the local geomorphology. The area has undergone substantial oil and gas development. An agricultural zone is located along the Pecos River approximately five miles to the east and is supplied by shallow subsurface aquifers due to issues with poor Pecos River water quality.

3.2 Bedrock Geology

3.2.1 Basin Development

The Metropolis well is located on the Northwest Shelf of the Permian Basin (**Figure 3.2-1**). Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**), and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits within (**Figure 3.2-3**) a shallow marine sea that covered most of North America and Greenland. With continued down warping or sea-level rise, a broad, shallow marine basin formed. The Ellenberger Formation (0 – 1,000 ft) is dominated by dolostones and limestones that were deposited on a restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers in parentheses after the formation name indicate the range in thickness for that unit. Tectonic activity near the end of Ellenberger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones, and shales of, first, the Simpson Group (0 – 1,000 ft) and then the Montoya Formation (0 – 600 ft). This is the time period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4A**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within the shoreline sandstones (Broadhead, 2017). Another subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). Like the Ellenberger and Simpson carbonates, the subaerial exposure event at the end of Montoya deposition resulted in karstification.

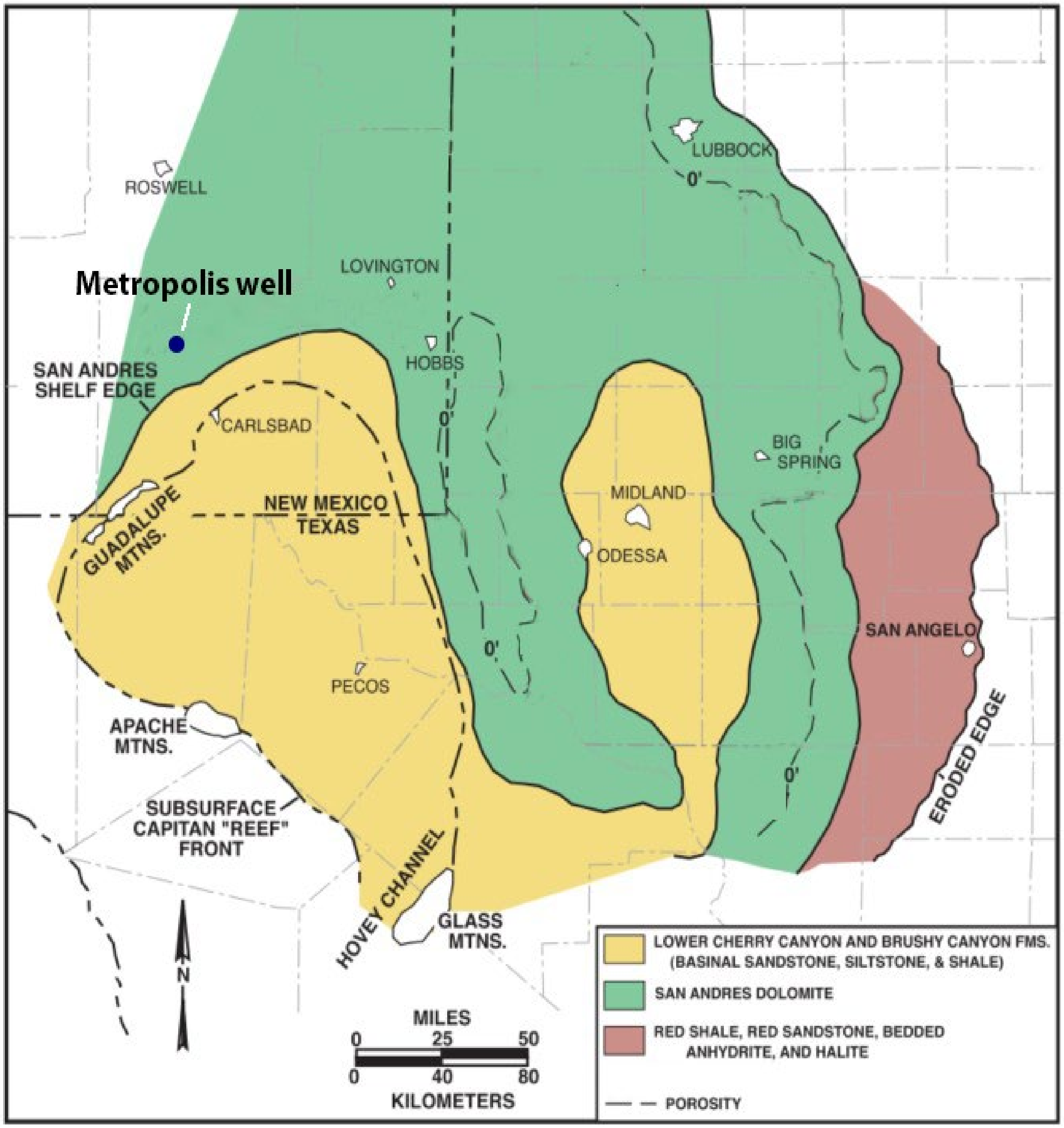


Figure 3.2-1: *Location of the Metropolis well with respect to Permian physiographic features (modified from Scholle et al, 2007)*

AGE		CENTRAL BASIN PLATFORM-NORTHWEST SHELF		DELAWARE BASIN	
Cenozoic			Alluvium		Alluvium
Triassic			Chinle Formation		Chinle Formation
			Santa Rosa Sandstone		Santa Rosa Sandstone
Permian	Lopingian (Ochoan)		Dewey Lake Formation		Dewey Lake Formation
			Rustler Formation		Rustler Formation
			Salado Formation		Salado Formation
					Castile Formation
	Guadalupian	Artesia Group	Tansill Formation	Delaware Mountain Group	Lamar Limestone
			Yates Formation		Bell Canyon Formation
			Seven Rivers Formation		
			Queen Formation		Cherry Canyon Formation
			Grayburg Formation		
			San Andres Formation		Brushy Canyon Formation
	Cisuralian (Leonardian)		Glorieta Formation		
		Yeso	Paddock Mbr.		Bone Spring Formation
			Blinebry Mbr		
			Tubb Sandstone Mbr.		
			Drinkard Mbr.		
	Wolfcampian		Abo Formation		
			Hueco ("Wolfcamp") Fm.		Hueco ("Wolfcamp") Fm.
Pennsylvanian	Virgilian		Cisco Formation		Cisco
	Missourian		Canyon Formation		Canyon
	Des Moinesian		Strawn Formation		Strawn
	Atokan		Atoka Formation		Atoka
	Morrowan		Morrow Formation		Morrow
Mississippian	*Upper*		Barnett Shale		Barnett Shale
	Lower		"Mississippian limestone"		"Mississippian limestone"
Devonian	*Upper*		Woodford Shale		Woodford Shale
	Middle				
	Lower		Thirtyone Formation		Thirtyone Formation
Silurian	*Upper*		Wristen Group		Wristen Group
	Middle				
	Lower		Fusselman Formation		Fusselman Formation
Ordovician	*Upper*		Montoya Formation		Montoya Formation
	Middle		Simpson Group		Simpson Group
	Lower		Ellenburger Formation		Ellenburger Formation
Cambrian			Bliss Ss.		Bliss Ss.
Precambrian			Miscellaneous igneous, metamorphic, volcanic rocks		Miscellaneous igneous, metamorphic, volcanic rocks

Figure 3.2-2: *General stratigraphic chart for southeastern New Mexico (modified from Broadhead, 2017)*

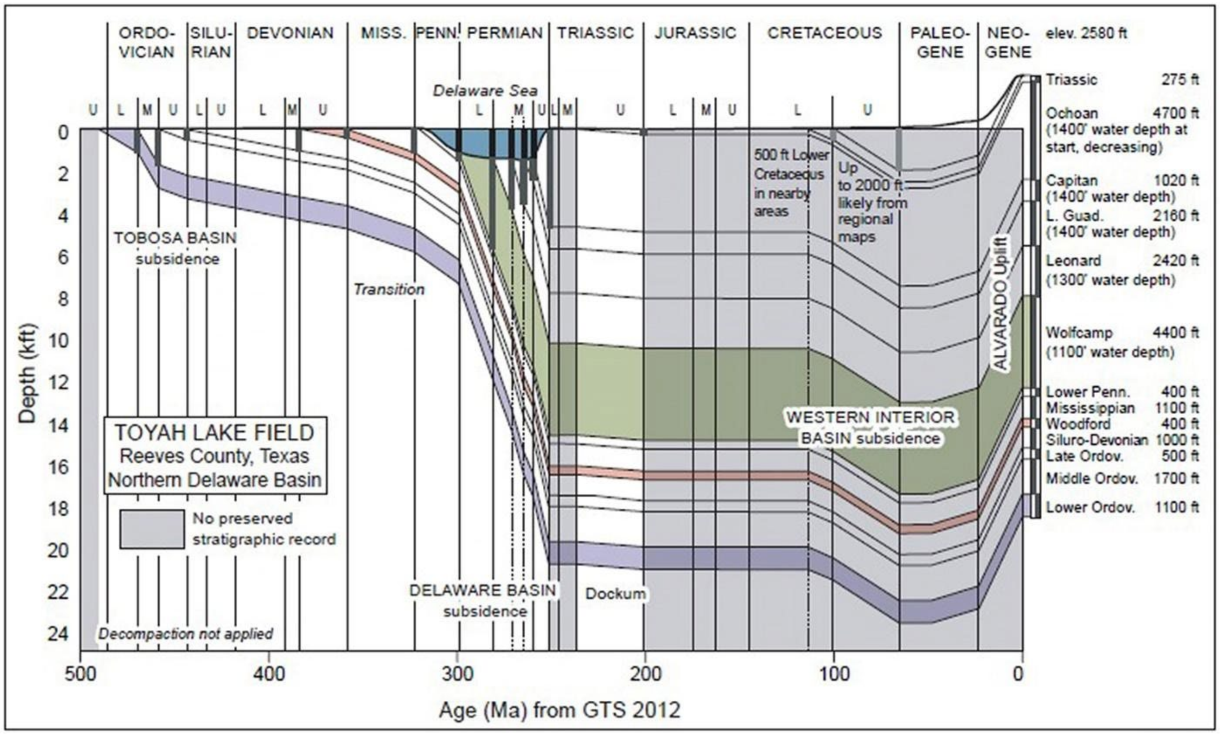
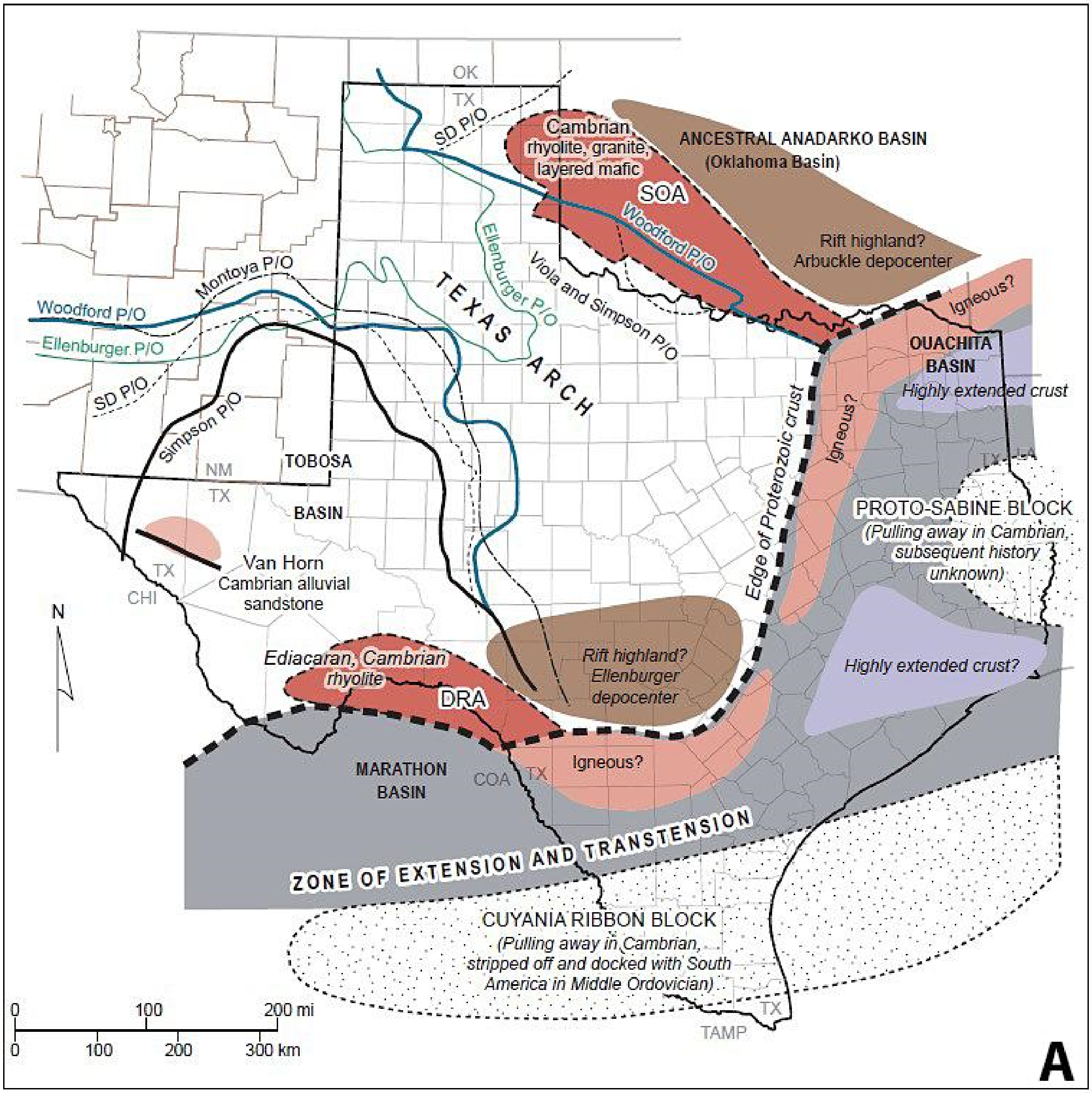


Figure 3.2-3: *A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

Silurio-Devonian formations consist of the Upper Ordovician to Lower Silurian Fusselman Formation (0 – 1,500 ft), the Upper Silurian to Lower Devonian Wristen Group (0 – 1,400 ft), and the Lower Devonian Thirtyone Formation (0 – 250 ft). The Fusselmen Formation was deposited on a shallow-marine platform and consists of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with another unconformity at top of the Fusselman Formation as well as intraformational exposure events created brecciated fabrics, widespread dolomitization, and solution-enlarged pores and fractures (Broadhead, 2017). The Wristen and Thirtyone units appear to be conformable. The Wristen Group consists of tidal to high-energy platform margin carbonate deposits of dolostones, limestones, and cherts with minor siliciclastics (Broadhead, 2017; Ruppel, 2020a). The Thirtyone Formation is present in the southeastern corner of New Mexico and appears to be either removed by erosion or not deposited (**Figure 3.2-5**) elsewhere in New Mexico. It is shelfal carbonate with varying amounts of chert nodules and represents the last carbonate deposition in the area during Devonian time (Ruppel et al., 2020a).

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from an organic-rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020c). The Woodford sediments represent stratified deeper marine basinal deposits. The organic content of this unit is a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.



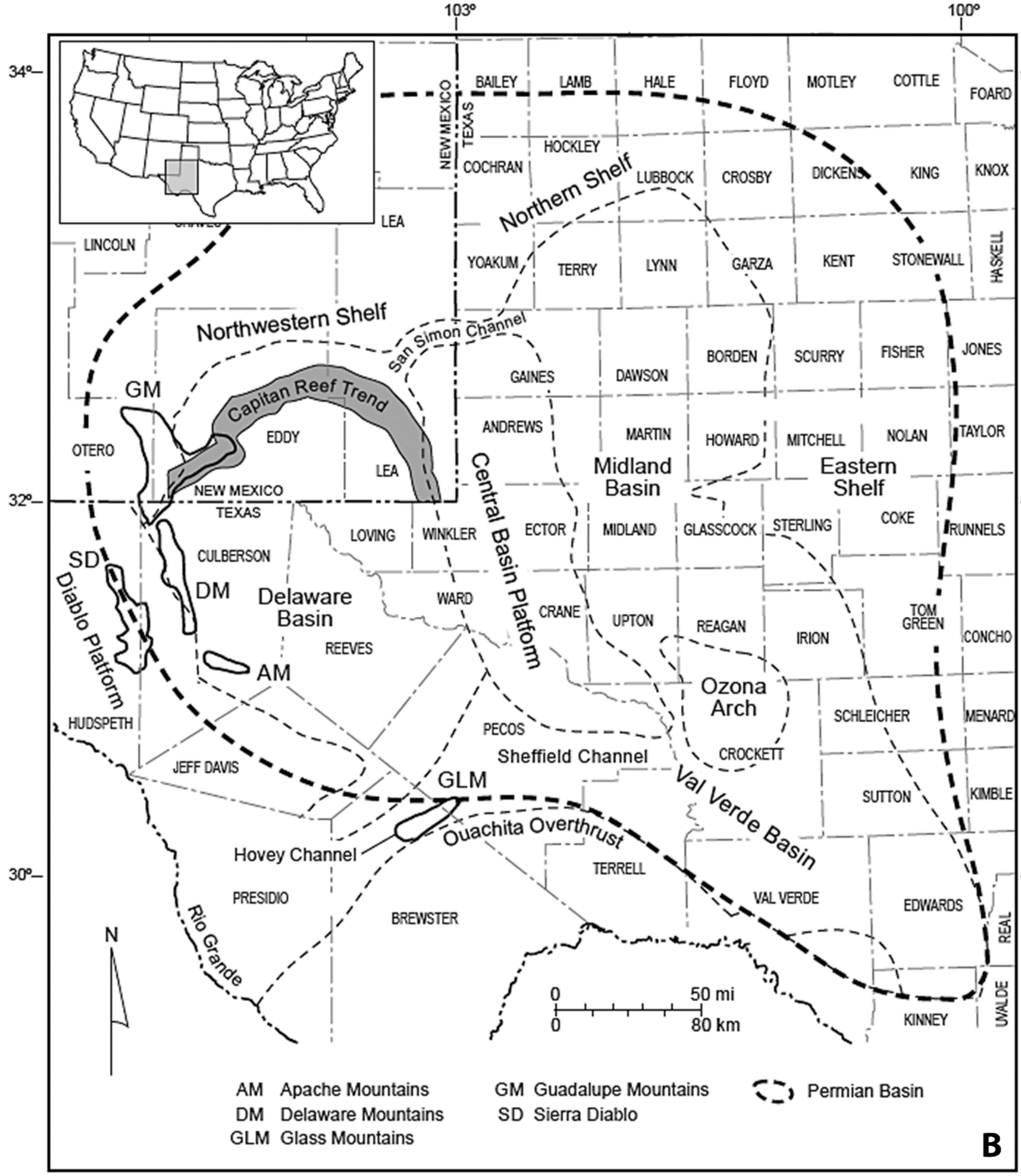


Figure 3.2-4: *Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a)*

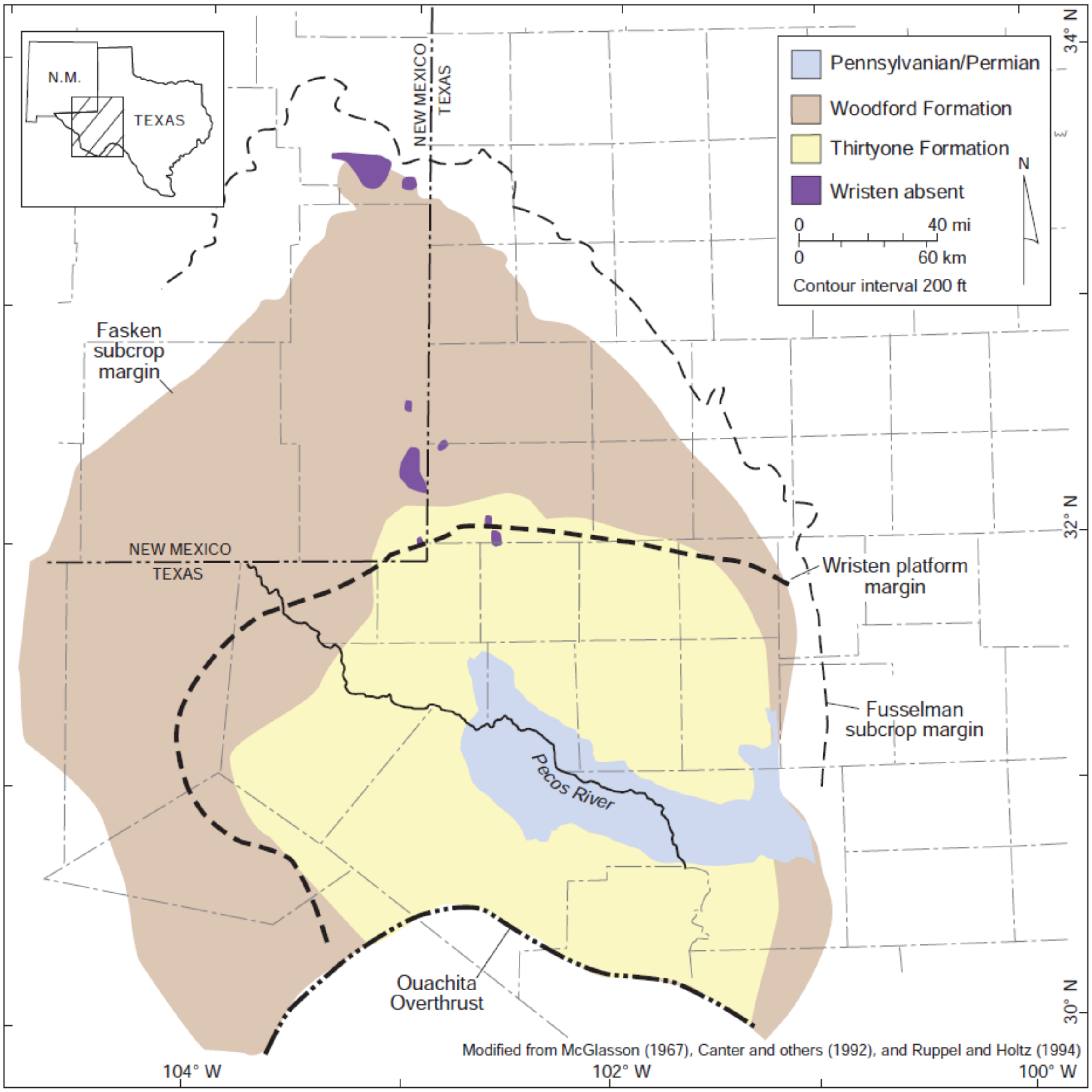


Figure 3.2-5: *A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there is no Thirtyone sediments (yellow). Diagram is from Ruppel (2020)*

The Mississippian strata within the northern Delaware Basin consists of an unnamed carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoir's limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) uncomfortably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale). Within the area of the Metropolis well, there is at least one tongue of Chesterian limestone within the Barnett Shale and numerous sandstone/siltstone interbeds within the mudstone deposits.

Pennsylvanian sedimentation in the area is influenced by glacio-eustatic sea-level cycles producing numerous shallowing upward cycles within the rock record; the intensity and number of cycles increase upward in the Pennsylvanian section. The cycles normally start with a sea-level rise that drowns the platform and deposits marine mudstones. As sea-level starts to fall, the platform is shallower and deposition switches to marine carbonates and coastal siliciclastic sediments. Finally, as the seas withdraw from the area, the platform is exposed causing subaerial diagenesis and the deposition terrestrial mudstones, siltstones, and sandstones in alluvial fan to fluvial deposits. This is followed by the next cycle of sea-level rise and drowning of the platform.

Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250-1,000 ft) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales. Within the Dagger Draw area, sandstone horizons occur along the western edge of pinchout of the units (Broadhead, 2017).

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP) (**Figures 3.2-4B, 3.2-6, 3.2-7**). The Early Permian and older rocks have been fractured, faulted, and folded during this period of deformation and basin formation resulting in truncation of Wolfcampian and older units (**Figure 3.2-6**).

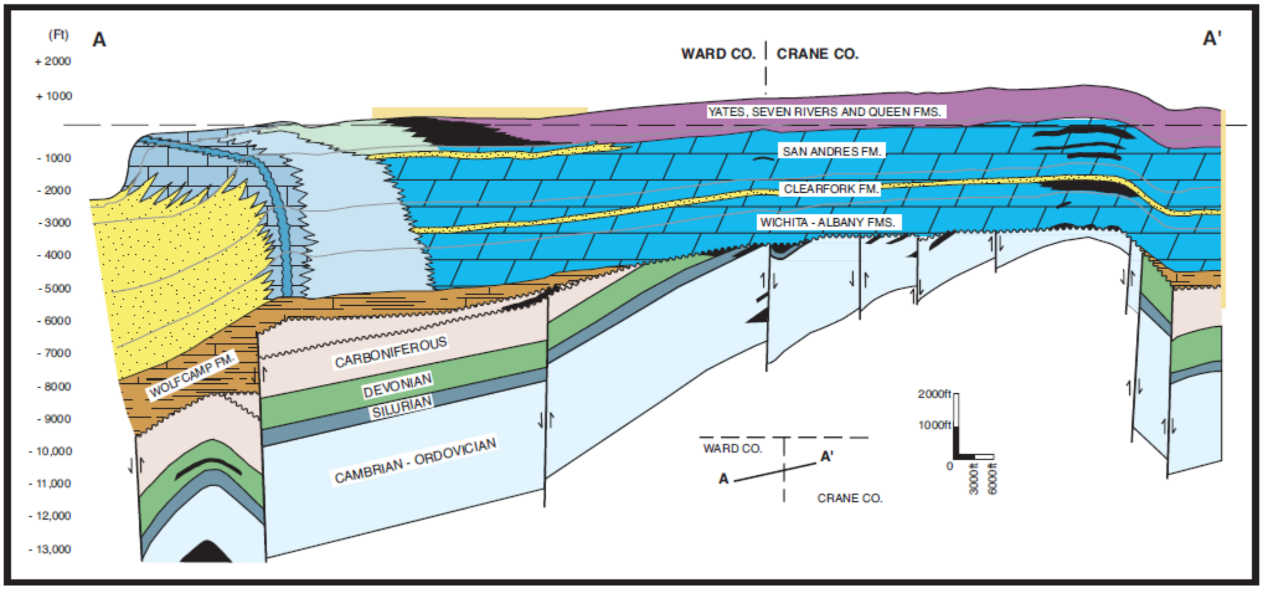


Figure 3.2-6: *Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).*

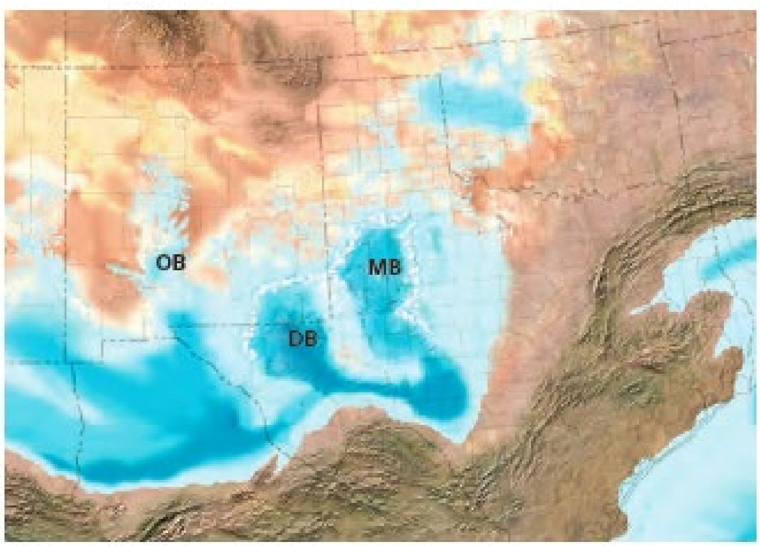


Figure 3.2-7: *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

The Wolfcampian Hueco Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020).

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a "carbonate factory" on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1977; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100's feet to feet). Below is a summary of the sediments found up on the NW Shelf where Dagger Draw is located.

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along NW Shelf margin and shallow-marine carbonates to the northwest of the margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2020b). Sediments basin ward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin, which is roughly in the same area, just south of Dagger Draw. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2020b). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation. It is a key marker bed in the region, both on the surface and subsurface. Within the basin, it is equivalent to the Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex at the end carbonate deposition within the Delaware Basin. Individual highstand carbonate units are separated by lowstand sandstones/siltstones that moved out over the exposed shelf. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that resulted in karstification and pervasive dolomitization of the unit. Within the Delaware Basin, it is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the time period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the NW Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal "freshening" of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represent the last Permian marine deposits in the Delaware Basin. The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350 ft, Nance, 2020), ending Permian deposition in the area.

Beginning early in the Triassic, uplift and the breakup of Pangea resulted in another regional unconformity and the deposition of non-marine, alluvial Triassic sediments (Santa Rosa Sandstone and Chinle Formation). They are unconformably overlain by Cenozoic alluvium (which is present at the surface). Cenozoic Basin and Range tectonics resulted in the current configuration of the region and reactivated numerous Paleozoic faults.

The unit thicknesses mentioned in this discussion are from Broadhead (2017) unless otherwise indicated.

3.2.2 Stratigraphy

Figure 3.2-2 is a stratigraphic column showing the formations that underlie the Dagger Draw Gas Plant and the Metropolis well. Section 3.2.1 provides a discussion of the geologic evolution of the area from Precambrian to Cenozoic time.

The thick sequence of Mississippian through Ordovician rocks is described below. These rock units overlie, contain, and underlie the injection zone for the Metropolis well.

Mississippian Rocks. Deposits of Mississippian age are commonly divided into the Barnett Shale and Chester Limestone of the Upper Mississippian, and the Mississippian limestone (an un-named unit) of the Lower Mississippian (**Figure 3.2-2**). The Mississippian section thins to the west of the Dagger Draw area and is ±590 ft thick. The Lower Mississippian limestone is dark-colored limestone containing minor cherts and shales. Within the Metropolis well, it is ±440 ft thick. The known production from this limestone consists of one to two well plays that normally have poor porosity (4-9%) and permeability (Broadhead, 2017). The Barnett Shale and Chester Limestone are a combined ±150 ft thick. The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability. The Chester Limestone within the Barnett Shale has a low porosity (<3%) within the Metropolis well. Overall, Mississippian units are good seals to prevent fluid movement upward through the section.

Devonian to Upper Ordovician Rocks. Within the Permian Basin, the Upper Devonian Woodford Shale serves as a seal to hydrocarbon migration out of Devonian and older units (Wright, 1979). Though still an effective seal, especially in combination with the Mississippian section, the Woodford Shale is only 20 ft thick in the Metropolis well.

Lower Devonian to Ordovician deposits, deposited in the Tobosa Basin, are dominated by shallow marine carbonates with occasional sandstones, shales, and cherts. Episodes of sea-level change and exposure-related diagenesis played a major role in porosity development within all of these reservoirs resulting in the pervasive dolomitization of the limestones and solution-collapse brecciation.

Siluro-Devonian deposits include the Thirtyone Formation, the Wristen Group, and the Fusselman Formation. The Thirtyone Formation pinches out further south in the southeastern corner of Lea County **(Figure 3.2-5**) of the Metropolis well. In the Metropolis well, the Wristen Group is ±260 ft thick and was completed in the Fusselman Formation. Both Wristen and Fusselman sediments pinchout to the northwest of the Dagger Draw area, and both reservoirs consist of vuggy, coarsely crystalline dolostones with intercrystalline, vuggy, fracture and breccia porosity formed by episodes of subaerial exposure (Broadhead, 2017). Log-measured porosity from the Metropolis well in both the Wristen and Fusselman units is 4.3%.

The Upper Ordovician Montoya Formation pinches out north of the well (**Figure 3.2-5**), and reservoirs are within dolostones containing intercrystalline, vuggy, fracture and breccia porosity. Like the Devonian strata, episodes of subaerial exposure and karstification are the origin of most of the porosity within the unit. The closest play in the Montoya Formation is Tule Field in Roosevelt County near the northern pinchout of Ordovician sediments (Broadhead, 2017).

Simpson Group (Middle – Upper Ordovician). None of the wells in the vicinity of the Metropolis well penetrate the Simpson Group, so its presence is based on regional studies (Broadhead, 2017; Harrington, 2019) that indicates the unit pinches out northwest of the Dagger Draw area (**Figure 3.2-5**). The Simpson Group is characterized by massive, fossiliferous limestones interbedded with green shales and sandstone. Within New Mexico, shales dominate the section making the unit an excellent seal for downward migration. Most reservoirs within the Simpson Group occur within shoreline-deposited sandstones (Broadhead, 2017).

3.2.3 Faulting

No faults were identified during the geologic characterization of the area around the Metropolis well.

3.3 Lithologic and Reservoir Characteristics

A 2010 study conducted by Geolex recommended acid gas injection and CO_2 sequestration in the Devonian through Montoya dolomite sequence of the Metropolis well. The dolomitic reservoir rocks have the requisite high porosity and are bounded by the fine-grained, low permeability rocks in the Barnett Shale, Chester Limestone, and Woodford Shale above and the shales of the upper Simpson below. The high net porosity of the Metropolis injection zone and low injection volumes indicate that the injected TAG will be easily contained close to the injection well. There are no structural traps to restrict lateral migration of injected gas, nor are there deep wells or faults that would serve as vertical conduits. The calcareous composition of the reservoir rocks may have the added benefit of neutralizing the acidity of the gas and providing improved porosity and permeability over time as buffering capacity is consumed.

Geophysical logs for the Metropolis well were collected during the initial drilling of the well in 2001 and later deepening in 2004. These logs, as well as records for other deep wells located within a three-mile radius of the Metropolis well were used as the basis for much of Geolex's detailed geological analysis. Only the Metropolis well penetrates below the Mississippian/Chester formations, so it was not possible to evaluate the area-wide structure of the Devonian-Montoya injection zone. However, there are ample data for the Chester Formation which, along with the overlying Barnett Shale, serves as the upper seal to the injection zone. Using the formation tops from 32 wells, a contour map was constructed for the top of the Chester Formation (**Figure 3.3-1**) in the vicinity of the well. This map reveals a 5-degree dip to the southeast, with no visible faults or offsets that might influence fluid migration, suggesting that injected fluid would spread radially from the point of injection with a small elliptical component to the northwest. This interpretation is supported by cross-sections of the overlying stratigraphy that reveal relatively horizontal contacts between the units (**Figures 3.3-2 and 3.3-3**). Local heterogeneities in permeability and porosity will exercise significant control over fluid migration and the overall three-dimensional shape of the injected gas plume.

Geophysical log analyses include an evaluation of the reservoir rock porosity. **Figure 3.3-4** shows the Thermal Neutron Porosity (TNPH) log from 9,350 ft to 10,500 ft total depth (TD) and includes the identified formational boundaries. The open-hole injection interval exhibits an average porosity of about 4.2%; taken over the entire interval of 570 ft this gives an effective porosity of approximately 24.3 ft. The overlying Mississippian Limestone and Woodford Shale combine to form a 450-ft layer with porosities of <2%, consistent with an effective seal on the injection zone.

No direct measurements have been made of the injection zone porosity or permeability. However, satisfactory injectivity of the injection zone can be inferred from the porosity logs described above and injection into the Metropolis well prior to Frontier's acquisition of the property. Injection records for the well for 2006-2007 reveal that the injection pressures remained between 1,100 and 1,200 pounds per square inch (psi) **(Figure 3.3-5**), significantly below the requested maximum injection pressure of 3,280 psi. No relationship was visible between injection rate and injection pressure (up to about 0.2 million standard cubic feet per day (MMSCFD)) indicating that the reservoir was not pressuring up. The good injectivity of the zone is supported by the performance of nearby saltwater disposal (SWD) wells. Nine SWD wells are located within a ten-mile radius, injecting into the same zone (**Figure 3.3-6**).

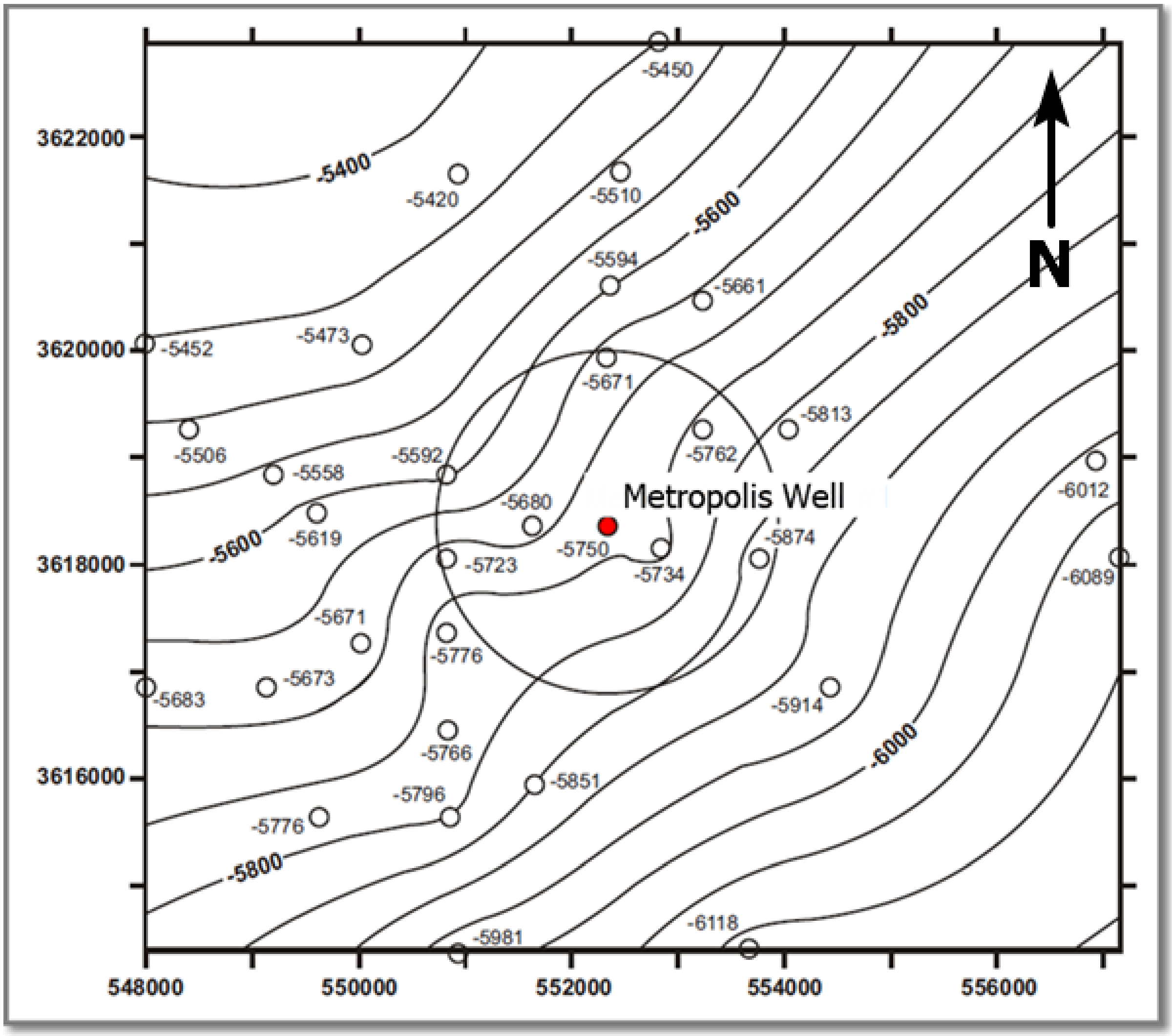


Figure 3.3-1: Structural contours on top of the Mississippian Chester Formation. Structure dips ~5.4 degrees to the southeast. Circle defines a one-mile radius around the Metropolis well.

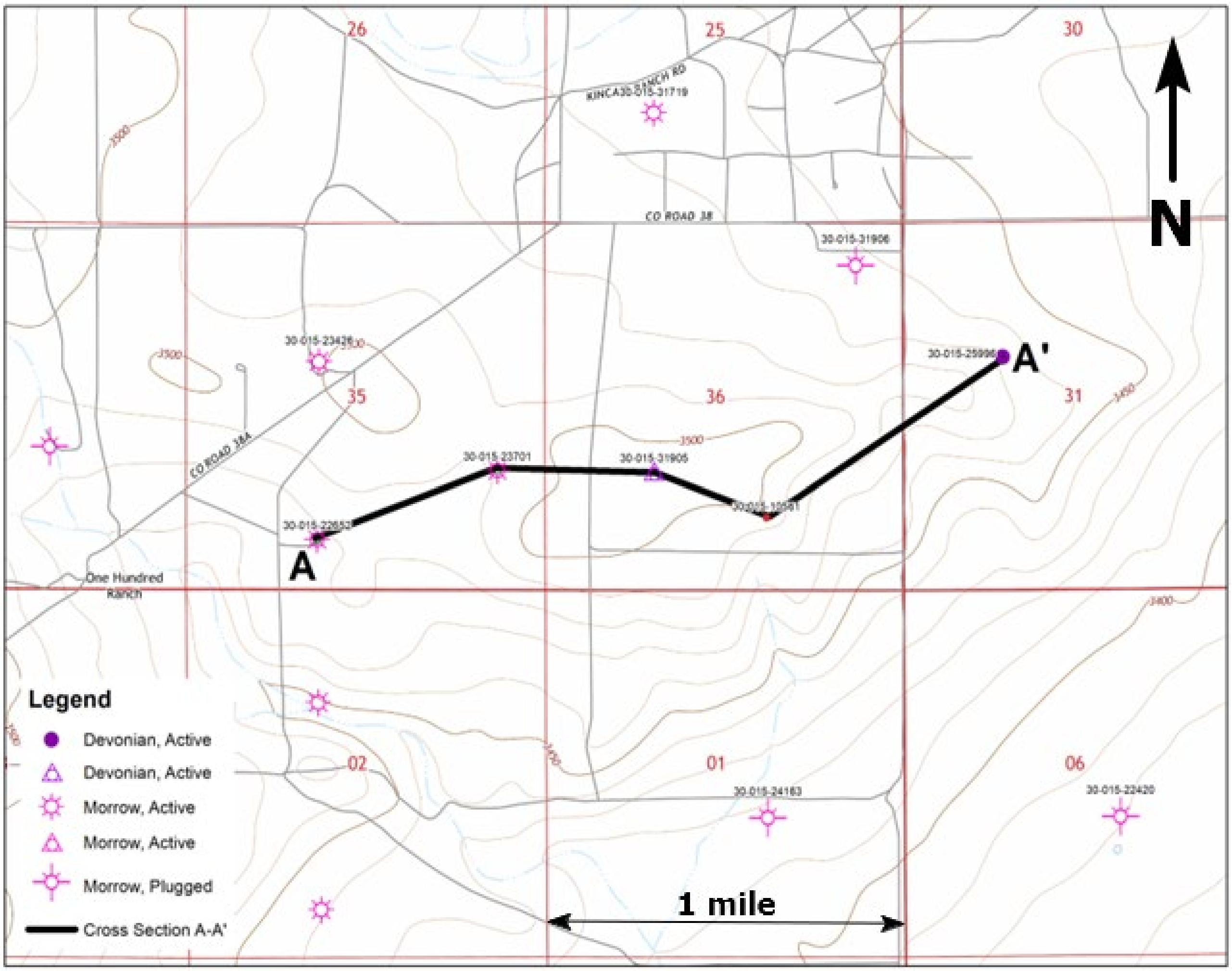


__Figure 3.3-2:__ Location of wells used in west – east cross-section, A-A'

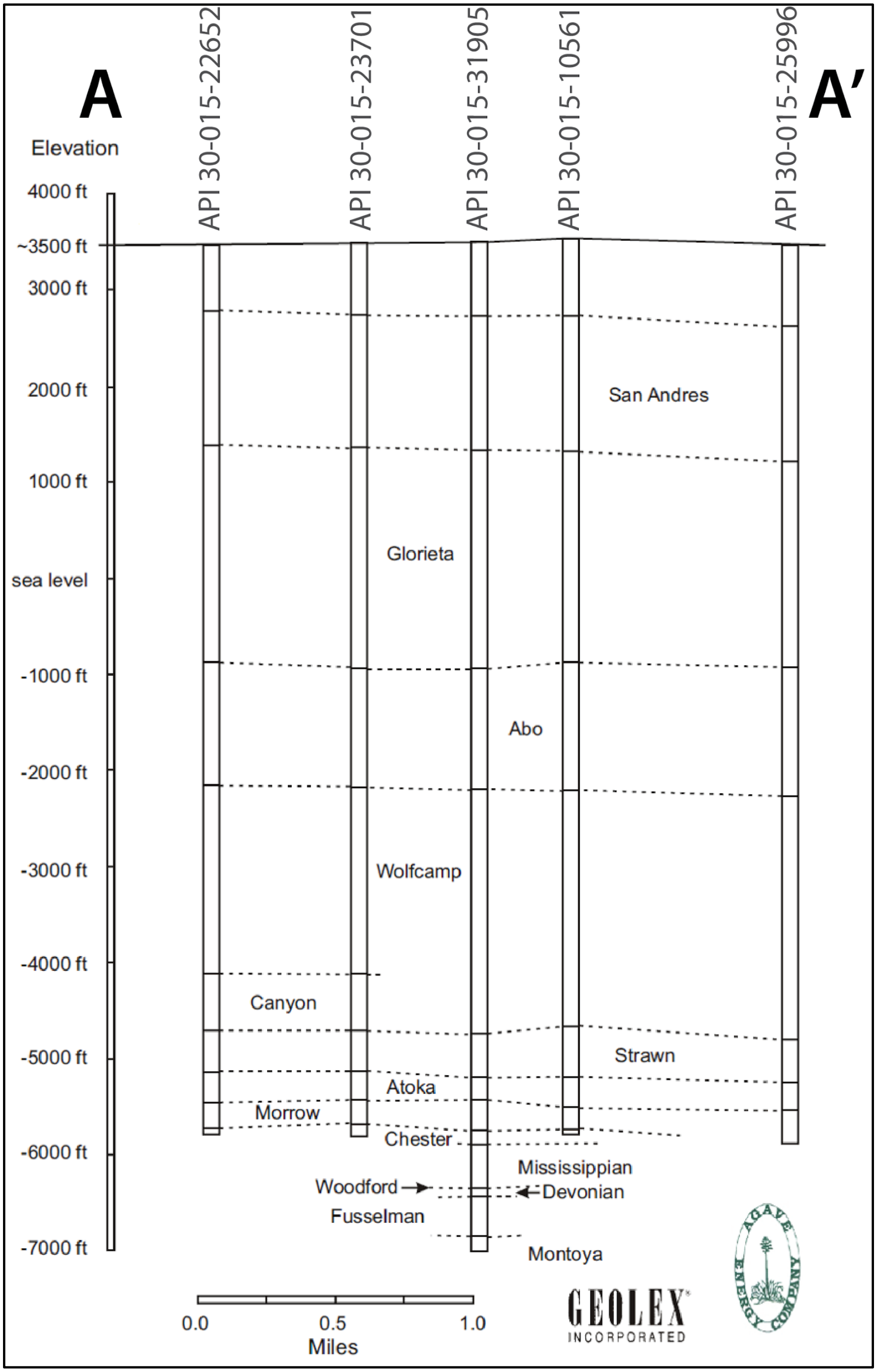


Figure 3.3-3: *Stratigraphic cross-section through Metropolis well. Location of wells shown in* ***Figure 3.3-2****.*

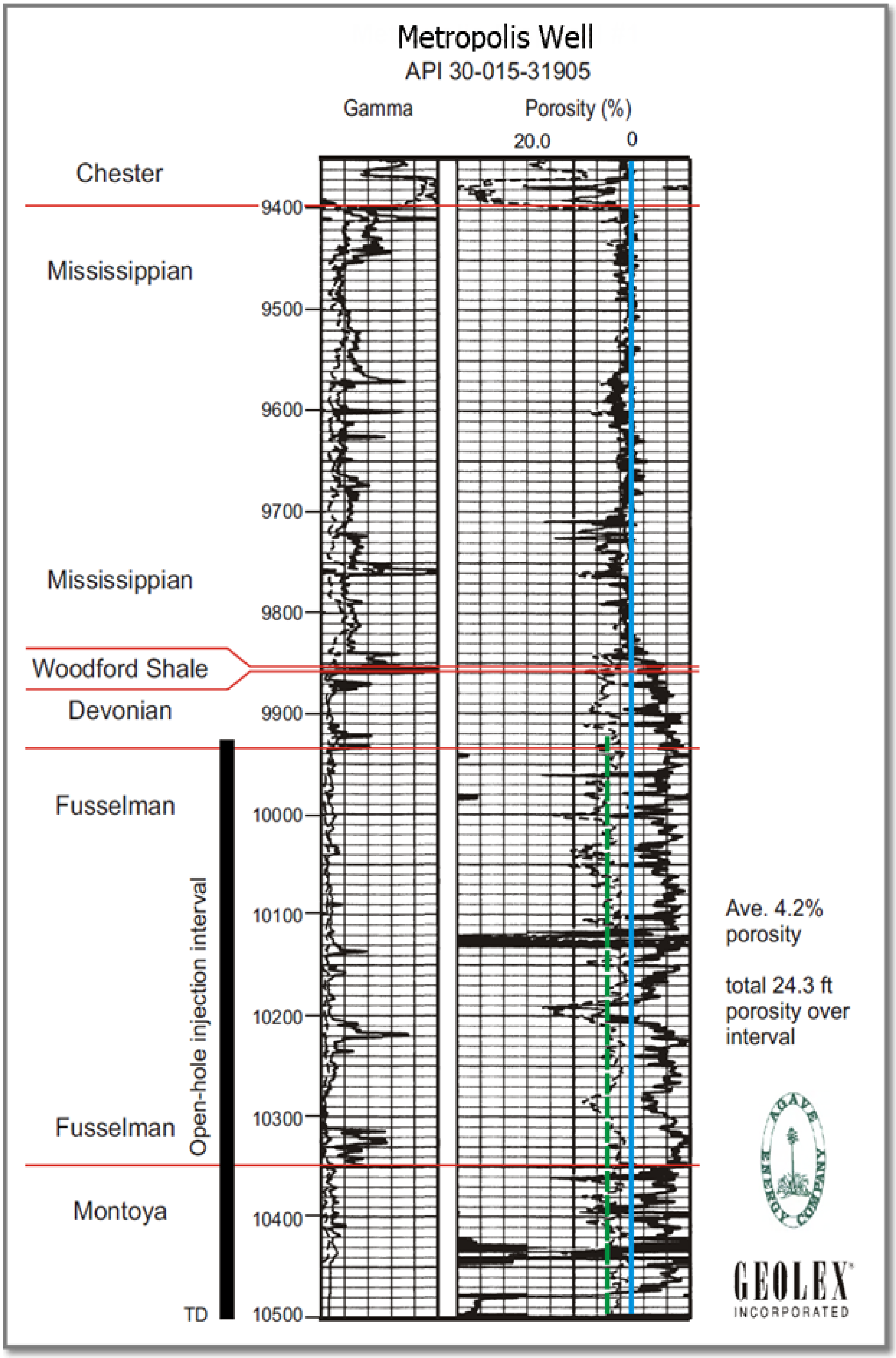


Figure 3.3-4: *Porosity and gamma log for Metropolis Well*

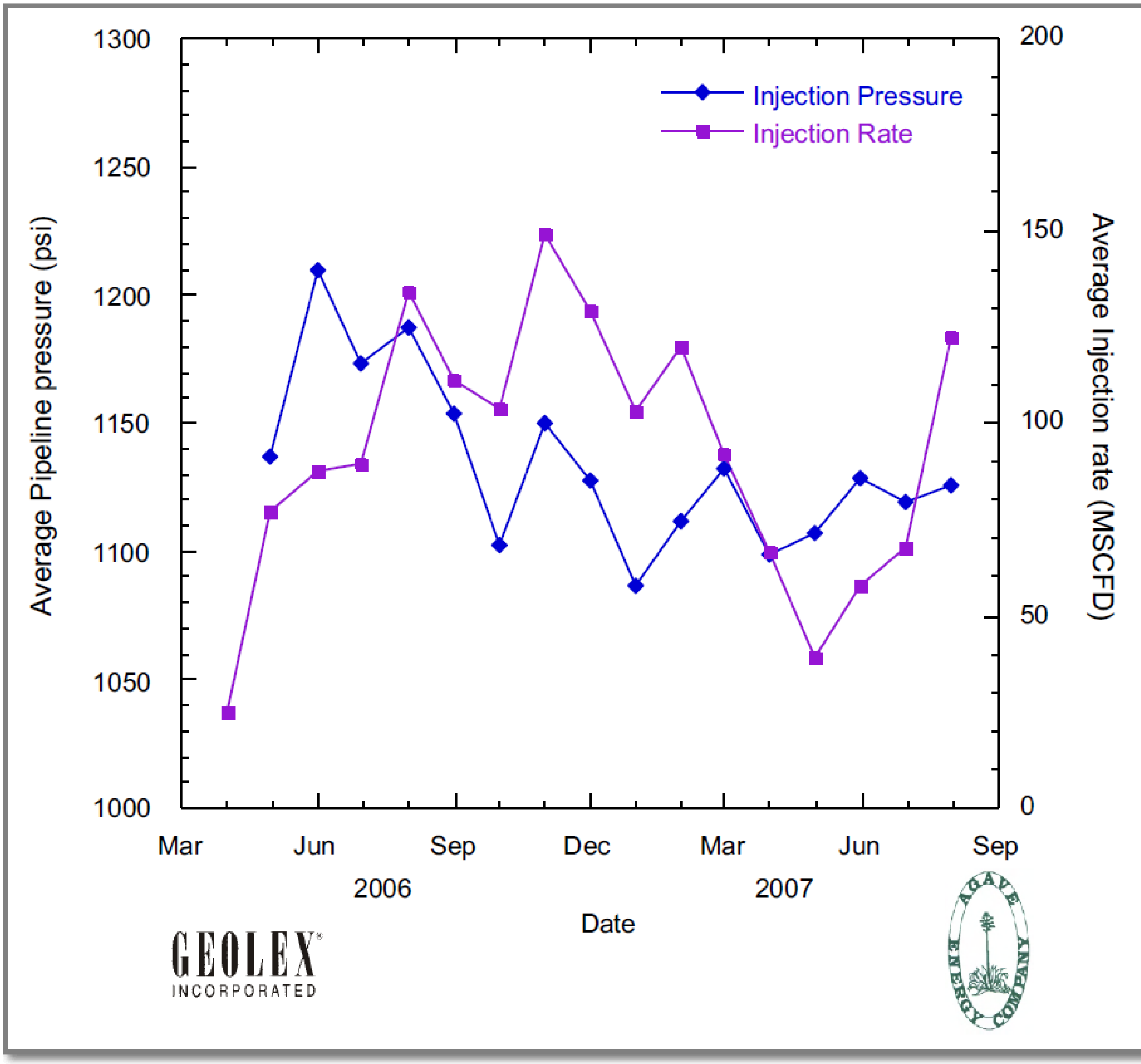


Figure 3.3-5: *Monthly average injection rates and pipeline pressures for days of injection at Metropolis Well, March 2006 – July 2007*

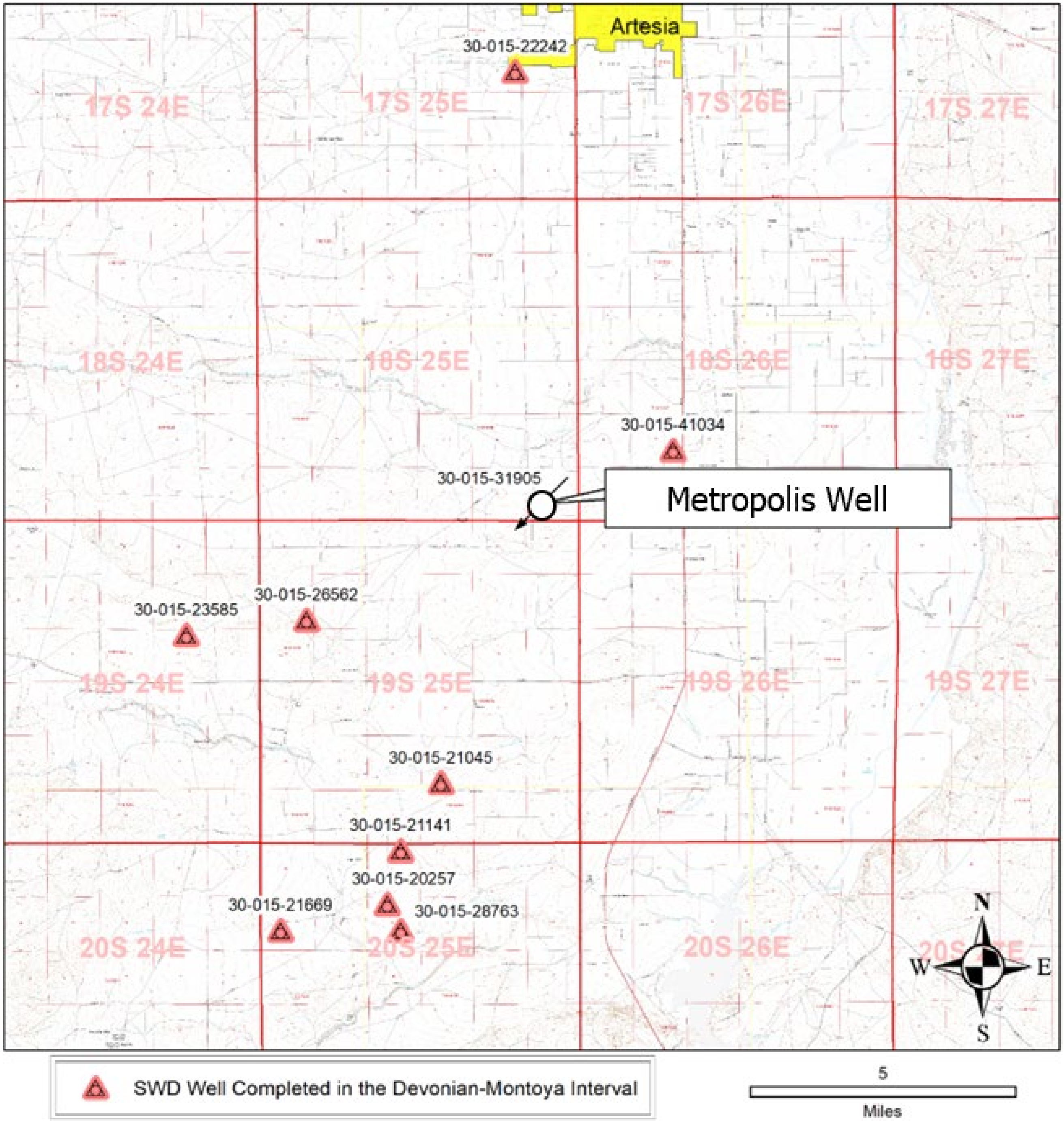


Figure 3.3-6: *Locations of Devonian through Montoya SWD wells and the Metropolis well. See **Table 3.4-1** for details.*

3.4 Formation Fluid Chemistry

Nine SWD wells located within a ten-mile radius of the Metropolis well currently inject into the Devonian-Montoya sequence, the injection zone (**Table 3.4-1**). The closest of these wells (30-015-41034) is located approximately 2.6 miles from the Metropolis well, the rest are located more than 5 miles away. A chemical analysis of water from the North Indian Basin Well No. 1 (API 30-015-10065), approximately 17 miles away, indicates that the formation waters are saline and compatible with injection into the Metropolis well (**Table 3.4-2**). The Devonian-Montoya sequence has already been approved for acid gas injection at the Duke AGI Well #1 (API 30-015-32324), 13.9 miles from the Metropolis well (Administrative Order SWD-838).

Table 3.4-1: *Saltwater disposal wells injecting into the Devonian – Montoya sequence within 10 miles of the Metropolis well which is also listed.*

API Number	Operator	Distance (Miles)	R	T	S	Well Name	Type	Status	Depth (ft)
30-015-31905	Frontier Field Services, LLC	0.00	25E	18S	36	METROPOLIS	AGI	Active	10,500
30-015-41034	MARATHON OIL PERMIAN LLC	2.63	26E	18S	29	REGULATOR 29 SWD #001	SWD	Active	9,960
30-015-26562	EOG RESOURCES INC	4.98	25E	19S	07	ROY SWD #003	SWD	Active	11,180
30-015-21045	Spur Energy Partners LLC	5.54	25E	19S	27	AIKMAN SWD STATE #001	SWD	Active	10,520
30-015-21141	Spur Energy Partners LLC	7.01	25E	20S	04	HOLSTUN SWD #001	SWD	Active	10,600
30-015-23585	EOG RESOURCES INC	7.18	24E	19S	14	ROUTH DEEP SWD #002	SWD	Active	9,900
30-015-20257	EOG RESOURCES INC	8.05	25E	20S	09	KING SWD #001	SWD	Active	10,555
30-015-22242	EOG RESOURCES INC	8.09	25E	17S	23	MITCHELL SWD #002	SWD	Active	9,500
30-015-28763	MEWBOURNE OIL CO	8.41	25E	20S	09	TWEEDY 9 SWD #001	SWD	Active	10,600
30-015-21669	OXY USA WTP LIMITED PARTNERSHIP	9.40	25E	20S	07	MOC SWD #001	SWD	Active	10,800

Table 3.4-2: *Analysis of water from the North Indian Basin Well No. 1 (API 30-015-10065). Located approximately 17 miles southwest of the Metropolis well*

Marathon Oil Company ran a DST on North Indian Basin Well No. 1 (Section 10, T 21 S, R 23 E, Eddy County, NM) in 1963. The DST tested the interval 10,009 – 10,100 ft. Based on the DST, the following analysis was reported:	
Specific Gravity	1.109
pH	6.8
Resistivity	0.285 @ 94 degrees F
Chlorides (Cl)	11,000 part per million (ppm)
Sulfates (SO4)	1,500 ppm
Alkalinity (HCO3)	610 ppm
Calcium (Ca)	1,080 ppm
Magnesium (Mg)	775 ppm
Iron (Fe)	20 ppm
Sodium (Na)	5,359 ppm
Sulfides (H_2S)	negligible

3.5 Groundwater Hydrology in the Vicinity of the Dagger Draw Gas Plant

Based on the New Mexico Water Rights Database (https://gis.ose.state.nm.us/gisapps/ose_pod_locations/) from the New Mexico Office of the State Engineer, five freshwater wells are located within a one-mile radius of the Metropolis well. (two of these wells lie within the delineated maximum monitoring area shown in **Figure 4.1-1** of Section 4).These five wells are shallow, ranging in depth from 211 to 455 ft. The shallow freshwater aquifer is protected by the surface casing of the Metropolis well that extends to a depth of 1,200 ft, into the lower San Andres.

The depth to the base of the freshwater aquifer in the Roswell Basin is variable (Maddox, 1969). In the immediate vicinity of the Metropolis well, the base is around 400 ft, consistent with the nearby freshwater wells (**Figure 3.5-1**). Away from Metropolis well, the base of the aquifer becomes deeper, and freshwater penetrates into carbonate rocks, including the San Andres Formation. Adjacent to the Pecos River, freshwater in the San Andres and overlying carbonate rocks is an important source of irrigation water (Hendrickson and Jones, 1952). However, freshwater is absent in the San Andres at the Metropolis well and therefore not at risk from the TAG injection.

The nearest body of surface water is the Peñasco River, an ephemeral river located approximately one mile to the north of the well. Several ephemeral/dry tributaries of the Four Mile Draw extend roughly one mile to the southeast and southwest of the well. There would be no impact from the Metropolis well on these streams/rivers since the surface casing for the well extends about 1,200 ft below the bottom of these features.

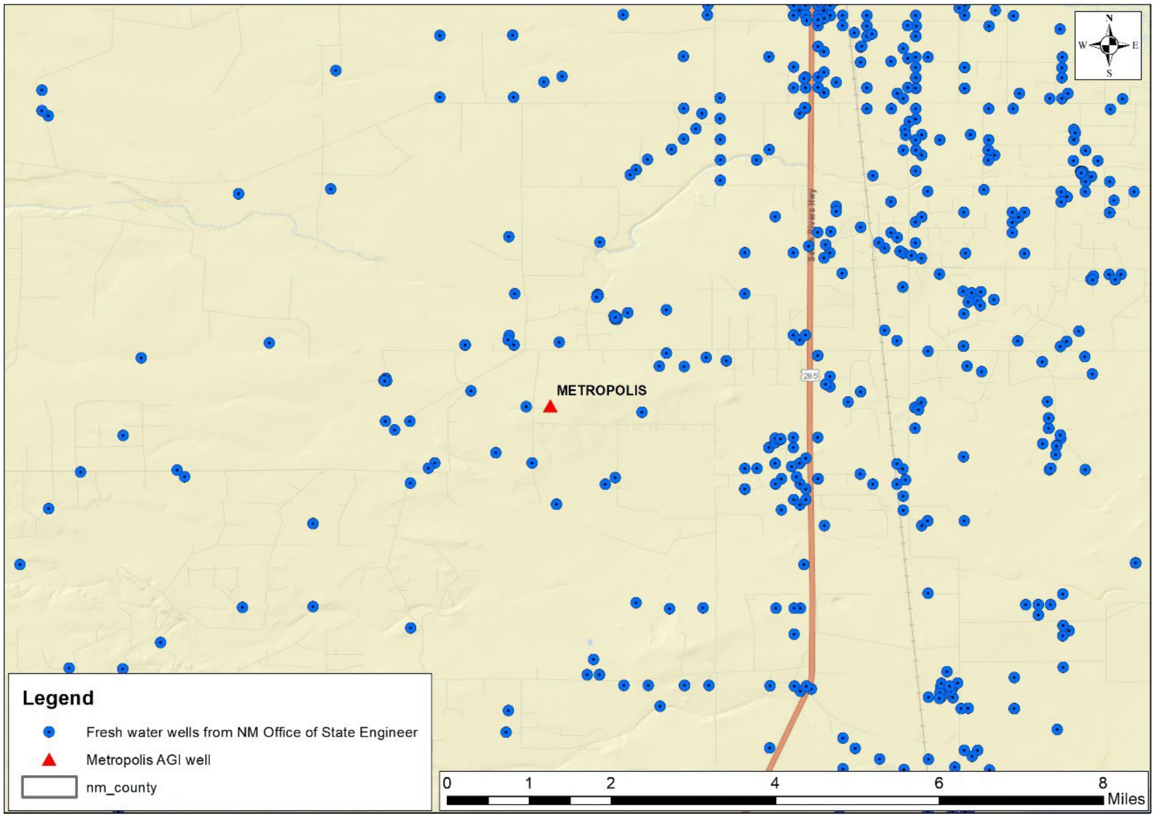


Figure 3.5-1: Water wells in the Roswell Basin

3.6 Historical Operations

3.6.1 Dagger Draw Gas Plant and the Metropolis Well Site

The Metropolis well was initially drilled in late 2001 by Yates Petroleum as an exploratory gas well, extending into the Chester Limestone, to a depth of 9,360 ft. After electric logs found no commercial deposits of hydrocarbons, the open hole portion of the well was abandoned in October 2001. Agave Energy filed an application with the NMOCD to convert the well to an acid gas disposal well in 2004, and Administrative Order SWD-936 (approval to inject acid gas and produced water) was issued August 31, 2004. Subsequent to NMOCD approval, Agave (in conjunction with Yates as the drilling consultant) re-entered the abandoned hole and drilled to a total depth of 10,500 ft on October 27, 2004.

The well and the surface facilities were completed, and acid gas injection commenced in late March-early April 2006. A total of 38.85 MMSCF of TAG was injected into the Metropolis well between March 24, 2006 and July 5, 2007. Although the well was permitted for the mixed injection of TAG and plant wastewater, no wastewater was ever injected. After July 5, 2007, no injection of any kind occurred. On September 10, 2009, the well underwent a successful Mechanical Integrity Test (MIT). In response to a March 25, 2010 1etter from NMOCD, Agave sought to re-permit the well for the injection of treated acid gas only.

In September 2018, the operator changed from Agave Energy Company to Lucid Artesia Company. On November 1, 2021, the operator changed again from Lucid to Frontier.

3.6.2 Operations within a 1-Mile Radius of the Metropolis Well

Numerous oil and gas pools (a term restricted to the productive interval of thicker formations) have been identified in the Permian Basin and older Tobosa Basin rocks. In the area of the Metropolis well, the Mississippian and older rocks consist predominately of carbonates with lesser clastic rocks – primarily shales, and the reservoir quality has been enhanced by dolomitization, fracturing and karstification of the carbonates. Local oil production is largely restricted to the San Andres-Yeso production zone, and gas production is concentrated in the Morrow with smaller amounts from the Abo and other zones. The injection zone tested wet (i.e., only water and no hydrocarbons in the pore space). No commercially significant deposits of oil or gas have been or is likely to be found in or below the Devonian through Montoya, the injection zone, or within a one-mile radius around the Metropolis well. **Figure 3.6-1** shows oil- and gas-related wells located within a 1-mile radius area around the Metropolis well. **Appendix 3** is a listing of these wells.

Active Oil- and Gas-Related Wells As shown in **Figure 3.6-1**, there are currently 21 active oil and gas wells within a 1-mile radius around the Metropolis well. None of the wells within the 1-mile radius around the Metropolis well penetrates the Devonian Formation at the top of the Metropolis well injection zone.

The active wells are divided between wells producing oil from the shallower San Andres-Yeso-Abo production zone and wells producing gas from the deeper Atoka-Morrow production zone. The majority of the wells producing gas from the Atoka- Morrow penetrated into the top of the Chester Limestone, but none penetrated into the Mississippian limestone. In the vicinity of the Metropolis well the Mississippian limestone is +/- 440 ft thick in the Metropolis well and, along with the underlying Woodford Shale, provides an excellent seal above the top of the Devonian-Montoya injection zone (see Section 3.2.2).

The wells producing oil from the San Andres-Yeso-Abo production zone have their top perforations in the San Andres at depths of 1,200-1,400 ft, just below the bottom of the surface casing for the Metropolis well. Three wells are listed as new (permitted but not yet drilled) in this production zone.

Plugged Oil and Gas Wells Twenty plugged wells were identified within the one-mile radius. As with the active oil and gas wells, none of the plugged wells penetrates the top of the Mississippian limestone. The data for these wells shows that there is no evidence of improperly plugged or abandoned wells within the one-mile radius which might cause communication between the injection zone and any other unit or to the surface.

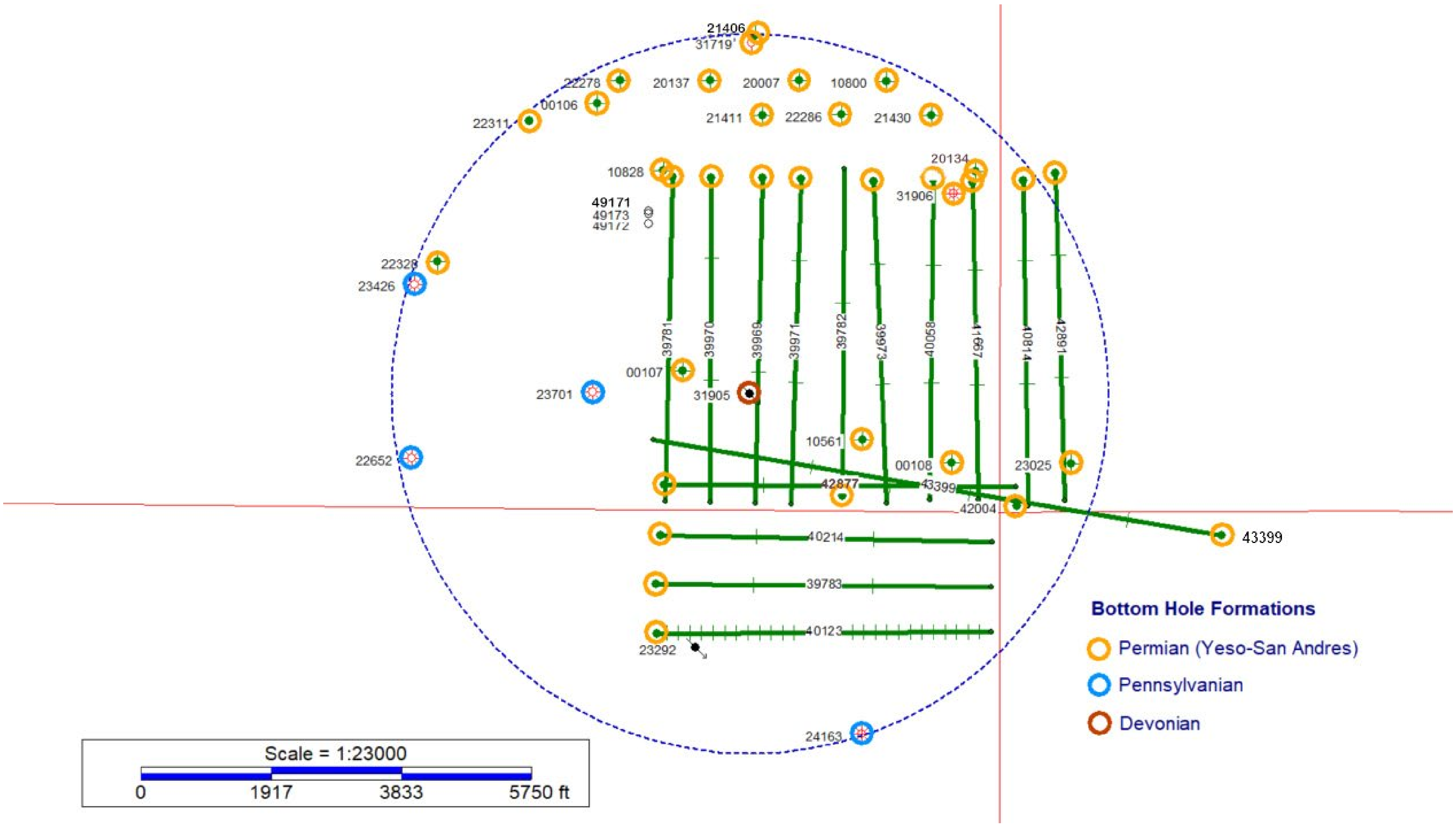


Figure 3.6-1: *Location of all oil- and gas-related wells within a 1-mile radius of the Metropolis well (API 30-015-31950). API numbers on the map have been shortened to the last 5 digits for clarity.*

3.7 Description of Injection Process

The following description of operations of the Dagger Draw Gas Plant and the Metropolis well was extracted from the H_2S Contingency Plan, April 2022, prepared by Geolex, Inc.

3.7.1 Dagger Draw Gas Plant – Description of Operations

The primary function of the Dagger Draw Gas Plant is to remove H_2S and CO_2 from sour field gas so that the gas can meet pipeline specifications. The operation of the plant is intended to process 115 MMSCFD of gas and is authorized to operate continuously (8,760 hr/yr) at design maximum capacity processing rates. The gas is treated to remove acid gas components, dehydrated to remove water, and processed to remove heavy (liquid) hydrocarbons from the gas stream. Several plant systems will be involved to perform these functions.

The amine unit is designed to remove acid gas components (CO_2, H_2S and mercaptans) from the natural gas stream. These components are removed from the natural gas stream because they are corrosive, hazardous to health, and reduce the heating value of the natural gas stream. In addition, the CO_2 can freeze in the cryogenic unit forming dry ice and forcing the shutdown of the facility. This is known as the gas sweetening process. The acid gas removed by the amine unit is disposed of by either acid gas injection into the Metropolis well or by incinerating in a flare (**Figure 3.7-1**). The preferred method of disposal will be to compress the gas and inject it into the Metropolis well. Under emergency situations, the gas will be sent to an acid gas flare.

The glycol dehydration unit receives approximately 115 MMSCFD of treated gas (sweet) from the amine unit and reduces the water content of the gas by circulating triethylene glycol (TEG). Molecular sieve dehydration is used upstream of the cryogenic processes to achieve a -150°F dew point. The process uses two molecular sieve vessels with one vessel in service absorbing moisture from the gas stream and the other vessel in the regeneration mode.

The cryogenic unit is designed to liquefy natural gas components from the sweet, dehydrated inlet gas by removing work (heat) from the gas by means of the turbo expander. The cryogenic unit recovers natural gas liquids (NGL) by cooling the gas stream to extremely cold temperatures (-150°F) and condensing components such as ethane, propane, butanes, and heavier hydrocarbons. Once the sweet, dry gas exits the cryogenic unit, it needs to be recompressed to approximately 800 to 1,200 psi before the gas is sent to the main transportation pipeline. This is accomplished by several residue gas compressors.

The hot oil system in the plant is used to provide heat to certain processes within the facility. The system circulates approximately 600 GPM of hot oil and deliver 23 MMBTU (million British thermal units)/hr to other processes.

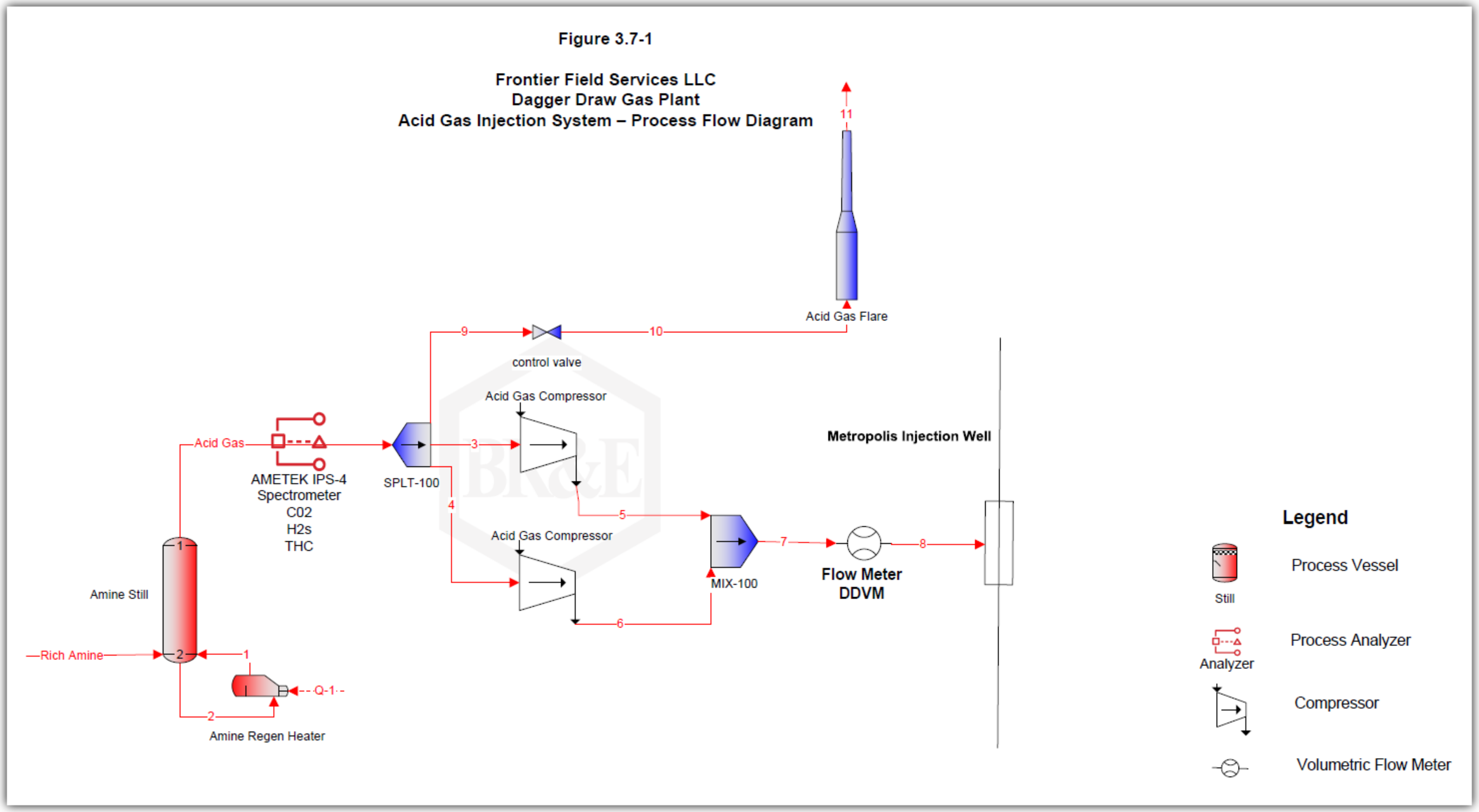


Figure 3.7-1: *Block flow diagram for the Dagger Draw Gas Plant showing volumetric flow meter for measuring CO_2 injected.*

3.7.2 Metropolis Well – Description of Operations

The low pressure (< 10 pounds per square inch gauge (psig)), acid gas stream from the amine unit is routed to the acid gas compressor. The stream is then subject to a series of compression and cooling cycles, thus dehydrating, and compressing the acid gas stream to the required injection pressure of approximately 1,100- 1,600 psig which is well under the maximum allowable working pressure for the pipeline of 2,350 psig. The high-pressure acid gas stream then flows through a 2-inch stainless steel pipeline to the injection well site. At this point, the stream is injected into the well.

There are a number of safeguards designed to prevent leaks or overpressure of the system. The acid gas compressor is equipped with multiple pressure transmitters. These transmitters monitor compressor suction and discharge pressures and are programmed to shut the acid gas system down when the pressures fall outside a pre-programmed operating range. As an additional safeguard, the compressor panel is also equipped with high- and low-pressure shutdowns for each stage of compression that will shut the compressor down when pressures reach preset high and low pressure set points.

As shown on **Figure 1-2**, the acid gas pipeline runs from the Frontier Dagger Draw Gas Plant in a southwesterly direction, crosses Kincaid Ranch Road at the plant boundary and continues southwesterly along a gravel road for approximately 3,680 ft. The pipeline then turns east along the Metropolis well access road for an additional 900 ft to the wellhead. The pipeline is buried at a depth of 6-1/2 ft for its entire length and is marked, as required, with permanent surface markers.

The acid gas pipeline is constructed from 2-inch 304 stainless steel tubing consistent with NACE standards for sour gas service. The pipeline has been designed with a maximum allowable working pressure of 2,350 psig. In order to assure the safety of the pipeline system, the acid gas pipeline is contained within a 6-inch SDR 11 polyethylene pipeline (rated at 100 psig) which is swept from the wellhead location to the main plant with pure “sweet” gas for leak detection purposes. This “sweet” gas stream flows through the annulus between the 6-inch and 2-inch pipelines at a preset pressure of 5 psig and flow rate sufficient to continuously be monitored by a Delmar™ H_2S gas analyzer. This sweet gas stream is monitored continuously for H_2S and over/ under pressure. If any single variable falls outside the narrow predetermined operating range, the automatic safety valves are activated, the acid gas compressor is shut down and the acid gas stream is routed to the flare.

The injection string within the well is also constructed with multiple safety features which include L80 FX FJ 2 ⅞-inch corrosion resistant tubing stabbed into a Halliburton 13-20 pound permanent packer, made of Incoloy® 925 with fluorel elements set at 9,857 ft and an automated Halliburton subsurface safety valve also made of Incoloy® 925, set at 250 ft. Incoloy® 925 is a nickel-iron chromium alloy that is resistant to corrosion and pitting. This valve is designed to isolate and automatically shut in the injection well if a leak occurs along the acid gas pipeline or at the surface of the well. The annular space between the tubing and the production casing above the packer is filled with diesel which is designed to allow the pressure in the annular space to be monitored and recorded continuously. If a pressure excursion outside of the narrow predetermined operating range occurs, the acid gas compressor is shut down and the automatic safety valves at the pipeline inlet (located at the plant) and at the wellhead are automatically closed preventing any escape of acid gas. The acid gas stream would then be routed to the flare until the problem with the well is corrected and the system can be safely re-started. These redundant systems are compliant with API RP 55 and API RP 49, various applicable NACE standards for sour service and current best management practices.

The approximate composition of the TAG stream from the Dagger Draw Gas Plant is: 34% H_2S, 66% CO_2, and Trace Components of C1 – C7 (methane - heptane) (≤1%). Based on the reservoir simulation modeling of the gas stream PVT phase behavior, fluctuations of the H_2S and CO_2 composition will not affect the plume migration given the supercritical reservoir pressure and temperature conditions. Frontier intends to continue the injection of TAG for 30 years.

3.8 Reservoir Characterization Modeling

In the geologic and reservoir simulation model, Devonian limestone is the main target injection formation for the injection project. The Metropolis well (API 30-015-31905) penetrates and is completed in the Devonian formation through 9,927 to 10,500 ft (TD). Formation tops from 10 wells were interpreted and mapped to construct the structural surfaces for the Devonian injection formation. A total of 45 wells with density logs was used to populate the porosity property of the reservoirs, among which 5 are within a 1-mile radius around the Metropolis well. There were no geological structures such as faults identified in the geologic model boundary. There are four (4) vertical units within the model zone. The model boundary was focused on 17.5-mile X 15.3-mile area with grid cells of 162 x 185 x 12 totaling 359,640 cells. The average grid dimension is 500 square ft. **Figure 3.8-1** shows the geological model in 3D view.

An average porosity of 12% and permeability of 10 millidarcies (mD) were assigned to the Devonian formation within the model based on information from available well log data. To meet these criteria, an empirical formula of k=0.0003Ø^4.2 and kriging interpolation method are used to distribute the well log porosity data into permeability (**Figure 3.8-2 and Figure 3.8-3**). **Figure 3.8-4** compares the histogram of mapped permeability to the input well logs data. As seen, 80% of permeability values lie within the range of 1 to 40 mD. These values are validated with the historical injection data of Metropolis well since 2006 as shown in **Figures 3.8-5, 3.8-6, and 3.8-7**.

The vertical permeability anisotropy was 0.1. Newman's correlation for limestone was calculated to estimate the reservoir rock compressibility of 5e-06 1/psi with a 4.81579e-13 1/psi^2 damping factor. Carter-Tracy limited reservoir was assigned to the boundary of the simulation domain to mimic infinite reservoir response. Mid-depth (12,500 ft – TD) reservoir pressure 4,285.7 psi was calculated based on the pore pressure measurement of 7,500 psi sample taken at 17,500 ft – TD in the Permian Basin. The reservoir temperature of 94.3 degrees F was calculated based on the sample of 225°F measurement at the same location as pressure. The reservoir conditions described was used to compute the fluid model by Peng-Robinson Equation of State. The components' solubility was considered in the fluid model by Henry's Law. Irreducible water saturation of 0.55 is used to generate the relative permeability curves for the gas/water system. The non-wetting phase hysteresis effect was represented by Carson and Land's model with the maximum trapping gas saturation equal to 0.4 on the relative permeability curve. This method allows a reasonable capillary trapping mechanism to be simulated when imbibition curves are not readily available. The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium.

Once the geological model was established, calibration of injection history of the Metropolis well since 2006 was simulated. Numerical simulations were further performed to estimate the reservoir responses when predicting TAG injection for 30 years and10 years post-injection monitoring period. The stream injection rate of 5 MMSCFD was assigned with the mole composition of 34% H_2S and 66% CO_2.

During the calibration period (April 1st, 2006 – June 1st, 2022), the historical injection rates were used as the primary injection control. A maximum bottom hole pressure (BHP) of 5,000 psi was imposed on the Metropolis well as a constraint. This restriction is estimated by the fracture gradient of 0.68 psi/foot, calculated at the shallowest perforation depth (9,860 ft - TD) in the Devonian to ensure safe injection operations. **Figure 3.8-5** shows that the injection pressure fluctuation was very limited responding to the historical injection rate. There are no known SWD wells within 2 miles of the Metropolis well therefore none were included in the modeling efforts within this target injection zone.

Following the historical rate injection, a forecasting model was performed for 40 years, among which 30 years of active injection period (2023 to 2053) and 10 years of post-injection monitoring period (2053 to 2063). **Figure 3.8-6** shows the injection profile for the forecasting period, and a 5 MMSCFD injection rate sustained through. The modeling results indicate that the Devonian formation is far more capable of storing the intended gas volume. **Figure 3.8-7** shows the cumulative disposed H_2S and CO_2 during the entire well lifetime since 2006. During the forecasting period, linear cumulative injection behavior indicates that the Devonian formation endured the TAG injected freely. **Figure 3.8-8** shows the gas saturation represented free phase TAG movement at the end of 30-year forecasting from the aerial view. It can be observed that the size of the free phase TAG is very limited at the end of injection compared to the size of the geological model. In the year 2063, after 10 years of monitoring, the injected gas remained in the reservoir and there was no significant migration of TAG footprint observed, compared to that at the end of injection.

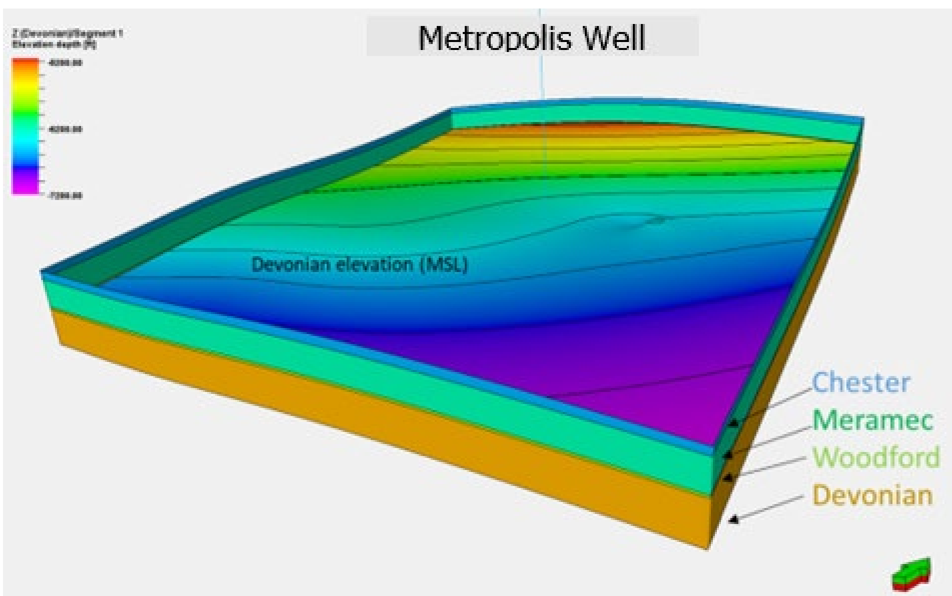


Figure 3.8-1: *Structure of the geological model using Chester, Meramec, Woodford, and Devonian formations. The elevation of the Devonian top surface with respect to Mean Sea Level (MSL) is depicted within the model.*

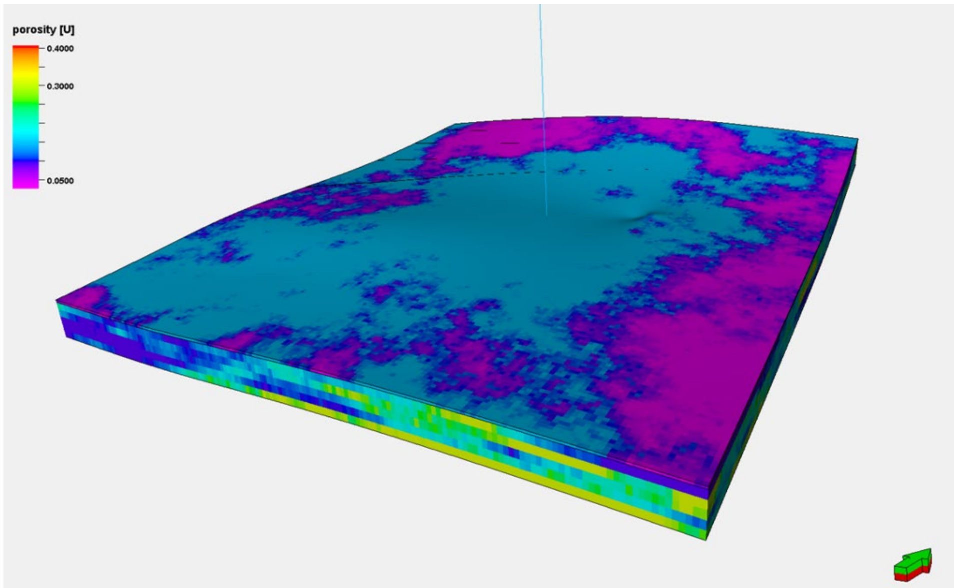


Figure 3.8-2: *Porosity estimation using available well data for Devonian formation.*

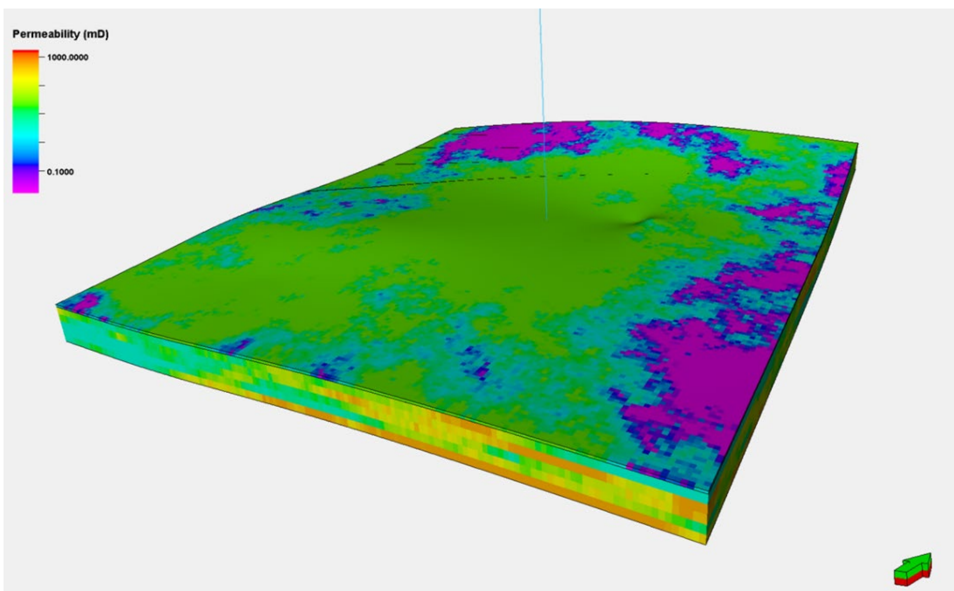


Figure 3.8-3: *Permeability estimation using available well data for Devonian formation.*

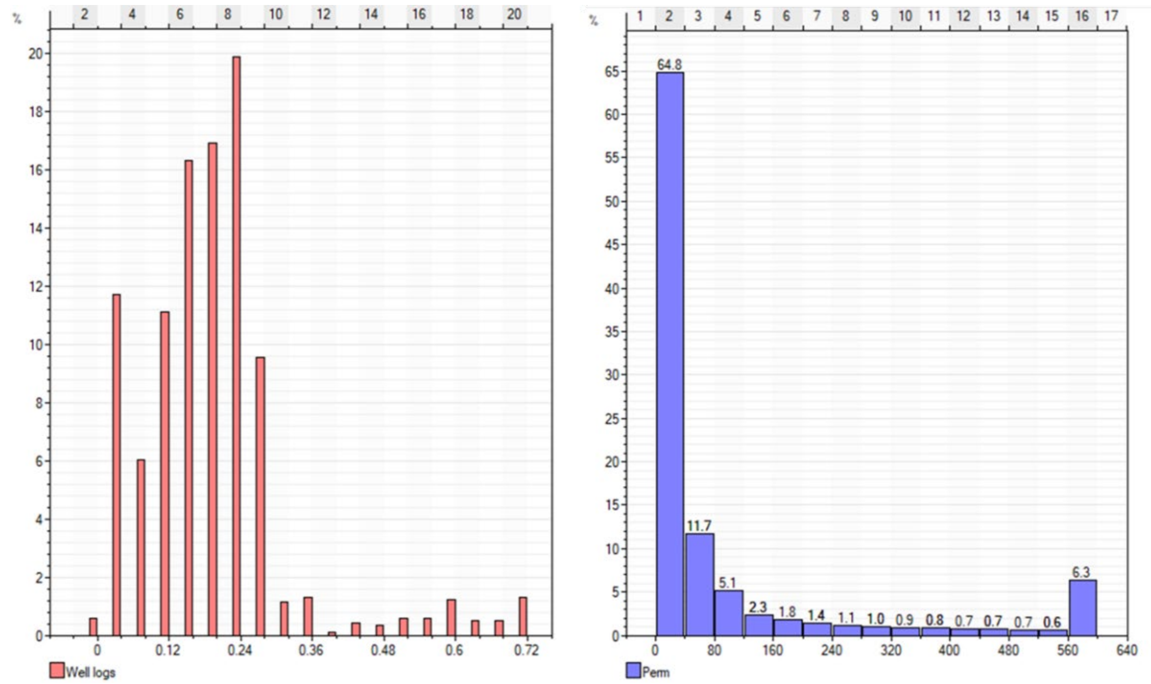


Figure 3.8-4: *Histogram comparison of permeability estimation in Devonian formation using available well log data.*

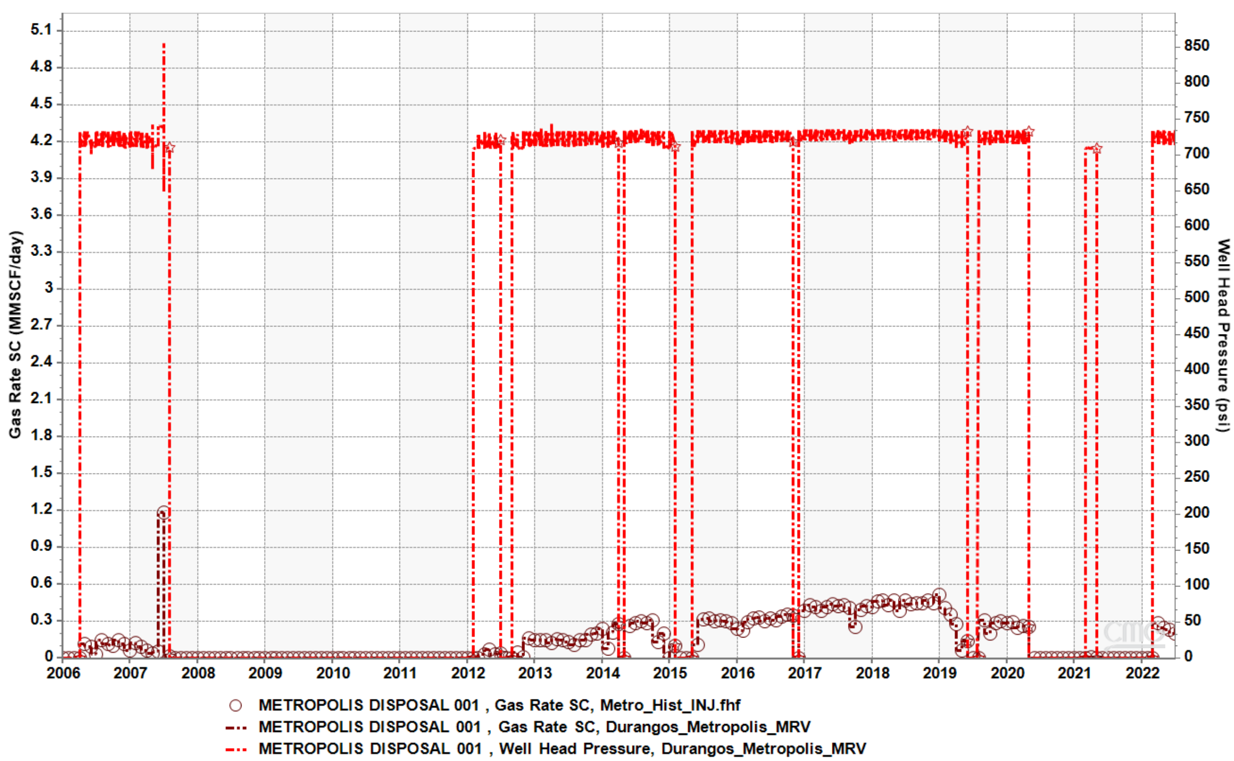


Figure 3.8-5: *shows the historical injection rate and injection pressure response (2006 to 2022).*

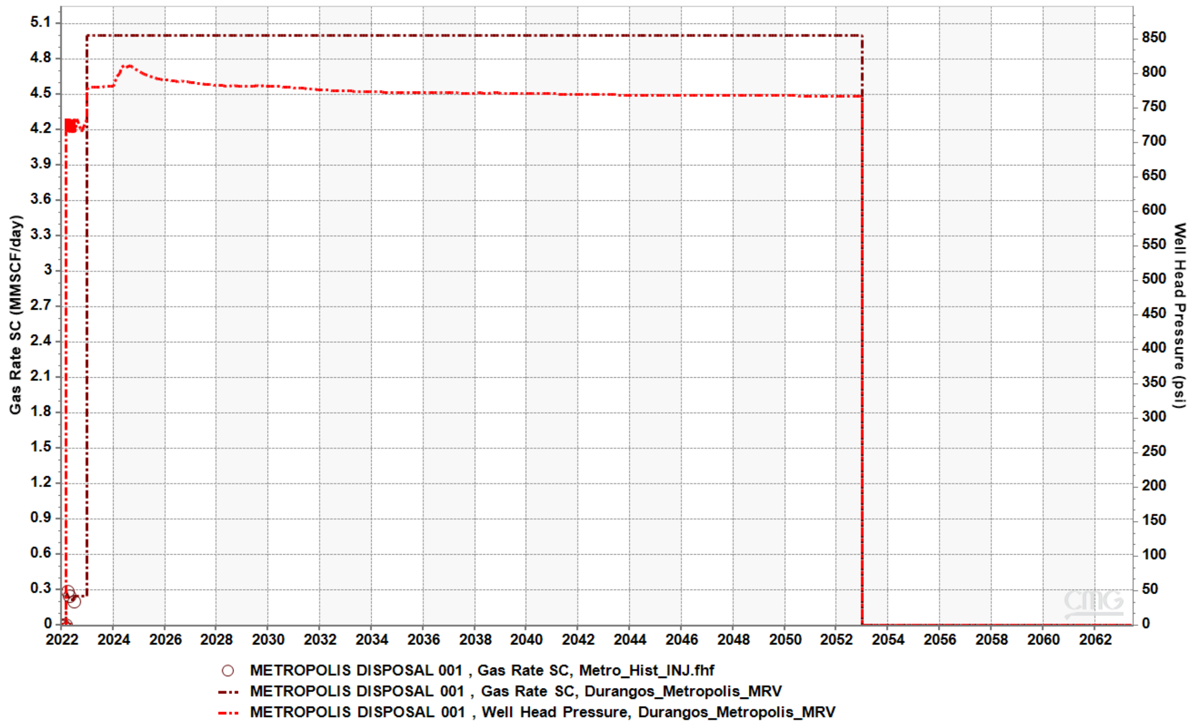


Figure 3.8-6: *shows the forecast profile for the injection rate and injection pressure response (2023 to 2063).*

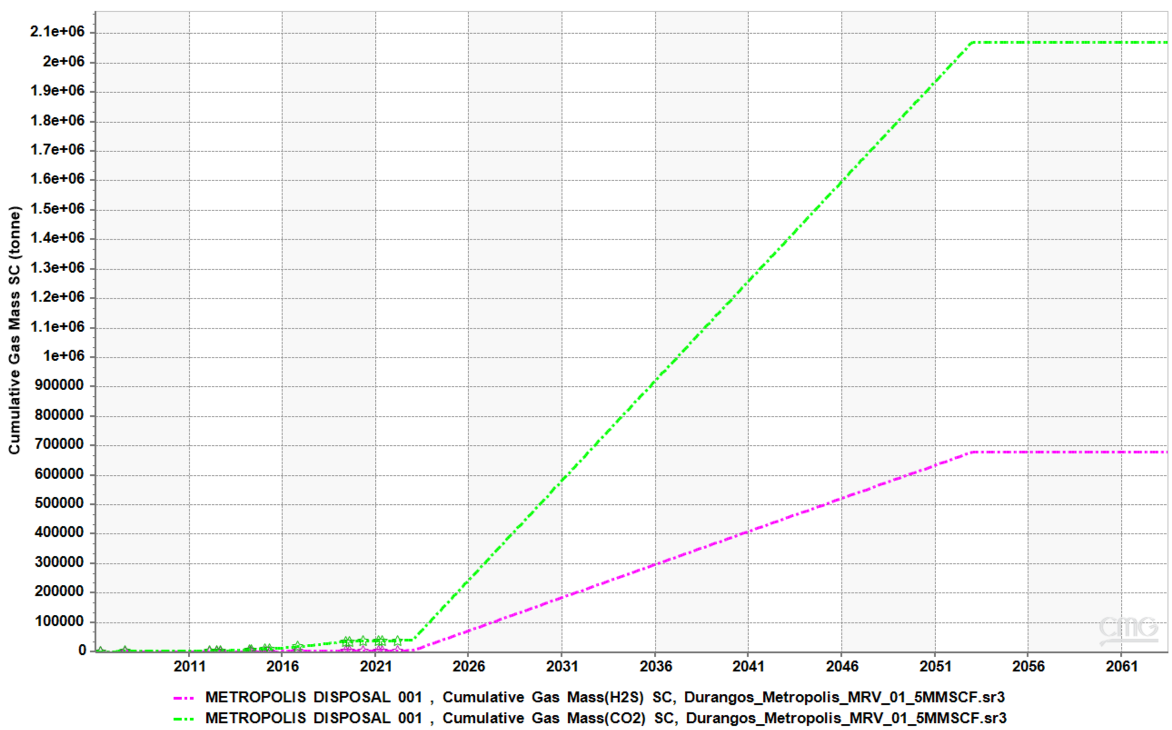


Figure 3.8-7: *shows the cumulative disposed H_2S and CO_2 behavior (2006 to 2063)*

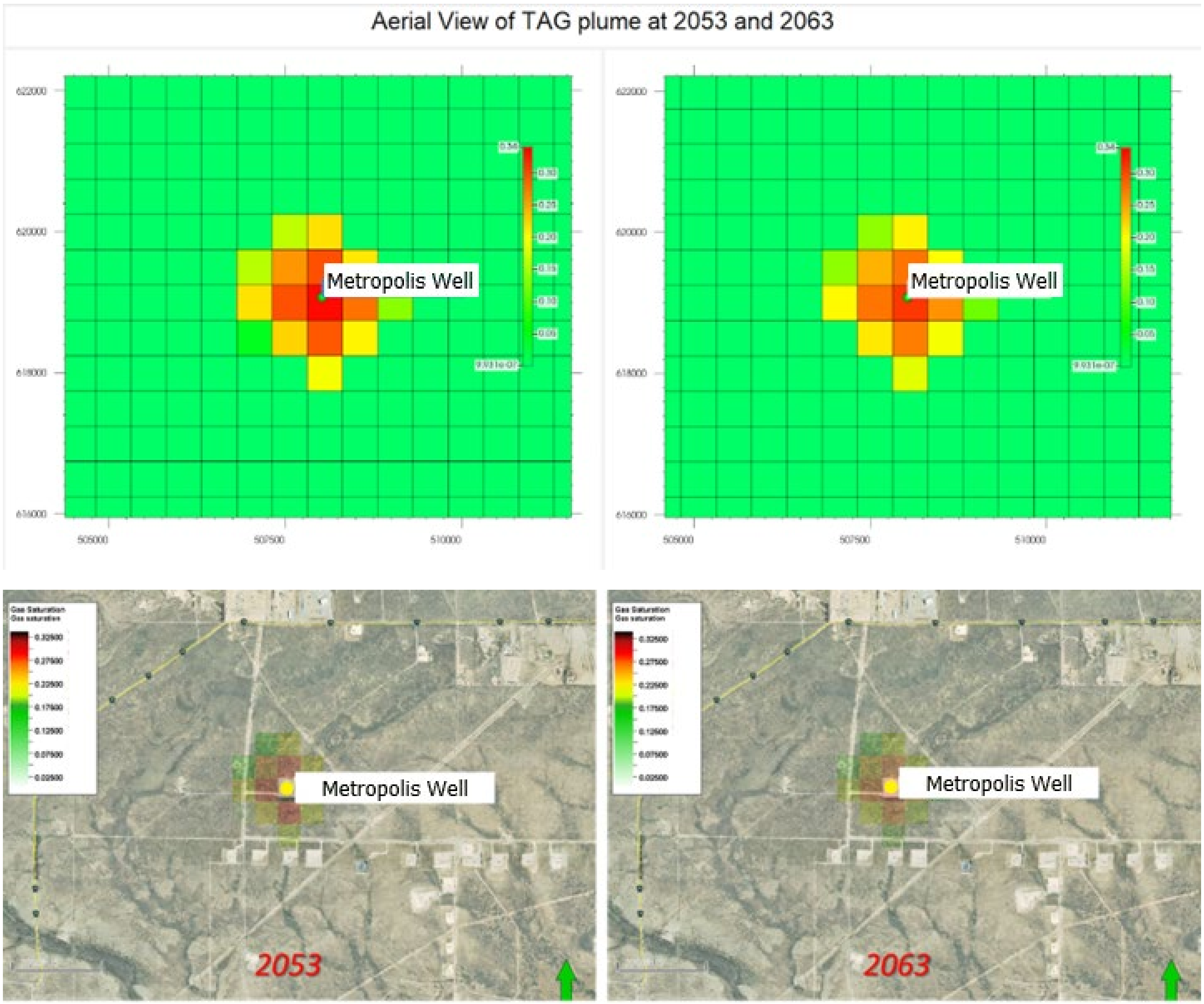


Figure 3.8-8: *shows the comparison of local free phase TAG saturation at the end of 30-year forecasting (2053, left) and the end of 10-year monitoring (2063, Right)*

4. Delineation of the monitoring areas

4.1 Maximum Monitoring Area (MMA)

As defined in Section 40 CFR 98.449 of Subpart RR, the maximum monitoring area (MMA) is "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling in Section 3.8 to define the extent of the plume.

The reservoir modeling in Section 3.8 states that "after 10 years of [post-injection] monitoring, the injected gas remained in the reservoir and there was no observed expansion of the TAG footprint, compared to that at the end of injection." Therefore, the plume extent at the end of 30 years of injection is the initial area with which to define the MMA. **Figure 4.1-1** shows the MMA as defined by the maximum extent of the TAG plume at year 2053 plus a 1/2-mile buffer.

4.2 Active Monitoring Area (AMA)

As defined in Section 40 CFR 98.449 of Subpart RR, the active monitoring area (AMA) is "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year t + 5."

Frontier has chosen t=2053 (the end of 30 years of injection) for purposes of calculating the AMA. As described in Section 3.8, the maximum extent of the TAG plume is at t=2053 so delineation of the first AMA area (Criteria 1) is equivalent to the delineation of the MMA since there are no known leakage pathways that would require the extension of this area laterally. Simulation of the second AMA area (Criteria 2) at t+5=2058 shows that the TAG plume extent is equivalent to the TAG plume extent at t=2053. Although TAG extent simulations for t+6=2059 shows the TAG plume shrinking, the maximum extent of the TAG plume is used in delineating the AMA. Superposition of the AMA Criteria 1 and 2 areas results in the AMA being equivalent to the MMA (**Figure 4.1-1**)

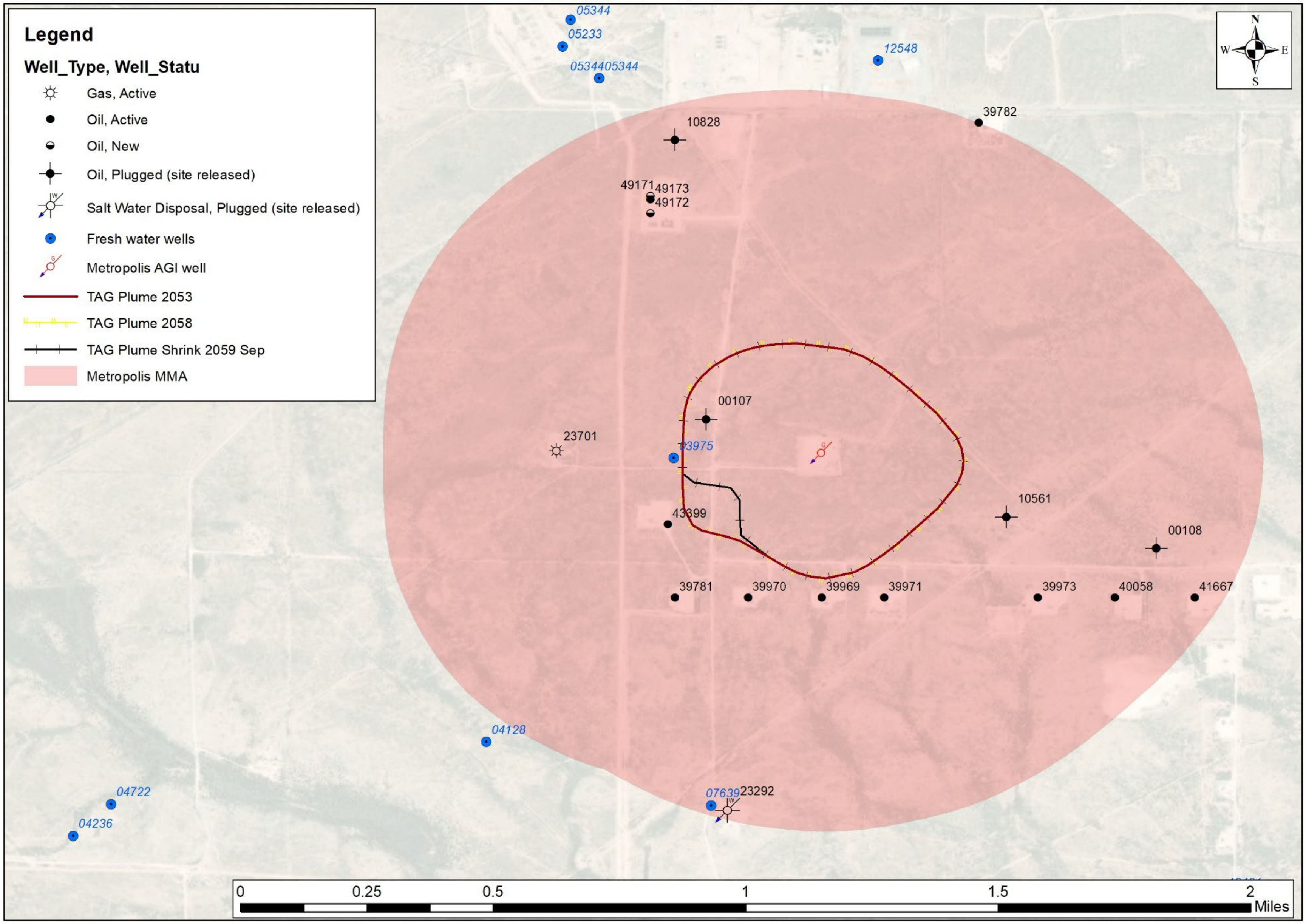


Figure 4.1-1: Maximum monitoring area (MMA) and active monitoring area (AMA) for the Metropolis well. The TAG plume extent at year 2053 and 2058 shows the plume as stabilized.

5. Identification and Evaluation of Potential Leakage Pathways

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways for CO_2 in the MMA and the evaluation of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways.

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells and the reservoir modeling described in Section 3.8, Frontier has identified and evaluated the potential CO_2 leakage pathways to the surface.

A qualitative evaluation of each of the potential leakage pathways is described in the following paragraphs. Risk estimates were made utilizing the National Risk Assessment Partnership (NRAP) tool, developed by five national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage environmental risks at geologic carbon storage sites. Utilizing the NRAP tool, Frontier conducted a risk assessment of CO_2 leakage through various potential pathways including surface equipment, existing and approved wellbores within MMA, faults and fractures, and confining zone formations.

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of the TAG stream, there is a potential for leakage from surface equipment at sour gas processing facilities. To minimize this potential for leakage, the construction, operation, and maintenance of gas plants follow industry standards and relevant regulatory requirements. Additionally, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

Operational risk mitigation measures relevant to potential CO_2 emissions from surface equipment include a schedule for regular inspection and maintenance of surface equipment. Additionally, Frontier implements several methods for detecting gas leaks at the surface. Detection is followed up by immediate response. These methods are described in more detail in sections 3.7.2, 6 and 7.

Section 3.7.2 describes the safeguards in place to prevent leakage between the acid gas compressor and the Metropolis wellhead. The compressor is pre-programmed to shut down if the operating pressure falls outside the pre-determined operational pressure range. The pressure is continuously monitored as the TAG goes through several compression cycles. Additionally, the final TAG stream pressure is approximately 1,100- 1,600 psig which is well below the maximum allowable working pressure for the pipeline of 2,350 psig. The TAG stream passes through a 2-inch diameter stainless steel pipe contained within a 6-inch pipe to the injection well. The annulus between the 2- and 6-inch piping contains sweet gas and is continuously monitored for H_2S and pressure to detect any leaks between the TAG compressor and the well head. These safeguards ensure the likelihood, magnitude, and duration of any TAG leakage between the TAG compressor and the injection well is minimal.

Furthermore, Frontier has standard operating procedures (SOP) in place to quantity pipeline leaks that occur on its supersystem. All leaks discovered by Frontier operations personnel, or third parties are quantified and reported in accordance with New Mexico Administrative Code (NMAC) Title 19, Chapter 15, Part 28 Natural Gas Gathering Systems administered by the Oil Conservation Division of the New Mexico Energy, Minerals and Natural Resources Department (EMNRD).

The injection well and the accompanying pipeline are the most likely surface components of the system that allow CO_2 leakage to the surface. The most likely reason for the leakage is the gradual deterioration of the surface components, particularly at the flanged connection points. Another potential factor contributing to leakage is the discharge of air via relief valves, which are specifically engineered to mitigate excessive pressure in pipelines. Leakage may occur when the surface components sustain damage due to an accident or natural disaster, resulting in the release of CO_2. Hence, we deduce that there is a possibility of leaking along this pathway.

Likelihood

Although leakage from surface equipment between the volumetric injection flow meter and the injection wellhead is possible, the mitigative measures described above and in Section 3.7.2 are in place to minimize the likelihood of a leakage event.

Magnitude

If a leak from the surface equipment between the volumetric injection flow meter and the injection wellhead occurs it will be detected immediately by the surveillance mechanisms described in Section 6.1 for surface equipment. The magnitude of a leak depends on the failure mode at the point of leakage, the duration of the leak, and the operational conditions at the time of the leak. A sudden and forceful break or rupture may discharge thousands of pounds of CO_2 into the atmosphere before it is brought under control. On the other hand, a gradual weakening of a seal at a flanged connection may only result in the release of a few pounds of CO_2 over a period of several hours or days.

Timing

During the operation of the injection system, any CO_2 leaks from surface equipment between the volumetric injection flow meter and the injection wellhead will be emitted immediately to the atmosphere. Mitigative measures are in place at the plant to minimize the duration and magnitude of any leaks. Leakage from surface equipment between the volumetric injection flow meter and the injection wellhead will only be possible during the operation of the injection system. Once injection ceases, surface injection equipment will be decommissioned thereby eliminating any potential for CO_2 leakage to the atmosphere.

5.2 Potential Leakage from Existing Wells

As listed in **Appendix 3**, there are 19 oil- and gas- related wells within the MMA including the Metropolis well.

Frontier considered all existing and new wells within the MMA in the NRAP risk assessment. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and new wellbores within the MMA. Reservoir properties, well data, formation stratigraphy, and the MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage. The worst-case scenario is that all of the wells were located right at the source of CO_2 – the injection well's location. In this case, the maximum leakage rate of one well is approximately 6.2e-5 kg/s. This value represents the maximum amount of CO_2 leakage from one well at 2,000 kg over 30 years of injection. Comparing the total amount of CO_2 injected (assuming 5 MMSCFD of CO_2 injected continuously for 30 years), the leakage mass amounts to 0.0023% of the total CO_2 injected. This leakage is considered negligible. Also, the worst-case scenario, where the wells were located right at the injection point, is impossible in reality. Therefore, CO_2 leakage to the surface via this pathway is considered unlikely.

We have applied a 5X5 Risk Matrix (**Figure 5.2-1**) to evaluate the relative risk of CO_2 emissions to the surface posed by the wells within the MMA shown in **Figure 4.1-1**. A risk probability of 2 is assigned to wells whose total depth is within the injection zone for the Maljamar wells and for wells that lie within the simulated TAG plume boundary. All other wells are assigned a risk probability of 1. A risk impact of 2 is assigned to wells whose total depth is within the injection zone and for wells that lie within the plume boundary. The overall risk rating is equal to the risk probability multiplied by the risk impact. These values are included in the table in **Appendix 3**.

5x5 Risk Matrix Example

Impact
How severe would the outcomes be if the risk occurred?

Probability
What is the probability the risk will happen?

	Insignificant 1	Minor 2	Significant 3	Major 4	Severe 5
5 Almost Certain	Medium 5	High 10	Very high 15	Extreme 20	Extreme 25
4 Likely	Medium 4	Medium 8	High 12	Very high 16	Extreme 20
3 Moderate	Low 3	Medium 6	Medium 9	High 12	Very high 15
2 Unlikely	Very low 2	Low 4	Medium 6	Medium 8	High 10
1 Very Unlikely	Very low 1	Very low 2	Low 3	Medium 4	Medium 5

Figure 5.2-1: *5X5 risk matrix used to assess relative risk of CO_2 emissions to the surface posed by wells within the MMA.*

5.2.1 Wells Completed in the San Andres-Glorieta-Yeso-Abo

Of the 19 wells within the MMA, 17 are completed in the San Andres-Yeso-Abo oil/gas production zone. The true vertical depth of these wells is more than 6,000 ft above the top of the injection zone for the Metropolis well at 9,930 ft. The intervening strata includes the upper confining zone consisting of approximately 150 ft of Barnett Shale, 470 ft of Mississippian Limestone with a porosity of <2%, and a lower 20 ft of Woodford Shale with a porosity of >1%. These units are an effective seal for the Metropolis well injection zone.

Likelihood

Due to the thickness of the intervening strata between the production zone of these wells and the injection zone of the Metropolis well, the thickness and low porosity and permeability of the confining zone above the injection zone and considering the NRAP risk analysis described in the introduction of Section 5.2, Frontier considers the likelihood of CO_2 emission to the surface via this group of well to be highly unlikely for those well outside the simulated TAG plume extent and unlikely for well 30-015-00107 which lies within the plume extent.

Magnitude

For the reasons described above, Frontier considers the magnitude of such a leak, if it were to occur, to be minimal. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO_2 emissions to the surface have occurred.

Timing

If CO_2 emissions to the surface were to occur via these wells, they would be delayed due to the 6,000 feet of strata between the production zone of these wells and the injection zone of the Metropolis well.

5.2.2 Wells Completed in the Atoka-Morrow

Of the 19 wells within the MMA, one (30-015-23701) is completed at a depth of 9,300 ft in the Atoka-Morrow oil/gas production zone. The well is located approximately ¼ mile west of the simulated maximum extent of the TAG plume (**Figure 4.1-1**). Below this production zone there is nearly 640 feet of Barnett Shale, upper Mississippian limestone, and Woodford Shale (see Section 5.2.1).

Likelihood

Due to the thickness of the confining zone above the injection zone for the Metropolis well, the location of the well outside the simulated maximum extent of the TAG plume, the presence of nearly 640 feet of confining zone strata between the bottom of the Atoka-Morrow production zone and the injection zone for the Metropolis well and considering the NRAP risk analysis described above, Frontier considers that CO_2 emission to the surface via this potential leakage pathway is unlikely.

Magnitude

Based on the worst-case scenario NRAP analysis described above, the magnitude of CO_2 emissions to the surface through the one well completed in the Atoka-Morrow production zone is negligible. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO_2 emissions to the surface have occurred.

Timing

If a leak of CO_2 to the surface were to occur through this one well completed in the Atoka-Morrow production zone, it would occur after the cessation of injection.

5.2.3 Wells Completed in the Devonian-Montoya

The only well completed in the Devonian-Montoya injection zone for the Metropolis well within the MMA is the Metropolis well itself.

NMOCC Order R-13371 limits the maximum injection pressure to 3,280 psi to prevent fracturing of the injection zone. The Order further requires that "the injection well or system shall be equipped with a pressure limiting device that will limit the wellhead pressure on the injection well to no more than 3,280 psi while injecting acid gas."

To further minimize the likelihood of surface leakage of CO_2 from the Metropolis well, Frontier is required, by NMOCC Order R-13371, to inject TAG through "2-7/8-inch corrosion-resistant L-80 tubing set in a nickel-based packer or any other corrosive-resistant materials." The Order also requires that "a one-way subsurface automatic safety valve shall be placed on the injection tubing 250 ft below the surface to prevent the injected acid gas from migrating upwards in case of an upset or emergency." Continuing with requirements of the Order, "the surface and the intermediate casing shall be set at 400 ft and 1,200 ft, respectively, and there shall be a total of three casing strings, all with cement circulated to the surface."

To further minimize the magnitude and duration (timing) of CO_2 leakage to the surface through the Metropolis well, Frontier is required by the Order to "at least once every two years…pressure test the casing from the surface to the packer-setting depth to assure casing integrity. Further, Frontier is required to "monitor pressure on the backside [of the casing] using continuous chart recorder or digital equivalent to immediately detect any leakage in the casing." A description of the monitoring of the Metropolis well is provided in sections 6 and 7.

As described in Section 3.7.2, an automated Halliburton subsurface safety valve made of Incoloy® 925 is set at a depth of 250 ft in the Metropolis well. Incoloy® 925 is a nickel-iron chromium alloy that is resistant to corrosion and pitting. This valve is designed to isolate and automatically shut in the injection well if a leak occurs along the acid gas pipeline or at the surface of the well. The annular space between the tubing and the production casing above the packer is filled with diesel which is designed to allow the pressure in the annular space to be monitored and recorded continuously. If a pressure excursion outside of the narrow predetermined operating range occurs, the acid gas compressor is shut down and the automatic safety valves at the pipeline inlet (located at the gas plant) and at the wellhead are automatically closed preventing any escape of acid gas.

Likelihood

Due to the safeguards described above, the continuous monitoring of Metropolis well operating parameters by the distributed control system (DCS) and considering the NRAP risk analysis described above, Frontier considers that the likelihood of CO_2 emission to the surface via the Metropolis AGI #1 to be possible but unlikely.

Magnitude

If a leak of CO_2 to the surface were to occur through failure of the internal and/or external mechanical integrity of the Metropolis AGI #1 well, it would be detected immediately by the continuous monitoring of the operating parameters by the DCS and the well would be shut-in until remedial measures were taken to address the leak. The magnitude of the leak would be quantified based on the operating conditions at the time of the leak and the duration of the leak.

Timing

Leaks of CO_2 to the surface through the Metropolis AGI #1 well would occur during the period of active injection.

5.2.4 Groundwater Wells

There are two groundwater wells (RA-03975 and RA-07639) within the MMA as shown on **Figure 4.1-1**. These wells are 430 feet and 260 feet deep, respectively.

Likelihood

Due to the shallow depth of these groundwater wells relative to the injection for the Metropolis well, it is highly unlikely that CO_2 emissions to the surface will occur via these wells. Nevertheless, these wells will be monitored as described in Section 7.7.

Magnitude

If CO_2 emissions to the surface are detected through monitoring of groundwater wells, Frontier will attempt to quantify the magnitude of the leak according to the strategies discussed in Section 6.8. However, due to the shallow depth of the groundwater wells within the MMA relative to the injection zone for the Metropolis well and the characteristics of the intervening strata, the magnitude of such a leak is expected to be minimal.

Timing

If a leak were to occur through groundwater wells, it would reach the surface well after the end of injection.

5.2.5 Saltwater Disposal (SWD) Wells

The only saltwater disposal well within the MMA is the LAKEWOOD SWD #003 (30-015-23292) with a total measured depth of 9,362 feet. This well is located at the southern boundary of the MMA (**Figure 4.1-1**). This well was plugged and abandoned on September 27, 2012 in accordance with NMAC 19.15.25 with five Class C cement plugs placed at depths from 6,586 feet to the surface.

Likelihood

Due to the location of the Lakewood SWD #003 well within the MMA and its approved plugging and abandonment by the NMOCD, Frontier considers CO_2 emissions to the surface though this well to be unlikely.

Magnitude

If a leak of CO_2 to the surface through this well were to occur, the magnitude of such a leak would be minimal due to the well's location (0.5 miles) relative to the simulated maximum plume extent and the robust nature of its plugging and abandonment.

Timing

If in the unlikely event that a leak of CO_2 to the surface through this well were to occur, the leak would occur after cessation of injection.

5.3 Potential Leakage from New Wells

Three new wells, wells that are permitted but not yet drilled, are listed in **Appendix 3**. These wells will target the San Andres-Yeso oil/gas production zone. As stated in Section 5.2.1 there is nearly 6,000 ft between this production zone and the top of the injection zone for the Metropolis well.

Likelihood

Due to the thickness of strata between the production zone of the San Andres-Yeso wells and the injection zone of the Metropolis well, the thickness of the confining zone above the Metropolis injection zone and considering the NRAP risk analysis described in the introductory paragraph of Section 5.2, Frontier considers the likelihood of CO_2 emission to the surface via this potential leakage pathway to be highly unlikely.

Magnitude

For the same reason described in Section 5.2.1 above, Frontier considers the magnitude of such a leak, if it were to occur, to be minimal.

Timing

If CO_2 emissions to the surface were to occur via these wells, they would be delayed due to the 6,000 feet of strata between the production zone of these wells and the injection zone of the Metropolis well.

5.4 Potential Leakage through Confining / Seal System

Subsurface lithologic characterization, geophysical log analysis, core analysis, and drill stem testing (DST) reveals excellent upper and lower confining zones for the injection zone for the Metropolis well described as follows. According to the available core and drill stem testing (DST) data, in the Chester, Mississippian limestone and Woodford, for the 500 ft of Mississippian limestone and 150 ft of Chester, the porosity is less than 3% and the permeability is estimated to be in the 0.1 millidarcy (mD) range. For the 20 ft of Woodford, the porosity is less than 1% and the permeability is less than 0.1 mD. Although the Metropolis well did not penetrate the Simpson Group, regional studies (see Section 3.2.2) indicate it pinches out northwest of the Dagger Draw area. These same studies indicate that within New Mexico, the Simpson Group is predominated by shales making the unit, if present, an excellent seal against downward migration.

Leakage through a confining zone happens at low-permeability shale formations containing natural fractures. The Metropolis well is injecting into the Devonian Group Formation, which lies under the Woodford Shale and Mississippian Limestone formations with less than 0.1 mD permeability acting as the seals. The NRAP risk analysis addressed leakage through the confining zone. The worst scenario is defined as leakage through the seal happening right above the injection well, where CO_2 saturation is highest. However, the worst case of leakage only shows that 0.01% of total CO_2 injection in 30 years was leaked from the injection zone to the seals. At increasing distances from the source of CO_2, the likelihood of a leakage event decreases proportionally with the distance from the source. Considering it is the worst amount of CO_2 leakage, if the event happens, and the leak must pass upward through the confining zone, the secondary confining strata that are also low permeability geologic units, and other geologic units, we conclude that the risk of leakage through this pathway is highly unlikely.

Likelihood

Based on the characterization of the porosity, permeability, thickness of the confining zone units, operational limitations on injection pressure to prevent initiation or opening of any existing fractures through the confining zone and considering the NRAP risk analysis described above, Frontier considers the likelihood of CO_2 emissions to the surface through the confining zone to be highly unlikely.

Magnitude

As described above in the NRAP risk analysis, the worst scenario is defined as leakage through the seal happening right above the injection well, where CO_2 saturation is highest. However, the worst case of leakage only shows that 0.01% of total CO_2 injection in 30 years was leaked from the injection zone to the seals. At increasing distances from the source of CO_2, the likelihood and magnitude of a leakage event decreases proportionally with the distance from the source. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO_2 emissions to the surface have occurred.

Timing

If a CO_2 leak were to occur through the confining zone, it would most likely occur during active injection close to the well where the greatest injection pressure is. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

5.5 Potential Leakage due to Lateral Migration

Characterization of the injection zone presented in Section 3.3 states "There are no structural traps to restrict lateral migration of injected gas, nor are there deep wells or faults that would serve as vertical conduits." Even so, lateral migration of the TAG plume was addressed in the simulation modeling detailed in Section 3.8. The results of that modeling indicate the TAG plume is unlikely to migrate laterally within the injection zone to conduits to the surface within the MMA.

Likelihood

Based on the results of the site characterization and simulation modeling, it is unlikely that CO_2 emissions to the surface would occur through lateral migration of the TAG plume.

Magnitude

Since the simulation modeling presented in Section 3.8 indicates that the TAG plume is unlikely to migrate laterally to conduits to the surface the magnitude of such a leak if it were to occur would be negligible. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO_2 emissions to the surface have occurred.

Timing

For reasons described above, a leak, if it were to occur, via lateral migration would occur well after injection ceased.

5.6 Potential Leakage due to Faults and Fractures

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology and identify and understand the distribution of faults and fractures. No faults were identified within the MMA of the Metropolis AGI #1 well that could serve as potential leakage pathways. In addition, according to Horne et al. 2021, the closest fault to the Metropolis well is 13 miles South-East (**Figure 5.6-1)**.

Finally, to ensure that operation of the Metropolis AGI #1 well does not initiate or propagate any existing fractures in the injection and confining zones, the maximum allowable wellhead injection pressure is limited by the NMOCD to no more than 1,980 psi. However, **Figure 3.8-5** showing the historical injection rate and injection pressure response reveals the injection pressure has not exceeded 850 psi, well below the maximum allowable injection pressure. Furthermore, the injection well is equipped with a pressure limiting device which limits the injection pressure to this maximum allowable injection pressure.

Likelihood

Due to the absence of faults within the MMA, the result of the NRAP risk assessment of the nearest fault to the Metropolis AGI #1 well, the limitation of the maximum allowable injection pressure, the historical injection pressure being well below the allowable maximum, and to the presence of a pressure limiting device in the injection system, Frontier concludes that the likelihood of CO_2 emissions to the surface via faults and fractures is highly unlikely.

Magnitude

For the reasons described above, the magnitude of a leak, if it were to occur, through faults and fractures is estimated to be negligible. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO_2 emissions to the surface have occurred.

Timing

For the reasons described above, the timing of a leak, if it were to occur, through faults and fractures would occur well after injection ceased.

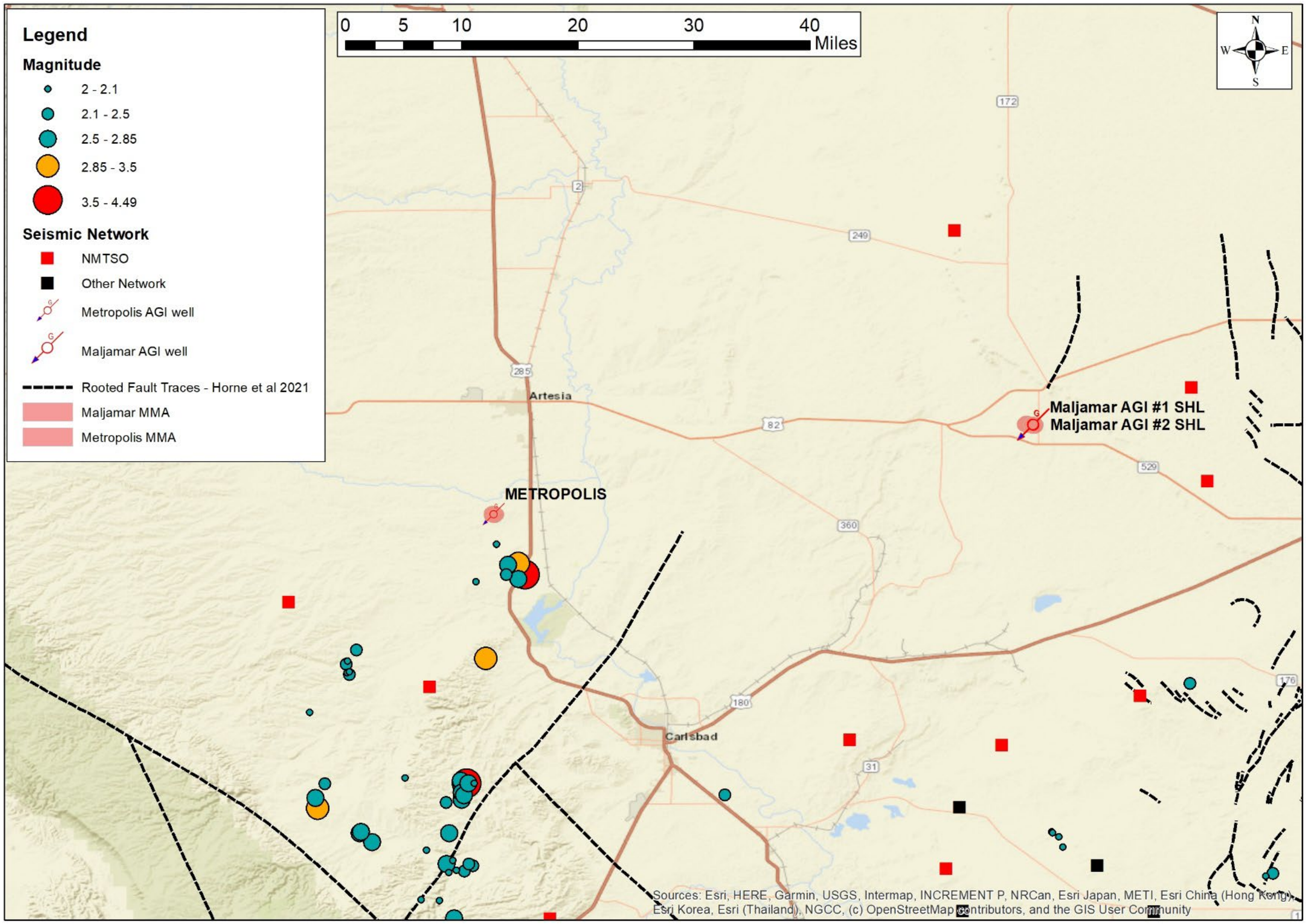


Figure 5.6-1: New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023)

5.7 Potential Leakage due to Natural or Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. The most recent seismic events close to the Metropolis well are shown in **Figure 5.7-1**. The closest recent seismic events are all south of the well:

- 2.05 miles, 02/2023, Magnitude 2.15
- 2.19 miles, 01/2023 Magnitude 2.10
- 4.26 miles, 11/2022 Magnitude 2.10
- 4.44 miles, 11/2022 Magnitude 2.10
- 4.64 miles, 12/2022 Magnitude 2.00
- 4.9 miles, 12/2022 Magnitude 2.20

Oil and gas wells, as well as saltwater disposal (SWD) wells in proximity of the registered seismic events could be the cause of this induced seismicity. The SWD wells south of Metropolis all have a true vertical depth (TVD) around 9,500 ft.

The Seismological Facility for the Advancement of Geoscience (SAGE) is operated by EarthScope Consortium via funding from the National Science Foundation. SAGE developed and currently maintains the IRIS Data Management Center that archives and distributes data to support the seismological research community. According to the data available, no seismographic activities were recorded in the area during the time the Metropolis well was injecting (from March 24, 2006 to July 5, 2007).

Likelihood

Due to the distance between the Metropolis well and the recent seismic events, the magnitude of the events, the fact that the Metropolis well was not injecting at the time of the recent events, and the fact that no seismic activity was recorded during the time the Metropolis well was injecting; Frontier considers the likelihood of CO_2 emissions to the surface caused by seismicity to be unlikely.

Magnitude

If a seismic event occurs at the time the Metropolis well is injecting and in the vicinity of the Dagger Draw plant, Frontier will implement the verification and quantification strategy described in Section 6.8.3 to attempt to verify whether the seismic event was due to the injection into the Metropolis well and to quantify any leak of CO_2 to the surface.

Timing

If a leak of CO_2 to the surface occurs as a result of a seismic event, if would likely occur at the time of the seismic event or shortly thereafter.

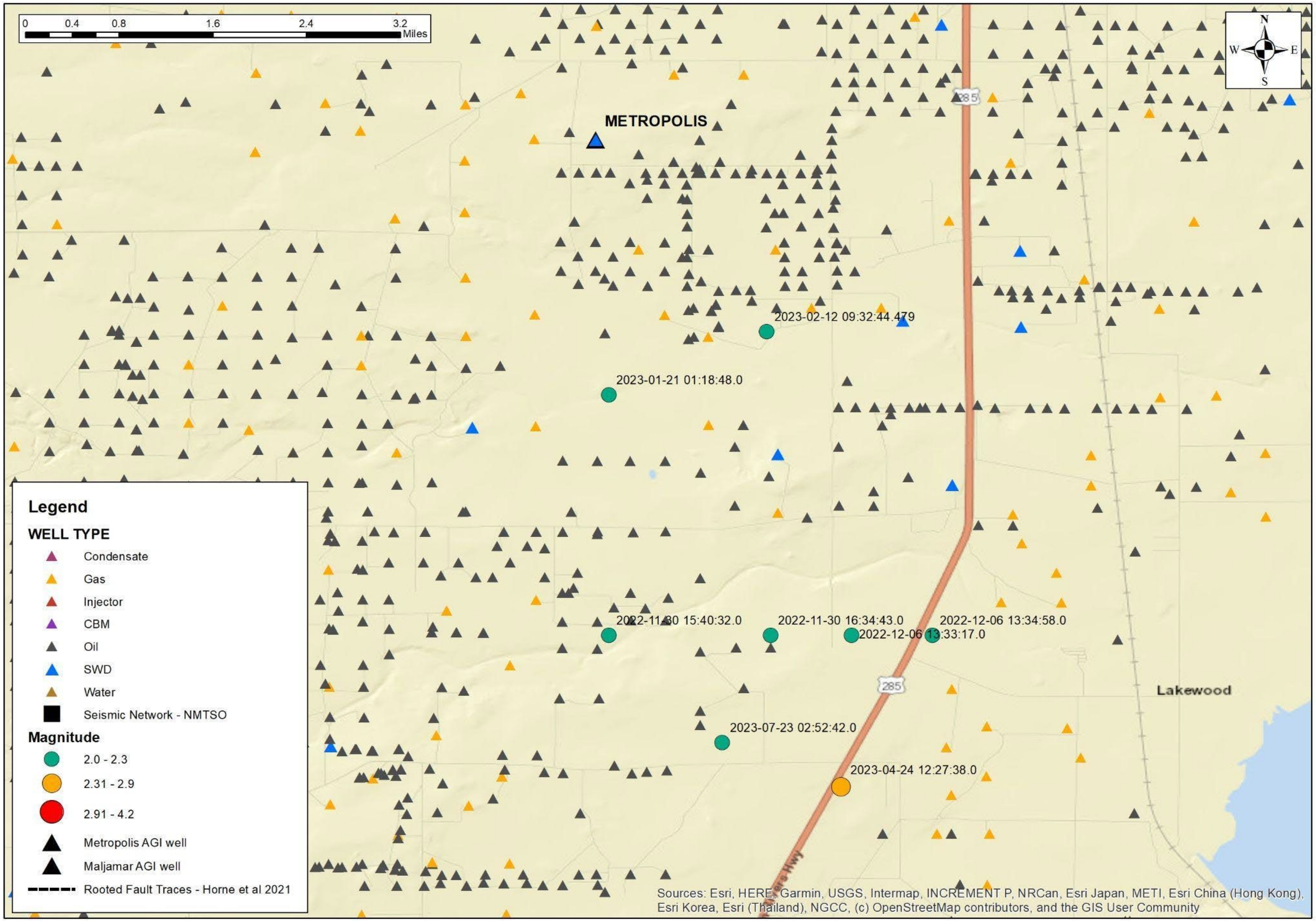


Figure 5.7-1: *NMTSO seismic network close to the Metropolis operation, recent seismic events, fault traces and oil and gas wells (2022-2023)*

6. Strategy for Detecting and Quantifying Surface Leakage of CO_2

Frontier will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. Frontier considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection.

Table 6-1: *Summary of Leak Detection Monitoring*

Leakage Pathway	Detection Monitoring
Surface Equipment	• DCS surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors • Personal and hand-held gas monitors
Metropolis Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors
Faults and Fractures	• DCS surveillance of well operating parameters • Fixed in-field gas monitors
Natural or Induced Seismicity	• NMTSO seismic monitoring stations • DCS surveillance of well operating parameters • Fixed in-field gas monitors
Additional monitoring	• Soil flux monitoring • Groundwater monitoring

6.1 Leakage from Surface Equipment

Frontier implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters.

Leaks from surface equipment are detected by Frontier field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events. Frontier also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

The following description of the gas detection equipment at the Dagger Draw Gas Plant was extracted from the H_2S Contingency Plan, April, 2022:

> "The Dagger Draw Gas Processing Plant uses Smart Sensor System™ fixed plant H_2S Sensors. These sensors are a fixed-point monitoring system used to detect the presence of hydrogen sulfide in ambient air. The yellow flashing beacon is activated at H_2S concentrations of 10 ppm or greater. The horn is activated with an intermittent alarm at H_2S concentrations of 10 ppm or greater. The lights change to red at 20 ppm H_2S and the horn remains intermittent. The fixed hydrogen sulfide monitors are strategically located throughout the plant to detect an uncontrolled release of hydrogen sulfide. The plant operators are able to monitor the H_2S level of all the plant sensors on the control monitor located in the control room and the Dagger Draw Plant Field Office. In addition, select employees can access this information remotely. These sensors all have to be acknowledged and will not clear themselves. This requires immediate action for any occurrence or malfunction. The plant sensors have battery backup systems and are calibrated monthly. Audible alarm systems are also calibrated monthly.
>
> Pemtech™ wireless H_2S detectors with battery backup systems are installed along the perimeter of the plant and the perimeter of the acid gas disposal well. Perimeter H_2S detectors report to the Pemtech monitor every five minutes to confirm detector functionality. Once H_2S gas is detected, the H_2S detectors report to the monitor every five seconds. The detectors will go into alarm at H_2S values of 10 ppm and above.
>
> Handheld gas detection monitors are available to plant personnel to check specific areas and equipment prior to initiating maintenance or work on the process equipment. There are 3 handheld monitors, and each individual is assigned a personal H_2S monitor. The handheld gas detection devices are Honeywell BW single gas monitors for H_2S and Honeywell 4-gas detectors. The 4-gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), hydrogen sulfide, and carbon dioxide. They indicate the presence of H_2S with a beeping sound at 10 ppm. The beeps change in tone as H_2S increases to 20 ppm. The personal monitors are set to alarm (beep) at 10 ppm with the beeps becoming closer together as the H_2S concentration increases to 20 ppm. Both the handheld and personal monitors have digital readouts of H_2S ppm concentration."

Figure 3.7-3 shows the location of the fixed infield H_2S and LEL monitors at the Dagger Draw Gas Plant and around the Metropolis AGI well. Frontier's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S.

Quantification of CO_2 emissions from surface equipment and components will be estimated according to the requirements of 98.444 (d) of Subpart RR as discussed in Sections 6.8.1 and 10.1.4. Furthermore, if CO_2 surface emissions from surface equipment and components are indicated by any of the monitoring methods listed in **Table 6.1**, Frontier will quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Frontier has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). Frontier will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by Frontier or third parties.

6.2 Leakage from the Metropolis Well

As part of ongoing operations, Frontier continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. These data are monitored continuously by qualified field personnel who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

Leaks from the Metropolis well are detected by implementing several monitoring programs including DCS surveillance, visual inspection of the surface facilities and wellheads, injection well monitoring and mechanical integrity testing, and personal H_2S monitors. To monitor leakage and wellbore integrity, data from the bottom hole temperature and pressure gauge and wellhead gauges are continuously recorded by the DCS. Mechanical integrity tests are performed annually. Failure of an MIT would indicate a leak in the well and result in immediate action by shutting in the well, accessing the MIT failure, and implementing mitigative steps.

If operational parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Frontier will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site.

6.3 Leakage from Other Existing Wells within the MMA

Well surveillance by other operators of existing wells will provide an indication of CO_2 leakage as will the fixed in-field gas monitors. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the Metropolis well, described in Sections 6.2 and 7.4, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters indicate leakage of CO_2 through the confining / seal system, Frontier will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well.

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the Metropolis well during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The continuous parameter monitoring described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If monitoring of operational parameters, fixed in-field gas monitors, groundwater and soil flux indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, Frontier will reassess the plume migration modeling for evidence that the plume may have intersected a lateral pathway for CO_2 release to the surface. As this scenario would be considered a material change per 40 CFR 98.448(d)(1), Frontier will submit a revised MRV plan as required by 40 CFR 98.448(d).

6.6 Leakage due to Faults and Fractures

The geologic characterization at the Metropolis well site (see Section 3) revealed no faults within the MMA. However, if monitoring of operational parameters, fixed in-field gas monitors, groundwater and soil flux indicate possible CO_2 leakage to the surface, Frontier will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures. Frontier will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission and take mitigative action to stop it, including shutting in the well. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.7 Leakage due to Natural or Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, Frontier will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the project has been mapped in **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at 5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

The following seismic stations will be monitored to assess potential natural and induced seismic events (The distance between the Metropolis well and the NMTSO seismic monitoring station is shown in parentheses):

- South of Dagger Draw - Metropolis:
  - DAG - Carlsbad, NM (15 miles)
  - SRH - Carlsbad, NM (32 miles)
  - CBET - Carlsbad, NM (42 miles)
  - CL7 - Carlsbad, NM (49.5 miles)

If monitoring of the NMTSO seismic monitoring stations, the operational parameters and the fixed in-field gas monitors indicates surface leakage of CO_2 linked to seismic events, Frontier will assess whether the CO_2 originated from the Metropolis well and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

As required by 40 CFR 98.444(d), monitoring and quantification of all CO_2 emissions from equipment located on the surface between the injection flow meter used to measure injection quantity and the injection well head will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP. Section 40 CFR 98.233(q)(1)(ii) of Subpart W requires that equipment leak surveys be conducted using leak detection methods listed in 98.234(a)(1) through (5) on equipment listed in 98.232(d)(7) for natural gas processing facilities and employ emission calculation procedures specified in 98.233(q)(2). The listed leak detection methods include optical gas imaging equipment which Frontier has chosen to conduct its equipment leak surveys. Frontier will operate the optical gas imaging equipment according to the requirements in 98.234 (a)(1) and as specified at 40 CFR 60.18. Frontier conducts monthly optical gas imaging in accordance with New Mexico Environment Department (NMED) rules contained in 20.2.50.1116.

Frontier will respond to detected and quantified leaks from surface equipment by isolating the source of the leak and repairing it immediately.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (**Table 6-1**) that identifies the leak.

Leaks associated with the point sources, such as the injection well, and identified by failed MITs, and variations of operational parameters outside acceptable ranges, can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. Frontier may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the soil CO_2 flux monitoring network placed strategically in their vicinity. The soil CO_2 flux monitoring network as described in Section 7.8 consists of placing 8-centimeter diameter PVC soil collar throughout the monitoring area. The soil collars will be left in place such that each measurement will use the same locations and collars during data collection. Measurements will be made by placing the LI-8100A chamber on the soil collars and using the integrated iOS application to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. Initially, data will be collected monthly, for six months, to establish a baseline. After the baseline is established, data will be collected at a quarterly interval. Data is presented as concentration of CO_2 (millimoles)/area (meters squared)/time (seconds). Quarterly measurements will be compared to baseline data to determine the percentage of change over time. During the baseline data collection phase, the collected data will be analyzed to establish a seasonal trend, and to identify any changes in the CO_2 concentration that could be caused by activities around the site, i.e. cattle, planting season, etc.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Surface emissions of CO_2 from nonpoint sources such as through the confining zone, along faults or fractures, or which may be initiated by seismic events will be detected by Frontier's leak detection network consisting of DCS surveillance of operating parameters, hand-held gas sensors, fixed in-field gas sensors, groundwater monitoring, NMTSO seismic monitoring, and CO_2 flux monitoring as listed in **Table 6-1**. If surface leaks are detected, Frontier will attempt to identify the pathway through which the leak occurred and to quantify the magnitude of the leak by employing various advanced verification and quantification methods as listed in the Technical Support Document. Additionally, technologies for quantifying CO_2 surface emissions are continuing to be developed and refined (e.g. satellite imaging, drones, etc.), including those currently under development by the New Mexico Institute of Technology and will be deployed in the event a leak is detected.

7. Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Frontier uses the existing automatic DCS to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. Frontier considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage. The following describes Frontier's strategy for collecting baseline information.

7.1 Visual Inspection

Frontier field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a surrogate for CO_2, at the Dagger Draw Gas Plant.

7.2 Fixed In-Field, Handheld, and Personal H_2S Monitors

Compositional analysis of Frontier's gas injectate at the Dagger Draw Gas Plant indicates an approximate H_2S concentration of 34% thus requiring Frontier to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Due to the toxicity of H_2S, multiple fixed H_2S monitors are located throughout the plant and at the injection well sites, and offsite (beacons) are positioned around the plant perimeter. Fixed H_2S monitors are set to alarm at 10 ppm. Additionally, all Frontier employees and contract personnel are required to wear personal H_2S monitors set to alarm at 5 ppm. Any alarm by a fixed or personal H_2S monitor would trigger emergency response procedures to immediately secure the facility and contain a leak. Both fixed and personal H_2S monitors act as a proxy for a CO_2 leak and the concentrations recorded by the spectrometer along with the duration of the leak will be used to determine the mass of CO_2 released.

In addition to using fixed and personal monitors, baseline monitoring at the Maljamar Gas Plant and the Dagger Draw Gas Plant will commence upon approval of this MRV plan. Both plants have been operating for multiple years and empirical data exists on the amount of CO_2 injected over multiple years thereby setting a baseline of expectations going forward. Measurements of the injection volume and the concentration of CO_2 in the acid gas stream will be recorded and compared to previous operating history. Any signification deviation from past injection history will be investigated.

7.3 Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if a parameter is outside the allowable operational window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat. Also, see Section 6.2 for continuous monitoring of pressure and temperature in the well.

7.4 Well Surveillance

Frontier adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. Frontier's Routine Operations and Maintenance Procedures for the Metropolis well ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

7.5 CO_2 Monitoring

Frontier has purchased an IPS-4 UV/IR Full Spectrum Analyzer to be deployed for measuring the concentration of CO_2 and H_2S in the injection stream into the Metropolis well. This will provide a high degree of accuracy in calculating the mass of CO_2 injected. As stated above, Frontier considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage.

7.6 Seismic (Microseismic) Monitoring

Data recorded by the existing seismometers within 10-mile radius, deployed by the State of New Mexico, will be analyzed by the New Mexico Bureau of Geology, see **Figure 5.6-1**, and made publicly available. A report and a map showing the magnitudes of recorded events from seismic activity will be generated. The data is being continuously recorded. By examining historical data, a baseline can be established. Measurements taken after baseline measurements will be inspected to identify anomalous values. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous values during that period .

7.7 Groundwater Monitoring

Groundwater wells, in the vicinity of the injection well(s), will be identified. Water samples will be collected and analyzed on a monthly basis, for six months, to establish baseline data. After establishing baseline, water samples will be collected and analyzed at a quarterly interval. The water analysis included total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). See **Table 7.7-1**.

Table 7.7-1: *Groundwater Analysis Parameters*

Parameters
pH
Alkalinity as HCO3- (mg/L)
Chloride (mg/L)
Fluoride (F-) (mg/L)
Bromide (mg/L)
Nitrate (NO3-) (mg/L)

Parameters
Phosphate (mg/L)
Sulfate (SO42-) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. Periodic monitoring of CO_2 soil flux allows for continual characterization of the interaction between the subsurface and surface to better understand the potential leakage pathways and to provide actionable recommendations based on the collected data. The data will be collected on a monthly basis, for six months, to establish a baseline. After the baseline is established, data will be collected at a quarterly interval.

CO_2 soil flux measurements will be taken using a LI-COR LI-8100A (LI-COR, 2010 flux chamber), or similar instrument, at pre planned locations at the site.

PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

8. Site Specific Considerations for Mass Balance Equation

Appendix 6 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 7** includes the details of the twelve equations from Subpart RR. Not all of these equations apply to Frontier's current operations at the Dagger Draw Gas and Maljamar Gas Plants but are included in the event Frontier's operations change in such a way that their use is required.

At both the Dagger Draw and Maljamar Gas Plants, acid gas from the amine treating process (amine still over-heads) is collected in a header system and measured by a volumetric flow meter. Also contained in the header system is an AMETEK IPS-4 Integrated Photometric Spectrometer (spectrometer). The spectrometer measures the concentration of CO_2, H_2S, and total hydrocarbons (THC) in the acid gas stream. Signal outputs from both the volumetric flow meter and the spectrometer are monitored continuously and recorded hourly via each plant's supervisory control and data acquisition (SCADA) or distributive control system (DCS). See **Figure 3.7-1** in Parts A and B of this plan for surface components including volumetric flow meters at the Dagger Draw and Maljamar Gas Plants, respectively.

8.1 CO_2 Received

Currently, Frontier receives natural gas to the Dagger Draw Gas Plant through Frontier's gathering super system. The gas is processed as described in Section 3.7 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection.

Per 40 CFR 98.443, the mass of CO_2 received must be calculated using the CO_2 received equations (RR-1, RR-2, and RR-3) unless the procedures in 40 CFR 98.444(a)(4) are followed. 40 CFR 98.444(a)(4) states that if the CO_2 received is wholly injected and is not mixed with any other supply of CO_2, the annual mass of CO_2 injected (RR-5 and RR-6) may be reported as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. This scenario applies to the operations at both the Dagger Draw and Maljamar Gas Plants as CO_2 received for the injection wells is wholly injected and not mixed with any other supply; therefore the annual mass of CO_2 injected will be equal to the amount received. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected at both gas plants. Any future streams would be metered separately before being combined into the calculated stream.

Although Frontier does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. If CO_2 received in containers results in a material change as described in 40 CFR 98.448(d)(1), Frontier will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Frontier injects CO_2 into the existing Metropolis well at the Dagger Draw Gas Plant. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the well. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. The volumetric flow meter, u, in Equation RR-5 corresponds to meter DDVM in **Figure 3.7-1** for the Dagger Draw Gas Plant.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

The volumetric flow meter, u, in Equation RR-6 corresponds to meter DDVM for the Dagger Draw Gas Plant and MVM for the Maljamar Gas Plant. Equation RR-6 will be used to calculate the annual mass of CO_2 injected at both the Dagger Draw and Maljamar Gas Plants.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

Frontier does not produce oil or gas or any other liquid at its Dagger Draw Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

The monitoring methods described in Sections 6 and 7 will indicate the occurrence of gas leakage at the surface. Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage (CO_{2E}) from the leakage pathways identified and evaluated in Section 5. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.5 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{(Equation RR-10)}$$

where:

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

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

x = Leakage pathway.

8.5 CO_2 Sequestered

Since Frontier does not actively produce oil or natural gas or any other fluid at the Dagger Draw Gas Plant, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Equation RR-12)}$$

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

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

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

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

9. Estimated Schedule for Implementation of MRV Plan

Frontier proposes to initiate collection of data to determine the amount of carbon dioxide sequestered beginning on June 1, 2024. Expected baseline data for the Maljamar Gas Plant has been determined as Frontier has been reporting the amount of CO_2 injected under subpart UU for quite some time. Additionally, Frontier has re-started the Dagger Draw Gas Plant (February 2022) and installed flow measurement and an Ametek IPS-4 spectrophotometer (similar to the flow measurement and spectrophotometer located at the Maljamar Gas Plant) on the acid gas stream. Frontier expects the Dagger Draw Gas Plant measurement system and the spectrophotometer to be operational by the end of September 2023.

10. GHG Monitoring and Quality Assurance Program

Frontier will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Frontier's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP, if applicable: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. Frontier will adhere to the American Gas Association (AGA) Report #3 – Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids

10.1.2 CO_2 Received.

Per 40 CFR §98.443, the mass of CO_2 received must be calculated using the CO_2 received equations (RR-1, RR-2, and RR-3) unless the procedures in 40 CFR 98.444(a)(4) are followed. 40 CFR 98.444(a)(4) states that if the CO_2 received is wholly injected and is not mixed with any other supply of CO_2, the annual mass of CO_2 injected (RR-5 and RR-6) may be reported as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. This scenario applies to the operations at both the Dagger Draw and Maljamar Gas Plants as CO_2 received for the injection wells is wholly injected and not mixed with any other supply; therefore the annual mass of CO_2 injected will be equal to the amount received. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected at both gas plants.

10.1.3 CO_2 Injected.

Daily volumes of CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipeline to the Metropolis well using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 emissions from equipment leaks and vented emissions of CO_2.

As required by 98.444 (d), Frontier will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 98.444 (d) of Subpart RR, Frontier will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used.

10.1.5 Measurement devices.

As required by 40 CFR 98.444(e), Frontier will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration,
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.

- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

Frontier will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.3 Estimating Missing Data

Frontier will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

10.4 Revisions of the MRV Plan

Frontier will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico.

11. Records Retention

Frontier will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Frontier will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors, if applicable.

(iii) The results of all required analyses.

(iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, Frontier will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(12) Any other records as specified for retention in this EPA-approved MRV plan.

12. Appendices

Appendix 1 - Frontier Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Metropolis	30-015-31905	1,650' FSL, 1,650' FWL; Section 36, T18S, R25E; NMPM	Eddy, NM	8/31/2001	10,500’	9,853’

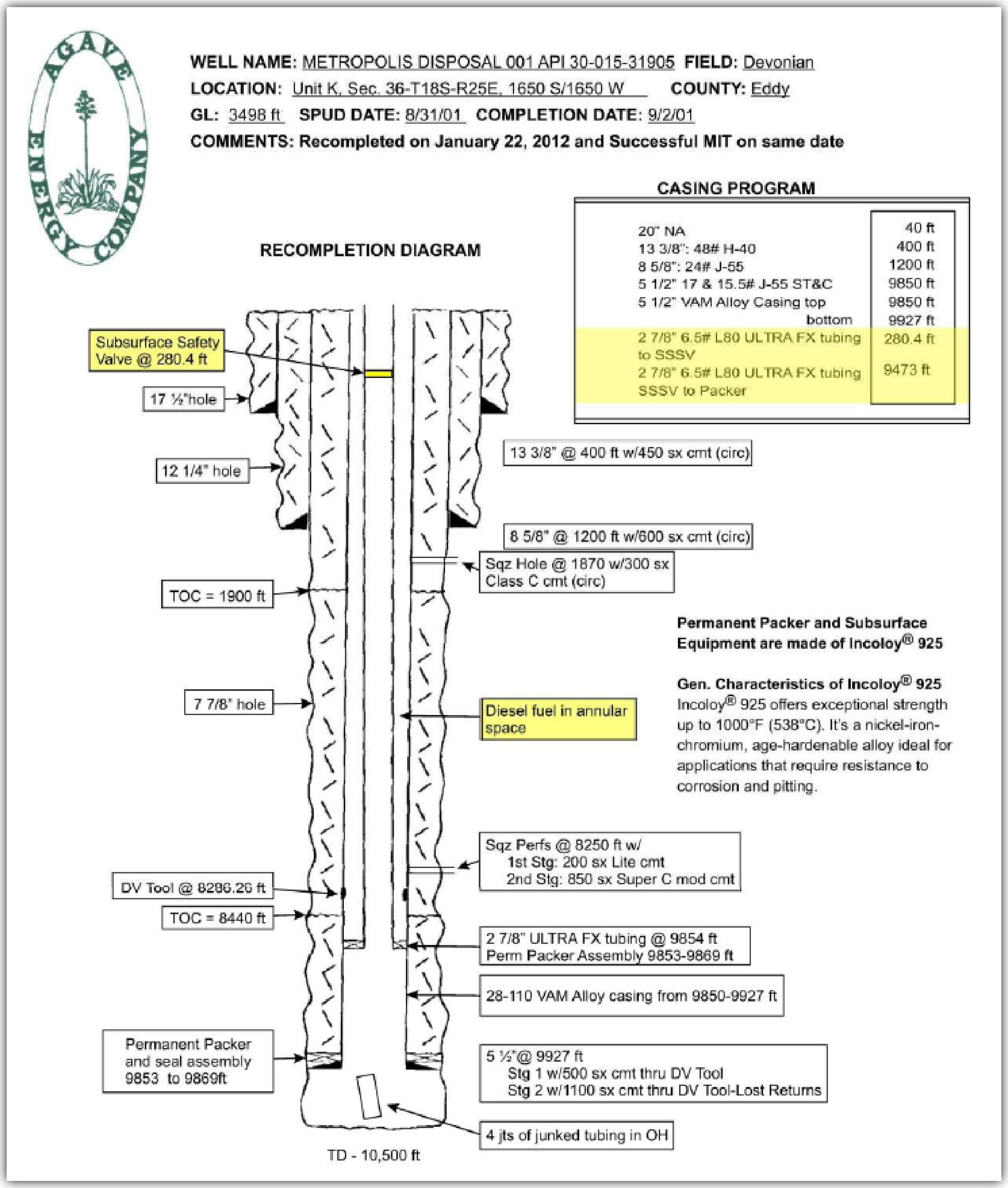


Figure Appendix 1-1: Design and well components for Metropolis AGI #1 well following recompletion and MIT testing on January 22, 2012. Modifications due to recompletion are highlighted in yellow.

Appendix 2 - Referenced Regulations

U.S. Code > Title 26. INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1. NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits > Section 45Q - Credit for carbon oxide sequestration

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS

19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES
19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 - Oil and Gas Wells within a 1-mile Radius of the Metropolis Well

Wells have been color coded according to the production zone in which they were completed: fushia for Atoka-Morrow, and blue for Devonian, remaining wells are completed in the SA-Yeso-Glorieta.

API	Well_Name	Well_Type	Well Status	PLSS_Locat	Latitude	Longitude	Trajectory	MD__ft_	TVD__ft_	5x5 Risk: Probability	5x5 Risk Impact	Total Risk Rating
30-015-00107	PRE-ONGARD WELL #001	Oil	Plugged (site released)	36-18S-25E	32.7028	-104.4449	No Data	0	0	2	2	4
30-015-00108	PRE-ONGARD WELL #002	Oil	Plugged (site released)	36-18S-25E	32.6991	-104.432	No Data	0	0	1	1	1
30-015-10561	PRE-ONGARD WELL #001	Oil	Plugged (site released)	36-18S-25E	32.7	-104.4363	No Data	0	0	1	1	1
30-015-10828	STATE AU #001	Oil	Plugged (site released)	36-18S-25E	32.7108	-104.4458	V	1834	1834	1	1	1
30-015-23292	LAKEWOOD SWD #003	Salt Water Disposal	Plugged (site released)	01-19S-25E	32.6916	-104.4443	V	9362	9362	2	2	4
30-015-23701	RIO PENASCO JX COM #002	Gas	Active	35-18S-25E	32.7019	-104.4492	V	9300	9300	2	2	4
30-015-39781	PINTO 36 STATE COM #001H	Oil	Active	36-18S-25E	32.6977	-104.4458	No Data	6938	2323	1	1	1
30-015-39782	PINTO 36 STATE COM #003H	Oil	Active	36-18S-25E	32.7113	-104.4371	No Data	6867	2441	1	1	1
30-015-39969	PINTO 36 STATE COM #002H	Oil	Active	36-18S-25E	32.6977	-104.4416	No Data	7028	2340	1	1	1
30-015-39970	PINTO 36 STATE COM #005H	Oil	Active	36-18S-25E	32.6977	-104.4437	No Data	7234	2600	1	1	1
30-015-39971	PINTO 36 STATE COM #006H	Oil	Active	36-18S-25E	32.6977	-104.4398	H	7203	2568	1	1	1
30-015-39973	PINTO 36 STATE COM #007H	Oil	Active	36-18S-25E	32.6977	-104.4354	H	7425	2580	1	1	1
30-015-40058	PINTO 36 STATE COM #004H	Oil	Active	36-18S-25E	32.6977	-104.4332	No Data	7335	7335	1	1	1
30-015-41667	PINTO 36 STATE COM #008H	Oil	Active	36-18S-25E	32.6977	-104.4309	H	7387	2669	1	1	1
30-015-43399	PINTO 36 STATE COM #027H	Oil	Active	36-18S-25E	32.6998	-104.446	H	8343	3598	1	1	1
30-015-49171	PINTO 36 STATE #060H	Oil	New	36-18S-25E	32.7092	-104.4465	H	0	0	1	1	1
30-015-49172	PINTO 36 STATE #070H	Oil	New	36-18S-25E	32.7087	-104.4465	H	0	0	1	1	1
30-015-49173	PINTO 36 STATE #090H	Oil	New	36-18S-25E	32.7091	-104.4465	H	0	0	1	1	1
30-015-31905	METROPOLIS	AGI	Active	36-18S-25E	32.7018	-104.4417	V	10,500	10,500	2	2	4

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AGI – acid gas injection
AMA – active monitoring area
API – American Petroleum Institute
BHP – bottom hole pressure
BMT – billion metric tonnes
bpd– barrels per day
C1 - methane
C7 – heptane
C7+ - standard heptane plus
cf – cubic feet
CFR – code of federal regulations
cm – centimeter(s)
CH4 – methane
CO2 – carbon dioxide
DCS – distributed control system
DST – drill stem test(ing)
EOS – equation of state
EPA – US Environmental Protection Agency
ft – foot (feet)
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H2S – hydrogen sulfide
km – kilometer(s)
LGR – local grid refinement
m – meter(s)
mD – millidarcy(ies)
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMBTU – million British thermal units
MSCF – thousand standard cubic feet
MMSCF– million standard cubic feet
MMSCFD– million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
MMMT – million metric tonnes
MMT – thousand metric tonnes
MT -- metric tonne
NIST - National Institute of Standards and Technology
NGL – natural gas liquids
NMOCC – New Mexico Oil Conservation Commission
NMOCD – New Mexico Oil Conservation Division
ppm – parts per million
psi – pounds per square inch

psia – pounds per square inch absolute
psig – pounds per square inch gauge
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
ST – short ton
SWD – salt water (or saltwater) disposal
TAG – treated acid gas
TD – total depth
TSD – Technical Support Document
TVD – true vertical depth
TVDSS – true vertical depth subsea
UIC – Underground Injection Control
USEPA – U.S. Environmental Protection Agency
USDW – Underground Source of Drinking Water

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR-8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 7 - Subpart RR Equations for Calculating Annual Mass of CO2 Sequestered

RR-1 for Calculating Mass of CO_2 Received through Pipeline Mass Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2},p,r}$$

(Equation RR-1 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

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

p = Quarter of the year.

r = Receiving flow meter.

RR-1 for Calculating Mass of CO_2 Received in Containers by Measuring Mass in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2},p,r}$$

(Equation RR-1 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Containers.

RR-2 for Calculating Mass of CO_2 Received through Pipeline Volumetric Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

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

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

p = Quarter of the year.

r = Receiving flow meter.

RR-2 for Calculating Mass of CO_2 Received in Containers by Measuring Volume in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

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

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Containers.

RR-3 for Summation of Mass of CO_2 Received through Multiple Flow Meters for Pipelines

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$

(Equation RR-3 for Pipelines)

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

RR-4 for Calculating Mass of CO_2 Injected through Mass Flow Meters into Injection Well

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

(Equation RR-4)

where:

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

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

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

p = Quarter of the year.

u = Flow meter.

RR-5 for Calculating Mass of CO_2 Injected through Volumetric Flow Meters into Injection Well

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

RR-6 for Summation of Mass of CO_2 Injected into Multiple Wells

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

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

u = Flow meter.

RR-7 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Mass Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * C_{CO_{2,p,w}} \qquad \text{(Equation RR-7)}$$

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

$C_{CO2,p,w}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

RR-8 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Volumetric Flow Meters

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

(Equation RR-8)

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas volumetric flow rate measurement for separator w in quarter p (standard cubic meters).

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

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

p = Quarter of the year.

w = Separator.

RR-9 for Summation of Mass of CO_2 Produced / Recycled through Multiple Gas Liquid Separators

$$CO_{2P} = (1+X) * \sum_{w=1}^{W} CO_{2,w}$$

(Equation RR-9)

where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) though all separators in the reporting year.

X = Entrained CO_2 in produced oil or other liquid divided by the CO_2 separated through all separators in the reporting year (wt. percent CO_2 expressed as a decimal fraction).

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

w = Separator.

RR-10 for Calculating Annual Mass of CO_2 Emitted by Surface Leakage

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

RR-11 for Calculating Annual Mass of CO_2 Sequestered for Operators Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Equation RR-11)}$$

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

RR-12 for Calculating Annual Mass of CO_2 Sequestered for Operators NOT Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{(Equation RR-12)}$$

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

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

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

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

Part B – Maljamar Gas Plant

1. Introduction

Frontier Field Services, LLC (Frontier) operates the Maljamar Gas Plant (MGP) located in Lea County, New Mexico. The Plant and associated facilities are located approximately three miles south of the town of Maljamar, NM in a very isolated area **(Figures 1-1, 1-2).** The Maljamar AGI #1 well (API # 30-025-40420) is located 130 ft FSL, 1,813 ft FEL in Section 21, Township 17 South, Range 32 East, Lea County, NM. It is a vertical well, completed on property leased by Frontier from the BLM and provides access to the primary injection zone (Wolfcamp Formation). The well was drilled to a final total depth of approximately 10,183 ft **(Figure Appendix 1-1)**. The Maljamar AGI #2 well (API # 30-025-42628) is located 400 ft FSL and 2,100 ft FEL in Section 21, Township 17 South, Range 32 East. This is a deviated well, which is also completed on property leased by Frontier from the BLM and provides access to the primary injection zone (Wolfcamp Formation) **(Figure Appendix 1-2)**. Frontier is currently authorized to inject treated acid gas (TAG) consisting of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) into the Wolfcamp Formation.

Frontier has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40 Code of Federal Regulations (CFR) 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Frontier intends to inject CO_2 for another 30 years.

Part B of this MRV plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the Maljamar Gas Plant and the Maljamar AGI wells project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the strategy for detecting and quantifying CO_2 surface leakage from the identified potential sources of leakage.

Section7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV plan as required by 40 CFR 98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 11 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV plan.

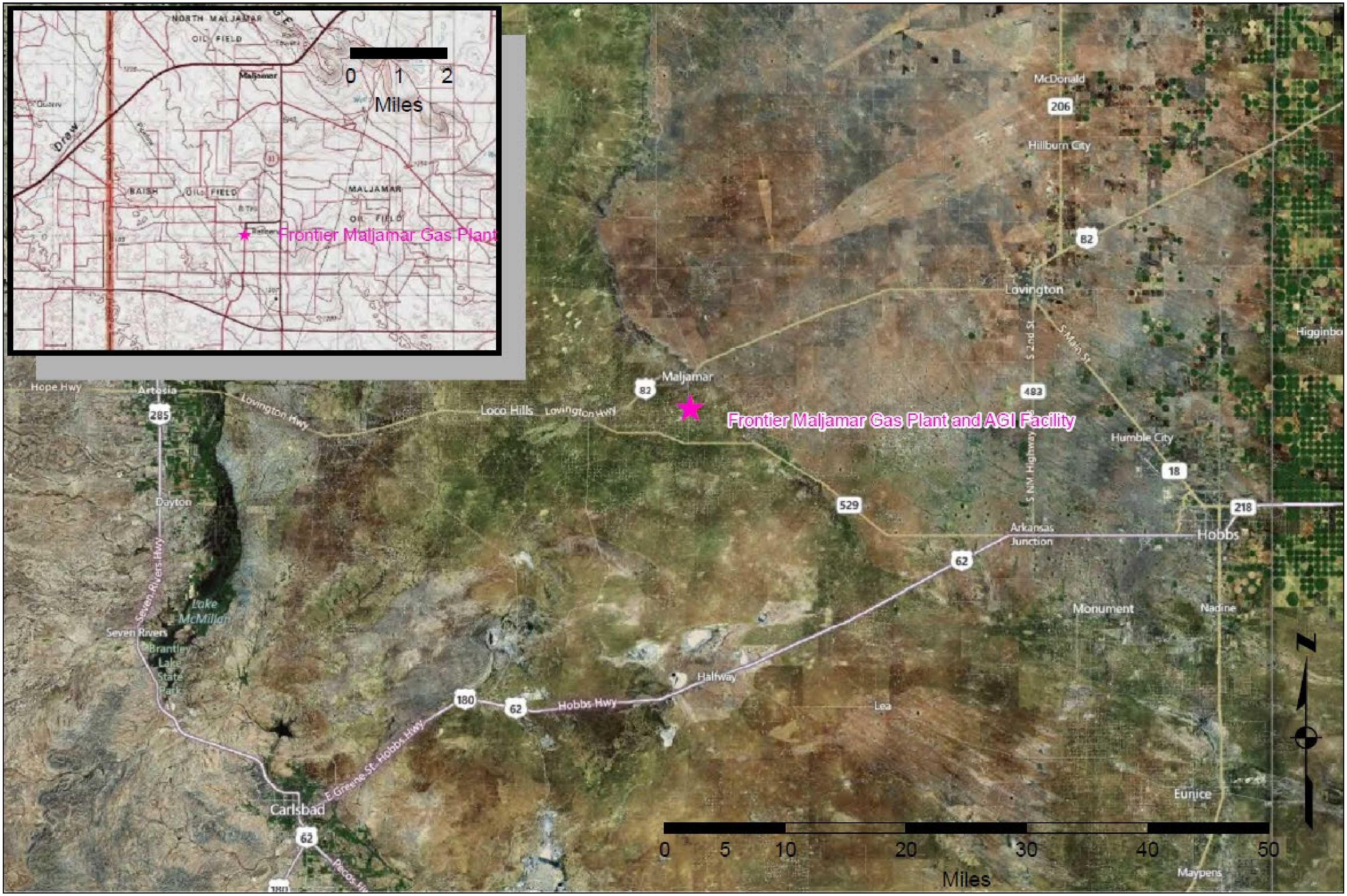


Figure 1-1: Location of the Frontier Maljamar Gas Plant and AGI Facility

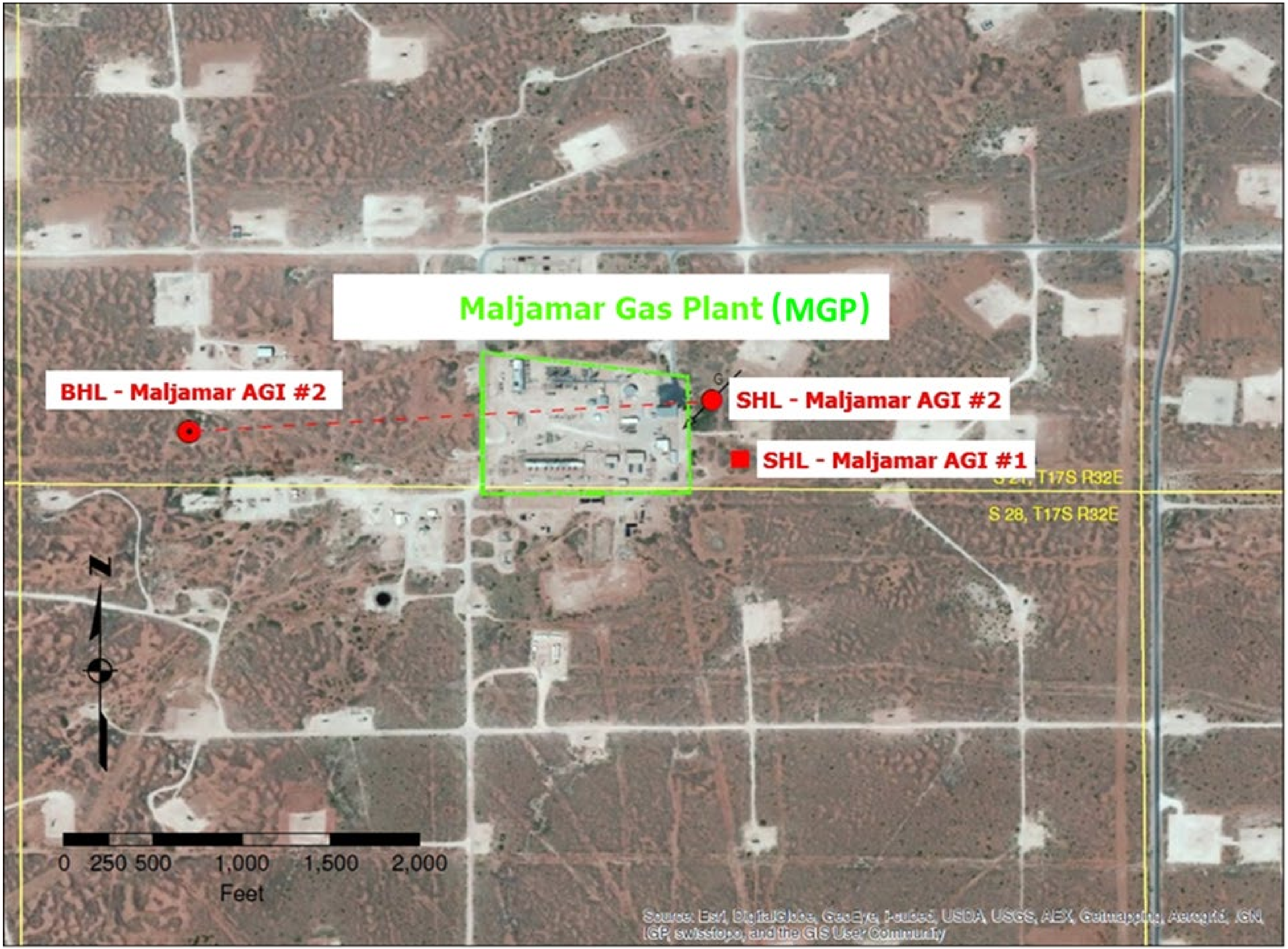


Figure 1-2: *Location of the Maljamar Gas Plant and Maljamar AGI #1 and #2 Wells*

2. Maljamar Gas Plant Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID for Daggers Draw is **1008432**. Once the MRV plan is approved, Frontier will seek a new ID under the merged facility.

2.2 UIC injection well identification number

Part B of the MRV plan is for the Maljamar Gas Plant and the associated Maljamar AGI #1 and #2 wells (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC Permit Class

The New Mexico Oil Conservation Division (NMOCD) has issued an Underground Injection Control (UIC) Class II acid gas injection (AGI) permit for Maljamar AGI #1 (under Order R-13443-A) and Maljamar AGI #2 (under Order R-13443-B) under its State Rule 19.15.26 NMAC (see Appendix 2). All oil- and gas-related wells in the vicinity of the Maljamar wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3. Maljamar Gas Plant/Maljamar AGI Wells Project Description

The following project description has been developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT).

3.1 General Geologic Setting / Surficial Geology

The area surrounding the Maljamar Gas Plant and the Maljamar wells lies on a large plain (Querecho Plains) covered by Holocene to middle Pleistocene interbedded reddish brown eolian and pediment-slope deposits. A hard caliche surface and calcareous silts underly dune sands and probably represent playa deposits. The area is west of the Mescalero Ridge and east of the Pecos River.

3.2 Bedrock Geology

3.2.1 Basin Development

The Maljamar AGI wells are located on the edge of the Northwest Shelf of the Permian Basin (**Figure 3.2.1**). Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2.2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits within (**Figure 3.2.3**) a shallow marine sea that covered most of North America and Greenland. With continued down warping or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1,000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers in parentheses after the formation name indicate the range in thickness for that unit. Tectonic activity near the end of Ellenberger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones, and shales of, first, the Simpson Group (0 – 1,000 ft) and then the Montoya Formation (0 – 600 ft). This is the time when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch **(Figure 3.2.4A**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within the shoreline sandstones (Broadhead, 2017). Another subaerial exposure and karstification event followed the deposition of the Simpson

Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). Like the Ellenburger and Simpson carbonates, the subaerial exposure event at the end of Montoya deposition resulted in karstification.

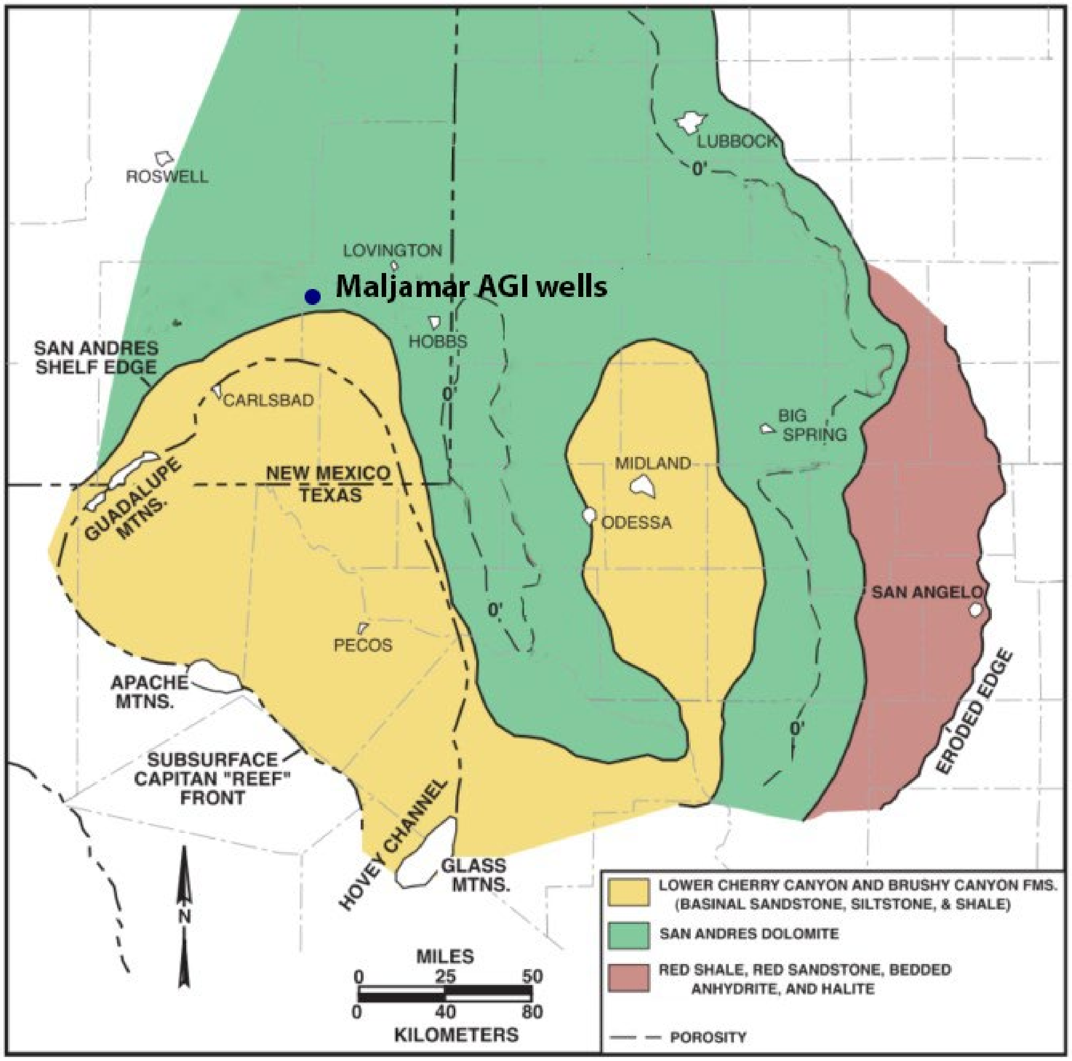


Figure 3.2-1: *Location of the Maljamar AGI wells with respect to Permian physiographic features (modified from Ward et al., 1986; Scholle et al., 2007).*

AGE		CENTRAL BASIN PLATFORM-NORTHWEST SHELF		DELAWARE BASIN	
Cenozoic			Alluvium		Alluvium
Triassic			Chinle Formation		Chinle Formation
			Santa Rosa Sandstone		Santa Rosa Sandstone
Permian	Lopingian (Ochoan)		Dewey Lake Formation		Dewey Lake Formation
			Rustler Formation		Rustler Formation
			Salado Formation		Salado Formation
					Castile Formation
	Guadalupian	Artesia Group	Tansill Formation	Delaware Mountain Group	Lamar Limestone
			Yates Formation		Bell Canyon Formation
			Seven Rivers Formation		
			Queen Formation		Cherry Canyon Formation
			Grayburg Formation		
			San Andres Formation		Brushy Canyon Formation
	Cisuralian (Leonardian)		Glorieta Formation		
		Yeso	Paddock Mbr.		Bone Spring Formation
			Blinebry Mbr		
			Tubb Sandstone Mbr.		
			Drinkard Mbr.		
	Wolfcampian		Abo Formation		
			Hueco ("Wolfcamp") Fm.		Hueco ("Wolfcamp") Fm.
Pennsylvanian	Virgilian		Cisco Formation		Cisco
	Missourian		Canyon Formation		Canyon
	Des Moinesian		Strawn Formation		Strawn
	Atokan		Atoka Formation		Atoka
	Morrowan		Morrow Formation		Morrow
Mississippian	*Upper*		Barnett Shale		Barnett Shale
	Lower		"Mississippian limestone"		"Mississippian limestone"
Devonian	*Upper*		Woodford Shale		Woodford Shale
	Middle				
	Lower		Thirtyone Formation		Thirtyone Formation
Silurian	*Upper*		Wristen Group		Wristen Group
	Middle				
	Lower		Fusselman Formation		Fusselman Formation
Ordovician	*Upper*		Montoya Formation		Montoya Formation
	Middle		Simpson Group		Simpson Group
	Lower		Ellenburger Formation		Ellenburger Formation
Cambrian			Bliss Ss.		Bliss Ss.
Precambrian			Miscellaneous igneous, metamorphic, volcanic rocks		Miscellaneous igneous, metamorphic, volcanic rocks

Figure 3.2-2: *General stratigraphic chart for southeastern New Mexico (modified from Broadhead, 2017).*

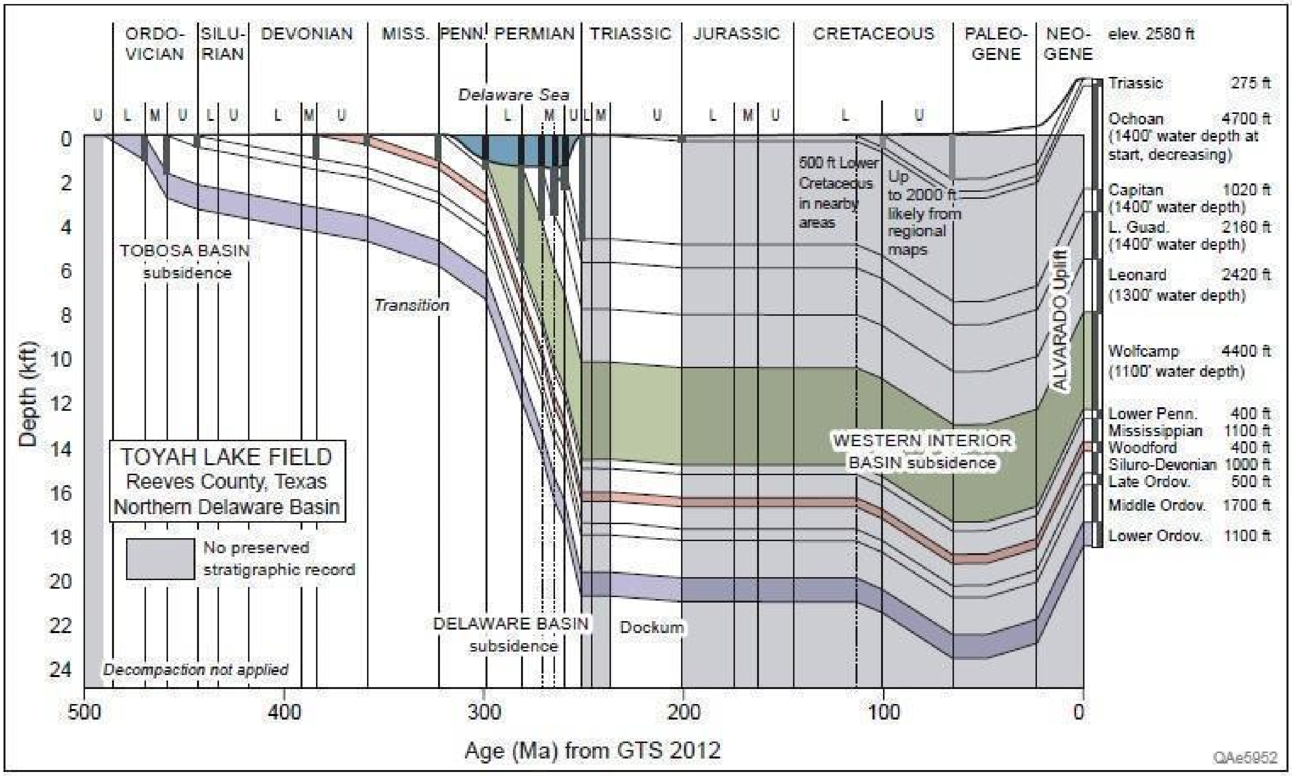


Figure 3.2-3: *A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019).*

Siluro-Devonian formations consist of the Upper Ordovician to Lower Silurian Fusselman Formation (0 – 1,500 ft), the Upper Silurian to Lower Devonian Wristen Group (0 – 1,400 ft), and the Lower Devonian Thirtyone Formation (0 – 250 ft). The Fusselman was deposited on a shallow-marine platform and consists of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with another unconformity at top of the Fusselman Formation as well as intraformational exposure events created brecciated fabrics, widespread dolomitization, and solution-enlarged pores and fractures (Broadhead, 2017). The Wristen and Thirtyone units appear to be conformable. The Wristen Group consists of tidal to high-energy platform margin carbonate deposits of dolostones, limestones, and cherts with minor siliciclastics (Broadhead, 2017; Ruppel, 2020a). The Thirtyone Formation is present in the southeastern corner of New Mexico and appears to be either removed by erosion or not deposited (**Figure 3.2-5**) elsewhere in New Mexico. It is a shelfal carbonate with varying amounts of chert nodules and represents the last carbonate deposition in the area during Devonian time (Ruppel et al., 2020a).

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020c). The Woodford sediments represent stratified deeper marine basinal deposits. The organic content of this unit is a function of the oxygenation levels within the bottom waters – the more anoxic the waters, the higher the organic content.

The Mississippian strata within the northern Delaware Basin consists of an unnamed carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoir's limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) uncomfortably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale). Within part of the area of the Maljamar wells, there is at least one tongue of Chesterian limestone within the Barnett Shale and numerous sandstone/siltstone interbeds within the mudstone deposits.

Pennsylvanian sedimentation in the area is influenced by glacio-eustatic sea-level cycles producing numerous shallowing upward cycles within the rock record; the intensity and number of cycles increase upward in the Pennsylvanian section. The cycles normally start with a sea-level rise that drowns the platform and deposits marine mudstones. As sea-level starts to fall, the platform becomes shallower and deposition switches to marine carbonates and coastal siliciclastic sediments. Finally, as the seas withdraw from the area, the platform is exposed causing subaerial diagenesis and the deposition of terrestrial mudstones, siltstones, and sandstones in alluvial fan to fluvial deposits. This is followed by the next cycle of sea-level rise and drowning of the platform.

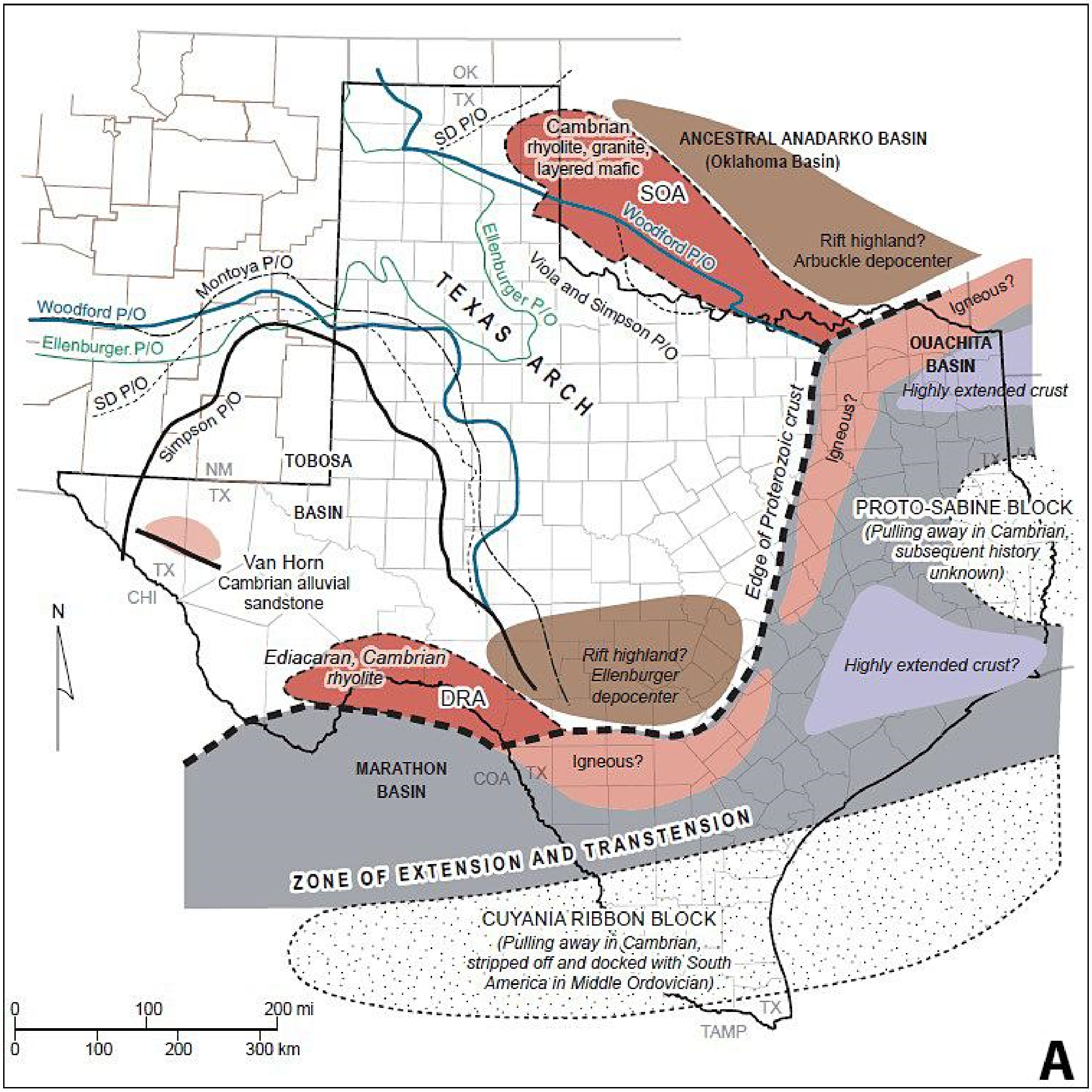
Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250-1,000 ft) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

The Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales. Within the Maljamar area, sandstone horizons occur.

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins

(Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP; **Figures 3.2-4B, 3.2-6, 3.2-7**). The Early Permian and older rocks have been fractured, faulted, and folded during this period of deformation and basin formation resulting in the deposition of the Wolfcamp and truncation of Wolfcampian and older units (**Figure 3.2-6**).



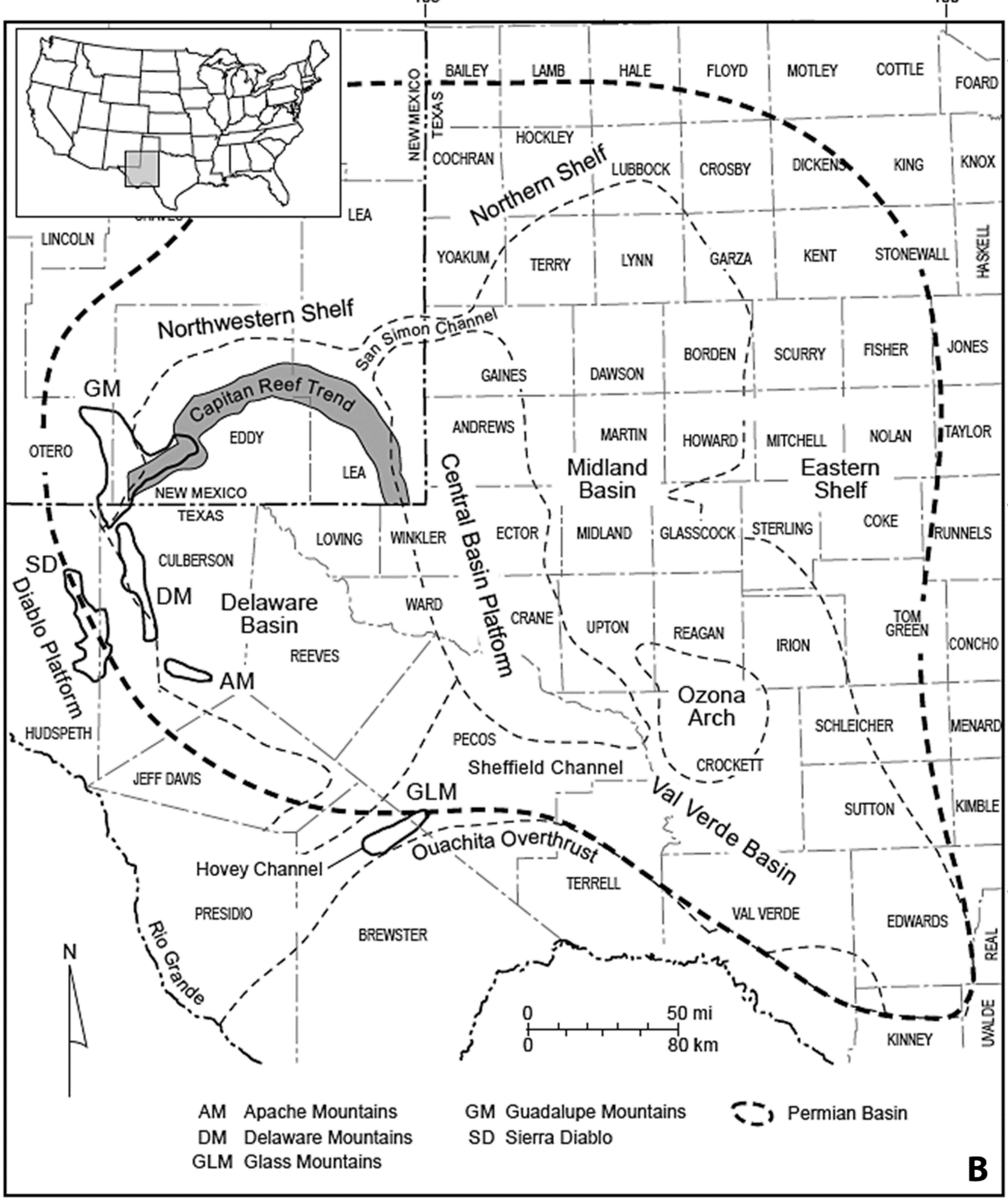


Figure 3.2-4: *Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

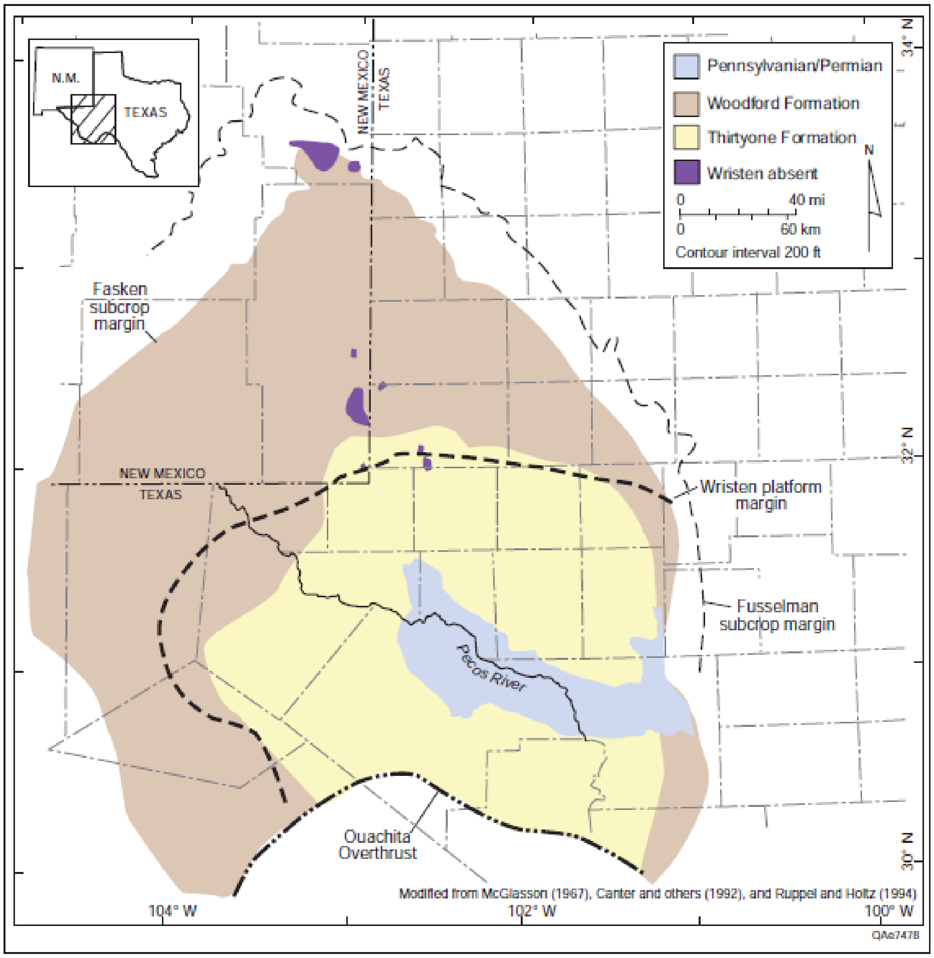


Figure 3.2-5: *A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

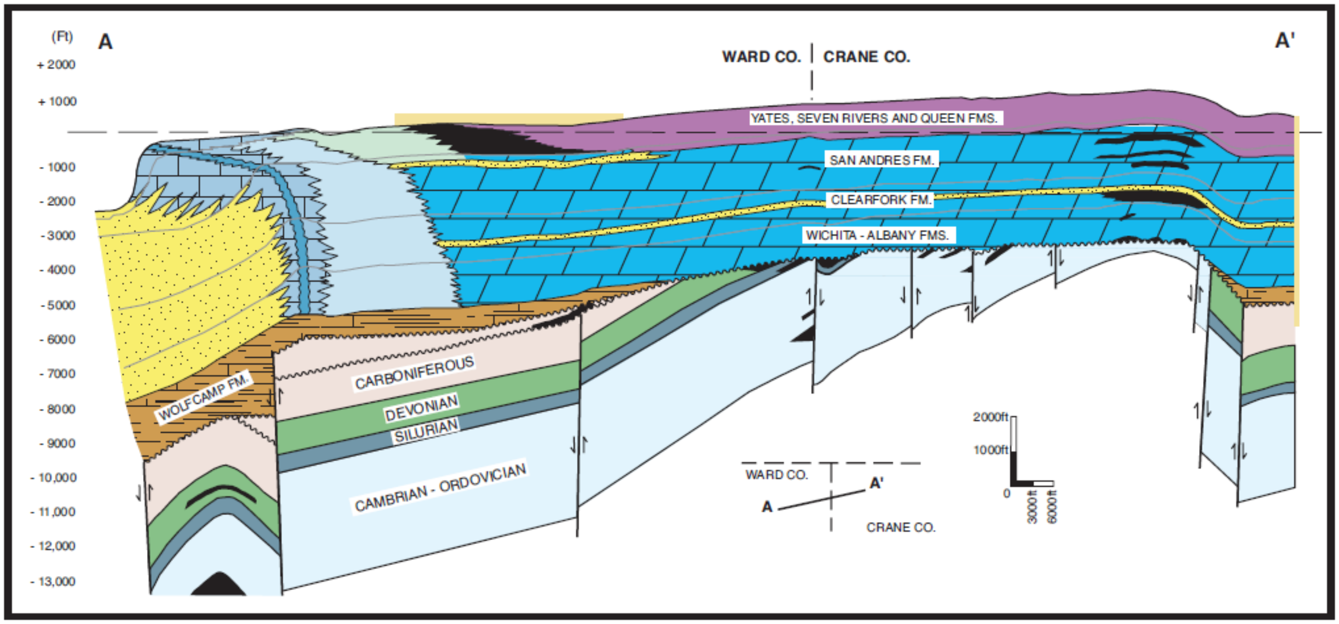


Figure 3.2-6: Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

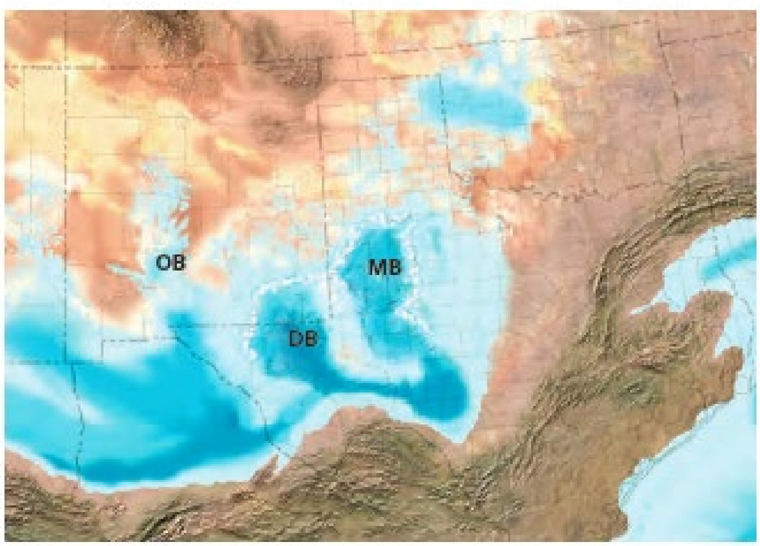


Figure 3.2-7: Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).

The Wolfcampian Hueco Group is informally known as the Wolfcamp and this terminology will be used in this document. The Wolfcamp Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate and sandstone shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020).

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Wolfcamp deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a "carbonate factory" on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1977; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100's feet to feet). The Maljamar AoR straddles the northern shelf/basin margin during Permian sedimentation. The following discussion covers the stratigraphy for these two different settings.

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along NW Shelf margin and shallow-marine carbonates to the northwest of the margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2020b). Sediments basin ward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin, which is roughly in the same area, just south of Dagger Draw. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2020b). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation. It is a key marker bed in the region, both on the surface and subsurface. Within the basin, it is equivalent to the Lower Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex at the end carbonate deposition within the Delaware Basin. The individual highstand carbonate units are separated by lowstand sandstones/siltstones that move out over the exposed shelf. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. Within the Delaware Basin, it is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the

Artesia Group is equivalent to the upper Cherry and Bell Canyon formations. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the time when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the NW Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile Formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal "freshening" of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represent the last Permian marine deposits in the Delaware Basin. The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350 ft, Nance, 2020), ending Permian deposition in the area.

Beginning early in the Triassic, uplift and the breakup of Pangea resulted in another regional unconformity and the deposition of non-marine, alluvial Triassic sediments (Santa Rosa Sandstone and Chinle Formation). They are unconformably overlain by Cenozoic alluvium (which is present at the surface). Cenozoic Basin and Range tectonics resulted in the current configuration of the region and reactivated numerous Paleozoic faults.

The unit thicknesses mentioned in this discussion are from Broadhead (2017) unless otherwise indicated.

3.2.2 Stratigraphy

Figure 3.2-2 is a stratigraphic column showing the formations that underlie the Maljamar Gas Plant and the Maljamar AGI wells. Section 3.2.1 provides a discussion of the geologic evolution of the area from Precambrian to Cenozoic times.

The sequence of Virgilian through Leonardian strata is described below. These rock units overlie, contain, and underlie the injection zone for the Maljamar AGI wells.

Virgilian Rocks. Pennsylvanian Virgilian-age deposits are represented by the Cisco Formation **(Figures 3.2-2, 3.2-8**). The Ancestral Rocky Mountain deformation and the Ouachita Orogeny, starting in Late Pennsylvanian (Missourian) and going through Wolfcampian time, resulted in the formation of the Delaware and Midland basins. This produced changes in the shelf to basin margin throughout Pennsylvanian time in the Maljamar area. The Cisco Formation consists of interbedded carbonates, sandstones, and shales. Deeper marine sediments were dominated by organic-rich shales, the shelf edge was dominated by fusulinid-rich Syringopora-phylloid algal bioherms and carbonate grainstone shoals, and the platform shelf, which shallows northward, progressively changing from marine backreef and lagoonal deposits to subtidal deposits with increasing amounts of sandstone that was sourced from the Pedernal Uplift (Scholle et al., 2007; Broadhead, 2017). The Cisco Formation is one of several highly productive zones in the Delaware Basin. The nearby Dagger Draw field has produced more than 70 billion barrels of oil (2019). Oil production with the Dagger Draw and Tatum field (approximately 30-40 mi northeast of Maljamar area) is restricted mostly to the platform-edge carbonate bioherms and, to a lesser extent, the high-energy carbonate grainstones. The bioherms have seen variable amounts of dolomitization, dissolution, and secondary porosity development. Productive zones typically have porosities that range from 7 – 12% (Broadhead, 2017). The interbedded shales, interior platform carbonates and sandstones have minimal porosity.

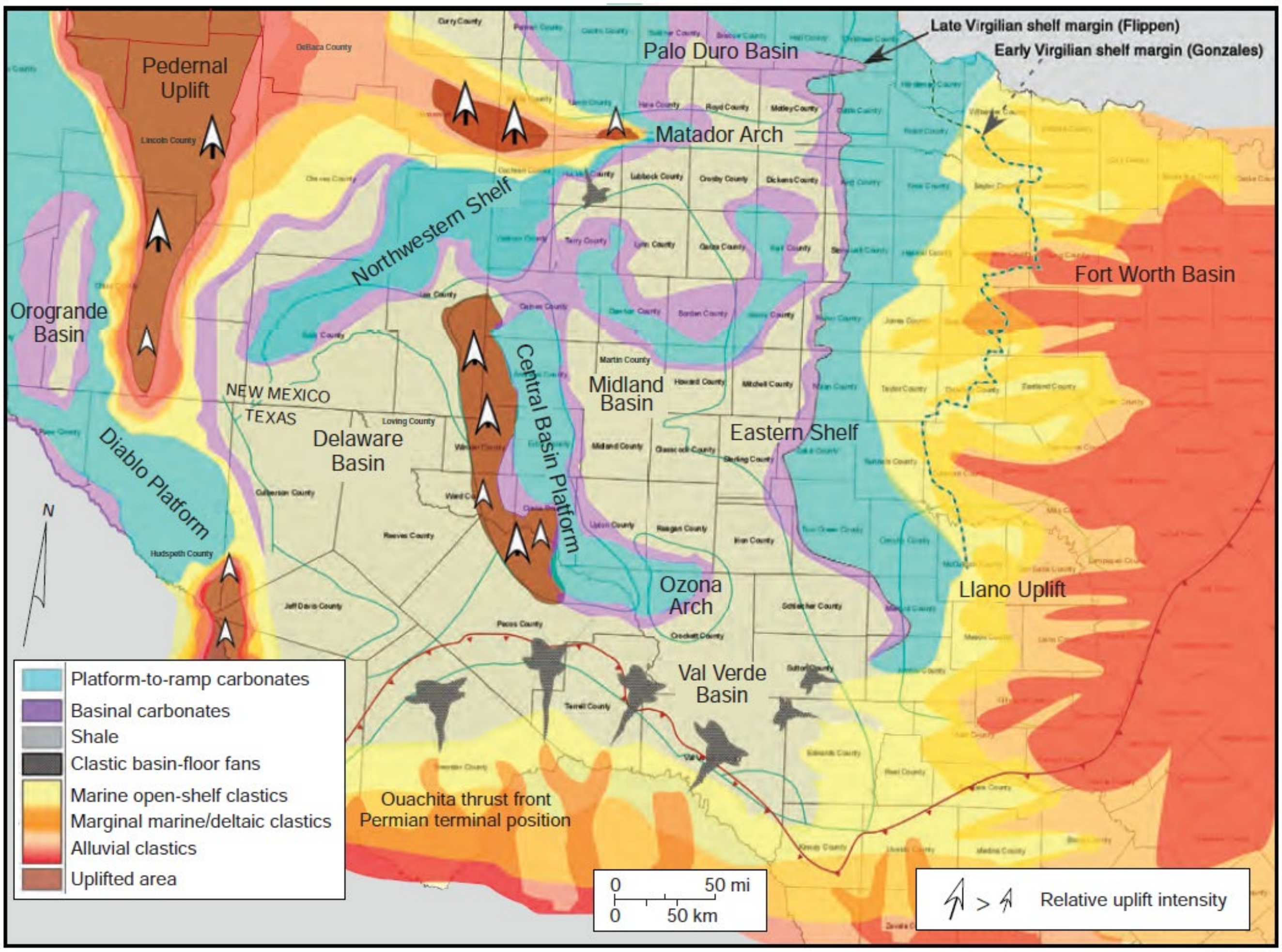


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Figure 3.2-8: *Paleodepositional environments within the Permian Basin area during Virgilian deposition (from Wright, 2020).*

Wolfcampian Rocks. Wolfcampian rocks in the Delaware Basin area have been assigned to the Hueco Group, but they are informally called the “Wolfcamp”. Like the Virgilian sediments, the Wolfcamp units in the Maljamar area were deposited on shelf margin during a time of high-frequency, high-amplitude sea-level fluctuations (Hu et al., 2020). On the shelf, Wolfcamp sediments range up to 1,000 ft thick, but in the deeper basin, sediments in the Maljamar area are over 2,500 ft thick. Like the Cisco Formation, the lower Wolfcamp deposits consist of marine shelf to basin facies. The shelf deposits range from low-energy lagoonal/subtidal mudstones/wackestones to high-energy packstone/grainstone shoals (**Figure 3.2-9**). Along the shelf margin, like the Cisco Formation, phylloid algal bioherms (boundstones) rim the shelf margin. On many of the bioherms, oolitic grainstones occur as caps and were deposited in a very high-energy environment (Scholle et al., 2007). On the foreslope and proximal basin margin, shelf detritus makes up most of the sediments. In more distal areas within the basin, carbonate- and radiolarian-rich mudstones and shales were deposited.

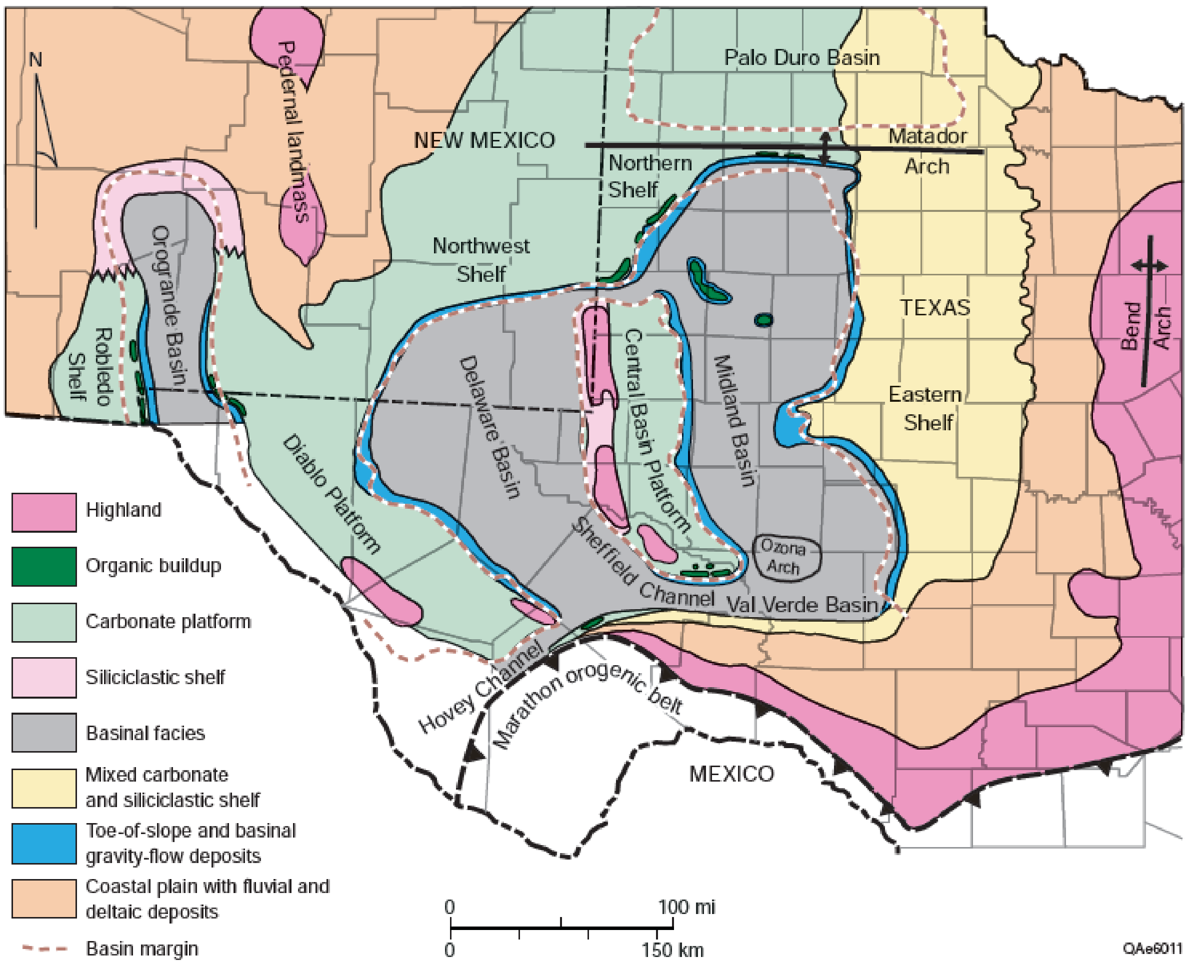

Figure 3.2-9: *Paleodepositional environments within the Permian Basin area during late Wolfcampian deposition (from Hu et al., 2020).*

Wolfcamp reservoirs have porosities averaging approximately 7 to 10% and occur mainly in the reef margin facies (Broadhead, 2017). During the Ouachita Orogeny, faults and compression produced uplift in the east forming the CBP and folding resulting in the formation of the NW Shelf and the Delaware Basin. This deformation resulted in the erosion on the CBP of lower Paleozoic units (down to the Ordovician strata). Within the basin, Wolfcamp sediments were partially eroded on fault block and fold highs and redeposited in topographic lows. By the end of Wolfcamp sedimentation, most of the faulting had ceased, but down warping of the basins continued.

Leonardian/Cisuralian Rocks. The Maljamar area straddles the shelf break, and the Leonardian strata consists of the Abo Formation on the shelf and the Bone Spring Formation within the Delaware Basin. Both the Abo and Bone Springs formations are prolific producers within the Delaware basin area. The Abo Formation consists of dolomitized fringing barrier reef boundstones at the shelf break and dolomitized backreef deposits that grade into dolomitized and anhydrite-bearing tidal flat and supratidal deposits to red bed sabkha and fluvial/deltaic sandstone and shale deposits to the north (**Figure 3.2-10**). The main Abo reservoirs are in dolomitized reefal facies and have porosity ranging from 5 to 15% (Broadhead, 2017). The fine-grained backreef deposits act as both lateral and vertical seals, produced by changing sea levels and migration of the facies across the shelf.

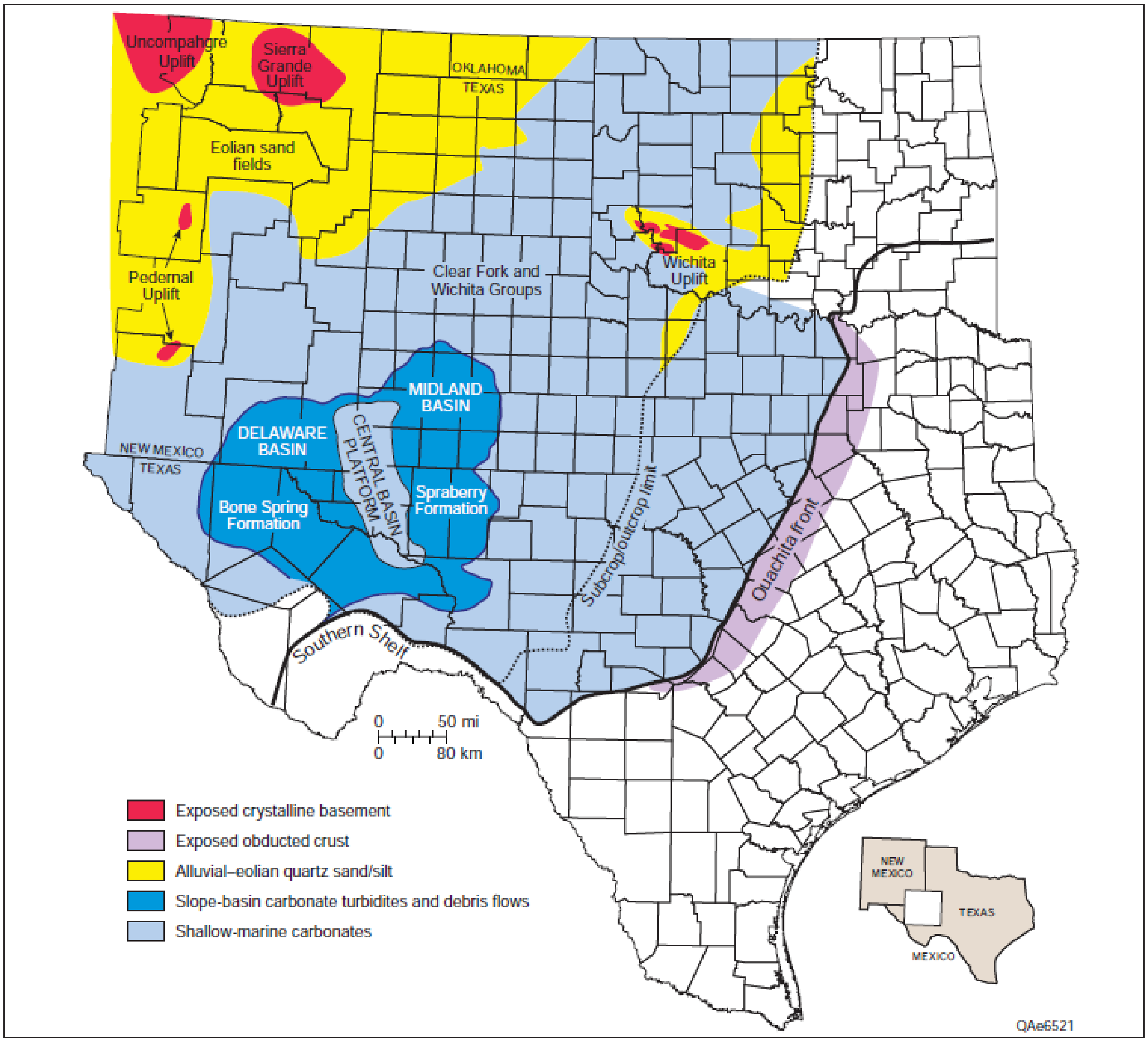

Figure 3.2-10: *Paleodepositional environments within the Permian Basin area during Leonardian deposition during sea-level highstands (from Ruppel, 2020b).*

The Bone Spring Formation is equivalent to the Abo and overlying Yeso formations and represents the basin facies in the area. The Bone Spring consists of carbonate debris derived from the shelf as rockfalls, debris flows, and submarine fans during periods of widespread carbonate deposition during sea-level highstands. Sandstone turbidites and submarine fan complexes move sandstones out into the basin during sea-level lowstands, when the carbonate factory has been shut down up on the shelf and siliciclastic sands move across the shelf. Bone Spring reservoirs are dominated by turbidite sandstones with porosities averaging between 7 and 20% (Broadhead, 2017). A few dolomitized carbonate debris flows have also been found.

3.2.3 Faulting

In this immediate area of the Maljamar facility, faulting is primarily confined to the lower Paleozoic section (Baumgardner et al., 2016). Faults that have been identified in the area are normal faults associated with Ouachita-related movement. The closest identified fault (Baumgardner et al., 2016) lies approximately 3.5 miles northeast of the Maljamar site (**Figure 3.2-11**).

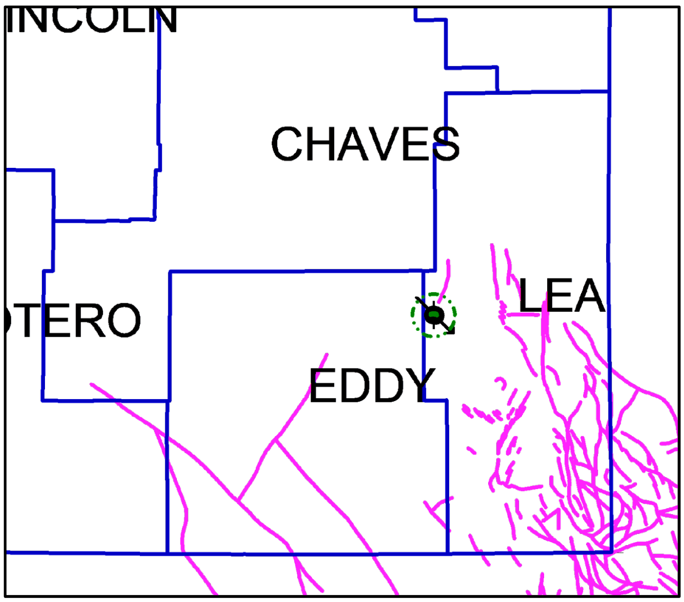

Figure 3.2-11: *Map of the basement faults that were reactivated during Pennsylvanian/lower Permian tectonics (from Baumgardner et al., 2016). The green circle is a 5-mile circle around the Maljamar facility.*

3.3 Lithologic and Reservoir Characteristics

The plant is located on the edge of the shelf-basin topographic break for the Northwest Shelf to the Delaware Basin during lower Permian deposition (**Figure 3.2-9**). Within the Wolfcamp strata, the injection horizons are carbonate horizons made up of tabular foraminiferal-phylloid algal mounds and associated debris beds. These beds contain up to 20% percent porosity. Because of its location on the shelf edge (controlled by faulting), the location and size of the mounds are impacted by sea-level fluctuations that dominate most of Pennsylvanian and Permian deposition. Foraminiferal-algal mounds build up during sea-level highstands, and during lowstands, these mounds are reworked and redeposited in debris fans surrounding the mounds and into the basin (**Figure 3.3-1**). The size of the mounds is controlled by the accommodation space created during sea-level highstands. During lowstands, the mounds become exposed, undergoing both physical and chemical diagenesis and forming debris beds around the mounds. Shelf deposits, including lagoonal mudstones, encase the algal mounds in lower porosity and permeability, carbonate mudstones/wackestones.

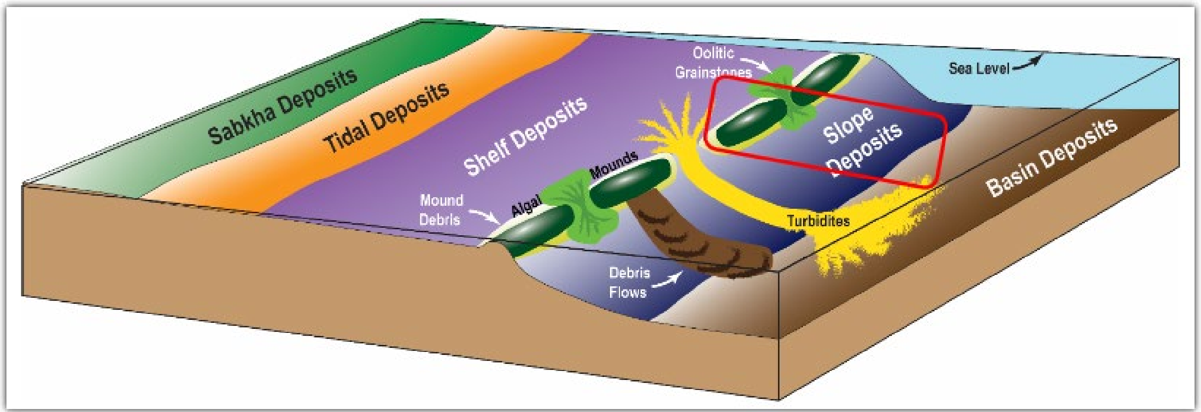

Figure 3.3-1: A depositional model for the Wolfcampian sediments in the Delaware Basin. The red box is the range of depositional environments found at the Maljamar facility.

These types of reservoirs are the main hydrocarbon plays for the shelf carbonate Wolfcamp strata. Examples of these types of hydrocarbon reservoirs (**Figure 3.3-2**), include the nearby Anderson Ranch, Anderson Ranch North, Kemnitz West, and Kemnitz reservoirs.

Using the formation tops from approximately 110 wells, Subsea structure contour maps were constructed for the tops of the Wolfcamp, Cisco (middle Wolfcamp) and Canyon (lower Wolfcamp) formations (Figure 3.3-3 to 3.3-5). The maps show that the Maljamar facility is situated on the Wolfcamp shelf edge. Only one fault (based on the maps of Baumgardner et al., 2016) is visible within the 10-mile-wide circle.

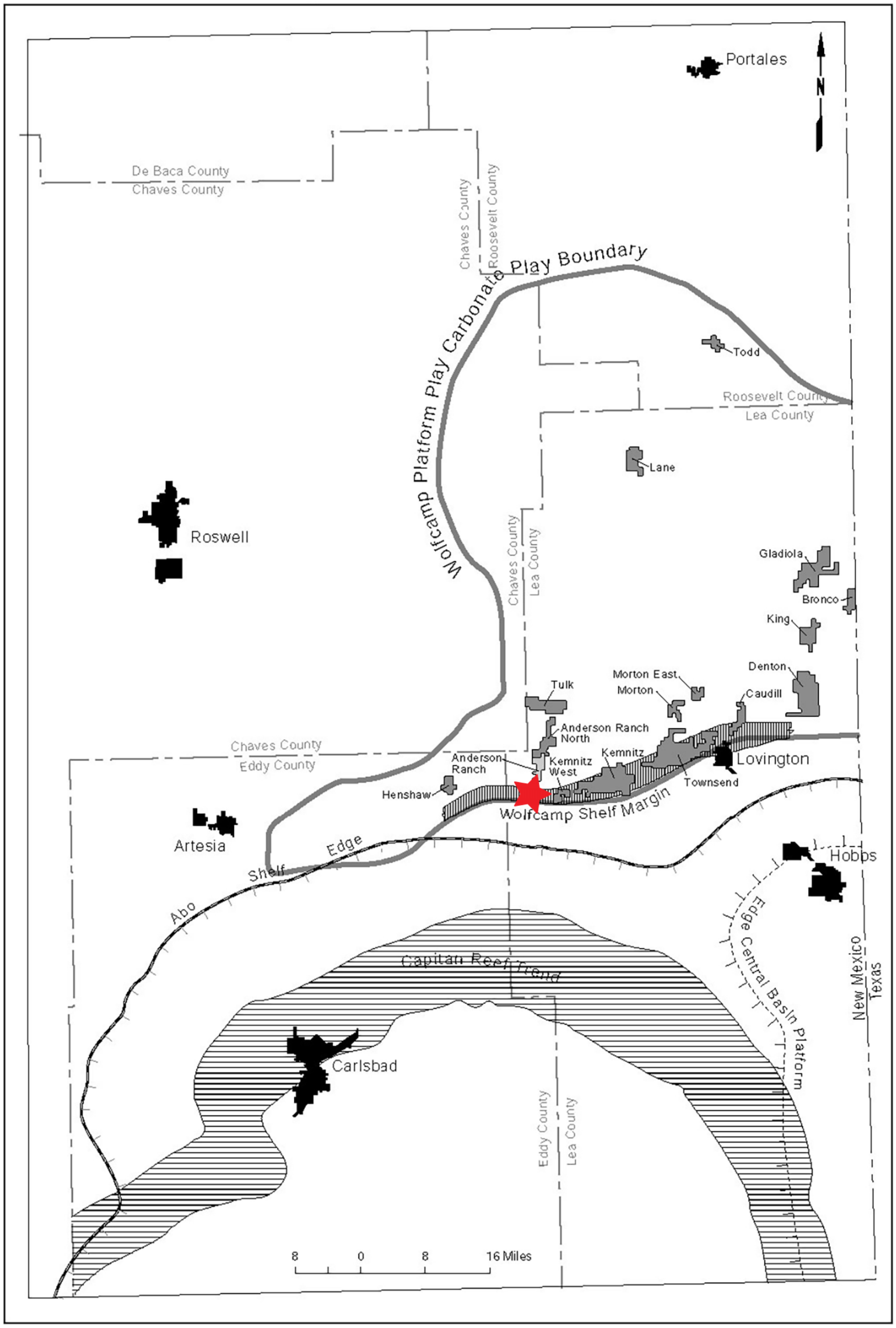

Figure 3.3-2: *Oil and gas fields in Wolfcamp shelf-edge carbonates (Broadhead et al., 2004. The red star indicates the location of the Maljamar facility.*

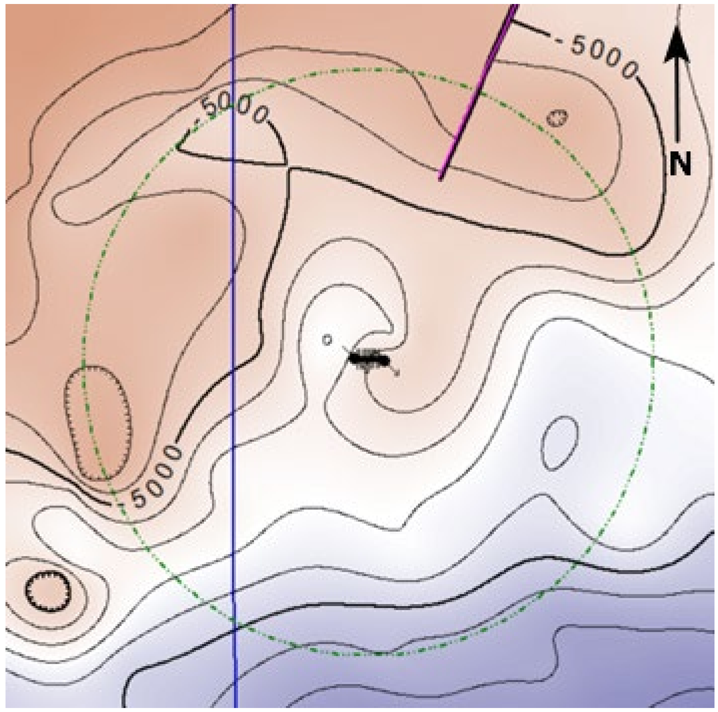

Figure 3.3-3: *Structure map on top of Wolfcamp strata. The green circle encompasses a 5-mile radius from the Maljamar wells. The contour interval = 200 ft.*

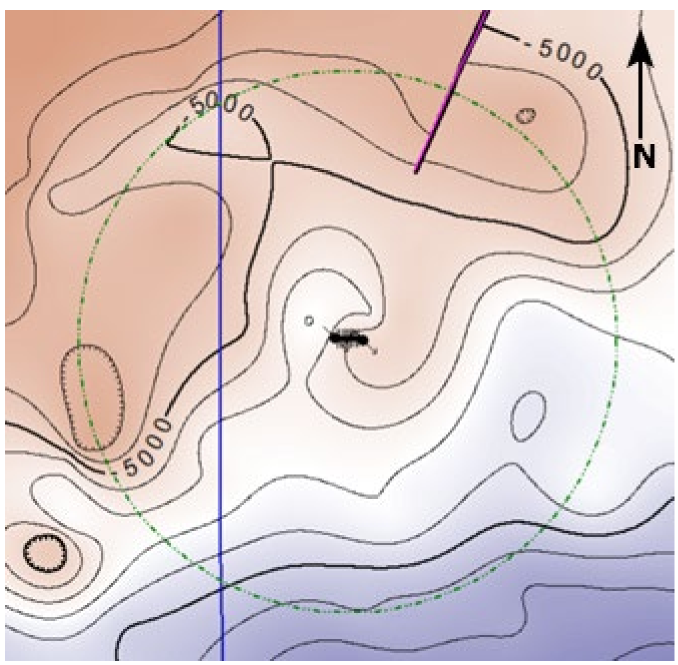

Figure 3.3-4: *Structure map on top of the middle Wolfcamp strata (Cisco Formation). The green circle encompasses a 5-mile radius from the Maljamar wells. The contour interval = 200 ft.*

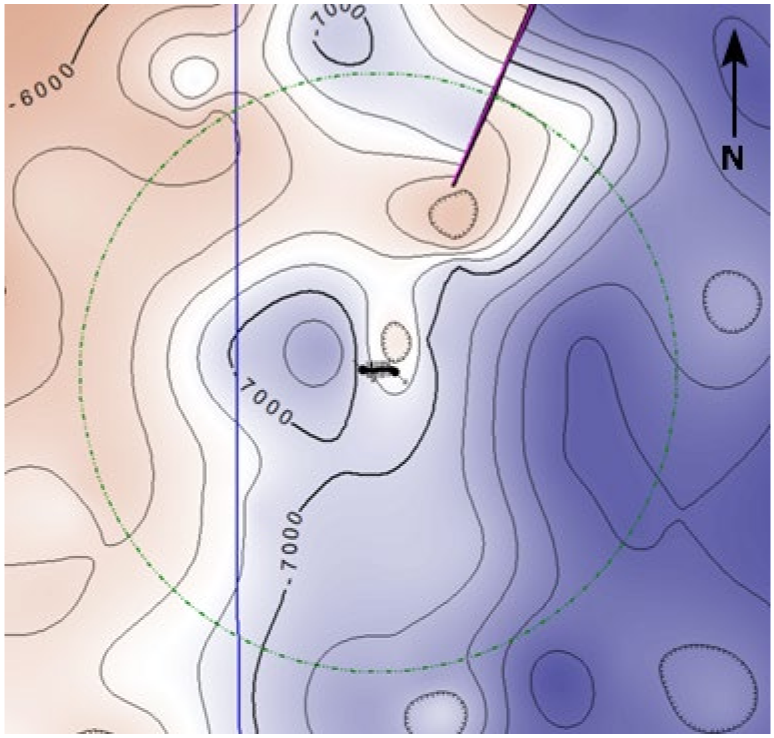

Figure 3.3-5: *Structure map on top of the lower Wolfcamp strata (Canyon Formation). The green circle encompasses a 5-mile radius from the Maljamar wells. The contour interval = 200 ft.*

This map reveals a 5-degree dip to the southeast, with no visible faults or offsets that might influence fluid migration, suggesting that injected fluid would spread radially from the point of injection with a small elliptical component to the northwest. This interpretation is supported by cross-sections of the overlying stratigraphy that reveal relatively horizontal contacts between the units (**Figures 3.3-3 to 3.3-7**). Local heterogeneities in permeability and porosity will exercise significant control over fluid migration and the overall three-dimensional shape of the injected gas plume.

Geophysical log analyses include an evaluation of the reservoir rock porosity. **Figure 3.3-8** shows the X-Multipole Array Acoustilog from 8,700 ft to 10,150 ft measured depth (MD) and includes the identified formational boundaries. Porosity ranges from <1 to 13% within the Wolfcamp interval; taken over the entire drilled interval this gives an effective porosity (>8%) of approximately 80-90 ft.

The development of a static model in Petrel Software was also supplemented by porosity and permeability data from investigated rock samples extracted from the nearby wells. The direct determination of those parameters was carried out by helium porosity measurements and air absolute permeability technique by core analysis service companies e.g. CoreLab. The obtained values were in a wide range i.e., from 0.1% to more than 20% for porosity tests and from 0.1 mD to more than several hundred millidarcies (e.g. 500 mD) for permeability studies, including vertical and horizontal orientation of samples. This observation clearly indicates high anisotropy and heterogeneity of the investigated formations. Variation of changing rock properties with the location and direction in which it was measured will clearly affect the behavior of fluid flow in the rock formations. In this case, the hosting rock has a highly complicated dual pore-fracture structure. The rock matrix, characterized by low permeability and relatively high porosity will provide storage volume while highly permeable fractures will be serving as the main routes distributing injected fluids across the reservoir. These characteristics in conjunction with capillary pressure effect will affect the CO_2/H_2S plume size, shape, and direction of propagation.

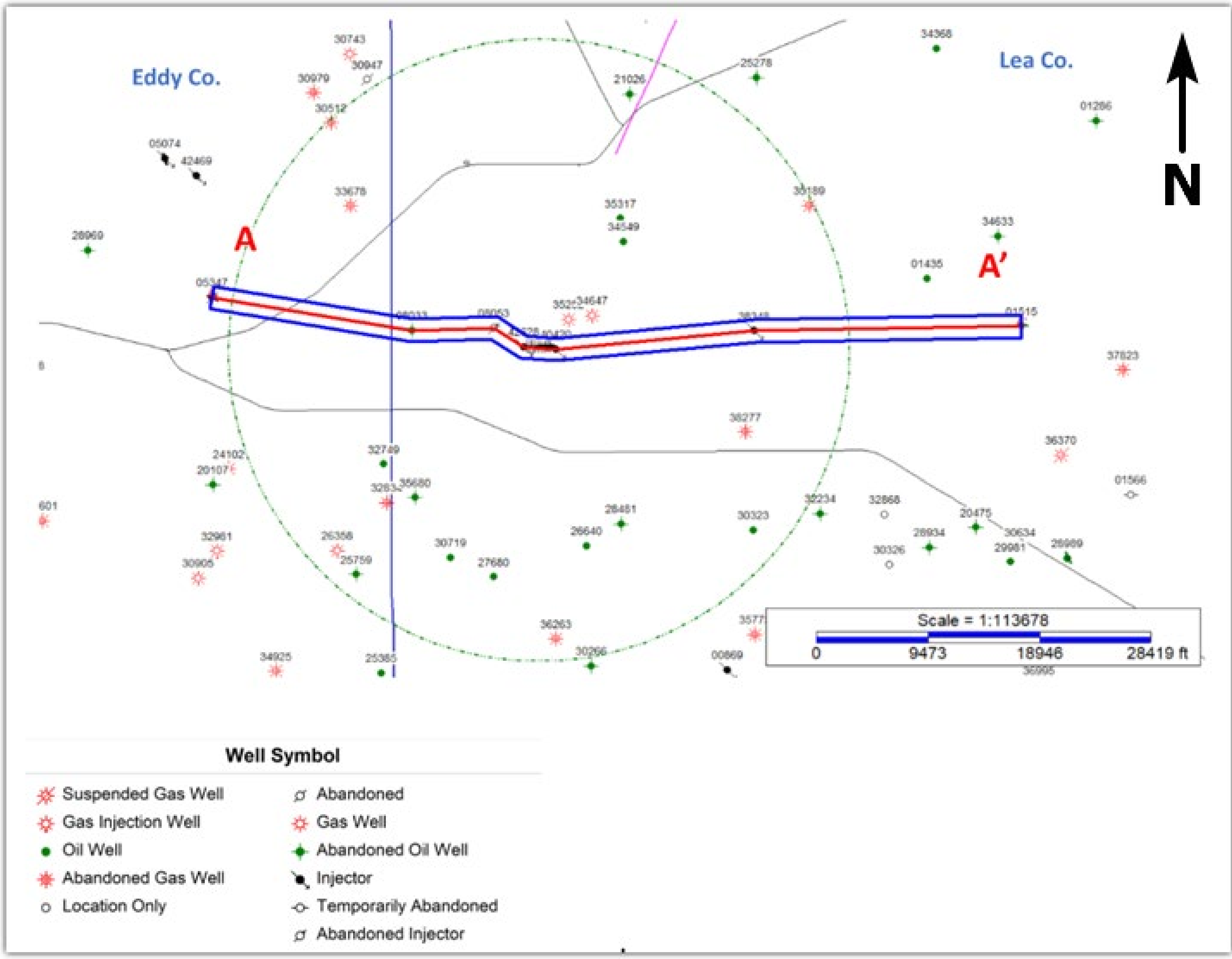

Figure 3.3-6: *Location of wells used in west – east cross-section, A-A', shown in* ***Figure 3.3-7****.*

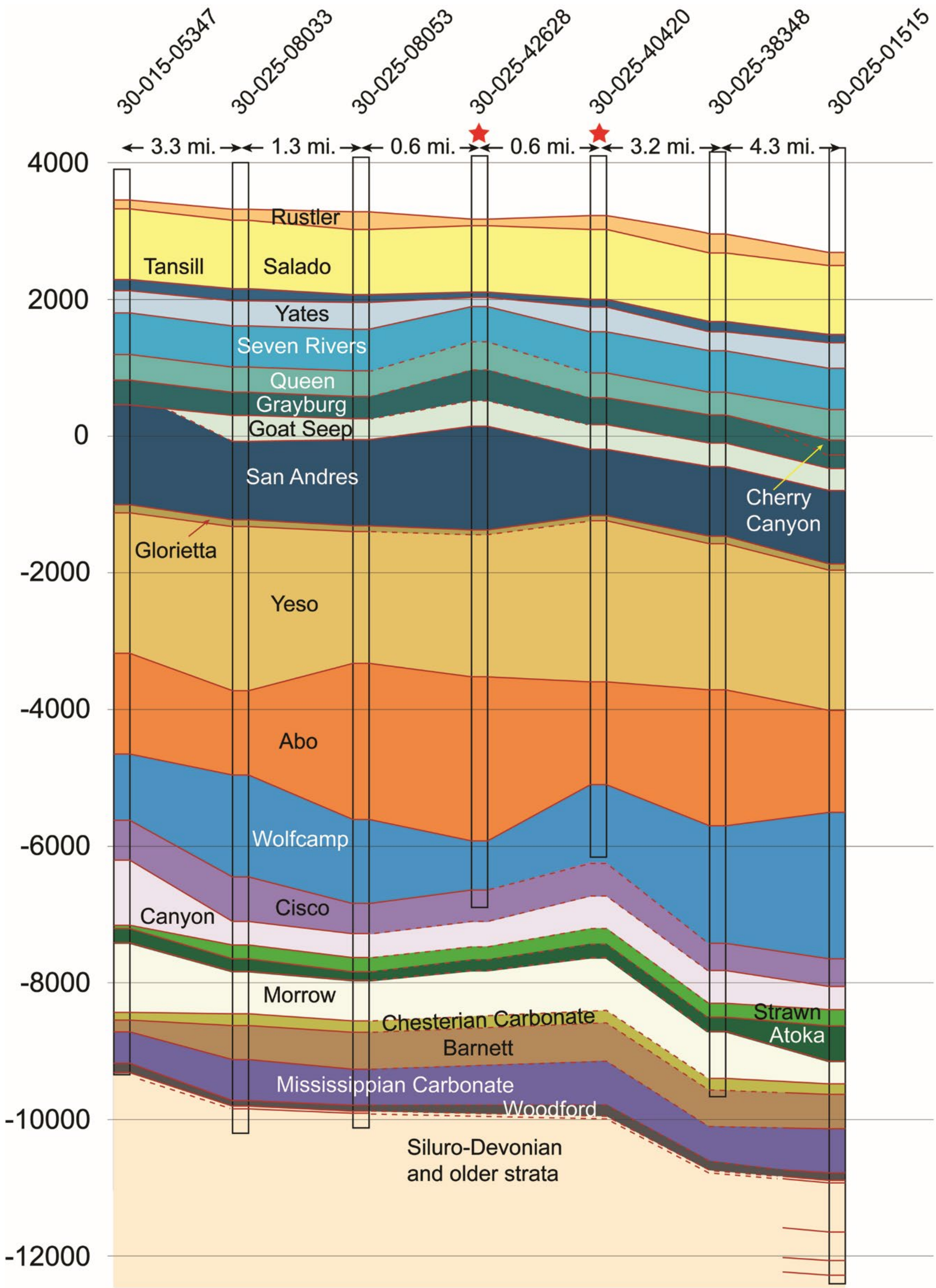

Figure 3.3-7: *Stratigraphic cross-section through Maljamar injection wells (red stars). Location of wells shown in* ***Figure 3.3-6****.*

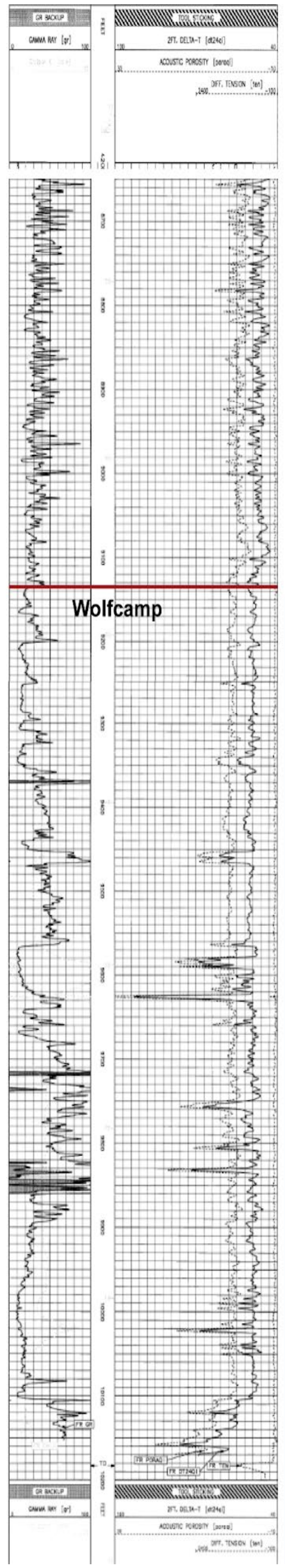

Figure 3.3-8: *Porosity and gamma log for Maljamar AGI #1 Well (30-025-40420).*

3.4 Formation Fluid Chemistry

Formation fluid chemistry for the Wolfcamp is available from three nearby wells: Baish A 012 (API # 30-025-20568) located in Sec. 21, T17S, R32E, approximately one mile southwest of the Maljamar Gas Plant, Baish B 001 (API# 30-025-00637) located in Sec. 22, T17S, R32E, approximately 1.25 miles northeast of the Maljamar Gas Plant, and the Maljamar AGI #1.

Table 3.4-1: *Wolfcamp fluid chemistry from within the vicinity of the Maljamar Gas Plant (extracted from C-108 application for Maljamar AGI #2, prepared by Geolex, Inc.)*

Parameter	BAISH A 012	BAISH B 001	Maljamar AGI #1
Mg^{++}	972	680	401
Na^{+}	52,298	34,704	84,400
$CO_3^{=}$	ND	ND	ND
$HCO_3^{=}$	1,220	481	195
$SO_4^{=}$	4,400	3,900	3340
Cl^{-}	50,000	33,000	132,000
Fe (free)	11	14	ND
pH	7.6	7.4	7.70
$CaCO_3$	1.4	0.9	ND

Analyses show that the formation waters are sodium/chloride brines.

3.5 Groundwater Hydrology in the Vicinity of the Maljamar Gas Plant

In the area of the Frontier Gas Plant, the surficial deposits are relatively thin layers of aeolian sands and both active and stabilized dunes. These materials are described in the Soil Survey-Lea County, New Mexico (United States Department of Agriculture, 1974) as the Kermit Dune Lands and the Maljamar Fine Sands. Under these sandy deposits lie the “redbeds” of the Triassic Dockum Group, in which ground water locally occurs in sandier beds of the mudrocks characterizing the Dockum. Local depth to groundwater in the Dockum is reported to be approximately 70 ft. The only significant aquifer in the area is the Pliocene Ogallala Formation, which crops out in the Mescalero Ridge, a prominent landform seen near Maljamar, approximately three miles northeast of the Plant (Nicholson and Clebsch, 1961).

The results of a search of the New Mexico State Engineer’s online files for registered water wells in this area showed 18 wells within a one-mile radius area around the Maljamar wells (**Figure 3.5-1**). These wells are shallow, completed at depths of less than 400 ft. In the vicinity of the Maljamar wells, there is nearly 9,000 ft of strata between the deepest groundwater well and the top of the injection zone for the Maljamar wells. Data for these wells are in **Appendix 4**.

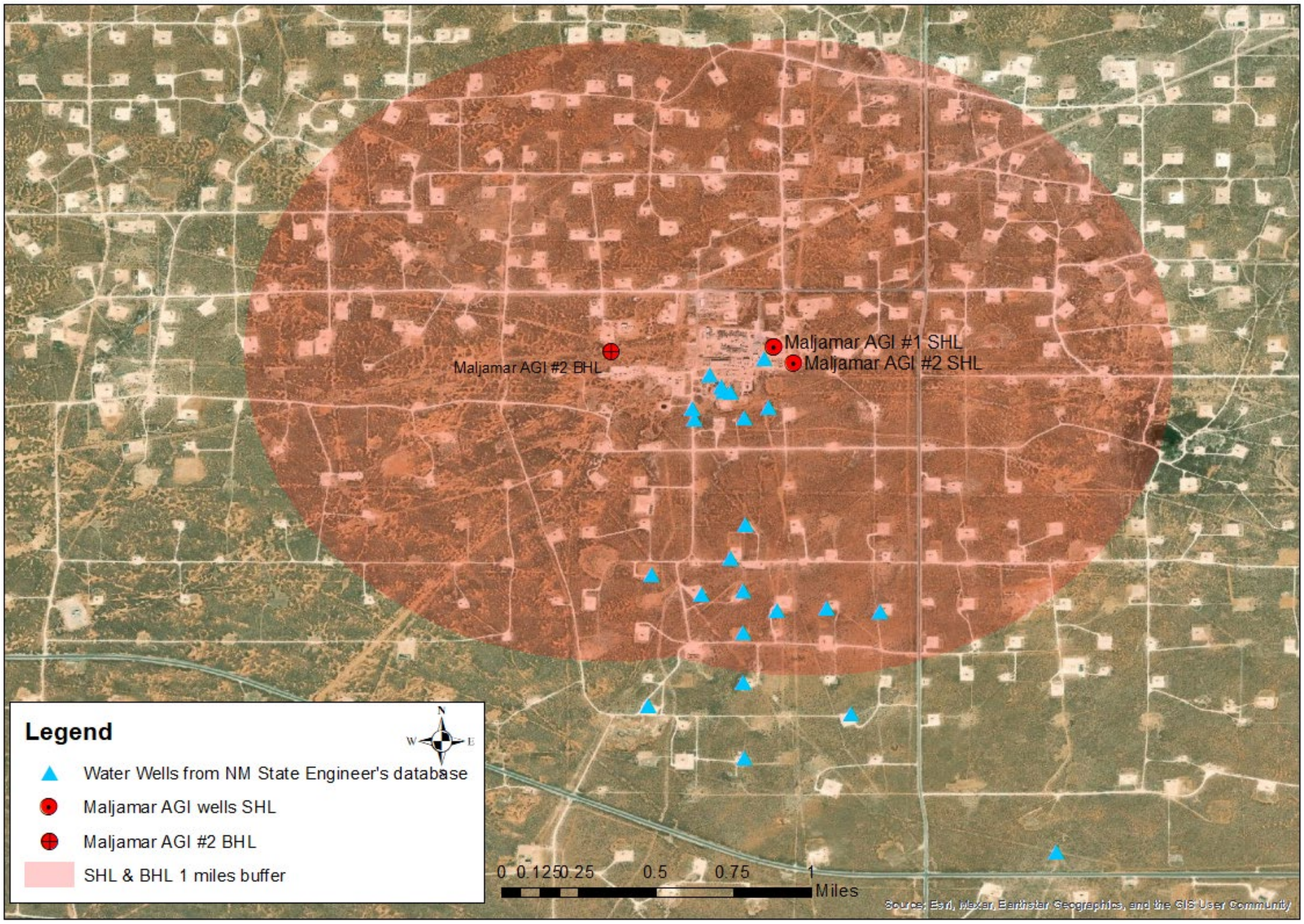

Figure 3.5-1: *Groundwater wells within a 1-mile radius area around the Maljamar wells.*

3.6 Historical Operations in the Vicinity of the Maljamar AGI Wells

There are numerous oil- and gas-related wells in the vicinity of the Maljamar gas plant and the Maljamar AGI wells. **Appendix 3** lists those wells, including the Maljamar AGI #1 and AGI #2 wells, that lie within the maximum monitoring area/active monitoring area (MMA/AMA) (see Section 4 and **Figure 4.1-1**).

Those wells are completed in the Yates-7 Rivers, Grayburg-San Andres, and Paddock production zones have true vertical depths of more than 4,000 ft above the top of the injection zone for the Maljamar AGI #1 and #2 wells (at 9,580 ft and 9,603 ft, respectively).

The two wells are completed in the Abo (API# 30-025-08362 and 30-025-00622) are plugged and abandoned.

The Maljamar AGI wells are included in the Wolfcamp-Cisco (see **Appendix 3**). The two wells listed as completed in the Wolfcamp (API#30-025-41557 and 30-025-00751) are both plugged and abandoned.

The remaining well (API# 30-025-40712) is an active saltwater disposal well located approximately 0.63 miles SW of the SHL of Maljamar AGI #2.

Of the three wells completed in the Devonian, two (API# 30-025-21951 and 30-025-00634) are plugged and abandoned. The remaining well (API# 30-025-35252) is a gas production well located approximately 0.5 miles NE of the SHL of Maljamar AGI #2.

3.7 Description of Injection Process

The following description of operations for the Maljamar Gas Plant and the Maljamar AGI #1 and #2 wells were extracted from the H_2S Contingency Plan, dated October 6, 2015 and revised October 28, 2015, prepared by Geolex, Inc. for Durango Midstream, LLC.

3.7.1 Maljamar Gas Plant – Description of Operations

The primary function of the Maljamar Gas Plant (plant) is to remove acid gas (H_2S and CO_2) from sour field gas so that the gas can meet pipeline specifications. The gas is treated to remove acid gas components, dehydrated to remove water, and processed to remove heavy (liquid) hydrocarbons from the gas stream. Several Plant systems are involved in performing these functions. The amine unit is designed to remove acid gas components from the natural gas stream. These components are removed from the natural gas stream because they are corrosive, hazardous to health, and reduce the heating value of the natural gas stream. This process is known as the gas sweetening process. Prior to the installation of the Maljamar AGI Facility, the H_2S gas removed by the amine unit was routed to the flare for incineration, and the CO_2 was released to the atmosphere. With the installation of the Maljamar AGI Facility the H_2S and CO_2 removed during the sweetening process are compressed at the AGI Facility and then injected into one of the AGI wells.

Figure 3.7-1 is a block flow diagram for the Maljamar Gas Plant. **Figure 3.7-2** shows the location of alarms, monitors, and safety equipment at the Maljamar Gas Plant and Maljamar wells.

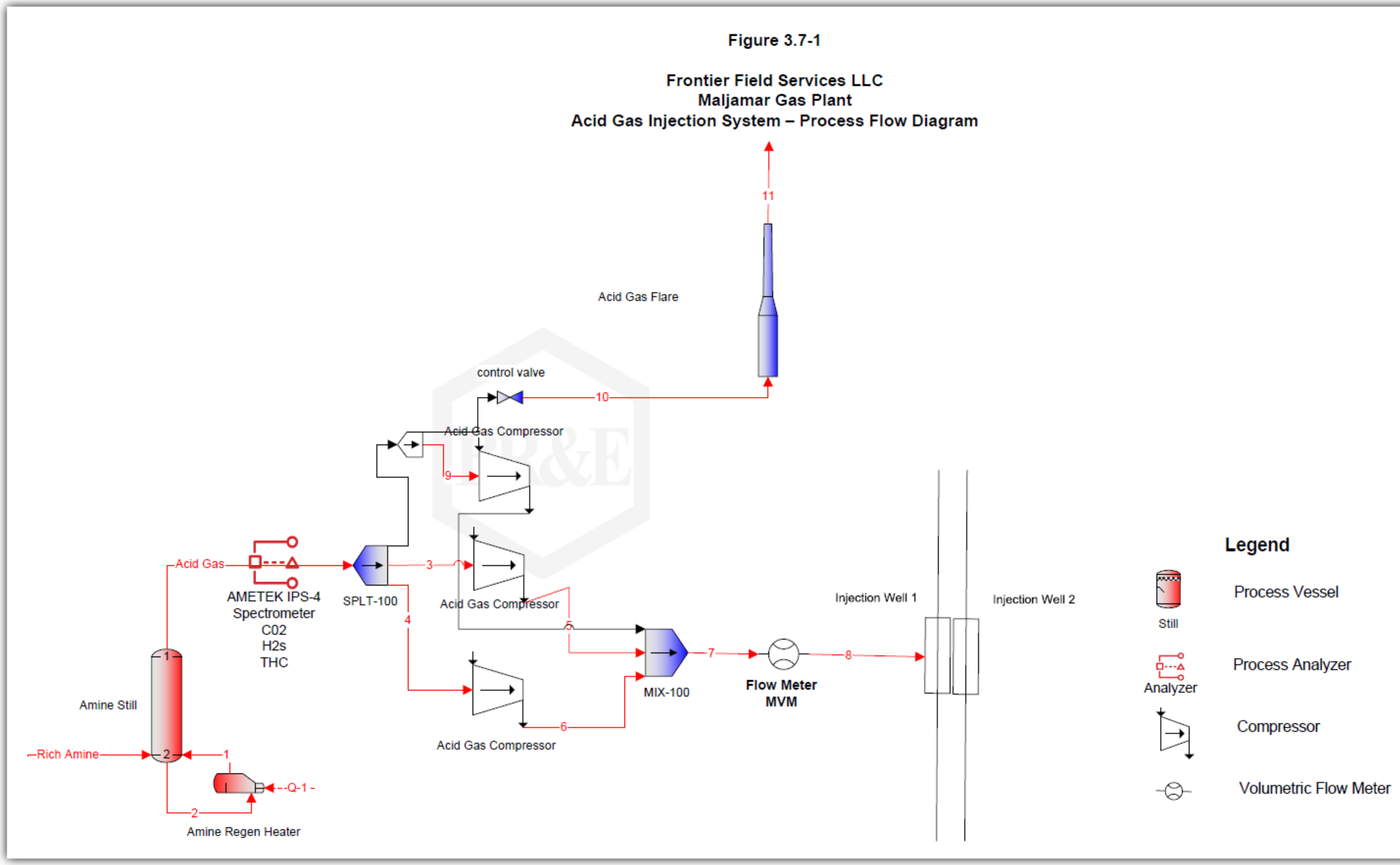

Figure 3.7-1: Block flow diagram for the Maljamar Gas Plant showing volumetric flow meter (MVM) for measuring CO_2 injected and AMETK IPS-4 spectrometer for measuring the concentration of the injected TAG stream.

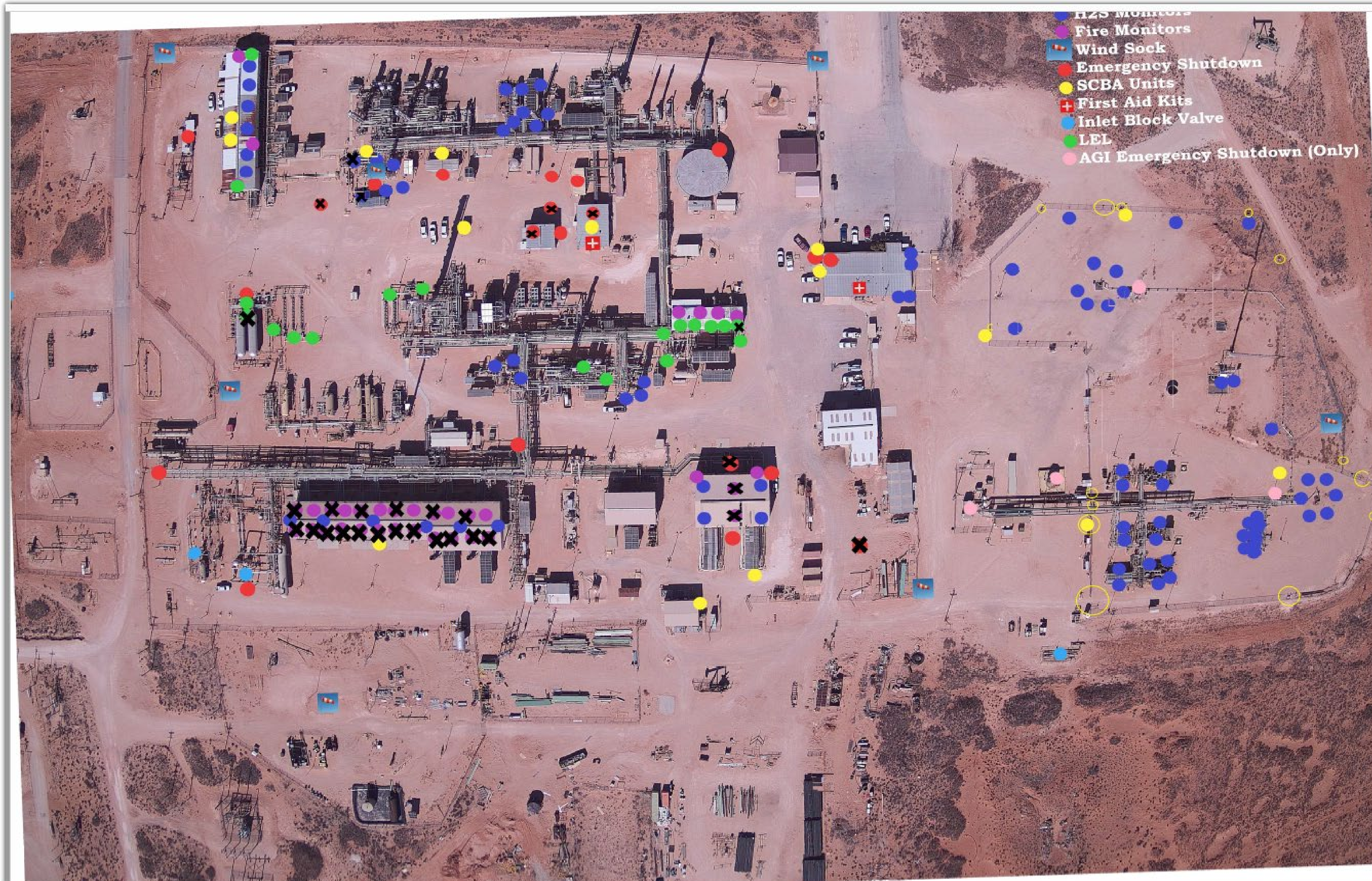

Figure 3.7-3: *Location of alarms, monitors, and safety equipment at the Maljamar Gas Plant and Maljamar wells. The blue circles are the H_2S monitors.*

3.7.2 AGI Facility including the Maljamar AGI Wells – Description of Operations

The lines that convey the TAG to the wells from the compression facilities are three-inch, stainless-steel, corrosion-resistant pipes (compliant with NACE standards). The pipes between the compressors and the AGI wells are contained totally within the boundaries of the plant and AGI facility and do not cross any public road. H_2S sensors are located at critical junctions along the pipes which are run on overhead pipe racks. The pressure in the pipes is monitored continuously so the acid gas injection process could be stopped should there be any unusual variations in pressure. The designs for the injection wells are shown in **Appendix 1**, and the schematic of the AGI facility and tie-in to the plant are shown in **Figure 3.7-4**.

The location and details of the Maljamar AGI #1 and #2 wells are presented in **Appendix 1.** Each well has a string of telescoping casing cemented to the surface and includes a “downhole” SSV (safety shutdown valve) on the production tubing to assure that fluid cannot flow back out of the well during an injection equipment failure event. This valve is designed to isolate and automatically shut in the injection well if a leak occurs. The injection string within the well is also constructed with multiple safety features which include L80 ULTRA FJ 2-7/8” corrosion resistant tubing stabbed into a Halliburton BWD Perma-Series permanent packer, made of Incoloy® 925 with fluorel elements and an automated Halliburton SSV also made of Incoloy® 925. Incoloy® 925 is a nickel-iron chromium alloy that is resistant to corrosion and pitting and conforms to NACE specifications for sour gas service. In addition, the annular space between the projection tubing and the wellbore is filled with corrosion-inhibited diesel as a further safety measure and is designed to allow the pressure in the annular space to be monitored and recorded continuously. If a pressure excursion outside the narrow predetermined operating range occurs, the acid gas compressor is shut down and the automatic safety valves at the wellhead are automatically closed to prevent any escape of acid gas. The acid gas stream would then be routed to the flare until the problem with the well could be corrected and the system safely re-started. These redundant systems are compliant with API RP 55 and API RP 49, various applicable NACE standards for sour gas service and current best management practices. All downhole equipment includes necessary features which will allow for safe workover of a well in the event of a major equipment failure.

The Christmas tree of each well is made of standard carbon steel components and outfitted with annular pressure gauges that remotely report operating pressure conditions in real time to a gas control center. Pursuant to NMAC 19.15.11.12.D(2), in the case of abnormal pressures or any other situation requiring immediate action, the acid gas injection process can be stopped at the compressor, and the wellhead can be shut in using a hydraulically operated wing valve on the Christmas tree. The plant operator may also shut the SSV. In addition, the well has profile nipples which provide the ability to insert a blanking plug into the base of the well below the packer which would allow for the safe reentry of the well. These safety devices provide for downhole accessibility and reentry under pressure for permanent well control. The SSV provides a redundant safety feature to shut in the wells in case the wing valves do not close properly. (See **Figures 3.7-4 and Appendix 1-1 and 1-2** for location of these downhole safety features).

The approximate composition of the TAG stream from the Maljamar Gas Plant is: 22% H_2S and 78% CO_2. Frontier intends to continue the injection of TAG for 30 years. Based on the reservoir simulation modeling (see Section 3.8) of the gas stream PVT phase behavior, fluctuations of the H_2S and CO_2 composition will not affect the plume migration given the supercritical reservoir pressure and temperature conditions.

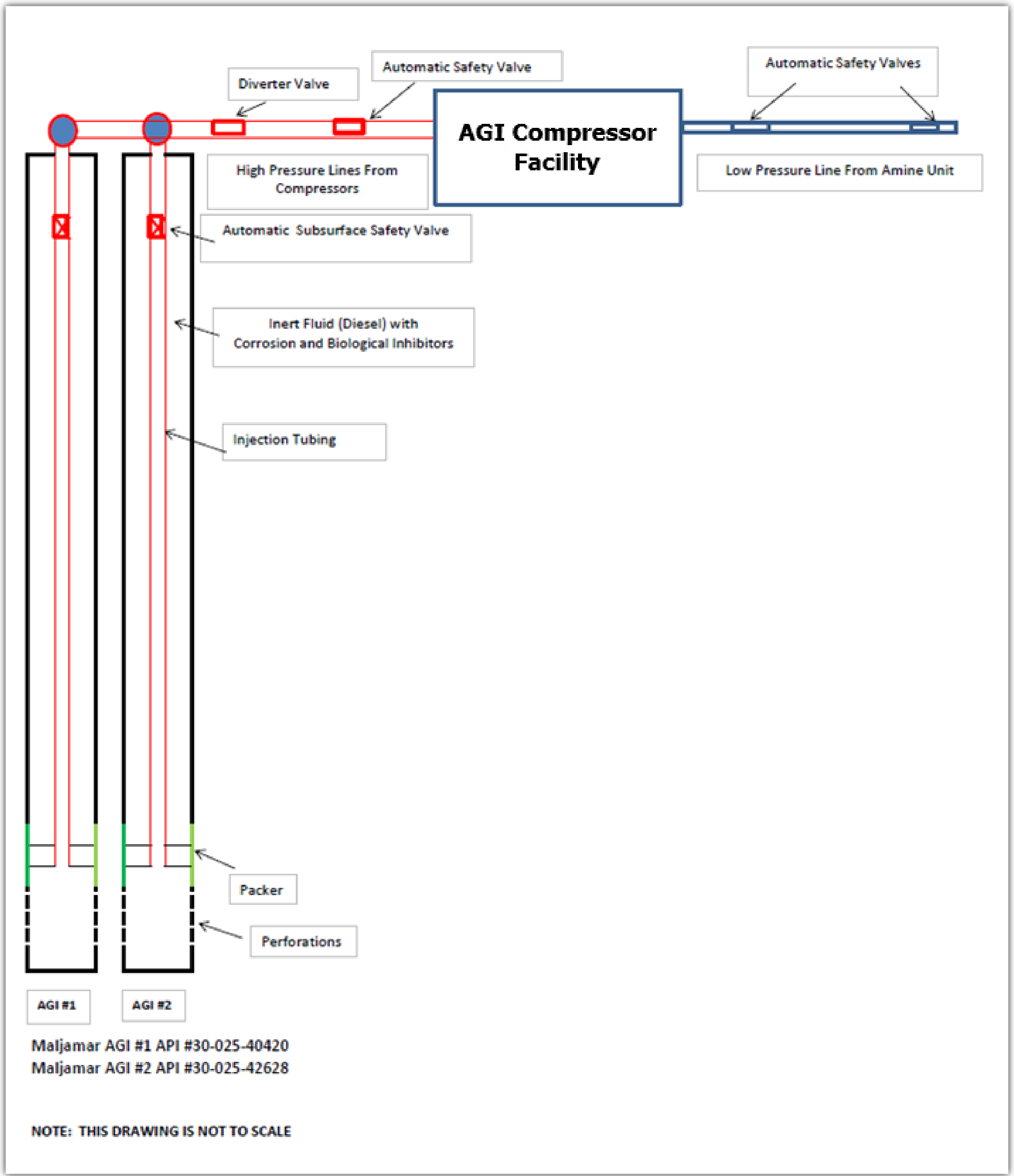

Figure 3.7-4: *Schematic of AGI facility – Maljamar Gas Plant. (Extracted from Figure 6 of H_2S Contingency Plan, prepared by Geolex, Inc.)*

3.8 Reservoir Characterization Modeling

The modeling task focused on the Wolfcamp formation as the main target injection zone for acid gas storage. The Maljamar AGI #1 well (API 30-025-40420) and Maljamar AGI #2 (API 30-025-42628) are the approved injectors for treated acid gas injection. Both injectors are completed in the same formation interval. The Maljamar AGI #1 well is perforated between 9,579 to 10,130 ft (MD), and the Maljamar AGI #2 well, a deviated well, is perforated between 9,600 to 10,220 ft (MD).

The static model is constructed with 95 well tops to interpret and delineate the structural surfaces of Wolfcamp and its overlaying, underlying formations. The geologic model covers 47 miles by 52 miles area. No distinctive geological structures such as faults are identified within the geologic model boundary. Based on the approved injection rate, the simulation model is centralized in the 5 miles by 5 miles region of the Maljamar injectors. The model is gridded with 52 x 52 x 9, totaling 24,336 cells. Local grid refinement is applied to the center of six adjacent layers of the perforated wellbore intervals into 5 sub-grids. The average grid dimension of the active injection area is 100 feet square. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.16. The initial permeability are interpolated between 0.02 to 36 millidarcy (mD), and the vertical permeability anisotropy was 0.1. (**Figure 3.8-2** and **Figure 3.8-3**). These values are validated and calibrated with the historical injection data of Maljamar Wells and adjacent saltwater disposal wells since 1990 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6.**

In the simulation model, ten times of the reservoir pore volume multiplier was assigned to the boundary of the simulation domain to mimic infinite reservoir response. Mid-depth (6000 ft - MSL) reservoir pressure of 4800 psi was calculated based on the pore pressure measurement of the Wolfcamp reservoir in the Delaware Basin. The reservoir temperature of 130°F was assigned and used to compute the reservoir EOS fluid model by the Peng-Robinson Equation of State. The components' solubility was considered in the fluid model by Henry's Law and the irreducible water saturation of 0.21 is used to generate the relative permeability curves for the oil/water/gas system. The non-wetting phase hysteresis effect was represented by Carson and Land's model with the maximum trapping gas saturation equal to 0.3 on the relative permeability scanning curve. This method allows a reasonable capillary trapping mechanism to be simulated when imbibition curves are not readily available. The reservoir is assumed to be initially equilibrated with oil and water with the oil-water contact assigned at 7,000 ft – MSL.

The simulation model is calibrated with the injection and production history within the 5 miles square around the Maljamar injectors since 1997. Simulations studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both Maljamar AGI #1 well (API 30-025-40420) and Maljamar AGI #2 (API 30-025-42628) with approved rate and following at least 20 years of the post-injection monitoring period to estimate the maximum impacted area. The stream injection rate of 3.5 MMSCFD was assigned to the injection group with a mole composition of 22% H_2S and 78% CO_2. The maximum injection rate of the Maljamar AGI #1 well is 1.8 MMSCFD, and 2.0 MMSCFD per the state oil and gas conservation commission order.

During the calibration period (June 1st, 1997 – Jan 1st, 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well in the Wolfcamp formation to ensure safe injection operations. The reservoir properties are tuned to match the historical injection till it was reasonably matched. **Figure 3.8-4** shows that the injection pressure and rates from the SWD wells within the 5 miles square model are aligned and these wells are included in the modeling efforts within this target injection zone during the prediction period.

Following the historical rate injection, a forecasting injection was performed. Maljamar AGI #1 well started its approved 30-year injection in 2013 and shut-in in 2043. The Maljamar AGI #2 well started its approved 30-year injection in 2016 and shut-in in 2046. The monitoring period is from 2046 to 2076, which is 30 years post the injection termination of the Maljamar AGI #2 well. **Figure 3.8-5** shows the injection profile for the group of two AGI injectors. In the forecasting period, the maximum allowed surface gas rate of 3.5 MMSCFD was sustained from 2023 to 2043. Following the shut-in of Maljamar AGI #1, the rate was reduced to the maximum allowed rate of 2.0 MMSCFD for the Maljamar AGI #2 well. The modeling results indicate that the Wolfcamp formation can store and trap the intended gas volume without any impact on the adjacent wells. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 during the entire group lifetime since 2013. During the forecasting period, linear cumulative injection behavior indicates that the Wolfcamp formation endured the TAG injected freely. **Figure 3.8-7** shows the gas molarity represented free phase TAG movement at the end of 30-year forecasting from the aerial view. Because connate CO_2 exists in the Wolfcamp formation at initialization, the molarity of H_2S is shown in the figure to represent the gas plume extent. It can be observed that the size of the free phase TAG is very limited at the end of injection compared to the size of the geological model. In the year 2076, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant migration of TAG footprint observed, compared to that at the end of injection. **Figure 3.8-8** shows the extent of the plume impact in a map view.

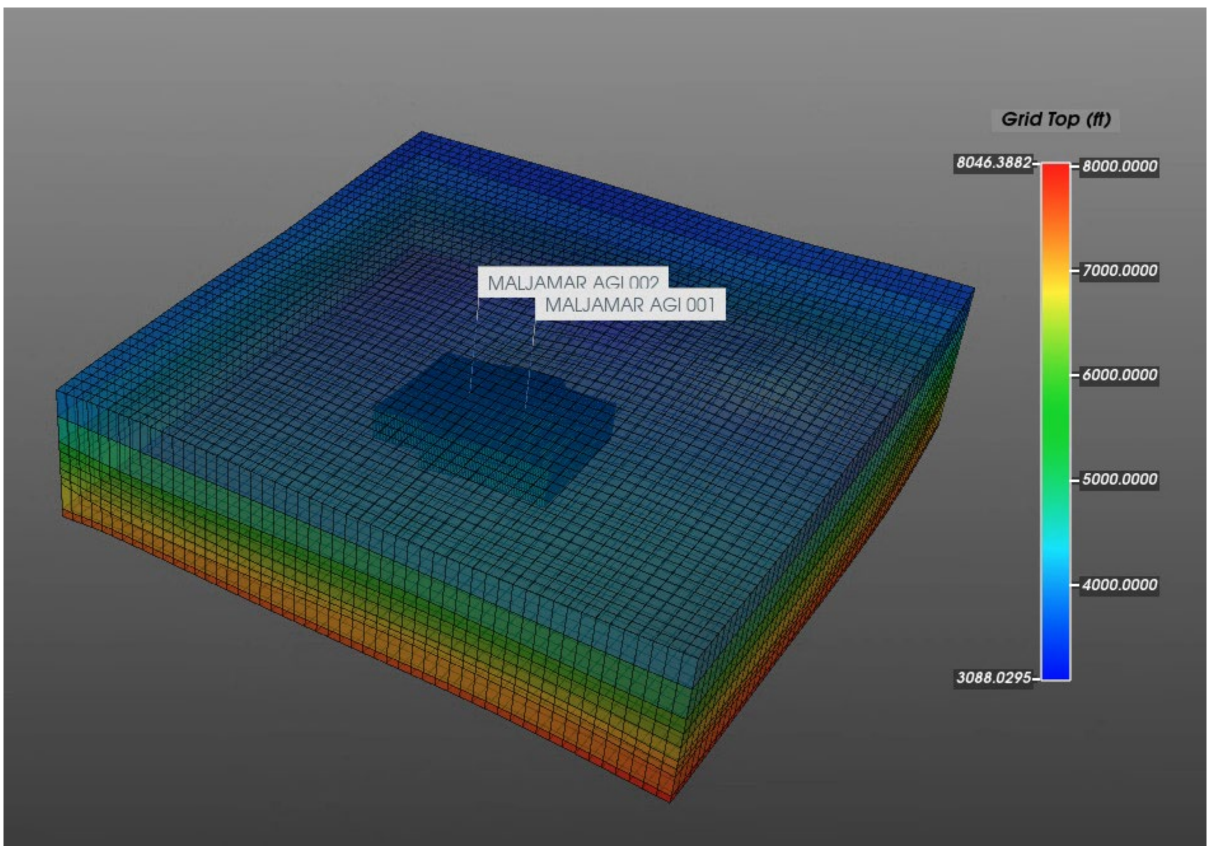

Figure 3.8-1: *Structure of the reservoir model using ABO, Wolfcamp, Woodford, Cisco, Canyon, Strawn, and Atoka formations. The elevation of the top surface elevations with respect to the Mean Sea Level (MSL) is depicted within the model.*

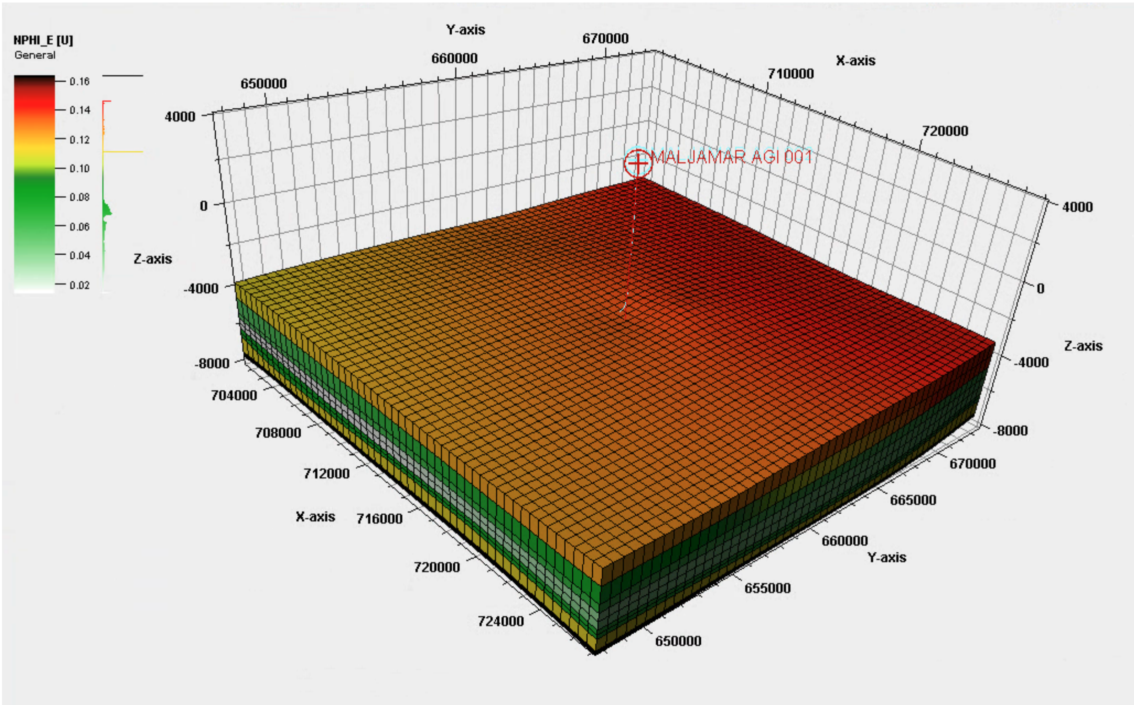

Figure 3.8-2: Porosity estimation using available well data for the simulation domain.

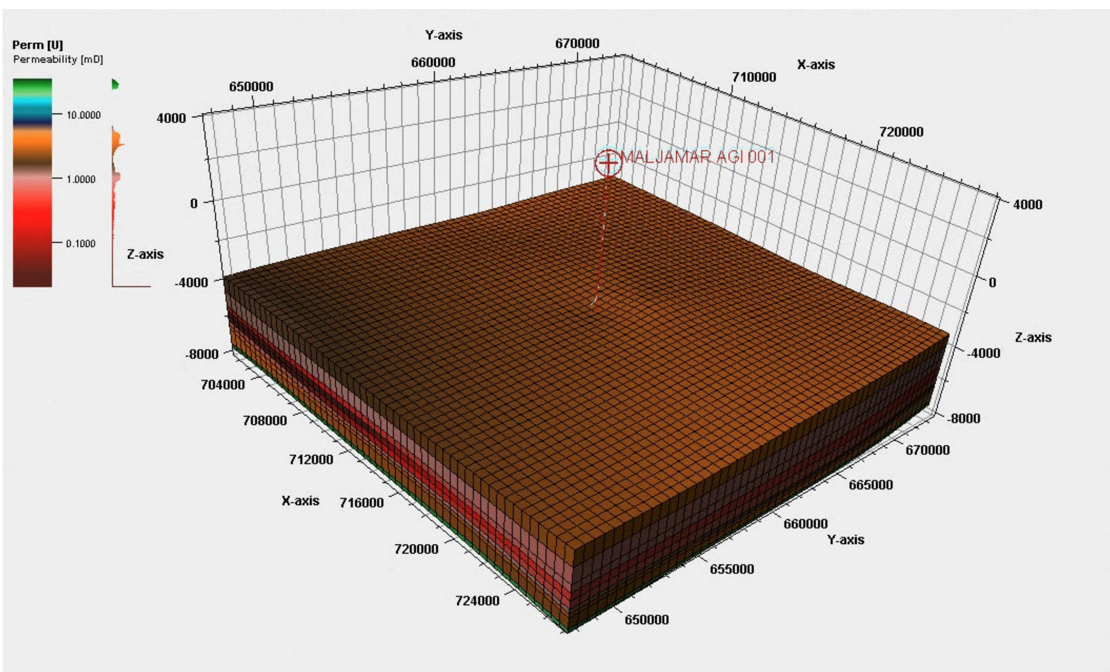

Figure 3.8-3: Permeability estimation using available well data for simulation domain.

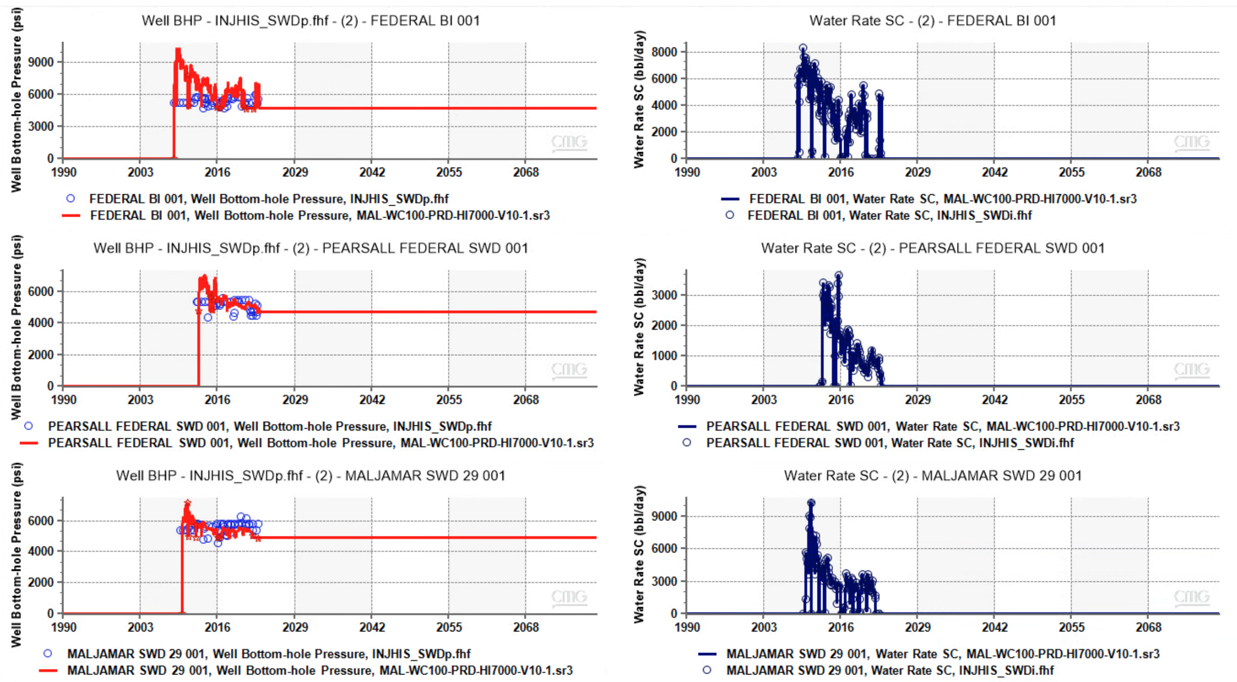

Figure 3.8-4: *The historical injection rate and injection bottom hole pressure response (1997 to 2022).*

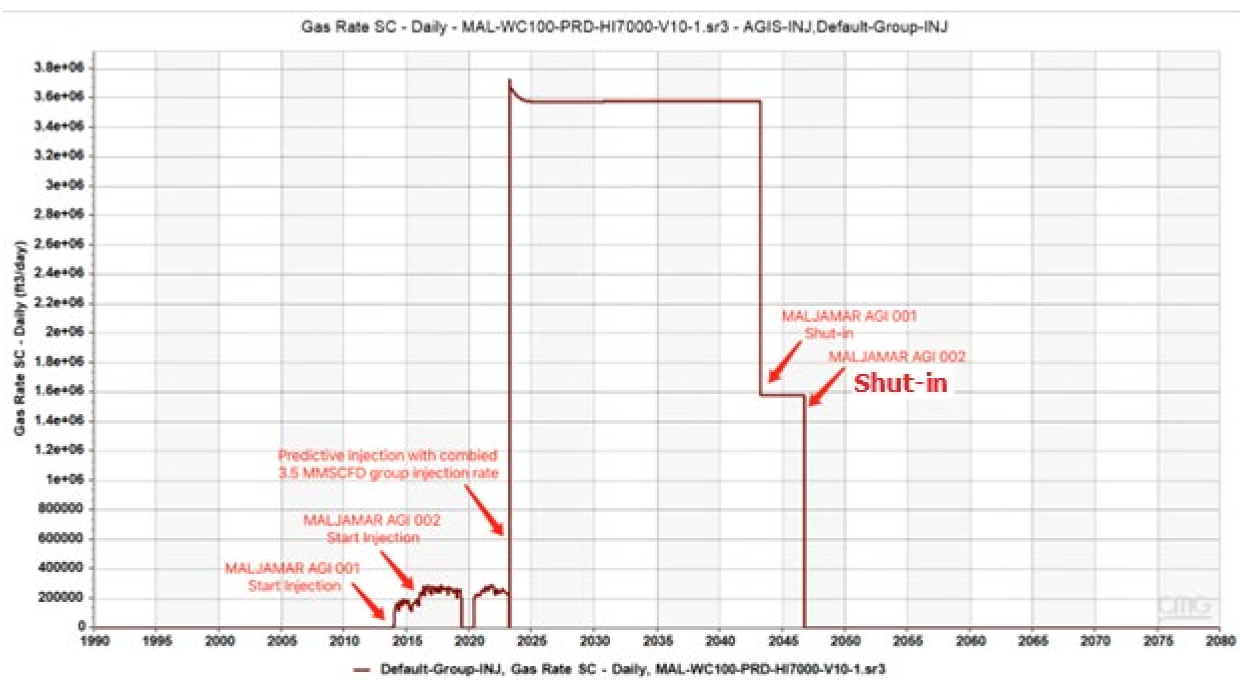

Figure 3.8-5: *The group injection rate of Maljamar AGI wells (2006 to 2022).*

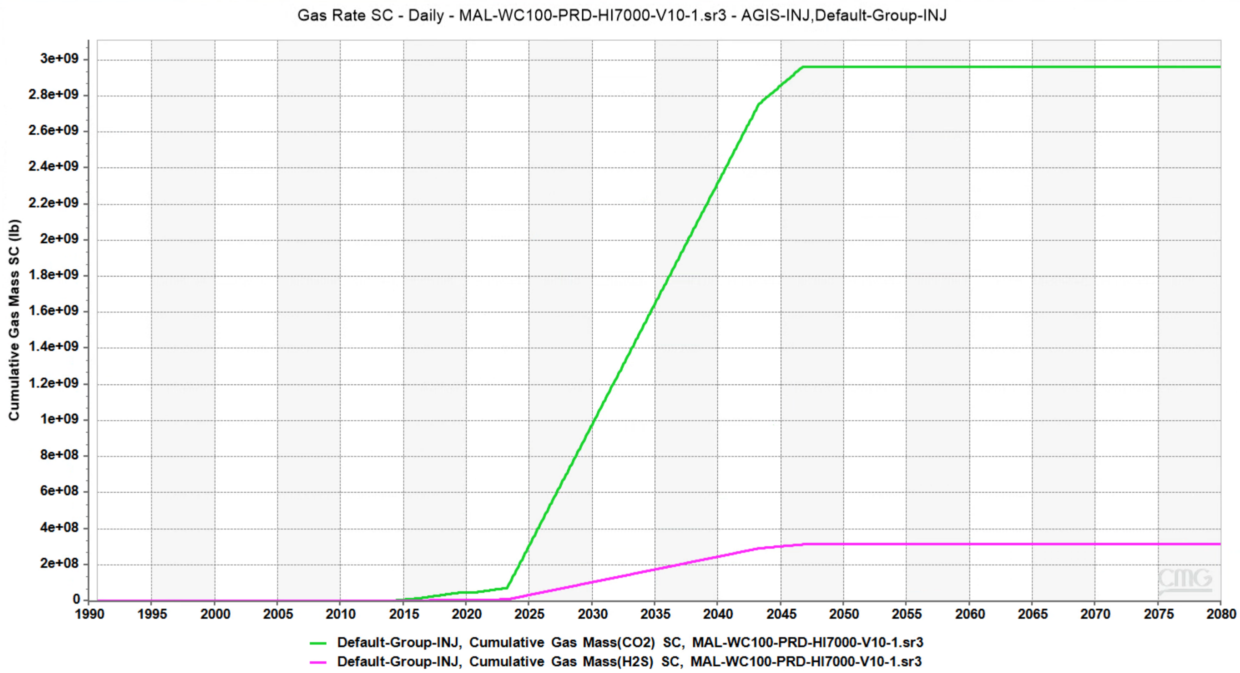

Figure 3.8-6: *The cumulative mass of injected CO_2 and H_2S (2013 to 2046).*

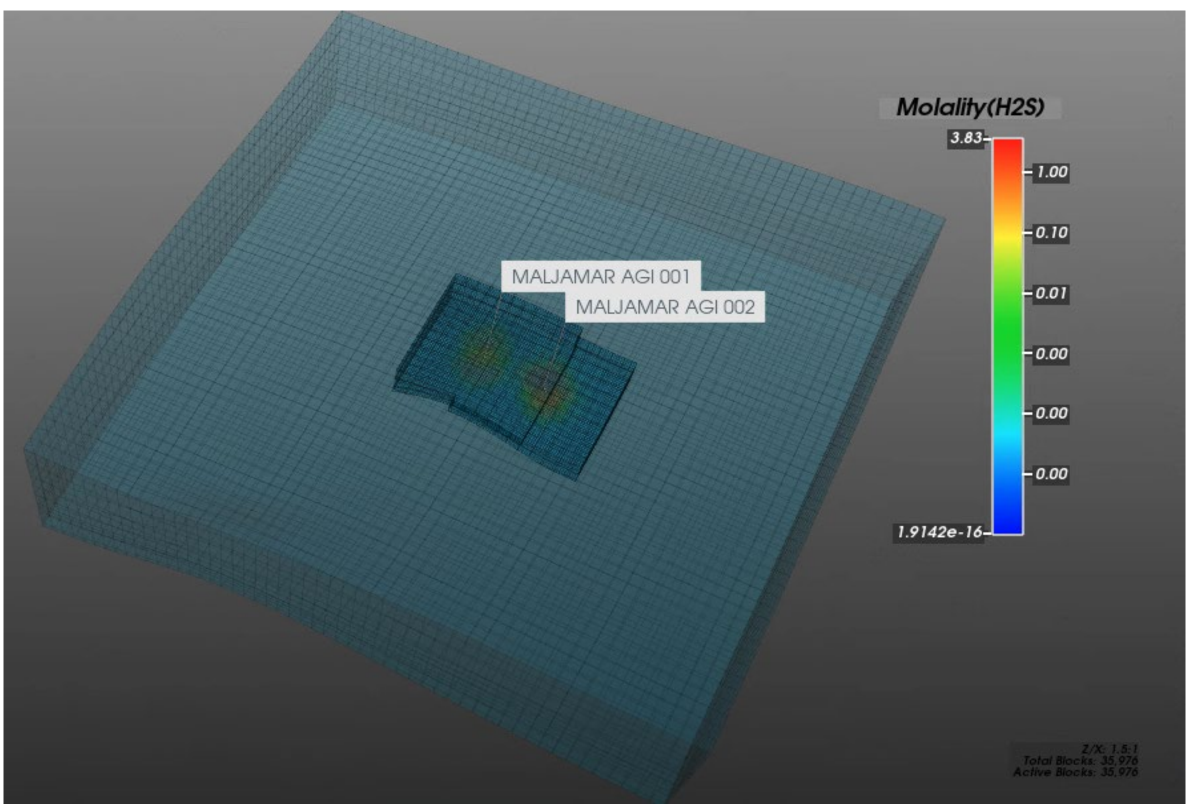

Figure 3.8-7: *The free phase TAG (represented by H_2S molarity) at the end of 30-year post-injection monitoring (2076) in a map view.*

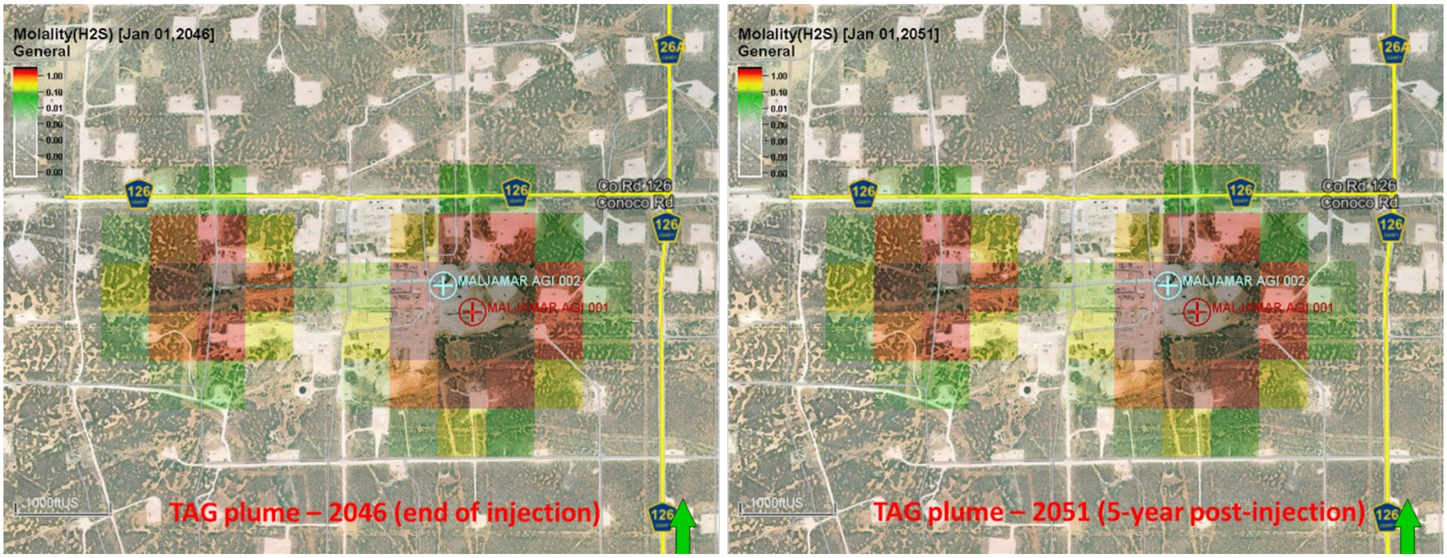

Figure 3.8-8: *The free phase TAG at the end of 30-year post-injection monitoring (2076) in a map view.*

4. Delineation of the monitoring areas

4.1 Maximum Monitoring Area (MMA)

As defined in Section 40 CFR 98.449 of Subpart RR, the maximum monitoring area (MMA) is "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling in Section 3.8 to define the extent of the plume.

The reservoir modeling in Section 3.8 states that "after 30 years of [post-injection] monitoring, the injected gas remained in the reservoir and there was no observed expansion of the TAG footprint, compared to that at the end of injection." This applies to both AGI #1 and AGI #2; that is the maximum extent of the TAG plume for AGI #1 was at the end of its injection at 2043 and that for AGI #2 was at the end of its injection in 2046. Therefore, the plume extent at the end of 30 years of injection is the initial area with which to define the MMA. **Figure 4.1-1** shows the MMA as defined by the superposition of the maximum extent of the TAG plume at year 2043 and 2046 plus a 1/2-mile buffer.

4.2 Active Monitoring Area (MMA)

As defined in Section 40 CFR 98.449 of Subpart RR, the active monitoring area (AMA) is "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year t + 5."

Frontier has chosen t=2043 and 2046 (the end of 30 years of injection for AGI #1 and AGI #2, respectively) for purposes of calculating the AMA. As described in Section 3.8, the maximum extent of the TAG plume is at t=2043 and 2046 so delineation of the first AMA area (Criteria 1) is equivalent to the delineation of the MMA since there are no known leakage pathways that would require the extension of this area laterally. Simulation of the second AMA area (Criteria 2) at t+5=2048 and 2051 shows that the TAG plume extent is equivalent to the TAG plume extent at t=2043 and 2046. Superposition of the AMA Criteria 1 and 2 areas results in the AMA being equivalent to the MMA (**Figure 4.1-1**).

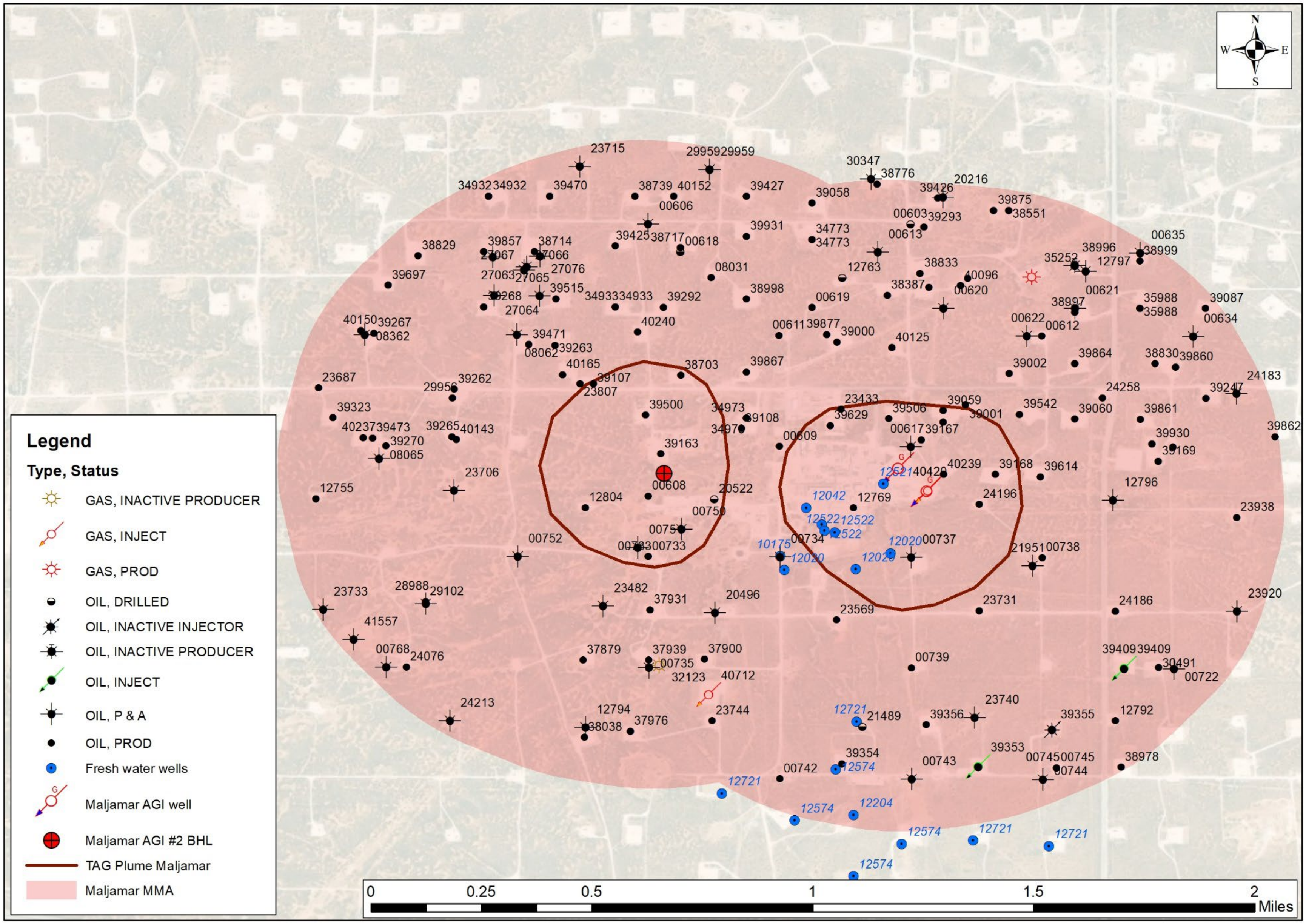

Figure 4.1-1: *Active monitoring area (AMA) for Frontier Maljamar AGI #1 and #2 wells at the end of injection of each well and 5 years post-monitoring*

5. Identification and Evaluation of Potential Leakage Pathways

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways for CO_2 in the MMA and the evaluation of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways.

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells and the reservoir modeling described in Section 3.8, Frontier has identified and evaluated the potential CO_2 leakage pathways to the surface.

A qualitative evaluation of each of the potential leakage pathways is described in the following paragraphs. Risk estimates were made utilizing the National Risk Assessment Partnership (NRAP) tool, developed by five national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage environmental risks at geologic carbon storage sites. Utilizing the NRAP tool, Frontier conducted a risk assessment of CO_2 leakage through various potential pathways including surface equipment, existing and approved wellbores within MMA, faults and fractures, and confining zone formations.

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of the TAG stream, there is a potential for leakage from surface equipment at sour gas processing facilities. To minimize this potential for leakage, the construction, operation, and maintenance of gas plants follow industry standards and relevant regulatory requirements. Additionally, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

Operational risk mitigation measures relevant to potential CO_2 emissions from surface equipment include a schedule for regular inspection and maintenance of surface equipment. Additionally, Frontier implements several methods for detecting gas leaks at the surface. Detection is followed up by immediate response. These methods are described in more detail in sections 3.7.2, 6 and 7.

Section 3.7.2 describes the safeguards in place to prevent leakage between the acid gas compressor and the Maljamar wellheads. Each well has a string of telescoping casing cemented to the surface and includes a "downhole" SSV (safety shutdown valve) on the production tubing to assure that fluid cannot flow back out of the well during an injection equipment failure event. This valve is designed to isolate and automatically shut in the injection well if a leak occurs. The injection string within the well is also constructed with multiple safety features which include L80 ULTRA FJ 2-7/8" corrosion resistant tubing stabbed into a Halliburton BWD Perma-Series permanent packer, made of Incoloy® 925 with fluorel elements and an automated Halliburton SSV also made of Incoloy® 925. Incoloy® 925 is a nickel-iron chromium alloy that is resistant to corrosion and pitting and conforms to NACE specifications for sour gas service. In addition, the annular space between the projection tubing and the wellbore is filled with corrosion-inhibited diesel as a further safety measure and is designed to allow the pressure in the annular space to be monitored and recorded continuously. If a pressure excursion outside the narrow predetermined operating range occurs, the acid gas compressor is shut down and the automatic safety valves at the wellhead are automatically closed to prevent any escape of acid gas. The acid gas stream would then be routed to the flare until the problem with the well could be corrected and the system safely re-started. These redundant systems are compliant with API RP 55 and API RP 49, various applicable NACE standards for sour gas service and current best management practices. All downhole equipment includes necessary features which will allow for safe workover of a well in the event of a major equipment failure.

The Christmas tree of each well is made of standard carbon steel components and outfitted with annular pressure gauges that remotely report operating pressure conditions in real time to a gas control center. Pursuant to NMAC 19.15.11.12.D(2), in the case of abnormal pressures or any other situation requiring immediate action, the acid gas injection process can be stopped at the compressor, and the wellhead can be shut in using a hydraulically operated wing valve on the Christmas tree. The plant operator may also shut the SSV. In addition, the well has profile nipples which provide the ability to insert a blanking plug into the base of the well below the packer which would allow for the safe reentry of the well. These safety devices provide for downhole accessibility and reentry under pressure for permanent well control. The SSV provides a redundant safety feature to shut in the wells in case the wing valves do not close properly.

Furthermore, Frontier has standard operating procedures (SOP) in place to quantity pipeline leaks that occur on its supersystem. All leaks discovered by Frontier operations personnel, or third parties are quantified and reported in accordance with New Mexico Administrative Code (NMAC) Title 19, Chapter 15, Part 28 Natural Gas Gathering Systems administered by the Oil Conservation Division of the New Mexico Energy, Minerals and Natural Resources Department (EMNRD).

The injection well and the accompanying pipeline are the most likely surface components of the system that allow CO_2 leakage to the surface. The most likely reason for the leakage is the gradual deterioration of the surface components, particularly at the flanged connection points. Another potential factor contributing to leakage is the discharge of air via relief valves, which are specifically engineered to mitigate excessive pressure in pipelines. Leakage may occur when the surface components sustain damage due to an accident or natural disaster, resulting in the release of CO_2. Hence, we deduce that there is a possibility of leaking along this pathway.

Likelihood

Although leakage from surface equipment between the volumetric injection flow meter and the injection wellhead is possible, the mitigative measures described above and in Section 3.7.2 are in place to minimize the likelihood of a leakage event.

Magnitude

If a leak from the surface equipment between the volumetric injection flow meter and the injection wellhead occurs it will be detected immediately by the surveillance mechanisms described in Section 6.1 for surface equipment. The magnitude of a leak depends on the failure mode at the point of leakage, the duration of the leak, and the operational conditions at the time of the leak. A sudden and forceful break or rupture may discharge thousands of pounds of CO_2 into the atmosphere before it is brought under control. On the other hand, a gradual weakening of a seal at a flanged connection may only result in the release of a few pounds of CO_2 over a period of several hours or days.

Timing

During the operation of the injection system, any CO_2 leaks from surface equipment between the volumetric injection flow meter and the injection wellhead will be emitted immediately to the atmosphere. Mitigative measures are in place at the plant to minimize the duration and magnitude of any leaks. Leakage from surface equipment between the volumetric injection flow meter and the injection wellhead will only be possible during the operation of the injection system. Once injection ceases, surface injection equipment will be decommissioned thereby eliminating any potential for CO_2 leakage to the atmosphere.

5.2 Potential Leakage from Existing Wells

Injection wells, if not constructed, operated, and maintained properly, can present a potential for leakage of injected fluids to the surface. To minimize this potential risk, New Mexico has rules to address this. NMAC 19.15.26.9 for casing and cementing of injection wells states that injection well operators "shall case the well with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another zone or to the surface around the outside of a casing string." Additionally, NMAC 19.15.26.10 for operation and maintenance of injection wells states that operators shall "operate and maintain at all times the injection project, including injection wells, … in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

Likewise, oil and gas production wells, if not constructed, operated, and maintained properly, can present a potential for leakage of fluids out of the producing horizon. To minimize this potential risk, New Mexico has rules to address this. NMAC 19.15.16.9 for sealing off strata states that "during drilling of an oil well, injection well or other service well, the operator shall seal and separate the oil, gas and water strata above the producing or injection horizon to prevent their contents from passing into other strata." Additionally, NMAC 19.15.16.10(A) for casing and cementing states that the "operator shall equip a well drilled for oil or gas with surface and intermediate casing strings and cement as may be necessary to effectively seal off and isolate all water-, oil- and gas-bearing strata and other strata encountered in the well down to the casing point."

As shown on **Figure 4.1-1** and discussed in Section 3.6, there are multiple oil- and gas- related wells within the MMA for the Maljamar wells. As discussed in Section 3.6, most of these wells are completed in production zones more than 4,000 ft above the injection zone for the Maljamar AGI #1 and #2 wells (at 9,580 ft and 9,603 ft, respectively).

Figure 5.2-1 shows the location of the oil- and gas- related wells completed in the Abo, Cisco, Devonian, and Wolfcamp with respect to the MMA and the TAG plume.

The NRAP risk assessment focused on the deep wells within the MMA (see **Figure 5.2-1** and **Appendix 3**) which were completed in the Abo, Cisco, Devonian and Wolfcamp. Some of these wells penetrate the injection and/or confining zones while others do not. These deep wells were chosen for NRAP analysis due to the proximity of their total depth to the confining and injection of the Maljamar AGI wells. While it is highly unlikely that CO_2 would leak from wells that do not penetrate the confining zone, Frontier addressed all of these deep wells in the NRAP risk analysis. The NRAP tool utilized the reservoir parameters, well data, formation geology, and MMA area to predict the rate and quantity of CO_2

leakage. The worst-case scenario is that all the deep wells were situated directly at the source of CO_2, that is at the location of the injection well. The highest leakage rate for one well in this situation is approximately 4.7e-5 kg/s. The maximum CO_2 leakage from a single well over a 30-year injection period is 1,400 kg. When compared to the total amount of CO_2 injected over a continuous period of 30 years (with an injection rate of 3.5 million standard cubic feet per day), the mass of leaked CO_2 accounts for only 0.0018% of the total injected CO_2. This leakage is considered negligible. Furthermore, the worst-case scenario in which the deep wells are positioned directly at the injection site, is unattainable in reality further diminishing the likelihood of risk. Hence, this CO_2 emissions to the surface via this leakage pathway is considered unlikely.

We have applied a 5X5 Risk Matrix (**Figure 5.2-2**) to evaluate the relative risk of CO_2 emissions to the surface posed by the numerous wells within the MMA shown in **Figure 4.1-1**. A risk probability of 2 is assigned to wells whose total depth is within the injection zone for the Maljamar wells and for wells that lie within the simulated TAG plume boundary. All other wells are assigned a risk probability of 1. A risk impact of 2 is assigned to wells whose total depth is within the injection zone and for wells that lie within the plume boundary except the Maljamar wells are assigned a risk impact value of 3. The overall risk rating is equal to the risk probability multiplied by the risk impact. These values are included in the table in **Appendix 3** for each of the wells.

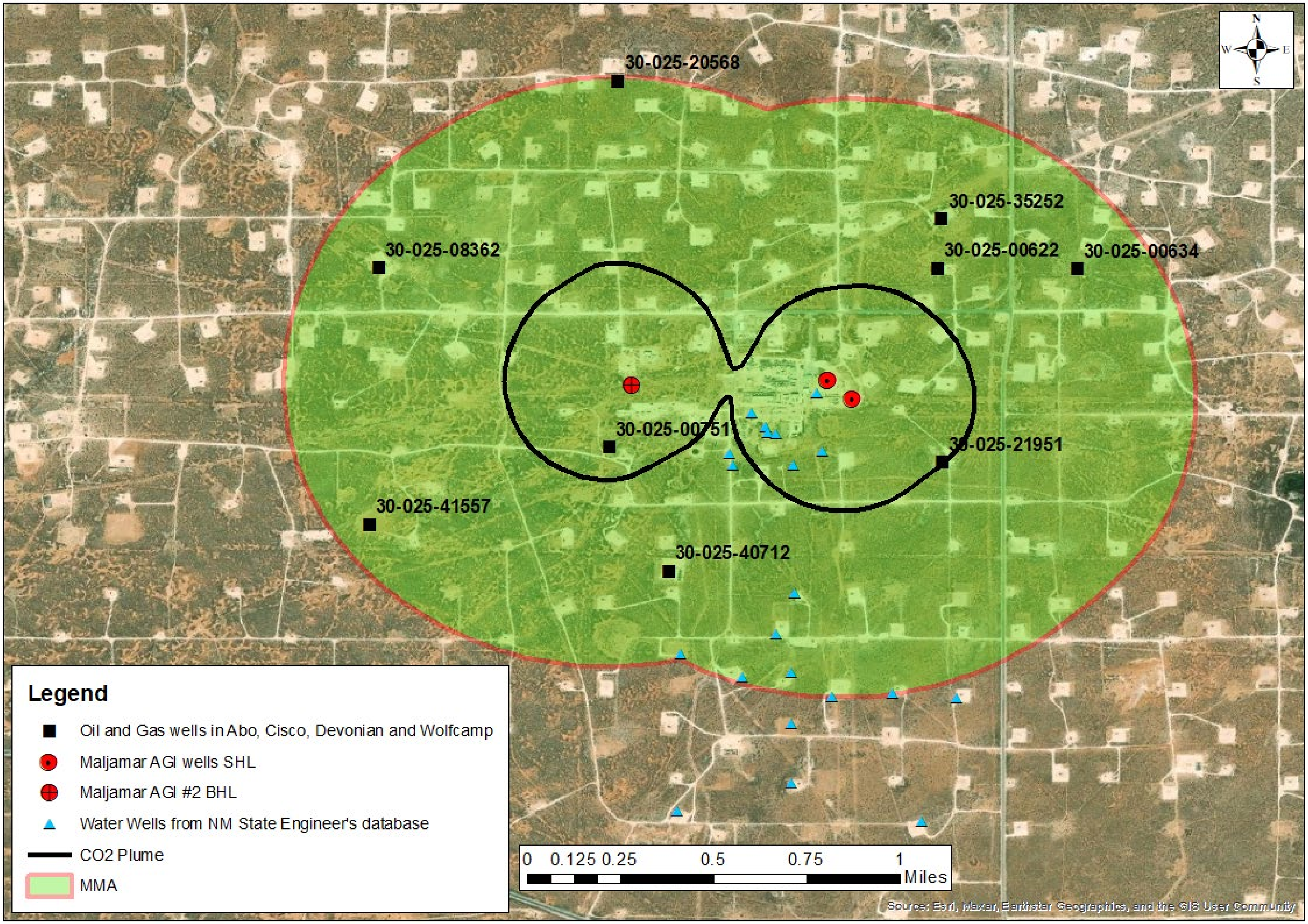

Figure 5.2-1: *shows the location of oil- and gas- related wells completed in the Abo, Cisco, Wolfcamp and Devonian within the MMA.*

5x5 Risk Matrix Example

Impact
How severe would the outcomes be if the risk occurred?

Probability — *What is the probability the risk will happen?*

	Insignificant 1	Minor 2	Significant 3	Major 4	Severe 5
5 Almost Certain	Medium 5	High 10	Very high 15	Extreme 20	Extreme 25
4 Likely	Medium 4	Medium 8	High 12	Very high 16	Extreme 20
3 Moderate	Low 3	Medium 6	Medium 9	High 12	Very high 15
2 Unlikely	Very low 2	Low 4	Medium 6	Medium 8	High 10
1 Very Unlikely	Very low 1	Very low 2	Low 3	Medium 4	Medium 5

Figure 5.2-1: *5X5 risk matrix used to assess relative risk of CO_2 emissions to the surface posed by wells within the MMA.*

5.2.1 Wells Completed in theYates-7 Rivers, Grayburg-San Andres, and Paddock Oil/Gas Production Zones

As discussed in Section 3.6, 210 of the 220 wells within the MMA are completed at depths more than 4,000 feet above the injection zone of the Maljamar AGI wells in the Yates-7 Rivers, Grayburg-San Andres, and Paddock oil/gas production zones.

Likelihood

Although these wells were not included in the NRAP analysis described above, Frontier concludes that these wells pose an even smaller risk to CO_2 leakage to the surface than the deeper wells that were included in the NRAP analysis. Therefore, Frontier concludes that CO_2 emissions to the surface through these wells is highly unlikely to unlikely (**See Appendix 3**).

Magnitude

Due to the depth of the production zone for this group of wells relative to the depth of the injection zone for the Maljamar wells, Frontier concludes that the magnitude of CO_2 emissions to the surface via these wells would be minimal. Carbon dioxide migrating upward through the confining zone of the Maljamar wells would be subject to other CO_2 trapping mechanisms (e.g. dissolution in formation fluids, mineralization) before encountering the production zones for this group of wells further reducing the magnitude of potential emissions. If detection monitoring indicates CO_2 emissions to the surface have occurred, the verification and quantification strategies described in Section 6.8 will be employed.

Timing

If CO_2 emissions to the surface were to occur via this group of wells, such emissions would occur well after the end of injection into the Maljamar wells.

5.2.2 Wells Completed in the Abo

As discussed in Section 3.6, the two wells reported in the NMOCD database to have been completed in the Abo are plugged and abandoned (API# 30-025-08362 and 30-025-00622 (see plugging & abandonment record in **Appendix 9**)). These two wells are 1.06 miles NW and 0.39 miles NE, respectively, from the SHL of Maljamar AGI #2. However, records for well 30-025-08362 indicate this well was drilled to 5,359 ft into the Upper Yeso to test the Paddock zone for oil/gas production - well above the injection zone for the Maljamar wells. Well 30-025-00622 was actually drilled to a total depth into the Devonian and was plugged back and produced from the Wolfcamp.

Likelihood

Due to the location of the Abo wells outside the simulated plume extent, Frontier concludes that CO_2 emissions to the surface via these wells is highly unlikely to unlikely (See **Appendix 3** for risk ratings).

Magnitude

The verification and quantification strategies described in Section 6.8 will be employed if detection monitoring in the vicinity of these wells indicates that CO_2 emissions to the surface have occurred.

Timing

If CO_2 emissions to the surface were to occur through the Abo wells, it would most likely occur during operation of the Maljamar wells when pressures due to injection are greatest.

5.2.3 Wells Completed in the Wolfcamp-Cisco

As discussed in Section 3.6, the Maljamar AGI wells are included in the Wolfcamp-Cisco. The two wells listed as completed in the Wolfcamp (API#30-025-41557 and 30-025-00751) are both plugged and abandoned (see plugging and abandonment records in **Appendix 9**). These wells are 1.12 miles WSW and 0.53 miles WSW, respectively, from the SHL of Maljamar AGI #2. Well 30-025-41557 is near the boundary of the MMA southwest of the BHL of AGI #2; well 30-025-00751 is south southwest of the BHL of AGI #2 and within the modeled delineation of the TAG plume.

The remaining well (API# 30-025-40712) is an active saltwater disposal well located approximately 0.63 miles SW of the SHL of Maljamar AGI #2 and outside the delineated TAG plume and within the MMA as shown on **Figure 5.2-1.** This well was spudded in 2012 and constructed with all casing strings cemented to the surface.

Likelihood

Due to the location of these wells relative to the BHL of the AGI wells and that there is a 5-degree dip of the Wolfcamp units to the southeast (see Section 3.3) causing preferential TAG flow to the northwest , Frontier considers CO_2 emissions to the surface via this these wells to be unlikely (See **Appendix 3** for risk ratings).

Magnitude

The verification and quantification strategies described in Section 6.8 will be employed if detection monitoring in the vicinity of these wells indicates that CO_2 emissions to the surface have occurred.

Timing

If CO_2 emissions to the surface were to occur through these Wolfcamp Cisco wells, it would most likely occur during operation of the Maljamar wells when pressures due to injection are greatest.

5.2.4 Wells Completed in the Devonian Formation

Of the three wells completed in the Devonian, two (API# 30-025-21951 and 30-025-00634) are plugged and abandoned (see plugging and abandonment records in **Appendix 9**). These two wells are 0.34 miles SE and 0.64 miles NE, respectively, from the SHL of Maljamar AGI #2. The remaining well (API# 30-025-35252) is a gas production well located approximately 0.5 miles NE of the SHL of Maljamar AGI #2 and outside the delineated TAG plume and within the MMA.

Likelihood

Due to their location outside the simulated TAG plume extent these wells are considered unlikely to pose a risk of CO_2 emissions to the surface.

Magnitude

The verification and quantification strategies described in Section 6.8 will be employed if detection monitoring in the vicinity of these wells indicates that CO_2 emissions to the surface have occurred.

Timing

If CO_2 emissions to the surface were to occur through these Devonian wells, it would most likely occur during operation of the Maljamar wells when pressures due to injection are greatest.

5.2.5 Groundwater Wells

There are 12 groundwater wells (**Figure 4.1-1 and Appendix 4**) within the MMA for the Maljamar wells. The deepest of these wells is 400 feet deep while the rest of the wells with reported depths have depths between 100 and 160 feet. There is nearly 9,000 ft of strata between the deepest groundwater well and the top of the injection zone for the Maljamar wells.

Likelihood

Due to the shallow depth of the groundwater wells within the MMA relative to the injection zone for the Maljamar wells and the characteristics of the intervening 9,000 feet of strata, Frontier considers CO_2 emissions to the surface via the groundwater wells to be very unlikely.

Magnitude

If CO_2 emissions to the surface are detected through monitoring of groundwater wells as described in Section 7.7, Frontier will attempt to quantify the magnitude of the leak according to the strategies discussed in Section 6.8. However, due to the shallow depth of the groundwater wells within the MMA relative to the injection zone for the Maljamar wells and the characteristics of the intervening 9,000 feet of strata, the magnitude of such a leak is expected to be minimal.

Timing

If a leak were to occur through groundwater wells, it would reach the surface well after the end of injection.

5.2.6 Saltwater Disposal (SWD) Wells

Four injectors were identified within the MMA. These are wells 30-025-40712 which injects into the Cisco Formation and wells 30-025-39353, 30-025-39355 (inactive), and 30-025-39409 which inject into the San Andres Formation. These injectors are located south of the simulated TAG extent (**Figure 4.1-1**).

Likelihood

The three wells injecting into the San Andres do so at depths of approximately 4,200 feet well above the injection zone for the Maljamar wells. These wells are considered highly unlikely to pose a risk of CO_2 emissions to the surface. The well injecting into the Cisco is considered unlikely to pose a risk. (See Appendix 3 for risk ratings).for risk ratings).

Magnitude

The verification and quantification strategies described in Section 6.8 will be employed if detection monitoring in the vicinity of these wells indicates that CO2 emissions to the surface have occurred.

Timing

If a leak were to occur through these injector wells, it would reach the surface well after the end of injection.

5.3 Potential Leakage through Confining / Seal System

The reservoir characterization modeling discussed in Section 3.8 concluded that "the modeling results indicate that the Wolfcamp formation is capable of storing and trapping the intended gas volume without any impact on the adjacent wells." Section 3.3 states that the injection zones in the Wolfcamp strata are carbonate horizons made up of tabular foraminiferal-phylloid algal mounds and associated debris beds containing up to 20% percent porosity. Furthermore, shelf deposits, including lagoonal mudstones, encase the algal mounds in lower porosity and permeability, carbonate mudstones/wackestones. Finally, the fine-grained facies of the overlying Abo Formation provide vertical and lateral confinement for the Wolfcamp injection zone below.

Leakage through a confining zone happens at low-permeability shale formations containing natural fractures. The Maljamar AGI wells are injecting into the Wolfcamp Formation, located beneath the Abo Formation. The fine-grained facies of the overlying Abo Formation provide vertical and lateral confinement for the Wolfcamp injection zone below. Hence, an approximate permeability of 0.01 mD was considered in the Abo formation to conduct leakage assessment through confining zones using NRAP simulation. The worst scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, the worst case of leakage only shows that 0.0134% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. As we go further from the source of CO_2, the likelihood of such an event will reduce proportionally with the distance from the source. Considering it is the worst amount of CO_2 leakage, if the event happens, and the leak must pass upward through the confining zone and other geologic units, we conclude that the risk of leakage through this pathway is highly improbable.

Likelihood

Given the encasement of the algal mounds by carbonate mudstone, the low porosity and permeability of the fine-grained facies of the overlying Abo, operational limitations on injection pressure to prevent initiation or opening of any existing fractures through the confining zone and considering the NRAP risk analysis described above, Frontier considers the likelihood of CO_2 emissions to the surface through the confining zone to be highly unlikely.

Magnitude

As described above in the NRAP risk analysis, the worst scenario is defined as leakage through the seal happening right above the injection well, where CO_2 saturation is highest. However, the worst case of leakage only shows that 0.0134% of total CO_2 injection in 30 years was leaked from the injection zone to the seals. At increasing distances from the source of CO_2, the likelihood and magnitude of a leakage event decreases proportionally with the distance from the source. Furthermore, if such a leak through the confining zone were to occur, dissolution in overlying formation waters, mineralization and other trapping mechanisms for the CO_2 would further reduce the mass of CO_2 that might reach the surface. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO_2 emissions to the surface have occurred.

Timing

If a CO_2 leak were to occur through the confining zone, it would most likely occur during active injection close to the well where the greatest injection pressure is. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

5.4 Potential Leakage due to Lateral Migration

Lateral migration of the TAG plume was addressed in Section 3.3 (Lithologic and Reservoir Characteristics) and in Section 3.8 (Reservoir Characterization Modeling). The lithologic and reservoir characterization indicated “that injected fluid would spread radially from the point of injection with a small elliptical component to the northwest” although “local heterogeneities in permeability and porosity will exercise significant control over fluid migration and the overall three-dimensional shape of the injected gas plume.” The results of the reservoir modeling indicate the TAG plume is unlikely to migrate laterally within the injection zone to conduits to the surface.

Likelihood

The discussion of the lithologic and reservoir characteristics presented in Section 3.3 indicated several modes of lateral movement of the TAG stream during the 30 years of injection. However, there are no identified potential leakage pathways northwest of the BHL of the AGI wells - the likely preferential movement of the TAG plume due to the 5-degree dip of the Wolfcamp units to the southeast. Therefore, Frontier considers CO_2 emissions to the surface via lateral migration to be unlikely.

Magnitude

Since the simulation modeling presented in Section 3.8 indicates that the TAG plume is unlikely to migrate laterally to conduits to the surface the magnitude of such a leak if it were to occur would be negligible. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO2 emissions to the surface have occurred.

Timing

For reasons described above, a leak, if it were to occur, via lateral migration would occur well after injection ceased.

5.5 Potential Leakage due to Faults and Fractures

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. The closest fault to the Maljamar wells is 3.5 miles north (**Figure 5.5-1**).

Prior to the injection, a thorough geological examination of the injection zone and surrounding formations was done to acquire information about the geology and to locate and understand the distribution of faults and fractures. However, no faults were found within the MMA that may act as potential leakage pathways. The nearest recognized fault is located around 3.5 miles north of the Maljamar site.

Likelihood

Due to the fact that there are no identified faults within the MMA, CO_2 emissions to the surface via faults and fractures is unlikely. Furthermore, the results of the NRAP risk analysis of leakage through the fault 3.5 miles north of the Maljamar wells indicates a leakage rate of zero. Therefore, Frontier considers CO_2 emissions to the surface via faults and fractures to be unlikely.

Magnitude

For the reasons described above, the magnitude of a leak, if it were to occur, through faults and fractures is estimated to be negligible. Nevertheless, the verification and quantification strategies described in Section 6.8 will be employed if detection monitoring indicates that CO_2 emissions to the surface have occurred.

Timing

For the reasons described above, the timing of a leak, if it were to occur, through faults and fractures would occur well after injection ceased.

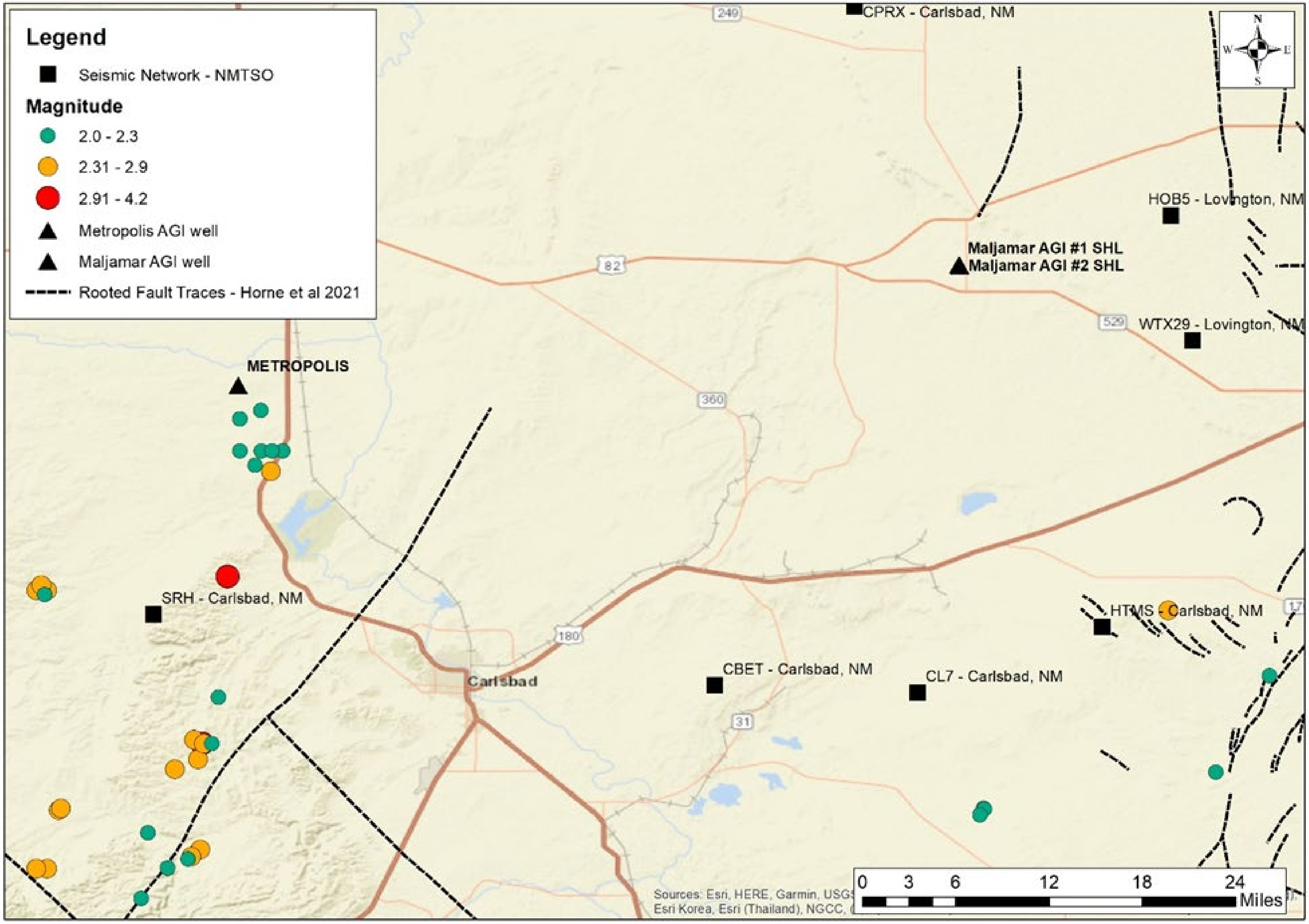

Figure 5.5-1: *New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023)*

5.6 Potential Leakage due to Natural or Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Maljamar Gas Plant operations. The closest recent seismic events are:

- 25 miles, 07/2023, Magnitude 2.36
- 30 miles, 02/2023 Magnitude 2.13

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Maljamar Gas Plant.

Likelihood

Due to the distance between the Maljamar wells and the recent seismic events and the magnitude of the events, Frontier considers CO_2 emissions to the surface due to seismicity to be unlikely.

Magnitude

If a seismic event occurs at the time the Maljamar wells are injecting and in the vicinity of the Maljamar plant, Frontier will implement the verification and quantification strategy described in Section 6.8 to attempt to verify whether the seismic event was due to the injection into the Maljamar well and to quantify any leak of CO_2 to the surface.

Timing

If a leak of CO_2 to the surface occurs as a result of a seismic event, if would likely occur at the time of the seismic event or shortly thereafter.

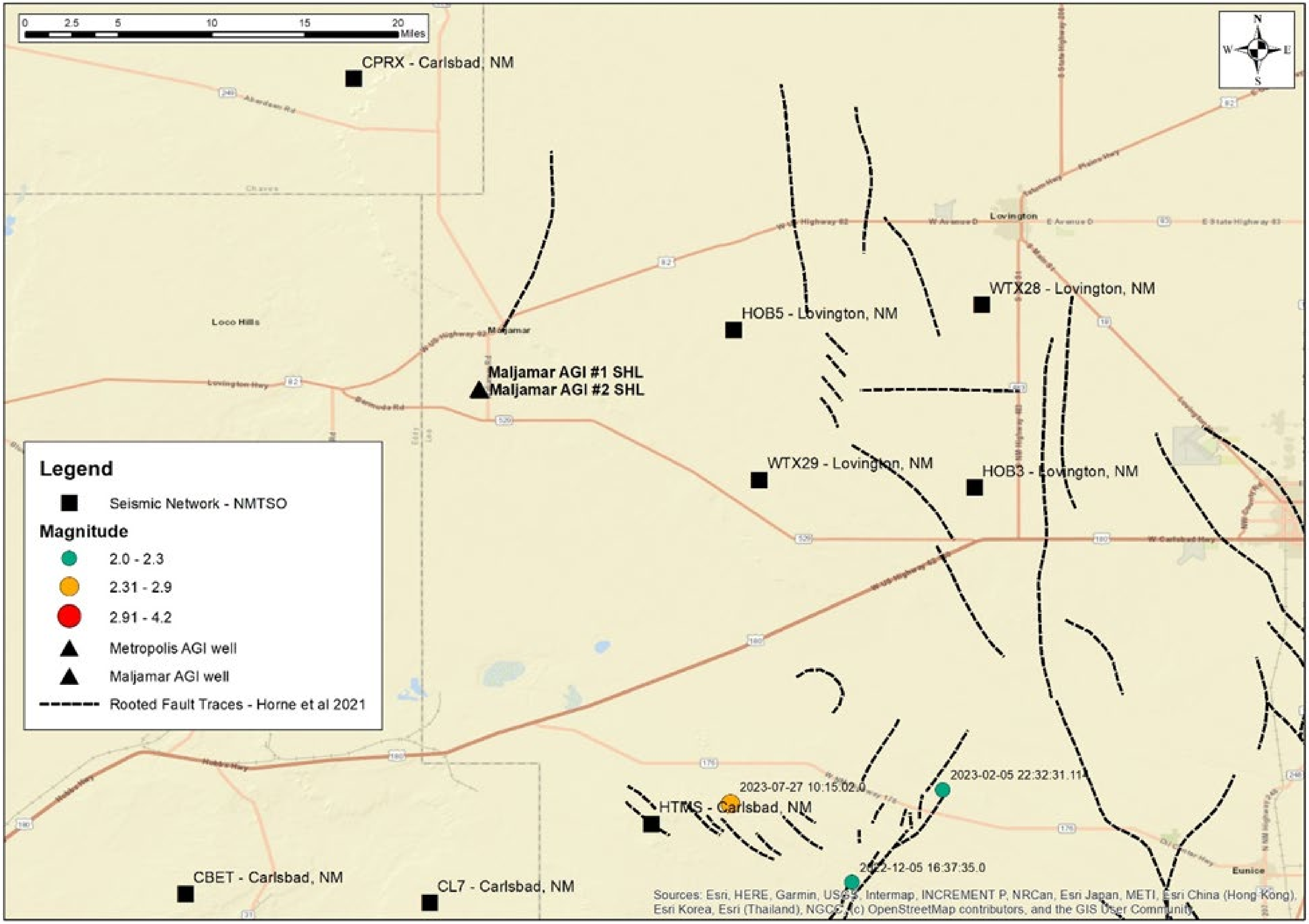

Figure 5.6-1: *NMTSO seismic network close to the Maljamar operation, recent seismic events and fault traces (2022-2023)*

6. Strategy for Detecting and Quantifying Surface Leakage of CO_2

Frontier will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. Compositional analysis of Frontier's gas injectate at the Maljamar Gas Plant indicates Frontier is required to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Frontier considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection.

Table 6-1: *Summary of Leak Detection Monitoring*

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors • Personal and hand-held gas monitors
Maljamar AGI #1 and #2 wells	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors
Faults and Fractures	• DCS surveillance of well operating parameters • Fixed in-field gas monitors
Natural or Induced Seismicity	• NMTSO seismic monitoring stations • DCS surveillance of well operating parameters • Fixed in-field gas monitors
Additional monitoring	• Soil flux monitoring • Groundwater monitoring

6.1 Leakage from Surface Equipment

Frontier implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters.

Leaks from surface equipment are detected by Frontier field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events. Frontier also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the Programmable Logic Controller (PLC) to the ESD system of the plant. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

The following description of the gas detection equipment at the Maljamar Gas Plant was extracted from the H_2S Contingency Plan, October, 2015:

> "The Plant and AGI Facility use RAE Guard EC, FGM-1300 fixed H_2S sensors. These sensors are part of a fixed-point monitoring system used to detect the presence of H_2S in ambient air. The blue flashing beacon is activated at H_2S concentrations of 10 ppm or greater. The horn is also activated with a continuous alarm at H_2S concentrations of 10 ppm or greater. The fixed H_2S monitors are strategically located throughout the Plant to detect an uncontrolled released of H_2S. Four continuous read H_2S monitors are located immediately around the wellhead and are monitored continuously, connected, and linked electronically through the Programmable Logic Controller (PLC) to the ESD system of the plant. These monitors will immediately activate the ESD system at the AGI Facility in the event that H_2S at 20 ppm is detected. The Automatic Subsurface Safety Valve (SSV) which is also linked to the PLC is designed to prevent any backflow from the level of the SSV (295 ft.), and it allows access for servicing the well or taking corrective actions as needed.
>
> The Plant operators are able to monitor the H_2S levels of all the Plant sensors on the control monitor located in the control room. In addition, select employees can access this information remotely. These sensors are shown in **Figure 6.1-1**. These sensors all have to be acknowledged and will not clear themselves. This requires immediate action for any occurrence or malfunction. The sensors have battery backup systems and are calibrated monthly. Audible alarm systems are also calibrated monthly. Handheld gas detection monitors are available to plant personnel to check specific areas and equipment prior to initiating maintenance or working on equipment. There are 4 handheld monitors, and each individual is assigned a personal H_2S monitor. The handheld gas detection devices are RKI GSX-2900 4-way monitors. The detectors have sensors for oxygen, LEL (lower explosive limit hydrocarbon atmospheres), H_2S, and carbon monoxide. They indicate the presence of H_2S with a beeping sound at 10 ppm. The beeps change in tone as H_2S increases to 20 ppm. The personal monitors are set to alarm (beep) at 10 ppm with the beeps becoming closer together as the H_2S concentration increases to 20 ppm. Both the handheld and personal monitors have digital readouts of H_2S ppm concentration. The Plant compressor building has two methane sensors; one sends a call out at the 30% lower explosive limit (LEL); the second shuts the compressors down at 50% LEL. The methane sensors are visual and audible alarms. The compressor building also is equipped with fire eyes that will also shut the units down. The four product pumps also have LEL sensors."

Frontier's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S.

Quantification of CO_2 emissions from surface equipment and components will be estimated according to the requirements of 98.444 (d) of Subpart RR as discussed in Sections 8.4 and 10.1.4. Furthermore, if

CO_2 surface emissions are indicated by any of the monitoring methods listed in **Table 6.1**, Frontier will quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Frontier has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). Frontier will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by Frontier or third parties.

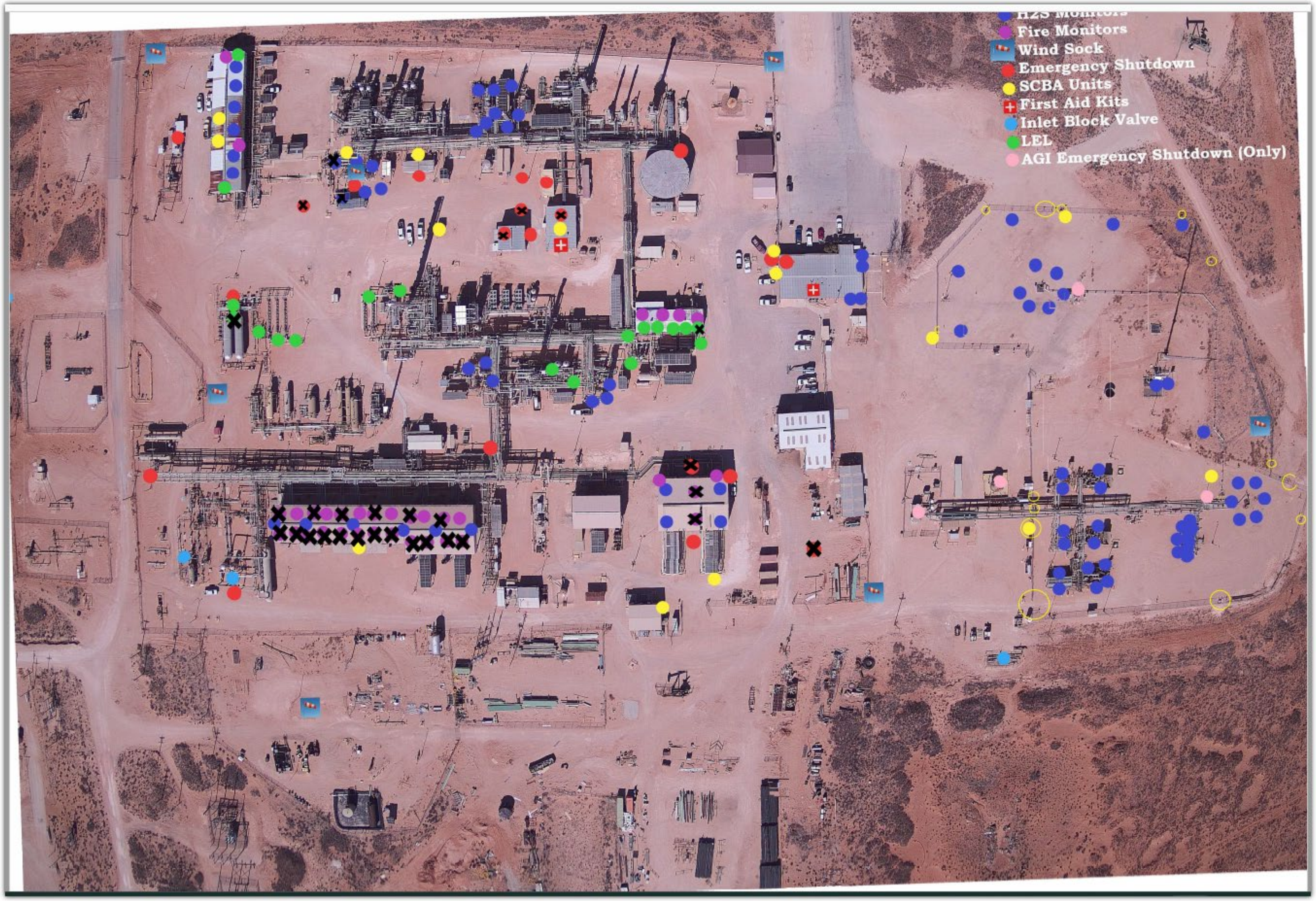

Figure 6.1-1: Location of alarms, monitors, and safety equipment. The blue circles are the H_2S monitors.

6.2 Leakage from the Maljamar Wells

As part of ongoing operations, Frontier continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. These data are monitored continuously by qualified field personnel who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

Leaks from the Maljamar wells are detected by implementing several monitoring methods including DCS surveillance, visual inspection of the surface facilities and wellheads, injection well monitoring and mechanical integrity testing, and personal H_2S monitors. To monitor leakage and wellbore integrity, data from the bottom hole temperature and pressure gauge and wellhead gauges are continuously recorded by the DCS. Mechanical integrity tests are performed annually. Failure of an MIT would indicate a leak in the well and result in immediate action by shutting in the well, accessing the MIT failure, and implementing mitigative steps.

If operational parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Frontier will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site.

6.3 Leakage from Other Existing Wells within the MMA

Well surveillance by other operators of existing wells will provide an indication of CO_2 leakage as will the fixed in-field gas monitors. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the Maljamar wells, described in Sections 6.2 and 7.4, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters indicate leakage of CO_2 through the confining / seal system, Frontier will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well(s).

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the Maljamar wells during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The continuous parameter monitoring described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If monitoring of operational parameters indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, Frontier will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. As this scenario would be considered a material change per 40 CFR 98.448(d)(1), Frontier will submit a revised MRV plan as required by 40 CFR 98.448(d).

6.6 Leakage due to Faults and Fractures

The geologic characterization at the Maljamar well site (see Section 3) revealed no faults within the MMA. The closest fault to the Maljamar wells 3.5 miles north. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, Frontier will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. Frontier will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.7 Leakage due to Natural or Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, Frontier will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Maljamar Gas Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at 5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

The following seismic stations will be monitored to assess potential natural and induced seismic events (The distance between the Maljamar wells and the NMTSO seismic monitoring station is shown in parentheses):

North:

- CPRX - Carlsbad, NM (17.6 miles)

East:

- HOB5 - Lovington, NM (11.8 miles)
- WTX28 - Lovington, NM (13.5 miles)
- WTX29 - Lovington, NM (23.1 miles)
- HOB3 - Lovington, NM (22.9 miles)

South:

- HTMS - Carlsbad, NM (30.1 miles)
- CL7 - Carlsbad, NM (27.6 miles)
- CBET - Carlsbad, NM (24.5 miles)

If monitoring of the NMTSO seismic monitoring stations, the operational parameters and the fixed in-field gas monitors indicates surface leakage of CO_2 linked to seismic events, Frontier will assess whether the CO_2 originated from the Maljamar wells and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

As required by 40 CFR 98.444(d), monitoring and quantification of all CO_2 emissions from equipment located on the surface between the injection flow meter used to measure injection quantity and the injection well head will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP. Section 40 CFR 98.233(q)(1)(ii) of Subpart W requires that equipment leak surveys be conducted using leak detection methods listed in 98.234(a)(1) through (5) on equipment listed in 98.232(d)(7) for natural gas processing facilities and employ emission calculation procedures specified in 98.233(q)(2). The listed leak detection methods include optical gas imaging equipment which Frontier has chosen to conduct its equipment leak surveys. Frontier will operate the optical gas imaging equipment according to the requirements in 98.234 (a)(1) and as specified at 40 CFR 60.18. Frontier conducts monthly optical gas imaging in accordance with New Mexico Environment Department (NMED) rules contained in 20.2.50.1116.

Frontier will respond to detected and quantified leaks from surface equipment by isolating the source of the leak and repairing it immediately.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (**Table 6-1**) that identifies the leak.

Leaks associated with the point sources, such as the injection well, and identified by failed MITs, and variations of operational parameters outside acceptable ranges, can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. Frontier may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the soil CO_2 flux monitoring network placed strategically in their vicinity. The soil CO_2 flux monitoring network as described in Section 7.8 consists of placing 8-centimeter diameter PVC soil collar throughout the monitoring area. The soil collars will be left in place such that each measurement will use the same locations and collars during data collection. Measurements will be made by placing the LI-8100A chamber on the soil collars and using the integrated iOS application to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. Initially, data will be collected monthly, for six months, to establish a baseline. After the baseline is established, data will be collected at a quarterly interval. Data is presented as concentration of CO_2 (millimoles)/area (meters squared)/time (seconds). Quarterly measurements will be compared to baseline data to determine the percentage of change over time.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Surface emissions of CO_2 from nonpoint sources such as through the confining zone, along faults or fractures, or which may be initiated by seismic events will be detected by Frontier's leak detection network consisting of DCS surveillance of operating parameters, hand-held gas sensors, fixed in-field gas sensors, groundwater monitoring, NMTSO seismic monitoring, and CO_2 flux monitoring as listed in **Table 6-1**. If surface leaks are detected, Frontier will attempt to identify the pathway through which the leak occurred and to quantify the magnitude of the leak by employing various advanced verification and quantification methods as listed in the Technical Support Document. Additionally, technologies for quantifying CO_2 surface emissions are continuing to be developed and refined, including those currently under development by the New Mexico Institute of Technology and will be deployed in the event a leak is detected.

7. Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Frontier uses the existing automatic DCS to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. Frontier considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage. The following describes Frontier's strategy for collecting baseline information.

7.1 Visual Inspection

Frontier field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a surrogate for CO_2, at the Maljamar Gas Plant.

7.2 Fixed In-Field, Handheld, and Personal H_2S Monitors

Compositional analysis of Frontier's gas injectate at the Maljamar Gas Plant indicates an approximate H_2S concentration of 22% thus requiring Frontier to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Due to the toxicity of H_2S, multiple fixed H_2S monitors are located throughout the plant and at the injection well sites, and offsite (beacons) are positioned around the plant perimeter. Fixed H_2S monitors are set to alarm at 10 ppm. Additionally, all Frontier employees and contract personnel are required to wear personal H_2S monitors set to alarm at 5 ppm. Any alarm by a fixed or personal H_2S monitor would trigger emergency response procedures to immediately secure the facility and contain a leak. Both fixed and personal H_2S monitors act as a proxy for a CO_2 leak and the concentrations recorded by the spectrometer along with the duration of the leak will be used to determine the mass of CO_2 released.

In addition to using fixed and personal monitors, baseline monitoring at the Maljamar Gas Plant will commence upon approval of this MRV plan. The Maljamar Gas Plant has been operating for multiple years and empirical data exists on the amount of CO_2 injected over multiple years thereby setting a baseline of expectations going forward. Measurements of the injection volume and the concentration of CO_2 in the acid gas stream will be recorded and compared to previous operating history. Any significant deviation from past injection history will be investigated.

7.3 Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat. Also, see Section 6.2 for continuous monitoring of pressure and temperature in the well.

7.4 Well Surveillance

Frontier adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. Frontier's Routine Operations and Maintenance Procedures for the Maljamar wells ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

7.5 CO_2 Monitoring

Frontier has purchased an IPS-4 UV/IR Full Spectrum Analyzer to be deployed for measuring the concentration of CO_2 and H_2S in the injection stream into the Maljamar AGI wells. This will provide a high degree of accuracy in calculating the mass of CO_2 injected. As stated above, Frontier considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage.

7.6 Seismic (Microseismic) Monitoring

Data recorded by the existing seismometers within 10-mile radius, deployed by the state of NM, will be analyzed by New Mexico Bureau of Geology, see **Figure 5.6-1**, and made publicly available. A report and a map showing the magnitudes of recorded events from seismic activity will be generated. The data is being continuously recorded. By examining historical data, a baseline can be established. Measurements taken after baseline measurements will be inspected to identify anomalous values. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous values during that period .

7.7 Groundwater Monitoring

Groundwater wells, in the vicinity of the injection well(s), will be identified. Water samples will be collected and analyzed on a monthly basis, for six months, to establish baseline data. After establishing baseline, water samples will be collected and analyzed at a quarterly interval. The water analysis included total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). See **Table 7.7-1**.

Table 7.7-1: *Groundwater Analysis Parameters*

Parameters
pH
Alkalinity as HCO3- (mg/L)

Parameters
Chloride (mg/L)
Fluoride (F-) (mg/L)
Bromide (mg/L)
Nitrate (NO3-) (mg/L)
Phosphate (mg/L)
Sulfate (SO42-) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. Periodic monitoring of CO_2 soil flux allows for continual characterization of the interaction between the subsurface and surface to better understand the potential leakage pathways and to provide actionable recommendations based on the collected data. The data will be collected on a monthly basis, for six months, to establish a baseline. After the baseline is established, data will be collected at a quarterly interval.

CO_2 soil flux measurements will be taken using a LI-COR LI-8100A (LI-COR, 2010 flux chamber), or similar instrument, at preplanned locations at the site.

PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

8. Site Specific Considerations for Mass Balance Equation

Appendix 6 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 7** includes the details of the twelve equations from Subpart RR. Not all of these equations apply to Frontier's current operations at the Maljamar Gas Plant but are included in the event Frontier's operations change in such a way that their use is required.

Each acid gas stream at both the Maljamar and Dagger Draw gas plants has a dedicated flow meter and spectrophotometer that measures both CO_2 and H_2S in real time. The signals from the spectrophotometer are continuously monitored and rolled up to an hourly basis and quantified on a mass basis. We propose to sum the two values from each plant for a daily and or annual total.

8.1 CO_2 Received

Currently, Frontier receives sour natural gas to the Maljamar Gas Plant through the Maljamar gathering system. The gas is processed as described in Section 3.7 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection.

Per 40 CFR §98.443, the mass of CO_2 received must be calculated using the CO_2 received equations (RR-1, RR-2, and RR-3) unless the procedures in 40 CFR 98.444(a)(4) are followed. 40 CFR 98.444(a)(4) states that if the CO_2 received is wholly injected and is not mixed with any other supply of CO_2, the annual mass of CO_2 injected (RR-5 and RR-6) may be reported as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. This scenario applies to the operations at both the Dagger Draw and Maljamar Gas Plants as CO_2 received for the injection wells is wholly injected and not mixed with any other supply; therefore the annual mass of CO_2 injected will be equal to the amount received. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected at both gas plants. Any future streams would be metered separately before being combined into the calculated stream.

Although Frontier does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. If CO_2 received in containers results in a material change as described in 40 CFR 98.448(d)(1), Frontier will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Frontier injects CO_2 into the existing Maljamar wells at the Maljamar Gas Plant. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the well. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter, u, in Equation RR-5 corresponds to meter MVM in **Figure 3.7-1** for the Maljamar Gas Plant.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

The volumetric flow meter, u, in Equation RR-6 corresponds to meter DDVM for the Dagger Draw Gas Plant and MVM for the Maljamar Gas Plant.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

Frontier does not produce oil or gas or any other liquid at its Maljamar Gas Plant facility so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Surface leakage of CO_2 will not be measured directly, rather it will be determined by employing the CO_2 proxy detection system described in Section 7.3. The monitoring methods described in Section 7 would indicate the occurrence of gas leakage at the surface. The mass of CO_2 emitted would be calculated based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage (CO_{2E}) from the leakage pathways identified and evaluated in Section 5. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.5 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{(Equation RR-10)}$$

where:

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

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

x = Leakage pathway.

8.5 CO_2 Sequestered

Since Frontier does not actively produce oil or natural gas or any other fluid at the Maljamar Gas Plant, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{(Equation RR-12)}$$

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

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

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

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

9. Estimated Schedule for Implementation of MRV Plan

Frontier proposes to initiate collection of data to determine the amount of carbon dioxide sequestered beginning on June 1, 2024. Expected baseline data for the Maljamar Gas Plant has been determined as Frontier has been reporting the amount of CO_2 injected under subpart UU for quite some time. Additionally, Frontier has installed flow measurement and an Ametek IPS-4 spectrophotometer at the Maljamar Gas Plan on the acid gas stream.

10. GHG Monitoring and Quality Assurance Program

Frontier will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Frontier's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-5 and RR-8 of Subpart RR of the GHGRP, if applicable: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. Frontier will adhere to the American Gas Association (AGA) Report #3 – Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids

10.1.2 CO_2 Received

Per 40 CFR §98.443, the mass of CO_2 received must be calculated using the CO_2 received equations (RR-1, RR-2, and RR-3) unless the procedures in 40 CFR 98.444(a)(4) are followed. 40 CFR 98.444(a)(4) states that if the CO_2 received is wholly injected and is not mixed with any other supply of CO_2, the annual mass of CO_2 injected (RR-5 and RR-6) may be reported as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. This scenario applies to the operations at both the Dagger Draw and Maljamar Gas Plants as CO_2 received for the injection wells is wholly injected and not mixed with any other supply; therefore the annual mass of CO_2 injected will be equal to the amount received. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected at both gas plants.

10.1.3 CO_2 Injected

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipeline to the Maljamar wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

As required by 98.444 (d), Frontier will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 98.444 (d) of Subpart RR, Frontier will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used.

10.1.5 Measurement Devices

As required by 40 CFR 98.444(e), Frontier will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration,

- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA / QC Procedures

Frontier will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.3 Estimating Missing Data

Frontier will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

10.4 Revisions of the MRV Plan

Frontier will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico.

11. Records Retention

Frontier will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Frontier will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors, if applicable.

(iii) The results of all required analyses.

(iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, Frontier will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(12) Any other records as specified for retention in this EPA-approved MRV plan.

12. Appendices

Appendix 1 - Frontier Maljamar Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Maljamar AGI #1	30-025-40420	130' FSL, 1,813' FEL; Section 21, T17S, R32E; NMPM	Lea, NM	09/24/2012	PBTD (plugged back total depth) 10,183’	9,452’
Maljamar AGI #2	30-025-42628	SHL 400’FSL, 2,100 FEL; Section 21, T21S, R32E; NMPM BHL 350’ FSL, 650’ FWL; Section 21, T21S, R32E; NMPM	Lea, NM	01/25/2016	TVD 10,236’ TMD 11,065’	10,168’

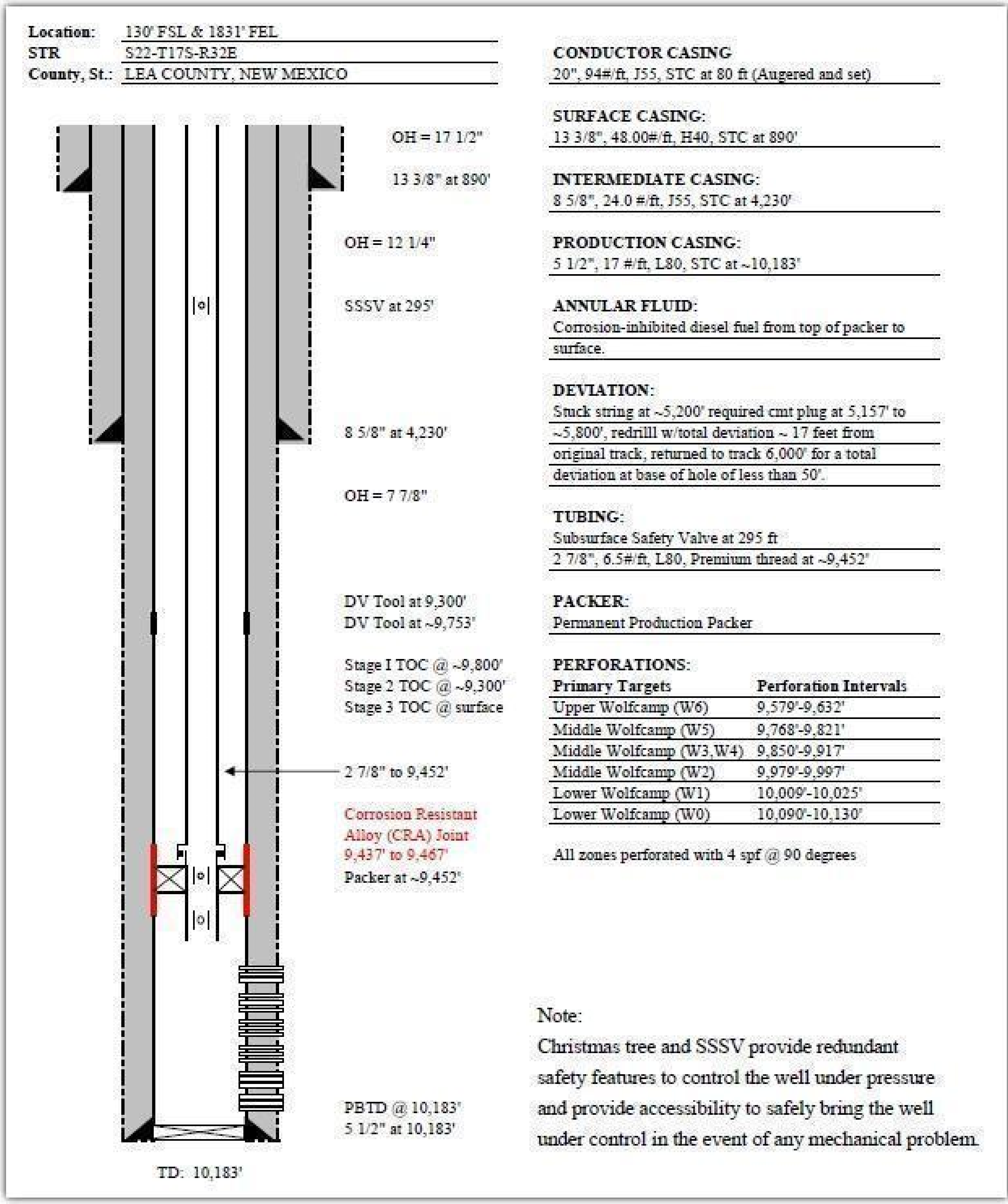

Figure Appendix 1-1: Maljamar AGI #1 Well schematic from H_2S Contingency Plan, October, 2015.

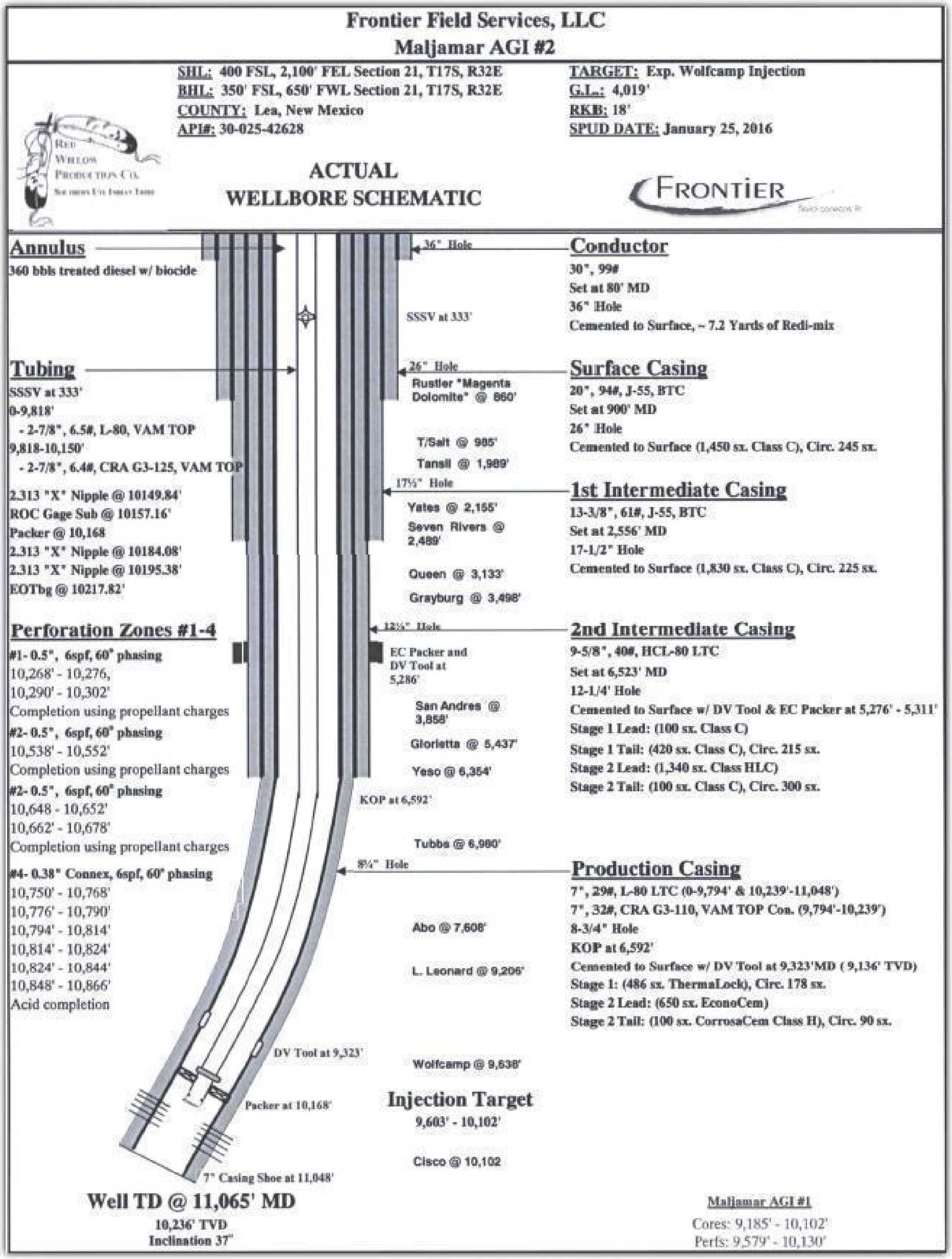

Figure Appendix 1-2: Maljamar AGI #2 Well Schematic from C-103 form dated April 20, 2017

Appendix 2 - Referenced Regulations

See **Appendix 2** of Part A of this MRV plan.

Appendix 3 - Oil and Gas Wells within the MMA / AMA for the Maljamar AGI #1 and #2 Wells

The Maljamar AGI #1 well is highlighted in bright yellow. The deep wells located within the MMA and completed in the Abo, Cisco, Devonian, and Wolfcamp are highlighted in orange.

API	Well Name	Type	Status	Trajectory	Formation	Lat	Long	TVD_FT	MD_FT	S	T	5x5 Risk Probability	5x5 Risk Impact	Total Risk Rating
30-025-35252	MC FEDERAL 006	GAS	PROD	VER	DEVONIAN	32.82018	-103.76536	15026	15026	21	17S	2	2	4
30-025-00622	BAISH A 008	OIL	P & A	VER	ABO	32.81825	-103.76552	13670	13670	21	17S	2	2	4
30-025-00634	BAISH B 005	OIL	P & A	VER	DEVONIAN	32.81824	-103.76008	13573	13573	22	17S	2	2	4
30-025-40712	PEARSALL FEDERAL SWD 001	GAS	INJECT	VER	CISCO	32.8065	-103.77595	10400	10400	28	17S	2	2	4
30-025-40420	MALJAMAR AGI 001	GAS	INJECT	VER	CISCO FM.	32.81318	-103.76877	10183	10183	21	17S	2	3	6
30-025-42628	MALJAMAR AGI 002	GAS	INJECT	Ver	CISCO FM.			10,236	11,065	21	17S	2	3	6
30-025-00751	QUEEN B 036	OIL	P & A	VER	WOLFCAMP	32.81132	-103.77826	10005	10015	28	17S	2	2	4
30-025-00619	BAISH A 005	OIL	PROD	VER	YATES	32.81918	-103.77255	9882	9882	21	17S	2	2	4
30-025-20216	BAISH A 009	OIL	P & A	VER	YATES	32.8228	-103.76827	9822	9822	21	17S	2	2	4
30-025-41557	CUTTHROAT FEDERAL 005	OIL	P & A	VER	WOLFCAMP	32.80831	-103.78758	9800	9800	29	17S	2	2	4
30-025-00745	MCA UNIT 382	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80411	-103.76454	9680	9680	28	17S	2	2	4
30-025-00745	MCA UNIT 382	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80411	-103.76454	9680	9680	28	17S	2	2	4
30-025-27064	MCA UNIT 361	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81958	-103.78297	8933	8933	20	17S	2	2	4
30-025-40239	J C FEDERAL 037	OIL	PROD	VER	PADDOCK	32.81372	-103.76824	7136	7136	21	17S	2	2	4
30-025-39167	J C FEDERAL 029	OIL	PROD	VER	PADDOCK	32.81485	-103.76898	7134	7134	21	17S	2	2	4
30-025-39168	J C FEDERAL 030	OIL	PROD	VER	PADDOCK	32.81372	-103.76655	7120	7120	21	17S	2	2	4
30-025-39506	J C FEDERAL 035	OIL	PROD	VER	PADDOCK	32.81554	-103.77004	7107	7107	21	17S	2	2	4
30-025-39629	MC FEDERAL 065	OIL	PROD	VER	PADDOCK	32.81532	-103.77196	7036	7036	21	17S	2	2	4
30-025-39500	MC FEDERAL 066	OIL	PROD	VER	PADDOCK	32.81566	-103.778	7025	7025	21	17S	2	2	4
30-025-39059	J C FEDERAL 025	OIL	PROD	VER	PADDOCK	32.81581	-103.76825	7017	7017	21	17S	2	2	4
30-025-39107	MC FEDERAL 035	OIL	PROD	VER	PADDOCK	32.81668	-103.77972	6969	6998	21	17S	2	2	4
30-025-39163	MC FEDERAL 036	OIL	PROD	VER	PADDOCK	32.81439	-103.77751	6906	6919	21	17S	2	2	4
30-025-23433	MCA UNIT 251	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81585	-103.7716	4250	4250	21	17S	2	2	4
30-025-24196	MCA UNIT 318	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81274	-103.76708	4200	4200	28	17S	2	2	4
30-025-24267	MCA UNIT 328	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81543	-103.76825	4200	4200	21	17S	2	2	4
30-025-12769	MCA UNIT 116	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81262	-103.7712	4119	4119	28	17S	2	2	4
30-025-20522	MCA UNIT 234	OIL	DRILLED	VER	GRAYBURG | SAN ANDRES	32.8129	-103.77575	4100	4100	21	17S	2	2	4
30-025-00608	MCA UNIT 093	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81301	-103.77792	4080	4080	21	17S	2	2	4
30-025-00733	MCA UNIT 114	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81103	-103.77791	4071	4071	28	17S	2	2	4
30-025-12804	MCA UNIT 113	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81263	-103.77998	4050	4050	28	17S	2	2	4

API	Well Name	Type	Status	Trajectory	Formation	Lat	Long	TVD_FT	MD_FT	S	T	5x5 Risk Probability	5x5 Risk Impact	Total Risk Rating
30-025-00737	MCA UNIT 117	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81101	-103.76931	3834	3834	28	17S	2	2	4
30-025-00617	STATE M COM 001	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81463	-103.76932	0	0	21	17S	2	2	4
30-025-00750	BAISH B 033	OIL	P & A	VER	7 RIVERS	32.81193	-103.77684	0	0	28	17S	2	2	4
30-025-39876	MC FEDERAL 059	OIL	PROD	VER	PADDOCK	32.81984	-103.76872	7205	7227	21	17S	1	1	1
30-025-40165	GC FEDERAL 047	OIL	PROD	VER	PADDOCK	32.81698	-103.78072	7127	7160	20	17S	1	1	1
30-025-40150	GC FEDERAL 036	OIL	PROD	VER	PADDOCK	32.81843	-103.78732	7129	7151	20	17S	1	1	1
30-025-40237	GC FEDERAL 044	OIL	PROD	VER	PADDOCK	32.81492	-103.78725	7122	7150	20	17S	1	1	1
30-025-39108	MC FEDERAL 037	OIL	PROD	DIRECTIONAL	PADDOCK	32.81522	-103.77486	7061	7148	21	17S	1	1	1
30-025-39697	GC FEDERAL 037	OIL	PROD	VER	PADDOCK	32.81991	-103.78644	7126	7147	20	17S	1	1	1
30-025-39614	J C FEDERAL 036	OIL	PROD	VER	PADDOCK	32.81364	-103.76507	7146	7146	21	17S	1	1	1
30-025-39877	MC FEDERAL 060	OIL	PROD	VER	PADDOCK	32.8183	-103.77207	7119	7145	21	17S	1	1	1
30-025-39001	MC FEDERAL 033	OIL	PROD	VER	PADDOCK	32.816	-103.76753	7099	7138	21	17S	1	1	1
30-025-39875	MC FEDERAL 055	OIL	PROD	VER	PADDOCK	32.82236	-103.7666	7110	7138	21	17S	1	1	1
30-025-39270	GC FEDERAL 032	OIL	P & A	VER	PADDOCK	32.81423	-103.78674	7114	7136	20	17S	1	1	1
30-025-39169	J C FEDERAL 031	OIL	PROD	VER	PADDOCK	32.81415	-103.76122	7135	7135	22	17S	1	1	1
30-025-39473	GC FEDERAL 045	OIL	PROD	VER	PADDOCK	32.81491	-103.78695	7104	7134	20	17S	1	1	1
30-025-40240	MC FEDERAL 062	OIL	PROD	VER	PADDOCK	32.81838	-103.77827	7105	7130	21	17S	1	1	1
30-025-39471	GC FEDERAL 038	OIL	PROD	DIRECTIONAL	PADDOCK	32.81797	-103.78183	7010	7129	20	17S	1	1	1
30-025-38551	MC FEDERAL 013	OIL	PROD	VER	PADDOCK	32.82235	-103.76611	7125	7125	21	17S	1	1	1
30-025-39930	J C FEDERAL 054	OIL	PROD	VER	PADDOCK	32.81472	-103.76142	7122	7122	22	17S	1	1	1
30-025-40125	MC FEDERAL 064	OIL	PROD	VER	PADDOCK	32.81787	-103.76994	7109	7120	21	17S	1	1	1
30-025-40143	GC FEDERAL 046	OIL	PROD	DIRECTIONAL	PADDOCK	32.81486	-103.7842	7103	7119	20	17S	1	1	1
30-025-39426	MC FEDERAL 053	OIL	PROD	VER	PADDOCK	32.82276	-103.76843	7115	7115	21	17S	1	1	1
30-025-39265	GC FEDERAL 029	OIL	PROD	VER	PADDOCK	32.81495	-103.78435	7087	7114	20	17S	1	1	1
30-025-39323	GC FEDERAL 028	OIL	PROD	VER	PADDOCK	32.81557	-103.78824	7114	7114	20	17S	1	1	1
30-025-39861	J C FEDERAL 052	OIL	PROD	VER	PADDOCK	32.81552	-103.7618	7112	7112	22	17S	1	1	1
30-025-40096	MC FEDERAL 057	OIL	PROD	VER	PADDOCK	32.8199	-103.76769	7067	7112	21	17S	1	1	1
30-025-39867	MC FEDERAL 063	OIL	PROD	VER	PADDOCK	32.81707	-103.7747	7110	7110	21	17S	1	1	1
30-025-39931	MC FEDERAL 056	OIL	PROD	VER	PADDOCK	32.82151	-103.7747	7110	7110	21	17S	1	1	1
30-025-39470	BC FEDERAL 059	OIL	PROD	VER	PADDOCK	32.82283	-103.78115	7099	7099	20	17S	1	1	1
30-025-39425	MC FEDERAL 042	OIL	PROD	VER	PADDOCK	32.8212	-103.779	7084	7084	21	17S	1	1	1
30-025-38999	MC FEDERAL 031	OIL	PROD	VER	PADDOCK	32.8207	-103.76181	7050	7050	22	17S	1	1	1
30-025-39087	J C FEDERAL 020	OIL	PROD	VER	PADDOCK	32.81915	-103.75966	7048	7048	22	17S	1	1	1
30-025-39262	GC FEDERAL 024	OIL	PROD	VER	PADDOCK	32.81651	-103.78427	7020	7045	20	17S	1	1	1
30-025-39427	MC FEDERAL 054	OIL	PROD	VER	PADDOCK	32.82282	-103.7747	7045	7045	21	17S	1	1	1
30-025-38717	MC FEDERAL 024	OIL	PROD	VER	PADDOCK	32.82114	-103.77686	7027	7042	21	17S	1	1	1
30-025-39247	J C FEDERAL 027	OIL	PROD	VER	PADDOCK	32.81621	-103.75965	7040	7040	22	17S	1	1	1
30-025-39293	MC FEDERAL 039	OIL	PROD	VER	PADDOCK	32.82181	-103.76888	7040	7040	21	17S	1	1	1
30-025-38776	MC FEDERAL 017	OIL	PROD	VER	PADDOCK	32.82322	-103.77042	7039	7039	21	17S	1	1	1

API	Well Name	Type	Status	Trajectory	Formation	Lat	Long	TVD_FT	MD_FT	S	T	5x5 Risk Probability	5x5 Risk Impact	Total Risk Rating
30-025-39267	GC FEDERAL 021	OIL	PROD	VER	PADDOCK	32.81834	-103.7869	7013	7038	20	17S	1	1	1
30-025-39857	BC FEDERAL 063	OIL	PROD	VER	PADDOCK	32.82101	-103.7833	7037	7037	20	17S	1	1	1
30-025-38833	MC FEDERAL 026	OIL	PROD	VER	PADDOCK	32.8203	-103.76901	7011	7035	21	17S	1	1	1
30-025-39292	MC FEDERAL 038	OIL	PROD	VER	PADDOCK	32.81919	-103.77742	7035	7035	21	17S	1	1	1
30-025-39002	MC FEDERAL 034	OIL	PROD	VER	PADDOCK	32.81702	-103.7661	7033	7033	21	17S	1	1	1
30-025-39058	MC FEDERAL 030	OIL	PROD	VER	PADDOCK	32.8226	-103.77256	7030	7030	21	17S	1	1	1
30-025-34932	BC FEDERAL 003	OIL	PROD	VER	PADDOCK	32.82283	-103.78314	7028	7028	20	17S	1	1	1
30-025-34932	BC FEDERAL 003	OIL	PROD	VER	PADDOCK	32.82283	-103.78314	7028	7028	20	17S	1	1	1
30-025-38703	MC FEDERAL 020	OIL	PROD	VER	PADDOCK	32.81696	-103.77685	7027	7027	21	17S	1	1	1
30-025-38714	BC FEDERAL 033	OIL	PROD	VER	PADDOCK	32.82101	-103.78164	7027	7027	20	17S	1	1	1
30-025-38998	MC FEDERAL 029	OIL	PROD	VER	PADDOCK	32.81946	-103.7747	7025	7025	21	17S	1	1	1
30-025-38739	MC FEDERAL 016	OIL	PROD	VER	PADDOCK	32.82282	-103.77835	7021	7021	21	17S	1	1	1
30-025-39515	GC FEDERAL 039	OIL	PROD	VER	PADDOCK	32.81947	-103.78094	7020	7020	20	17S	1	1	1
30-025-39864	MC FEDERAL 061	OIL	PROD	VER	PADDOCK	32.81734	-103.76395	7018	7018	21	17S	1	1	1
30-025-34773	MC FEDERAL 003	OIL	PROD	VER	PADDOCK	32.82141	-103.77255	7015	7015	21	17S	1	1	1
30-025-34773	MC FEDERAL 003	OIL	PROD	VER	PADDOCK	32.82141	-103.77255	7015	7015	21	17S	1	1	1
30-025-38387	MC FEDERAL 011	OIL	PROD	VER	PADDOCK	32.81958	-103.77008	7015	7015	21	17S	1	1	1
30-025-39268	GC FEDERAL 022	OIL	PROD	VER	PADDOCK	32.8192	-103.7833	7015	7015	20	17S	1	1	1
30-025-40152	MC FEDERAL 052	OIL	PROD	VER	PADDOCK	32.82282	-103.77708	7014	7014	21	17S	1	1	1
30-025-38997	MC FEDERAL 028	OIL	PROD	VER	PADDOCK	32.81902	-103.76395	7013	7013	21	17S	1	1	1
30-025-38996	MC FEDERAL 027	OIL	INACTIVE PRODUCER	VER	PADDOCK	32.82056	-103.76396	7012	7012	21	17S	1	1	1
30-025-39060	J C FEDERAL 026	OIL	PROD	VER	PADDOCK	32.81553	-103.76395	7010	7010	21	17S	1	1	1
30-025-39263	GC FEDERAL 025	OIL	PROD	VER	PADDOCK	32.81795	-103.78097	7010	7010	20	17S	1	1	1
30-025-38830	J C FEDERAL 018	OIL	PROD	VER	PADDOCK	32.81734	-103.76131	7007	7007	22	17S	1	1	1
30-025-39542	J C FEDERAL 034	OIL	PROD	VER	PADDOCK	32.81568	-103.76576	6995	6995	21	17S	1	1	1
30-025-34933	MC FEDERAL 004	OIL	PROD	VER	PADDOCK	32.8192	-103.779	6973	6975	21	17S	1	1	1
30-025-34933	MC FEDERAL 004	OIL	PROD	VER	PADDOCK	32.8192	-103.779	6973	6975	21	17S	1	1	1
30-025-34973	MC FEDERAL 005	OIL	PROD	VER	PADDOCK	32.81556	-103.7747	6908	6908	21	17S	1	1	1
30-025-34973	MC FEDERAL 005	OIL	PROD	VER	PADDOCK	32.81556	-103.7747	6908	6908	21	17S	1	1	1
30-025-38829	BC FEDERAL 032	OIL	PROD	VER	PADDOCK	32.82088	-103.78545	6900	6900	20	17S	1	1	1
30-025-35988	J C FEDERAL 003	OIL	PROD	VER	PADDOCK	32.81915	-103.76181	6889	6890	22	17S	1	1	1
30-025-35988	J C FEDERAL 003	OIL	PROD	VER	PADDOCK	32.81915	-103.76181	6889	6890	22	17S	1	1	1
30-025-39860	J C FEDERAL 050	OIL	PROD	VER	PADDOCK	32.81723	-103.76065	6510	6524	22	17S	1	1	1
30-025-39862	J C FEDERAL 053	OIL	PROD	VER	PADDOCK	32.81495	-103.75738	7117	6148	22	17S	1	1	1
30-025-39000	MC FEDERAL 032	OIL	PROD	VER	PADDOCK	32.81805	-103.77174	6031	6057	21	17S	1	1	1
30-025-37900	MCA UNIT 395	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80767	-103.77608	4488	4488	28	17S	1	1	1
30-025-37939	MCA UNIT 397	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80764	-103.7779	4460	4460	28	17S	1	1	1

API	Well Name	Type	Status	Trajectory	Formation	Lat	Long	TVD_FT	MD_FT	S	T	5x5 Risk Probability	5x5 Risk Impact	Total Risk Rating
30-025-37879	MCA UNIT 393	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80764	-103.78005	4450	4450	29	17S	1	1	1
30-025-37976	MCA UNIT 396	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80531	-103.7785	4450	4450	28	17S	1	1	1
30-025-38038	MCA UNIT 407	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80511	-103.78001	4450	4450	28	17S	1	1	1
30-025-37931	MCA UNIT 394	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80928	-103.77786	4445	4445	28	17S	1	1	1
30-025-29102	MCA UNIT 365Y	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80955	-103.7852	4440	4440	29	17S	1	1	1
30-025-29959	MCA UNIT 373	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.8237	-103.77591	4350	4350	21	17S	1	1	1
30-025-29959	MCA UNIT 373	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.8237	-103.77591	4350	4350	21	17S	1	1	1
30-025-27067	MCA UNIT 364	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.82051	-103.78191	4325	4325	20	17S	1	1	1
30-025-38978	MCA UNIT 409	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80413	-103.76243	4320	4320	27	17S	1	1	1
30-025-29854	MCA UNIT 368	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.82013	-103.76746	4300	4300	21	17S	1	1	1
30-025-29956	MCA UNIT 372	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81622	-103.78433	4300	4300	20	17S	1	1	1
30-025-24258	MCA UNIT 326	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81622	-103.76304	4250	4250	21	17S	1	1	1
30-025-27066	MCA UNIT 363	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.82041	-103.78199	4250	4250	20	17S	1	1	1
30-025-30347	MCA UNIT 379	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.8234	-103.77062	4220	4220	21	17S	1	1	1
30-025-39353	MCA UNIT 483	OIL	INJECT	VER	GRAYBURG | SAN ANDRES	32.80415	-103.76712	4208	4208	28	17S	1	1	1
30-025-39355	MCA UNIT 486	OIL	INACTIVE INJECTOR	VER	GRAYBURG | SAN ANDRES	32.80537	-103.76468	4206	4206	28	17S	1	1	1
30-025-23920	MCA UNIT 292	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80924	-103.75864	4200	4200	27	17S	1	1	1
30-025-23938	MCA UNIT 299	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81231	-103.75865	4200	4200	27	17S	1	1	1
30-025-24183	MCA UNIT 316	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81636	-103.75866	4200	4200	22	17S	1	1	1
30-025-24186	MCA UNIT 317	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80924	-103.76262	4200	4200	27	17S	1	1	1
30-025-30491	MCA UNIT 384	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.8074	-103.7612	4200	4200	27	17S	1	1	1
30-025-23731	MCA UNIT 274	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80925	-103.76708	4190	4190	28	17S	1	1	1

API	Well Name	Type	Status	Trajectory	Formation	Lat	Long	TVD_FT	MD_FT	S	T	5x5 Risk Probability	5x5 Risk Impact	Total Risk Rating
30-025-20496	MCA UNIT 235	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80919	-103.77574	4182	4182	28	17S	1	1	1
30-025-12792	MCA UNIT 149	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80565	-103.76261	4180	4180	27	17S	1	1	1
30-025-39409	MCA UNIT 472	OIL	INJECT	VER	SAN ANDRES	32.80736	-103.76234	4180	4180	27	17S	1	1	1
30-025-23740	MCA UNIT 280	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80576	-103.76724	4175	4175	28	17S	1	1	1
30-025-39356	MCA UNIT 487	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80552	-103.76881	4170	4170	28	17S	1	1	1
30-025-23715	MCA UNIT 271	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.8238	-103.78016	4163	4163	20	17S	1	1	1
30-025-00743	MCA UNIT 178	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80374	-103.7693	4156	4156	28	17S	1	1	1
30-025-23744	MCA UNIT 284	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80565	-103.77583	4150	4150	28	17S	1	1	1
30-025-27065	MCA UNIT 362	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81956	-103.78148	4150	4150	20	17S	1	1	1
30-025-27076	MCA UNIT 359	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.82086	-103.78146	4150	4150	20	17S	1	1	1
30-025-00628	MCA UNIT 088	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81461	-103.76073	4145	4145	22	17S	1	1	1
30-025-00738	MCA UNIT 118	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81099	-103.76502	4145	4145	28	17S	1	1	1
30-025-39354	MCA UNIT 484	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80424	-103.77157	4142	4142	28	17S	1	1	1
30-025-00611	MCA UNIT 069	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81827	-103.77363	4136	4136	21	17S	1	1	1
30-025-00612	MCA UNIT 071	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81825	-103.76503	4131	4131	21	17S	1	1	1
30-025-23706	MCA UNIT 269	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81319	-103.78428	4130	4130	20	17S	1	1	1
30-025-12796	MCA UNIT 089	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81287	-103.7627	4128	4128	22	17S	1	1	1
30-025-24213	MCA UNIT 319	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80566	-103.78442	4125	4125	29	17S	1	1	1
30-025-12763	MCA UNIT 044	OIL	DRILLED	VER	GRAYBURG | SAN ANDRES	32.82015	-103.77156	4124	4124	21	17S	1	1	1
30-025-21489	MCA UNIT 177	OIL	DRILLED	VER	GRAYBURG | SAN ANDRES	32.80545	-103.7709	4120	4120	28	17S	1	1	1
30-025-23807	MCA UNIT 287	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81668	-103.78015	4120	4120	20	17S	1	1	1
30-025-00603	MCA UNIT 043	OIL	DRILLED	VER	GRAYBURG | SAN ANDRES	32.8219	-103.76933	4119	4119	21	17S	1	1	1

API	Well Name	Type	Status	Trajectory	Formation	Lat	Long	TVD_FT	MD_FT	S	T	5x5 Risk Probability	5x5 Risk Impact	Total Risk Rating
30-025-23569	MCA UNIT 260	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80895	-103.77175	4110	4110	28	17S	1	1	1
30-025-23687	MCA UNIT 266	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81655	-103.78872	4110	4110	20	17S	1	1	1
30-025-12797	MCA UNIT 041	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.82037	-103.76359	4106	4106	21	17S	1	1	1
30-025-08031	MCA UNIT 046	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.82016	-103.77586	4102	4102	21	17S	1	1	1
30-025-00742	MCA UNIT 176	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80375	-103.7736	4100	4100	28	17S	1	1	1
30-025-24076	MCA UNIT 308	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80741	-103.78584	4100	4100	29	17S	1	1	1
30-025-00606	MCA UNIT 047	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.82192	-103.77793	4097	4097	21	17S	1	1	1
30-025-00734	MCA UNIT 115	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81102	-103.77361	4086	4086	28	17S	1	1	1
30-025-23733	MCA UNIT 277	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80929	-103.78857	4083	4083	29	17S	1	1	1
30-025-23482	MCA UNIT 252	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80941	-103.7794	4080	4080	28	17S	1	1	1
30-025-00752	MCA UNIT 112	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81103	-103.7822	4078	4078	29	17S	1	1	1
30-025-08062	MCA UNIT 066	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.81829	-103.78222	4072	4072	20	17S	1	1	1
30-025-00609	MCA UNIT 092	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81464	-103.77362	4062	4062	21	17S	1	1	1
30-025-08065	MCA UNIT 095	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81466	-103.78651	4055	4055	20	17S	1	1	1
30-025-12794	MCA UNIT 174	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80544	-103.77997	4055	4055	28	17S	1	1	1
30-025-12755	MCA UNIT 096	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.81292	-103.7888	4048	4048	20	17S	1	1	1
30-025-00744	MCA UNIT 179	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80373	-103.765	3925	3925	28	17S	1	1	1
30-025-00735	MCA UNIT 153	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.8074	-103.7779	3815	3815	28	17S	1	1	1
30-025-00739	MCA UNIT 151	OIL	PROD	VER	GRAYBURG | SAN ANDRES	32.80738	-103.7693	3806	3806	28	17S	1	1	1
30-025-00768	MCA UNIT BATTERY 2 155	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80741	-103.7865	3566	3566	29	17S	1	1	1
30-025-00618	BAISH A 003	OIL	DRILLED	VER	YATES	32.821	-103.77686	2386	2386	21	17S	1	1	1
30-025-00635	MCA UNIT 040	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.82097	-103.76181	2351	2351	22	17S	1	1	1
30-025-00613	BAISH A 004	OIL	P & A	VER	YATES	32.82099	-103.77041	0	0	21	17S	1	1	1

API	Well Name	Type	Status	Trajectory	Formation	Lat	Long	TVD_FT	MD_FT	S	T	5x5 Risk Probability	5x5 Risk Impact	Total Risk Rating
30-025-00620	BAISH A 006	OIL	P & A	VER	YATES	32.81916	-103.76826	0	0	21	17S	1	1	1
30-025-00621	LANE C 674 LTD 005	OIL	P & A	VER	YATES	32.81915	-103.76395	0	0	21	17S	1	1	1
30-025-00722	JOHN H MOORE B 001	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80735	-103.76071	0	0	27	17S	1	1	1
30-025-08362	HINTON 013	OIL	P & A	VER	ABO	32.81829	-103.78721	0	0	20	17S	1	2	2
30-025-21951	BAISH B FEDERAL 002	OIL	P & A	VER	DEVONIAN	32.81072	-103.76534	0	0	28	17S	2	2	4
30-025-27063	MCA UNIT 360	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.82084	-103.78301	0	0	20	17S	1	1	1
30-025-28988	MCA UNIT 365	OIL	P & A	VER	GRAYBURG | SAN ANDRES	32.80949	-103.7852	0	0	29	17S	1	1	1
30-025-32123	MCA UNIT 387E	GAS	INACTIVE PRODUCER	VER	GRAYBURG | SAN ANDRES	32.80747	-103.77757	0	0	28	17S	1	1	1
30-025-39409	MCA UNIT 472	OIL	INJECT	VER	SAN ANDRES	32.80736	-103.76234	4180	0	27	17S	1	1	1

Well Name	Use of Well	Status	Owner Name	Well Depth	Water Depth	Distance to Maljamar wells	Spud Date
RA 10175	DRNK/SAN	PMT	FLO CO_2	158	null	0.281	Sun Feb 03 2002
RA 12020 POD1	EXPLORE	PMT	PHILLIPS 66 COMPANY	120	81	0.293	Mon Sep 23 2013
RA 12020 POD2	null	PMT	PHILLIPS 66 COMPANY	null	null	0.205	Wed Dec 31 1969
RA 12020 POD3	null	PMT	PHILLIPS 66 COMPANY	112	83	0.149	Sun Jul 12 2015
RA 12042 POD1	MONITOR	PMT	DARRELL CRASS DRILLING	400	null	0.192	Tue Nov 12 2013
RA 12204 POD1	null	PMT	CONOCOPHILLIPS	null	null	0.744	Wed Dec 31 1969
RA 12521 POD1	null	PMT	PHILLIPS 66	105	92	0.04	Thu Jul 20 2017
RA 12522 POD1	null	PMT	PHILLIPS 66	100	null	0.176	Mon Jul 24 2017
RA 12522 POD2	null	PMT	PHILLIPS 66	100	null	0.179	Sun Jul 23 2017
RA 12522 POD3	null	PMT	PHILLIPS 66	100	null	0.165	Wed Jul 19 2017
RA 12574 POD1	null	PMT	CONOCOPHILLIPS COMPANY	null	null	0.648	Wed Dec 31 1969
RA 12574 POD2	null	PMT	CONOCOPHILLIPS COMPANY	null	null	0.803	Wed Dec 31 1969

Well Name	Use of Well	Status	Owner Name	Well Depth	Water Depth	Distance to Maljamar wells	Spud Date
RA 12574 POD3	null	PMT	CONOCOPHILLIPS COMPANY	null	null	0.881	Wed Dec 31 1969
RA 12574 POD4	null	PMT	CONOCOPHILLIPS COMPANY	null	null	0.778	Wed Dec 31 1969
RA 12721 POD1	null	PMT	CONOCOPHILLIPS COMPANY	125	null	0.771	Wed Apr 17 2019
RA 12721 POD2	null	PMT	CONOCOPHILLIPS COMPANY	124	75	0.535	Wed Apr 17 2019
RA 12721 POD3	null	PMT	CONOCOPHILLIPS COMPANY	115	null	0.806	Wed Apr 17 2019
RA 12721 POD5	null	PMT	CONOCOPHILLIPS COMPANY	130	124	0.854	Sun Apr 26 2020

PMT = permitted

Appendix 5 - References

C-108 Application for Approval to Drill and Operate a New Well For The Injection of Acid Gas; Frontier Field Services, LLC; Maljamar Natural Gas Processing Plant; May 16, 2011; Prepared by Geolex, Inc.

C-108 Application for Authority to Inject; Frontier Field Services, LLC; Maljamar AGI #2; May 9, 2014; Prepared by Geolex, Inc.

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Appendix 6 - Abbreviations and Acronyms

See **Appendix 5** of Part A of this MRV plan.

Appendix 7 - Frontier Maljamar – Subpart RR Equations for Calculating CO_2 Geologic Sequestration

See **Appendix 6** of Part A of this MRV Plan.

Appendix 8 - Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

See **Appendix 7** of Part A of this MRV plan.

Appendix 9 - Plugging & Abandonment Records

API 30-025-41557

Form 9-331a
(March 1942)

Budget Bureau No. 42-R358.1.
Approval expires 11-30-49.

(SUBMIT IN TRIPLICATE)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

Land Office Las Cruces
Lease No. 029405-B
Unit J

RECEIVED
AUG 2 ...
OIL CONSERVATION COMMISSION
HOBBS OFFICE

SUNDRY NOTICES AND REPORTS ON WELLS

NOTICE OF INTENTION TO DRILL		SUBSEQUENT REPORT OF WATER SHUT-OFF	
NOTICE OF INTENTION TO CHANGE PLANS		SUBSEQUENT REPORT OF SHOOTING OR ACIDIZING	
NOTICE OF INTENTION TO TEST WATER SHUT-OFF		SUBSEQUENT REPORT OF ALTERING CASING	
NOTICE OF INTENTION TO RE-DRILL OR REPAIR WELL		SUBSEQUENT REPORT OF REDRILLING OR REPAIR	
NOTICE OF INTENTION TO SHOOT OR ACIDIZE		SUBSEQUENT REPORT OF ABANDONMENT (Temporary)	
NOTICE OF INTENTION TO PULL OR ALTER CASING		SUPPLEMENTARY WELL HISTORY	
NOTICE OF INTENTION TO ABANDON WELL			

(INDICATE ABOVE BY CHECK MARK NATURE OF REPORT, NOTICE, OR OTHER DATA)

Artesia, N. Mex. August 26, 1950

Wm. Mitchell B

Well No. 23-P is located 1980 ft. from ~~N~~ [S] line and 2193 ft. from [E] ~~W~~ line of sec. 20

NW¼SE¼ Sec. 20	17S	32E	NMPM
(¼ Sec. and Sec. No.)	(Twp.)	(Range)	(Meridian)

Maljamar-Paddock	Lea	New Mexico
(Field)	(County or Subdivision)	(State or Territory)

The elevation of the derrick floor above sea level is 3997 ft.

DETAILS OF WORK

(State names of and expected depths to objective sands; show sizes, weights, and lengths of proposed casings; indicate mudding jobs, cementing points, and all other important proposed work)

In accordance with procedure approved by Mr. Frost by phone on August 25, 1950, this well has been temporarily abandoned. The work was performed as follows: 25 sacks of cement were spotted from 5359 to 5284' through drill pipe. Pipe was then raised and 185 sacks were spotted from 4150 to 3600'. Pipe was then raised and 10 sacks were spotted in 8-5/8" casing from 2470 to 2438'. A swage and valve has been placed in top of casing.

I understand that this plan of work must receive approval in writing by the Geological Survey before operations may be commenced.

Company BUFFALO OIL COMPANY

Address 203 CARPER BLDG.
ARTESIA, NEW MEXICO

By H. G. Ellis

Title Vice President

T. A.

U. S. GOVERNMENT PRINTING OFFICE 16-8437-3

API 30-025-41557

Form 3160-5
(June 2015)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

OCD Hobbs

FORM APPROVED
OMB NO. 1004-0137
Expires: January 31, 2018

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE - Other instructions on page 2

5. Lease Serial No.
NMLC060199A

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well
☒ Oil Well ☐ Gas Well ☐ Other

8. Well Name and No.
CUTTHROAT FEDERAL 5

2. Name of Operator
MACK ENERGY CORPORATION
Contact: DEANA WEAVER
E-Mail: DWEAVER@MEC.COM

9. API Well No.
30-025-41557-00-S1

3a. Address
ARTESIA, NM 88211-0960

3b. Phone No. (include area code)
Ph: 575-748-1288
Fx: 575-746-9539

10. Field and Pool or Exploratory Area
WC-025 G06 S173230A

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
Sec 29 T17S R32E SWNE 1650FNL 2310FEL
32.808247 N Lat, 103.787029 W Lon

11. County or Parish, State
LEA COUNTY, NM

12. CHECK THE APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production	Off
☒ Subsequent Report	☐ Alter Casing	☐ Hydraulic Fracturing	☐ Reclamatic	ty
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplet	
	☐ Change Plans	☒ Plug and Abandon	☐ Temporari	
	☐ Convert to Injection	☐ Plug Back	☐ Water Dis	

INT TO PA ______
P&A NR ______
P&A R ✓

13. Describe Proposed or Completed Operation: Clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports must be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 must be filed once testing has been completed. Final Abandonment Notices must be filed only after all requirements, including reclamation, have been completed and the operator has determined that the site is ready for final inspection.

11/16-22/2017 RIH W/ 223 JTS TAGGED CMT @ 7453'. DRILLED 40' CMT, DRILLED OUT CIBP @ 7500'. TAGGED CMT @ 8846' NOTIFIED PAT W/ BLM LEA COUNTY. CIRC 200BBLS SALT WATER GEL, TSTED CSG 500# SET 40SX PLUG @ 8116', POH W/ 27JTS, TAGGED PLUG @ 7790', PAT W/ BLM WITNESSED TAG. SET 30SX PLUG @ 7560', SET 35SX PLUG @ 5564'* TAGGED PLUG @ 3692' W/ 113JTS, NOTIFIED PAT W/ BLM, SET PLUG #5 W/ 45SX @ 2327', TAGGED PLUG @ 1870' W/ 57JTS, SET 25SX @ 917'. TAGGED PLUG @ 685', SET SURFACE PLUG @ 60'. POH W/ TBG, TOPPED OUT CSG, CIRC 10SX TO SURFACE. INSTALL DRY HOLE MARKER.

* Spot @ 3830
PA'd 11/22/17

RECLAMATION
DUE 5-22-18

14. I hereby certify that the foregoing is true and correct.
Electronic Submission #396139 verified by the BLM Well Information System
For MACK ENERGY CORPORATION, sent to the Hobbs
Committed to AFMSS for processing by PRISCILLA PEREZ on 12/04/2017 (17PP0284SE)

Name (Printed/Typed) DEANA WEAVER — Title PRODUCTION CLERK

Signature (Electronic Submission) — Date 11/28/2017

Accepted for Record

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved By James A. Amos — Title Supv. PET — Date 12-29-17

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Office CFO

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)
** BLM REVISED ** BLM REVISED ** BLM REVISED ** BLM REVISED ** BLM REVISED **

FOR RECORD ONLY
MW/OCD 01/09/2018

API 30-025-00622

Form 3160-5 (November 1983) (Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved. Budget Bureau No. 1004-0135 Expires August 31, 1985

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL ☑ GAS WELL ☐ OTHER
2. NAME OF OPERATOR: CONOCO INC.
3. ADDRESS OF OPERATOR: P. O. Box 460, Hobbs, N.M. 88240
4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.) At surface: Unit I

1980' FSL & 810' FEL

5. LEASE DESIGNATION AND SERIAL NO.: LC-029509(A)
6. IF INDIAN, ALLOTTEE OR TRIBE NAME:
7. UNIT AGREEMENT NAME:
8. FARM OR LEASE NAME: Baish A
9. WELL NO.: 8
10. FIELD AND POOL, OR WILDCAT: Maljamar Abo
11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 21-17S-32E
12. COUNTY OR PARISH: Lea 13. STATE: NM

14. PERMIT NO.: 30-025-00622
15. ELEVATIONS (Show whether DF, RT, GR, etc.):

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
TEST WATER SHUT-OFF ☐	PULL OR ALTER CASING ☐	WATER SHUT-OFF ☐	REPAIRING WELL ☐
FRACTURE TREAT ☐	MULTIPLE COMPLETE ☐	FRACTURE TREATMENT ☐	ALTERING CASING ☐
SHOOT OR ACIDIZE ☐	ABANDON* ☐	SHOOTING OR ACIDIZING ☐	ABANDONMENT* ☑
REPAIR WELL ☐	CHANGE PLANS ☐	(Other)	
(Other)			

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1. Already on well for casing repair, P&A work commenced 3-5-86
2. set cmt retainer @ 2973', load csg to 500 psi and pumped 500 sxs class "H" sting out retainer
3. Shot 4 holes @ 2900', set ret @ 2782', test backside to 500 psi. Pumped 500 sxs Class "H" cmt, sting out of retainer & spot 3 sxs on top.
4. *Spotted 50' cmt in top of 7" csg.
5. Cut wellhead off and install P&A marker. Rig down on 3-7-86.

*(3a) 100' plug 940' to 840'

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE Administrative Supervisor DATE 3-24-86

(This space for Federal or State office use)

APPROVED BY ________ TITLE ________ DATE 9-23-86

CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

BLM-Carlsbad (6) File

E

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL ☑ GAS WELL ☐ OTHER
2. NAME OF OPERATOR: CONOCO INC.
3. ADDRESS OF OPERATOR: P. O. Box 460, Hobbs, N.M. 88240
4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.) At surface: Unit I

1980' FSL & 810' FEL

14. PERMIT NO.: 30-025-00622
15. ELEVATIONS (Show whether DF, RT, GR, etc.)

5. LEASE DESIGNATION AND SERIAL NO.: LC-029509(A)
6. IF INDIAN, ALLOTTEE OR TRIBE NAME
7. UNIT AGREEMENT NAME
8. FARM OR LEASE NAME: Baish A
9. WELL NO.: 8
10. FIELD AND POOL, OR WILDCAT: Maljamar Abo
11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 21-17S-32E
12. COUNTY OR PARISH: Lea
13. STATE: NM

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☑	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1) Miru, set retainer @ 50' above fish (approx. 2980')
2) Pump 500 sxs class "H" cmt & displace w/ 90 bbls wtr
3) Place cmt behind 7" csg as follows:
   a. Perf w/ 4 JSPF @ 2900'
   b. Set retainer @ 2800'
   c. Pump 500 sxs Class "H" cmt & pull out of retainer & spot 2-3 bbls cmt on top of retainer
4) Set cmt plug in 7" csg across top of salt by spotting 25 sxs class "H" cmt from 940' to 840'
5) Pull up to 50' from surface & spot 50' cmt plug at surface.
6) Cut off csg to final restored ground level and cover well w/ cmt cap that is 2' in diameter and 4" in thickness. Place abandonment marker in wellbore. A proposed P & A wellbore sketch is attached.
7) Verbal app'l for this procedure given by Bob Pitscke on 3-3-86.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE Administrative Supervisor DATE 3-4-86

(This space for Federal or State office use)

Orig. Sgd.: Charles S. [illegible]

APPROVED BY [illegible] TITLE DATE 3-21-86

CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

BLM-Carlsbad (6) ~~[illegible]~~ File

Form 9-331 (May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

COPY TO U.S.G.S.

Form approved. Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO. LC-057210

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

7. UNIT AGREEMENT NAME

1. OIL WELL ☐ GAS WELL ☐ OTHER DRY HOLE

RECEIVED MAR 4

2. NAME OF OPERATOR: PAN AMERICAN PETROLEUM CORPORATION

8. FARM OR LEASE NAME: BAISH "B" Federal

3. ADDRESS OF OPERATOR: BOX 68, HOBBS, N. M. 88240

9. WELL NO. 2

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.) At surface

760' FNL × 760' FEL Sec. 28, (Unit A NE/4 NE/4)

10. FIELD AND POOL, OR WILDCAT: MALJAMAR

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: 28-17-32 NMPM

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.) 4032' R.D.B.

12. COUNTY OR PARISH: LEA | 13. STATE: N.M.

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☒
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Physical abandonment of hole completed 2-15-68 abandoned as follows:

Spotted 20 sx plug @ 9870'. Shot 5½" casing @ 8162, 8010, 7500, 7212, and pulled from 7005. Spotted 25 sx in and out of stub; 40 sx plug 5350-5250; 25 sx in + out of 8⅝" csg 4660. Shot 8⅝" @ 400, 310, and pulled from 185. 25 sx plug in + out of stub, 20 sx @ surface and erect P+A marker.

Final cleanup and ground restoration shall be made and subsequent report filed.

TD- 13735'
13⅜ CSA 390' (Cement Circ) LEFT IN HOLE
8⅝" LEFT IN HOLE 185' TO 4660'
5½" " " " 7005 TO 10301.

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE AREA SUPERINTENDENT DATE 2-29-68

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______

CONDITIONS OF APPROVAL, IF ANY:

APPROVED
JAN 13 1969
J L GORDON
ACTING DISTRICT ENGINEER

0+4 USGS- H
1- NSW
1- SUSP
1- RRY
1- KEWANEE OIL Co.
Box 1859
MIDLAND. TEXAS 79701

*See Instructions on Reverse Side

API 30-025-00634

Form 3160-5
(June 1990)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
LC-029509B

6. If Indian, Allottee or Tribe Name

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT—" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [ ] Other

8. Well Name and No.
Baish B no. 5

2. Name of Operator
Conoco Inc.

9. API Well No.
30-025-00634

3. Address and Telephone No.
10 Desta Dr. Midland, TX 79705

10. Field and Pool, or Exploratory Area
Maljamar Devonian

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
1980 FSL & 860 FWL
Unit letter L, Sect. 22, T17S, R32E

11. County or Parish, State
Lea, NM

12. CHECK APPROPRIATE BOX(s) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION	
[ ] Notice of Intent	[X] Abandonment	[ ] Change of Plans
[X] Subsequent Report	[ ] Recompletion	[ ] New Construction
	[ ] Plugging Back	[ ] Non-Routine Fracturing
	[ ] Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	[ ] Altering Casing	[ ] Conversion to Injection
	[ ] Other ______	[ ] Dispose Water

(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Tag at 4200, circ mud, spot 25 sxs cmt from 4200 to 3935, pull tbg to 2775, spot 15 sxs cmt from 2775 to 2625, pull tbg to 1065, spot 15 sxs cmt from 1065 to 915, pull tbg out of hole, perf well at 350, 4 shots, pmp 120 sxs cmt down 5½ up 9⅝, circ, cut off wellhead, fill csg w/cmt, put up marker. RD.

P&A 1-11-91

14. I hereby certify that the foregoing is true and correct

Signed Christine Neff for Title Analyst - Oil Production Date 4-9-91

(This space for Federal or State office use)

Approved by ______ Title ______ Date 6-6-91
Conditions of approval, if any:

*See Instruction on Reverse Side

Form 3160-5
(June 1990)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
LC-029509B

6. If Indian, Allottee or Tribe Name

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT—" for such proposals

7. If Unit or CA, Agreement Designation

SUBMIT IN TRIPLICATE

1. Type of Well
[x] Oil Well [ ] Gas Well [ ] Other

8. Well Name and No.
Batish B No. 5

2. Name of Operator
Conoco Inc. (915) 686-

9. API Well No.
30-025-00634

3. Address and Telephone No.
10 Desta Drive West Midland Tx 79705

10. Field and Pool, or Exploratory Area
Maljamar Devonian

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
1980' FSL & 860' FWL, Sec. 22, T17S, R32E
Unit L

11. County or Parish, State
Lea, N. Mex.

12. CHECK APPROPRIATE BOX(s) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION	
[x] Notice of Intent	[x] Abandonment	[ ] Change of Plans
	[ ] Recompletion	[ ] New Construction
[ ] Subsequent Report	[ ] Plugging Back	[ ] Non-Routine Fracturing
	[ ] Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	[ ] Altering Casing	[ ] Conversion to Injection
	[ ] Other ______	[ ] Dispose Water

(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

We propose to plug and abandon the Batish B No. 5 according to the attached procedure.

RECEIVED
OCT 11 10 33 AM '90

14. I hereby certify that the foregoing is true and correct

Signed J. Hudson Watson Title Administrative Supervisor Date 10-9-90

(This space for Federal or State office use)

Approved by ______ Title ______ Date 10-12-90
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

*See Instruction on Reverse Side

BAISH B NO. 5
PLUG AND ABANDON

Summary: The following procedure is recommended to permanently plug and abandon Baish B No. 5.

. Spot 25 sack cement plug on top of cement retainer.
.. Spot 15 sack cement plug across intermediate casing shoe.
3. Spot 15 sack cement plug across top of salt.
4. Perforate @ 350' and circulate 120 sacks of cement to set surface plug.

Location: 1980' FSL & 860' FWL, Unit L, Sec. 22, T17S, R32E
Lea County, New Mexico

Elevation: 4022' DF (14' AGL)

Completion: Maljamar Devonian
TD: 13,939' PBTD: 4200'

5-1/2" cement retainer set @ 4200'.

Casing/Tubing Specifications:

O.D. (in)	Weight (lbs/ft)	Grade	Depth (ft)	Drift (in)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Capacity (ft^3/ft)
13-3/8"	48.0	H-40	100	12.559	770	1,730	.1570	.8817
9-5/8"	36.0	J-55	2700	8.765	2,020	3,520	.0773	.4340
5-1/2"	20.0	C-75	2811	4.653	8,440	8,610	.0221	.1245
5-1/2"	20.0	N-80	12,535	4.653	8,830	9,190	.0221	.1245
5-1/2"	23.0	N-80	13,554	4.545	11,160	10,560	.0211	.1189
2-7/8"	6.5	N-80		2.347	11,160	10,570	.00579	.03250

-3/8" casing set @ 100' with 100 sacks cement circulated to surface.
5/8" casing set @ 2700' with 1700 sacks cement circulated to surface.
5-1/2" casing set @ 13,554' with 1390 sacks cement. TOC @ 4480' by temperature survey.
5-1/2" casing was perforated @ 4300' and squeezed with 400 sacks cement to protect Grayburg. Estimated TOC @ 3000'.
Use safety factor of 70% for collapse and burst pressures.
Assume 2-7/8" workstring will be used.

Notes:
1. All cement slurry used in this procedure shall be Class "C" w/2% $CaCl_2$ mixed @ 14.8 ppg.
2. All mud shall be 9.5 ppg with 25 lbs gel/bbl brine.
3. Notify BLM prior to commencing any work.

Safety:

This procedure includes cementing and perforating. A pre-job safety meeting involving all personnel on location should be held before any work commences. Conoco policies and the service company's safety procedures should be reviewed. Arrange for a pre-determined assembly area in case of an emergency. No unauthorized personnel are allowed on location.

The following checklist is recommended during cementing operations:

1. All pump and storage trucks should rig up outside dead man anchors and guy wires if possible.
2. All connections on the wellhead must have a pressure rating higher than the maximum pump pressure.
3. Data recording equipment should be located as far as practical from the discharge line.
4. Anchor all lines and pressure test as needed.
5. A service company and/or company employee must be designated to operate valves at the wellhead in case of an emergency.
6. All service and company personnel must keep a safe distance from pressured-up lines. No one should be in the derrick or on the rig floor while pumping cement.

The following checklist is recommended during perforating operations:

1. The perforating truck should rig up outside dead man anchors and guy wires and be positioned upwind of the wellhead if possible.
2. The perforating company must place warning signs at least 500' away from the operation on all incoming roads.
3. Welding, on location, is not permitted during the perforating operation.
4. Perforating must be suspended during electrical or thunderstorms and sandstorms.
5. Turn off all radios that are within 500' of the operation. They should not be used while rigging up and loading perforating guns or until the gun is at least 500' in the hole. The same process should be repeated when pulling out of the hole.
6. The perforating truck must be grounded to the rig and wellhead before installing the blasting cap(s).
7. Insure that the key to the perforating panel is removed from the panel and the generator on the truck is turned off while arming the gun.
8. No one is allowed in the derrick or on the rig floor while perforating.
9. Upon completion of the operation, the work area shall be thoroughly inspected and all scraps and explosive materials shall be properly removed from the location by the service company performing the operation.

Recommended Procedure:

1. Prepare well for P&A:

A. MIRU. Bleed well pressure down.
B. ND wellhead and NU BOP.

2. Spot cement on cement retainer: @ 4200'

A. MIRU cement services.
B. GIH w/2-7/8" workstring to 4200'. Tag cement retainer and pick up 2'.
C. Spot 25 sacks cement from 4200'-3935' and displace with 22 bbls mud.
D. PU to 3930' and circulate hole with 70 bbls mud.
E. POOH laying down WS to 2775'.

3. Spot cement plug across intermediate casing shoe:

A. Load hole with 2 bbls mud.

B. Spot 15 sacks cement from 2775'-2625' and displace with 15 bbls mud.
C. POOH laying down WS to 1065'.

4. Spot cement plug across top of salt:

A. Load hole with 3 bbls mud.
B. Spot 15 sacks cement from 1065'-915' and displace with 5 bbls mud.
C. POOH laying down WS.

5. Circulate cement up surface casing and set surface plug:

A. MIRU wireline services.
B. RIH with a 4" casing gun loaded 4 JSPF (120° phase, .4" EHD, centralized) and CCL.
C. Perforate 7" production casing @ 350'. POOH.
D. GIH w/1 joint 2-7/8" tubing. Close BOP. Pump 20 bbls mud to load hole and establish circulation up 9-5/8" x 5-1/2" annulus.
E. Pump 120 sacks of cement (16 sacks excess) to fill up 9-5/8" x 5-1/2" annulus and set surface plug in 5-1/2" casing.

Note: If cement does not circulate to surface, pump 25 sx down 9-5/8" x 5-1/2" annulus.

F. POOH with tubing.
G. RD wireline and cement services.

6. Prepare surface location for abandonment:

A. ND BOP and cut off all casing strings at the base of the cellar or 3' below the final restored ground level (whichever is deeper). RDMO pulling unit.
B. Fill the casing strings (if necessary) from the cement plug to surface with cement.
C. Cover the wellbore with a metal plate at least 1/4" thick, welded in place, or a cement cap extending radially at least 12" beyond the 13-3/8" casing and at least 4" thick.
D. Erect an abandonment marker according to the following specifications:

1. Marker must be at least 4" diameter pipe, 10' long with 4' above restored ground level, and embedded in cement.
2. Marker must be capped and inscribed with the following well information.

Baish B No. 5
Unit L, Sec. 22, T-17S, R-32E
Lea County, NM
Date

Note: 1/4" metal plate can be welded to marker and then to the casing after the marker is set in cement.

E. Cut off dead-man anchors below ground level and remove markers. Fill in cellar and workover pit.
F. Remove all equipment, concrete bases, and pipe not in use.

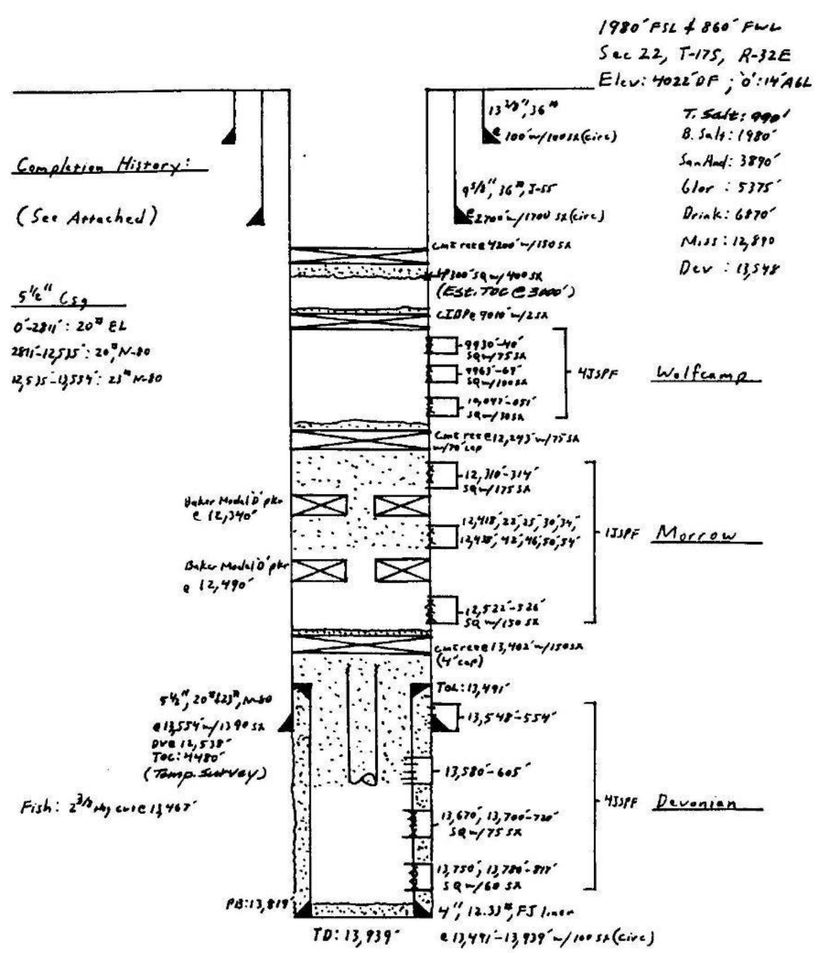
G. Clean and restore location to its natural state. Reseed according to BLM requirements.

7. Send a copy of the well service report and final P&A schematic to the Midland Office so the proper forms can be filed.

Approved:

Tom C. Caddell	8-27-90
Engineering Technician	Date
	8-28-90
Production Engineer	Date
	9/7/90
Supervising Production Engineer	Date
	9/28/90
Division Engineering Manager	Date
	10/1/90
Production Superintendent	Date
	08 OCT '90
Division Operations Manager	Date
	10/9/90
Division Manager	Date

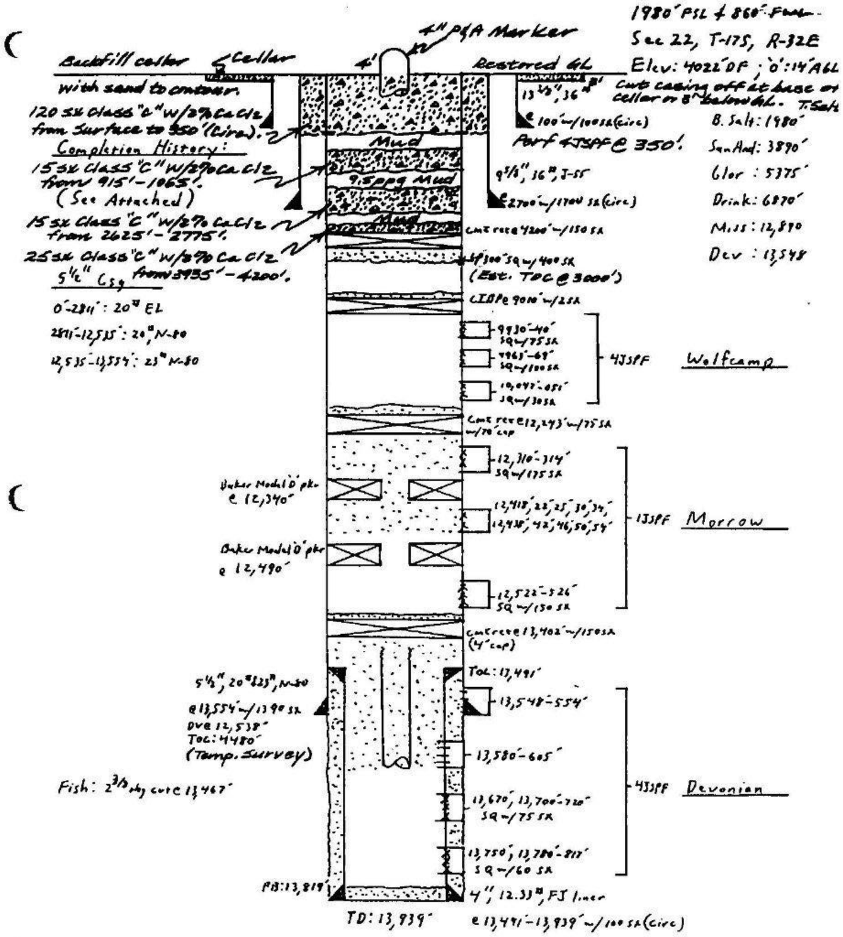
TCA\tk
BAISHB#5.PRO



JDV
6-13-90

Conoco Inc.
Calculation Sheet
Job No.

Title Baish B No. 5
~ Present Completion ~
Field Baish-Maljamar-Pearsall
State NM



TCA
8-13-90

Conoco Inc.
Calculation Sheet
Job No.

Title Baish B No. 5
~ Proposed P&A Completion ~
Field Baish-Maljamar-Pearsall
State NM