September 25, 2024

Mr. Brad Rogers
Bayswater Operating, LLC
1625 County Road 280
Westbrook, Texas 79565

Re: Monitoring, Reporting and Verification (MRV) Plan for Mongoose Amine Treating Facility

Dear Mr. Rogers:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Mongoose Amine Treating Facility, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Mongoose Amine Treating Facility on August 20, 2024, as the final MRV plan. The MRV Plan Approval Number is 1014747-1. This decision is effective September 30, 2024 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility is required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

If you have any questions regarding this determination, please contact me or Melinda Miller of the Greenhouse Gas Reporting Branch at miller.melinda@epa.gov.

Sincerely,

Julius Banks
Supervisor, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Mongoose Amine Treating Facility

September 2024

Contents

<u>Appendices</u>

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by Bayswater Operating Company, LLC (Bayswater) for the Mongoose Amine Treating Facility (MATF) treated acid gas (TAG) injection project, which injects into the Ellenburger Formation. Note that this evaluation pertains only to the subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

Section 1 of the MRV plan states that the MATF currently has a Class II UIC permit issued by the Texas Railroad Commission (TRRC) to inject TAG for the Mongoose acid gas injection (AGI) No. 1 well, API No. 42-335-36013, UIC No. 000125803. The permit was originally issued in March 2023 under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas). The MATF states that the permit currently authorizes the facility to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) into the Ellenburger Formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose AGI No. 1 well is a new well located in a rural area of Mitchell County, Texas. The MRV plan also states that the MATF is currently seeking TRRC approval to amend the existing Mongoose AGI No. 1 well permit by increasing the permitted maximum quantity of injected TAG from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. The MATF intends to inject up to 19.5 MMscf/D into this well for approximately 40 years. The primary source of the injected CO_2 is the MATF.

Section 2 of the MRV plan discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the MATF. The MRV plan states that the Mongoose AGI No. 1 well will inject a CO_2 stream containing 41.2% CO_2 and 58.8% H_2S. The target injection interval for the Mongoose AGI No. 1 well, the Ellenburger Formation, is 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the MATF states that the Mongoose AGI No. 1 well and the MATF are designed to protect against leakage out of the injection interval, to protect against contaminating other subsurface formations, and to prevent surface releases.

The MRV plan states that the MATF is located on the Eastern Shelf of the greater Permian Basin of West Texas and New Mexico. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician. During the lower Ordovician period, the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture and irregular mottling patterns, likely indicative of bioturbation structures. These same features were interpreted in the open-hole logs from the Mongoose AGI No. 1 well and the cores from the offset well Buchanan 3111 #1XD. On the Eastern Shelf, the Ellenburger Formation is roughly 900 ft thick and dips west-southwest, towards the

Midland Basin. The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. The predominant pore types of this group are ooid grainstone and ooid-peloid packstone-grainstone and reservoirs tend to be of good porosity and moderate permeability. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger Formation underwent significant "karsting" and dolomitization. This dolomitization process has facilitated porosity development within the Ellenburger Formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs.

The MRV plan states that the Devonian Woodford Formation will serve as the upper confining zone. The Ellenburger Group underlies the Woodford Formation on the Eastern Shelf, and the contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition. The Woodford shale was created through a widespread marine transgression. The MRV plan states that the U.S. Geological Survey (USGS) CO_2 Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit. The MATF states that permeability and porosity values from routine core analysis performed on rotary sidewall cores taken from the offset well Buchanan 3111 #1XD approximately 10.4 miles away reflect optimal confining characteristics and validate the USGS's assessment of an appropriate sealing formation for CO_2 storage.

According to the MRV plan, the Precambrian formations will serve as the lower confining zone. The MATF states that in the Permian Basin area, Precambrian formations are not normally specifically named in scientific literature. As a result, the MRV plan states these formations will be referred to as "Precambrian." Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section. Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. The MRV plan states that the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone. The lithologic and petrophysical characteristics of the Ellenburger Formation at the MATF indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity.

The description of the project provides the necessary information for 40 CFR 98.448(a)(6).

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines maximum monitoring area as “the area that must be monitored under this regulation and is defined as 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.” Subpart RR defines active monitoring area as “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.” See 40 CFR 98.449.

According to the MRV plan, the modeling software used to evaluate this project was Computer Modeling Group’s GEM 2023.2 (GEM) simulator. The plume boundary was defined by the weighted average gas saturation in the aquifer, and a weighted average value of 3% gas saturation was used to determine the boundary of the plume. The MATF states that when injection ceases after 40 years, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast. The MRV plan states that the MMA is the stabilized plume boundary after 120 years of density drift with an all-around buffer zone of one-half mile added. The MMA is displayed in Figure 42 of the MRV plan.

The MRV plan states that the initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free- phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. MATF states that by 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 of the MRV plan shows the area covered by the AMA.

The delineations of the MMA and AMA are acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly delineated in the plan and are consistent with the definitions in 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). The MATF identified the following as potential leakage pathways in Section 4 of their MRV plan that required consideration:

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults and fractures

- Leakage through the confining layer
- Leakage from natural or induced seismicity

A summary table of the MATF's evaluation of the likelihood, magnitude, and timing of any potential CO_2 leakage can be found in Table 12 of the MRV plan and is reproduced below.

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. Two artificial penetrations were drilled into the gross injection interval. These wells were plugged in accordance TRRC requirements.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There are no faults within the modeled area. Bayswater monitors the area for seismic activity.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining layer	Unlikely. The lateral continuity of the Woodford Shale blanketing the Ellenburger is recognized as a very competent seal. There is 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There have been no seismic events of 3.0 magnitude or greater detected. There is over 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

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

3.1 Leakage from Surface Equipment

Section 4.1 of the MRV plan states that the MATF and the Mongoose AGI No. 1 well are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. The site plan and the Mongoose AGI No. 1 wellbore schematic are depicted in Figures 44 and 45 of the MRV plan, respectively. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H_2S are installed at key locations around the MATF as depicted in the site plan in Appendix B-2 of the MRV plan. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H_2S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 parts per million (ppm) as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The MATF states that these facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the MATF and Mongoose AGI No. 1 well. The MATF installed a flare stack to safely depressurize piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2 of the MRV plan. Data from this flow meter will be used in the calculations of the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year, per 40 CFR §98.444(b).

The MRV plan states that with the level of monitoring implemented at the MATF, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The acid gas stream injected into the Mongoose AGI No. 1 well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the well is from the amine treater in the MATF adjacent to the well. The MATF will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release in accordance with 40 CFR §98.448(a)(5). The MATF concludes that the leakage of CO_2 through the surface equipment is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from surface equipment.

3.2 Leakage through Existing Wells within the MMA

Section 4.2 of the MRV plan states the Mongoose AGI No. 1 well was designed to prevent migration from the injection interval to the surface through a special casing and cementing design. Mechanical integrity tests (MIT), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23(b)(3)], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. The MRV plan also states that if an MIT were to indicate a leak, the well would be isolated, and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46 of the MRV plan as well as Appendix C of the MRV plan. According to the MRV plan, two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. There are additional wells that are shallower and do not penetrate the injection zone, but they are isolated by the Woodford Shale. The MRV plan states that the Woodford Shale provides 50 ft or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset artificial penetrations is unlikely. The MRV plan also states that Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes.

Future Drilling

The MRV plan states that potential leakage pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Cambrian, have proven to date to be non-productive in this area. Furthermore, any drilling permits issued by the TRRC around the MATF include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"), 16 TAC §3.13. The Ellenburger is among the formations listed for which operators in Mitchell County and district 8 (where the MATF is located) are required to comply with TRRC Rule 13. TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46, for any well proposed within a one-quarter mile radius of an injection well. The MRV plan also states that in this instance, any new well permitted and drilled to the Mongoose AGI No. 1 well's injection zone and located within a one-quarter-mile radius of the well, will be required under TRRC Rule 13 to set steel casing and cement above the MATF's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued.

Groundwater Wells

The MRV plan states that a groundwater well search resulted in three groundwater wells found within the MMA, as identified by the Texas Water Development Board. The surface, intermediate, and production casing strings in the Mongoose AGI No. 1 well, as shown in Figure 45 of the MRV plan, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the Groundwater Advisory Unit (GAU) letter issued for this location. The MRV plan also states that the wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole. For these reasons, the MATF concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through existing wells within the MMA.

3.3 Leakage through Faults and Fractures

Section 4.3 of the MRV plan states that no faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose AGI No. 1 well. This includes areas outside the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

The MRV plan states that in the event of an unmapped fault existing within the plume boundary, any displacement would be below 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing vertical migration.

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

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through faults and fractures.

3.4 Leakage through the Confining Layer

Section 4.4 of the MRV plan states that the overlying Woodford Formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in Section 2 of the MRV plan. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale, which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through the confining layer.

3.5 Leakage from Natural or Induced Seismicity

Section 4.5 of the MRV plan states that the Mongoose AGI No. 1 well is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic

Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48 of the MRV plan, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

The MRV plan states all seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, MATF states the risks associated with injectate migration beyond the injection interval are unlikely. Additionally, stringent operating procedures will be programmed into the SCADA and control systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from natural or induced seismicity.

Thus, the MRV plan provides an acceptable characterization of potential CO_2 leakage pathways as required by 40 CFR 98.448(a)(2).

4 Strategy for Detecting and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baselines for Monitoring

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 5 of the MRV plan discusses the strategy that the MATF will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 of the MRV plan, to meet the requirements of 40 CFR 98.448(a)(3). As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Monitoring will occur during the planned 40-year injection period, or otherwise the cessation of operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

A summary table of the MATF's strategies for monitoring and responding to any potential CO_2 leakage can be found in Table 13 of the MRV plan and is reproduced below.

Leakage Pathway	Monitoring Method
	Fixed H_2S monitors throughout the AGI facility

Leakage from surface equipment	Visual inspections
	SCADA continuous monitoring of the AGI facility
Leakage through existing wells	SCADA continuous monitoring of the AGI well
	Monitor CO_2 levels in Above Zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage from natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

4.1 Detection of Leakage from Surface Equipment

Section 5.1 of the MRV plan states that as the MATF and Mongoose AGI No. 1 well are designed to reduce the possibility of CO_2 and H_2S escaping, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used, and the connections are designed to minimize corrosion points. A baseline atmospheric CO_2 concentration will be established during the commissioning of the MATF. Ambient H_2S monitors located at the MATF and near the Mongoose AGI No. 1 well are connected to the SCADA system for continuous monitoring.

The MRV plan states the MATF is continuously monitored through automated systems. In addition, field personnel conduct daily visual field inspections of gauges, monitors, and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the surface equipment associated with the sequestered CO_2 and inspection of the cathodic protection system. These inspections and the automated systems allow the MATF to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5) and §98.444(d).

The MRV plan states that pressures and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Table 13 of the MRV plan provides a detailed characterization of detecting diffuse CO_2 leakage that could be expected from surface equipment. Thus, the MRV plan provides adequate characterization of MATF's approach to detect potential leakage from surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Existing and Future Wells within the MMA

Section 5.2 of the MRV plan states that the MATF continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems for the Mongoose AGI No. 1 well. These data are reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. The Mongoose AGI No. 1 well has a pressure and temperature gauge placed in the injection stream at its wellhead and a pressure gauge on the casing annulus. A change of injection or annular pressure would indicate the presence of a possible leak. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC regulations. The MIT would also indicate the presence of a leak if a leak were to occur. The MRV plan explains that upon a negative MIT, the well would be isolated, and the leak mitigated.

As discussed previously in the MRV plan, Rule 13 would ensure that new wells in the field will be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, the MRV plan states that the MATF will also establish and operate an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the MMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. The MRV plan also states that prior to approval and implementation of the MRV plan and through the post-injection site care period, the MATF will have these monitoring systems in place.

According to the MRV plan, two wells have been identified within the AMA that penetrate the upper confining zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, MATF believes a leak event is unlikely. The MRV plan states MATF will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

The MRV plan reiterates that Bayswater is the operator of many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2 migrates up-hole, the CO_2 will likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation.

Groundwater Quality Monitoring

The MRV plan states that no groundwater wells were found within the MMA after an extensive search of records. Therefore, there are no groundwater wells to monitor.

Table 13 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through existing and future wells within the MMA. Thus, the MRV plan provides adequate characterization of MATF's approach to detect potential leakage through existing and future wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Faults, Fractures, or Confining Seals

Section 5.3 of the MRV plan states the MATF continuously monitors the operations of the Mongoose AGI No. 1 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken to shut in the well, if necessary.

The MRV plan also states the MATF will monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO_2 content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO_2 content would be an early indicator of a potential issue. Should the CO_2 migrate vertically, the magnitude risk of this event would be very low, as the reservoir provides an ideal containment given the upper confining zone has successfully held hydrocarbons in place.

Table 13 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through faults, fractures, or confining seals. Thus, the MRV plan provides adequate characterization of MATF's approach to detect potential leakage through faults, fractures, or confining seals as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage from Natural or Induced Seismicity

The MRV plan states that while the likelihood of a natural or induced seismicity event is extremely low, the MATF plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose AGI No. 1 well. This station is 3.5 miles west-northwest of the well location, as shown in Figure 49 of the MRV plan. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the MATF. The MATF will monitor this station for any seismic activity that occurs near the well. The MRV plan also states if a seismic event of 3.0 magnitude or greater is detected, the MATF will review the injection volumes and pressures of the Mongoose AGI No. 1 well to determine if any significant changes have occurred that would indicate potential leakage.

Table 13 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from natural or induced seismicity. Thus, the MRV plan provides adequate characterization of

MATF's approach to detect potential leakage from natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.5 Quantification

Section 7 of the MRV plan states that the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, the MATF believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. The MRV plan also states in the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline.

4.6 Determination of Baselines

Section 6 of the MRV plan identifies the strategies that the MATF will undertake to establish the expected baselines for CO_2 surface leakage per 40 CFR §98.448(a)(4). The MRV plan states the MATF will use existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. The MRV plan identifies the following strategies for determining baselines:

Visual Inspections

The MRV plan states regular inspections will be conducted by field personnel at the MATF and the Mongoose AGI No. 1 well. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

CO_2/H_2S Detection

The MRV plan states that in addition to the fixed gas monitors at the well site, the MATF will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H_2S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface and collect samples over a 21-day period. These samples will then be sent to a third-party laboratory to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

Operational Data

The MRV plan states that upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

Continuous Monitoring

The MRV plan states the total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the OSHA Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) limit of 5,000 ppm. Direct leak surveys are hazardous due to the presence of H_2S in the acid gas stream. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. According to the MRV plan, this method is consistent with 40 CFR §98.448(a)(5) and §98.444(d), allowing the operator to calculate site-specific variables used in the mass balance equation.

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

Thus, the MRV plan provides an acceptable approach for detecting and quantifying leakage and for establishing expected baselines in accordance with 40 CFR 98.448(a)(3) and 40 CFR 98.448(a)(4).

5 Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation

5.1 Determining Mass of CO_2 Received

According to Section 7 of the MRV plan, the CO_2 received for the Mongoose AGI No. 1 well is wholly injected and not mixed with any other supply. Therefore, the MATF states the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

MATF provides an acceptable approach to calculating the mass of CO_2 received under subpart RR requirements.

5.2 Determining Mass of CO_2 Injected

The MRV plan states since the mass of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5:

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

Where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

MATF provides an acceptable approach to calculating the mass of CO_2 injected under subpart RR requirements.

5.3 Mass of CO_2 Produced

The MRV plan states the Mongoose AGI No. 1 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

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

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

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

Where:

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

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

X = Leakage pathway.

The MRV plan also states calculation methods using equations from subpart W will be used to calculate CO_2 emissions due to any surface equipment leakage between the flow meter used to measure injection quantity and the injection wellhead.

MATF provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage under subpart RR requirements.

5.5 Calculation of Mass of CO_2 Sequestered

The MRV plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12 as the Mongoose AGI No. 1 well will not actively produce oil or natural gas, or any other fluids, as follows:

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

Where:

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

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

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

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

The MRV plan states that CO_{2FI} will be calculated in accordance with subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required, and those emissions are sent to a flare stack and reported as part of the required GHG reporting for the MATF. The MRV plan also states calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

MATF provides an acceptable approach for calculating the mass of CO_2 sequestered under subpart RR requirements.

6 Summary of Findings

The subpart RR MRV plan for the Mongoose Amine Treating Facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the MATF MRV plan.

Subpart RR MRV Plan Requirement	**MATF MRV Plan**
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan describes the MMA and AMA. The MMA boundary was established by taking the stabilized plume boundary after 120 years of density drift and adding a one half-mile buffer. The initial AMA boundary was established by superimposing the area based on a one half-mile buffer around the anticipated plume location after 12 years of injection (2036) with the area of the projected free-phase CO_2 plume at five additional years (2041).

40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies and evaluates the potential surface leakage pathways. MATF identifies the following potential pathways: leakage from surface equipment; leakage through existing wells within the MMA; leakage through faults and fractures, leakage through the confining layer; and leakage from natural or induced seismicity. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Sections 5 and 7 of the MRV plan describe both strategies for how the MATF intends to detect CO_2 leakage to the surface and how the leakage would be quantified, should leakage occur. The MRV plan states that leaks would be detecting using methods such as visual inspections, SCADA systems, MITs, soil gas sampling, groundwater sampling, TexNet monitoring, and in-field as well as personal H_2S monitors.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV plan describes the strategy that the MATF will employ to establish baselines against which monitoring results can be compared to assess potential surface leakage. The MRV identifies the following strategies: visual inspections, H_2S/CO_2 monitoring, monitoring of operational data, and continuous monitoring.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV plan describes MATF's approach to determining the amount of CO_2 sequestered using the subpart RR mass balance equation, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan provides the well identification numbers for the Mongoose AGI No. 1 injection well. The MRV plan specifies that the wells have been issued a UIC Class II permit under TRRC Rule 9 and Rule 36.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 8 of the MRV plan states that the MATF will begin collecting data for calculating the total amount of CO_2 sequestered according to Equation RR-12 of this subpart upon receiving approval from EPA.

Appendix A: Final MRV Plan

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC*
Denver, CO

By

Lonquist Sequestration, LLC
Austin, TX

Version 4.0
August 2024

INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.

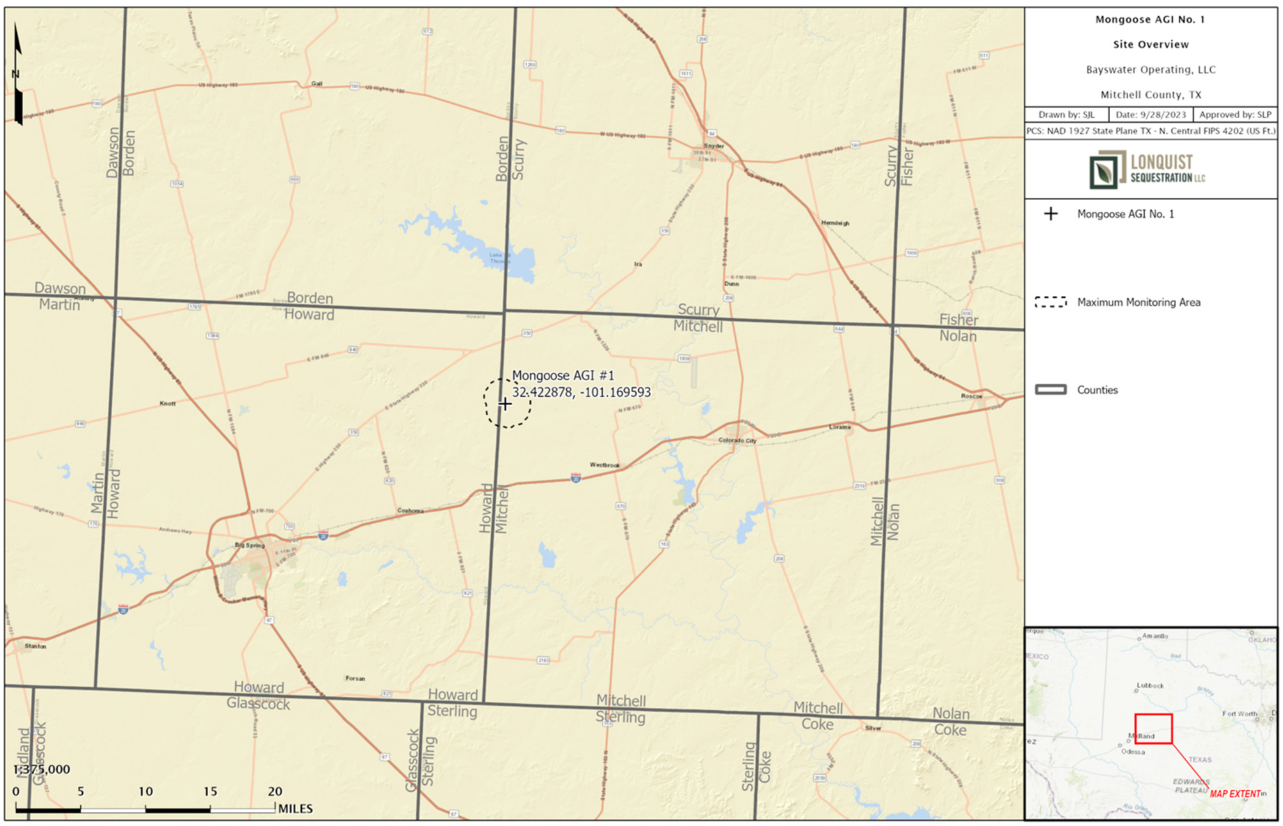

Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years up to a maximum of 19.5 MMscf/D. The primary source of this injected CO_2 gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NAD	North American Datum
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
pH	Scale of Acidity
PISC	Post Injection Site Care
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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Figures

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Appendices

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 Reporter Number

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
    - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility
1625 County Road 280
Westbrook, Texas 79565

Coordinates in North American Datum of 1983 (NAD 83) for this facility:

Latitude: 32.4225396641
Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).

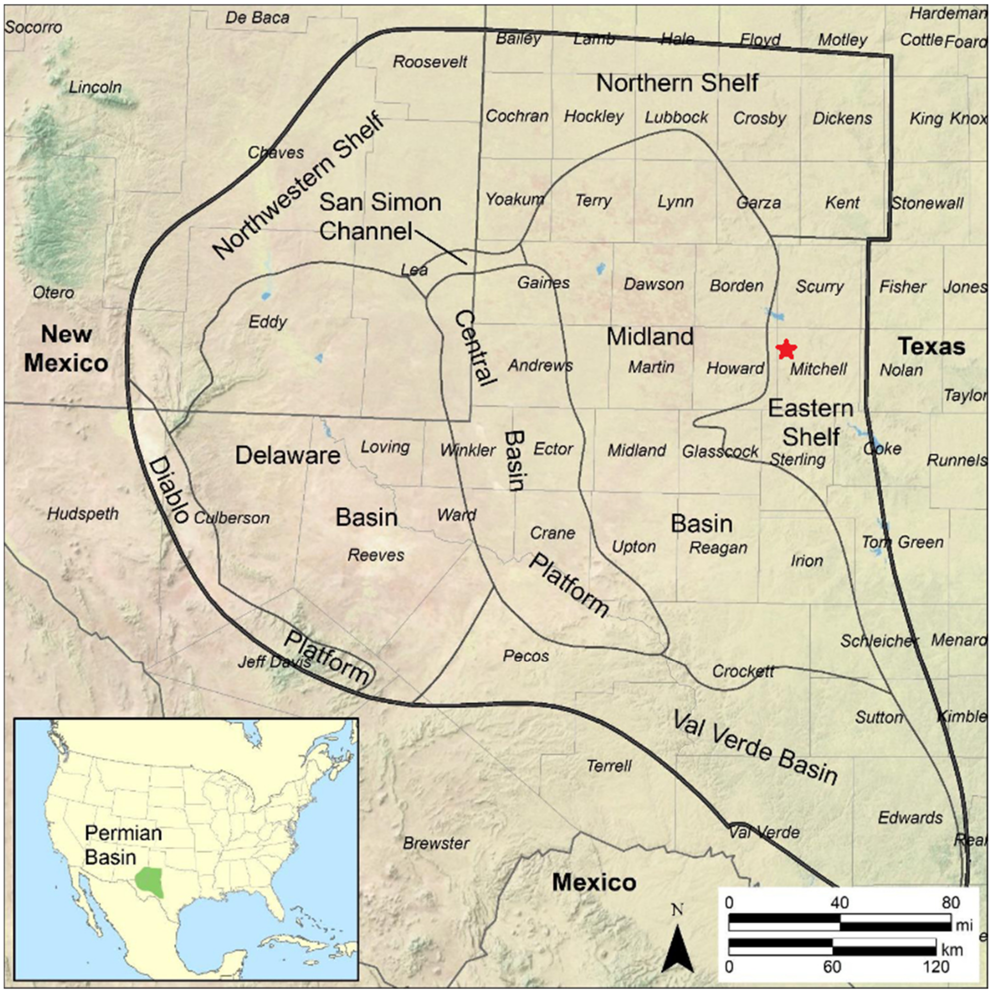


Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).

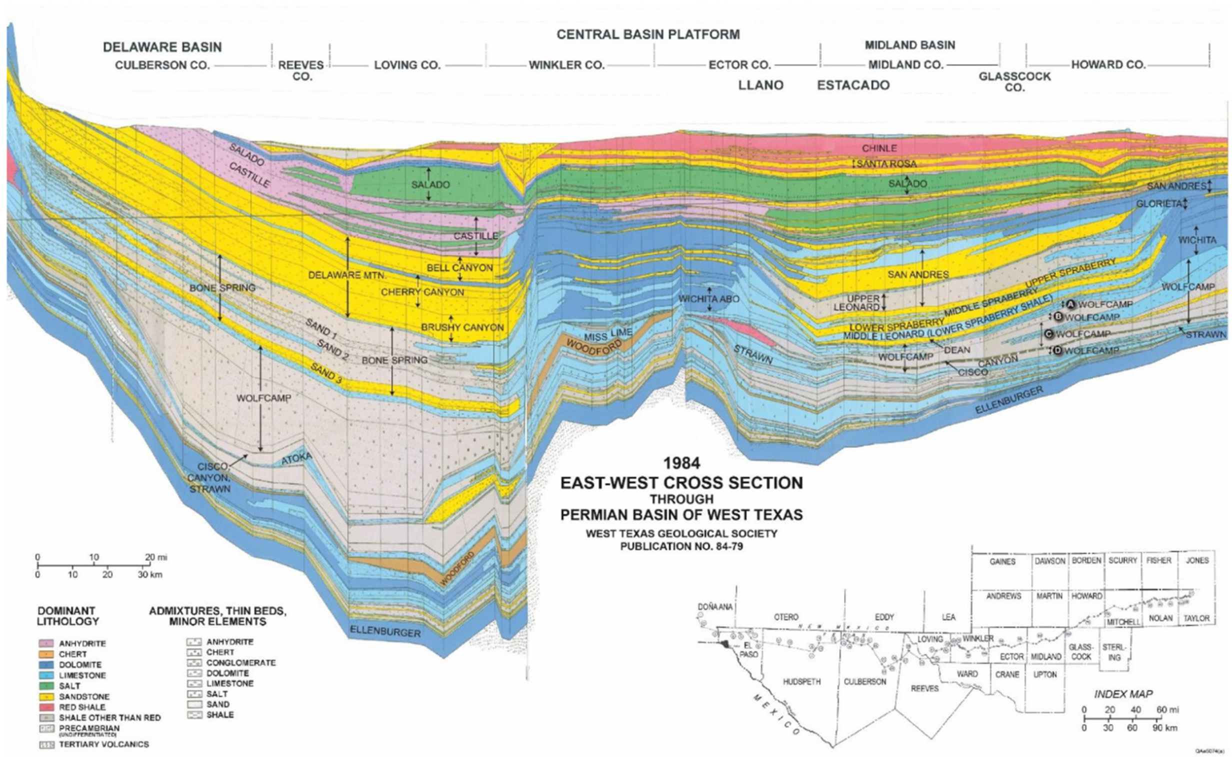


Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).

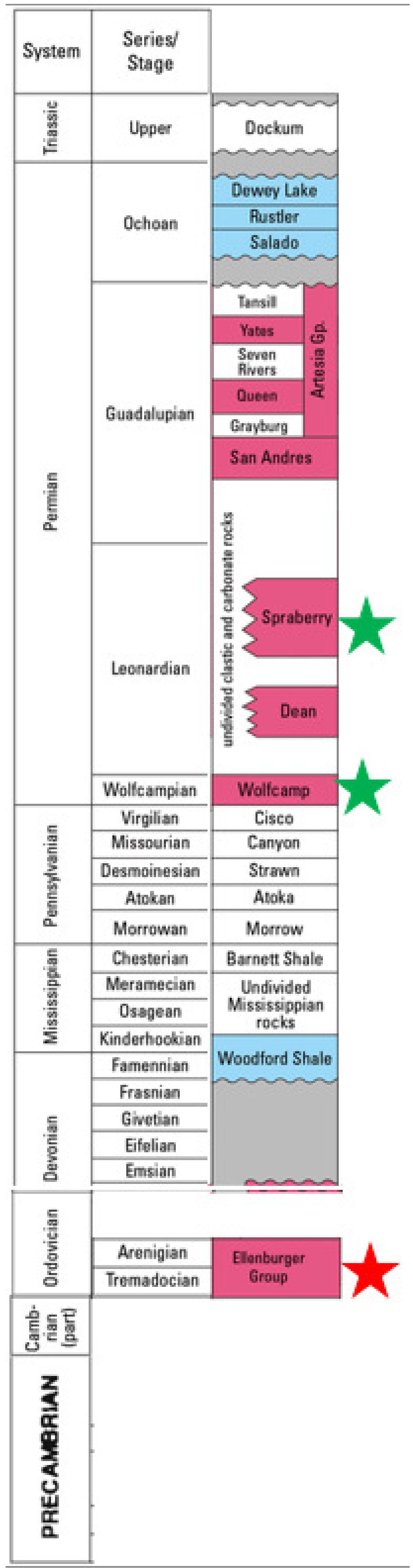


Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf

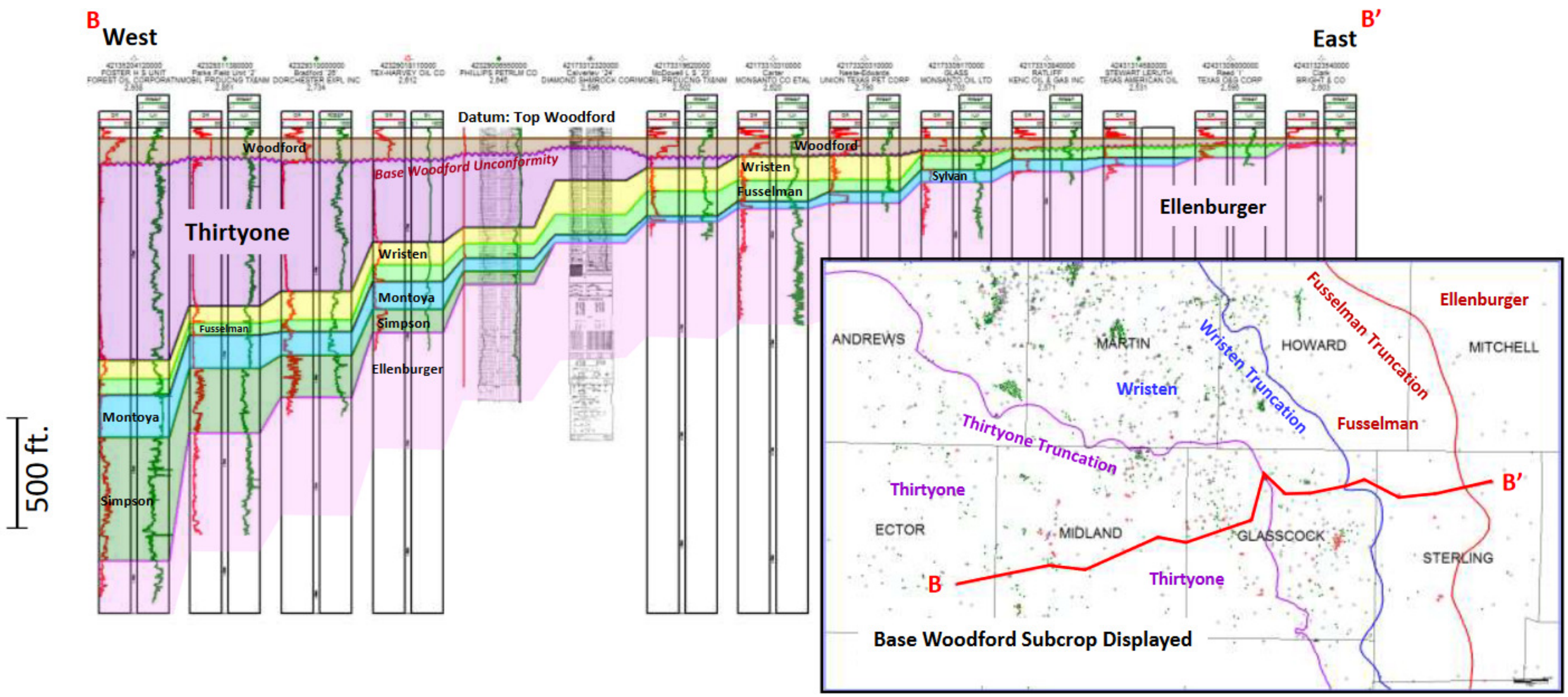


Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).

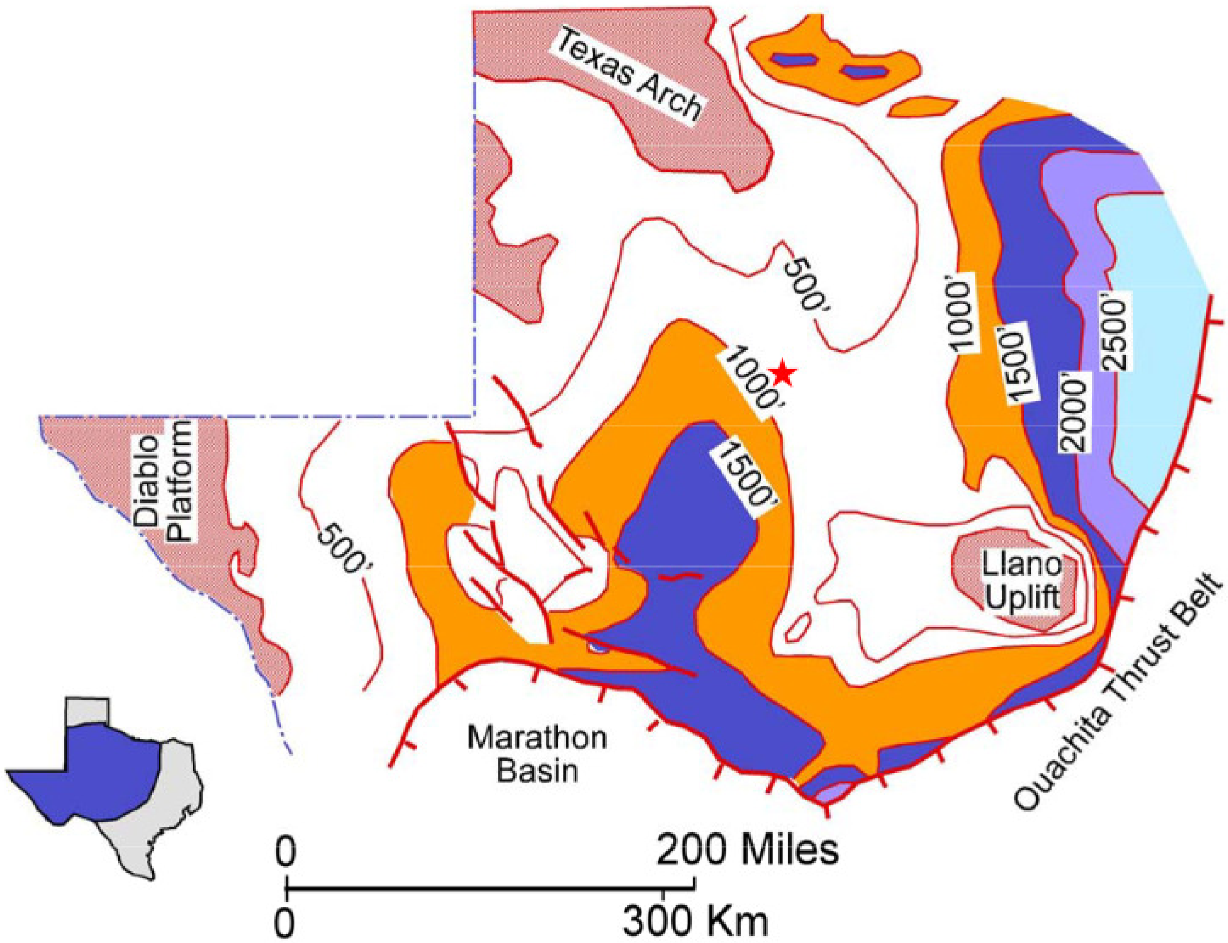


Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)

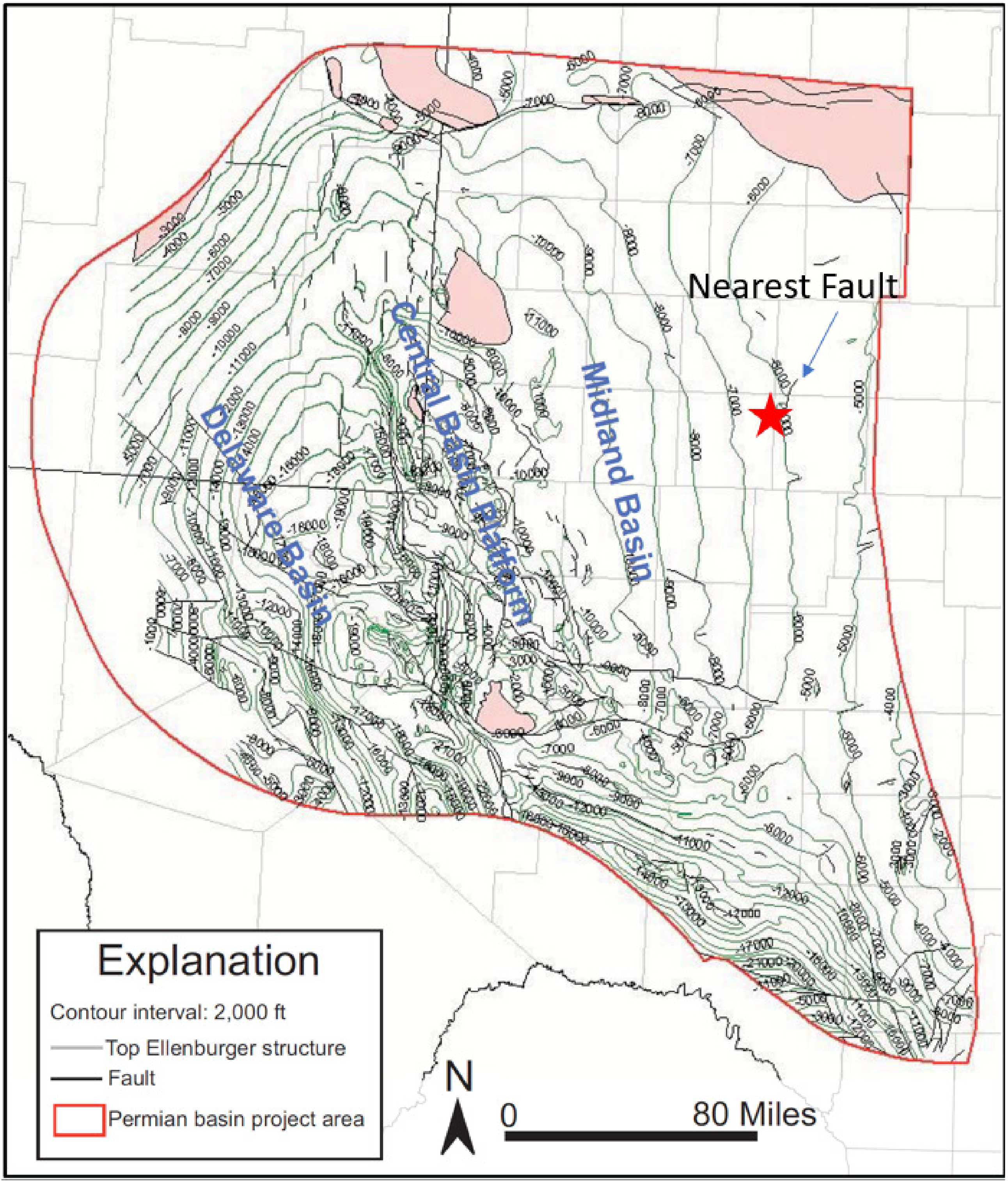


Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).

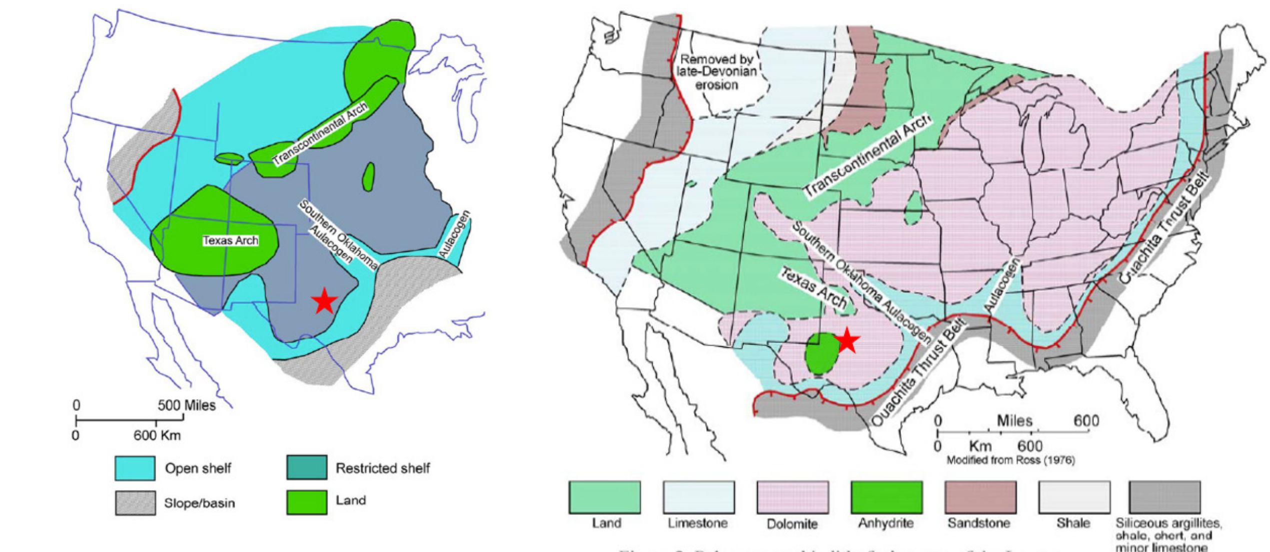


Figure 3. Interpreted regional depositional setting during Early Ordovician time. After Ross (1976) and Kerans (1990).

Figure 2. Paleogeographic lithofacies map of the Lower Ordovician section in the United States. From Ross (1976).

Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).

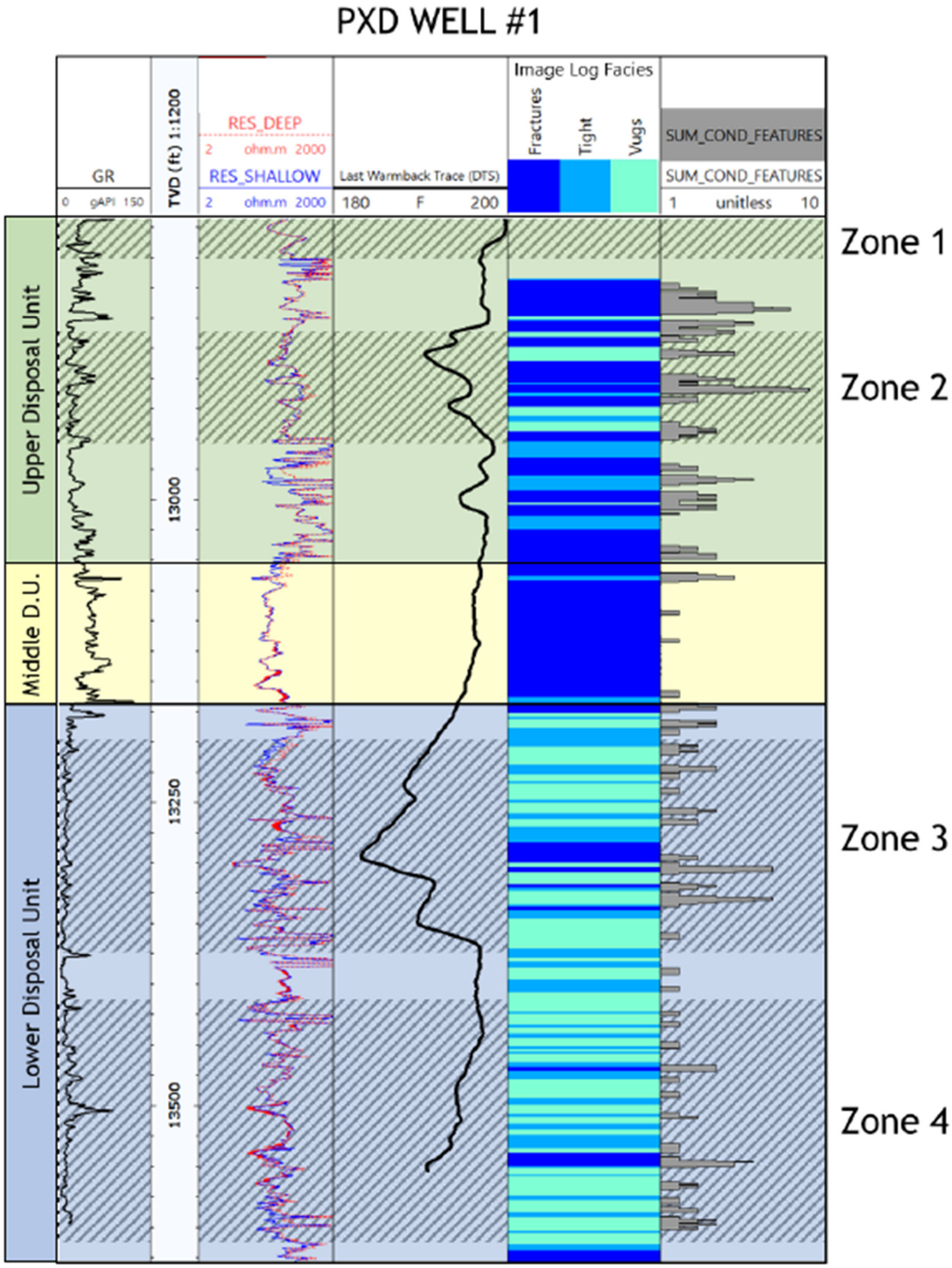


Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, & Coringrato, 2019)

2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displayed this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 <u>Site Characterization</u>

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.

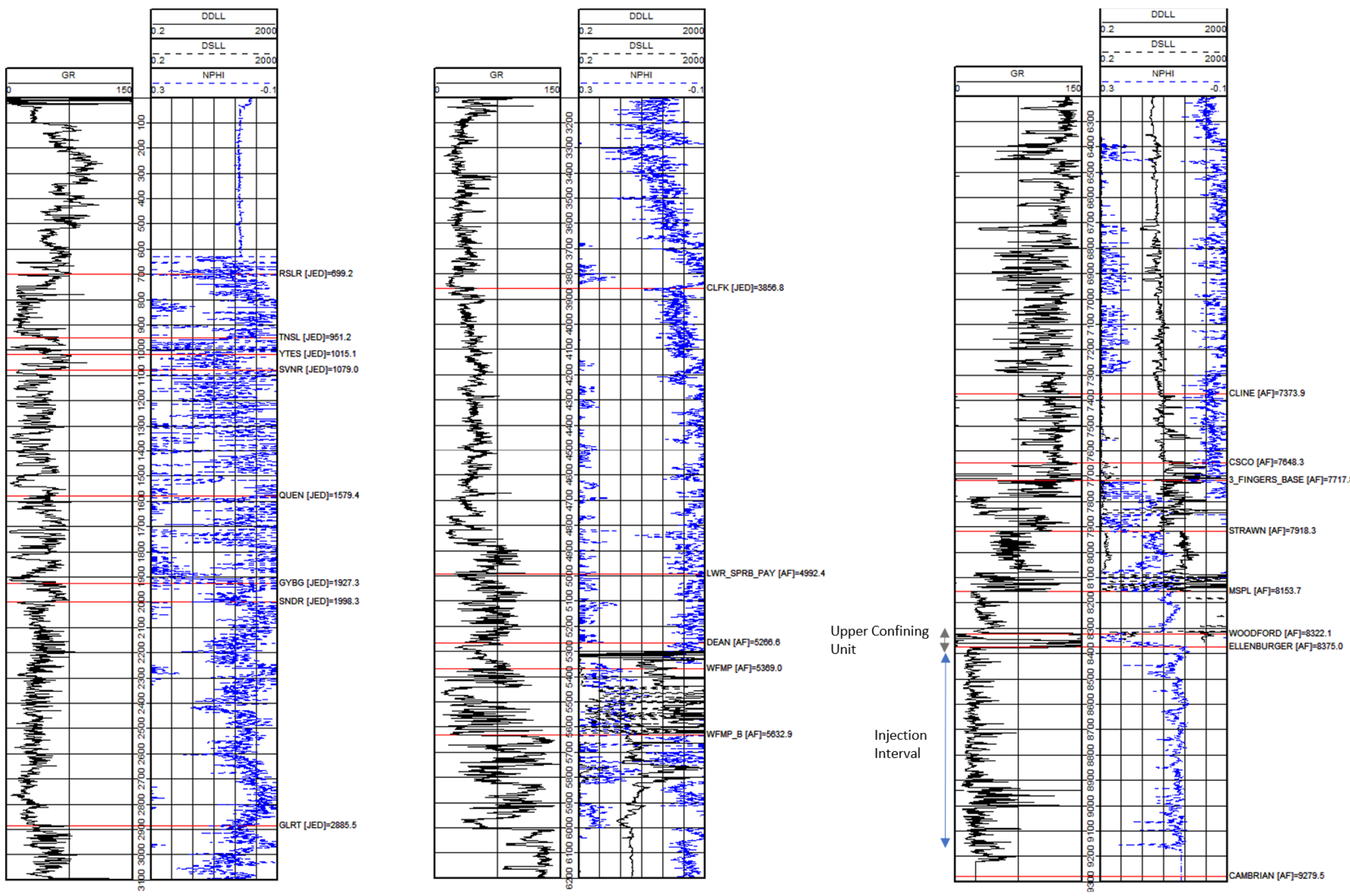


Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO_2 Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.

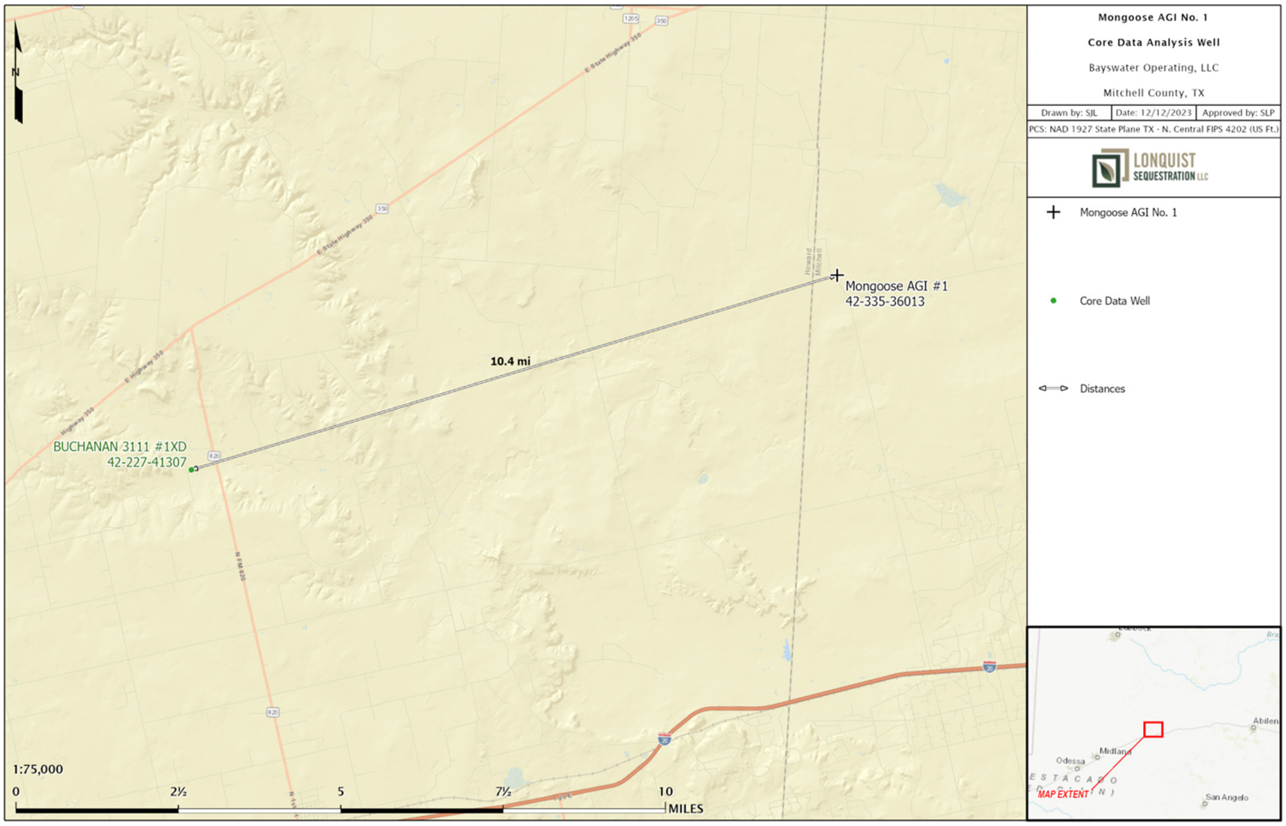


Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data

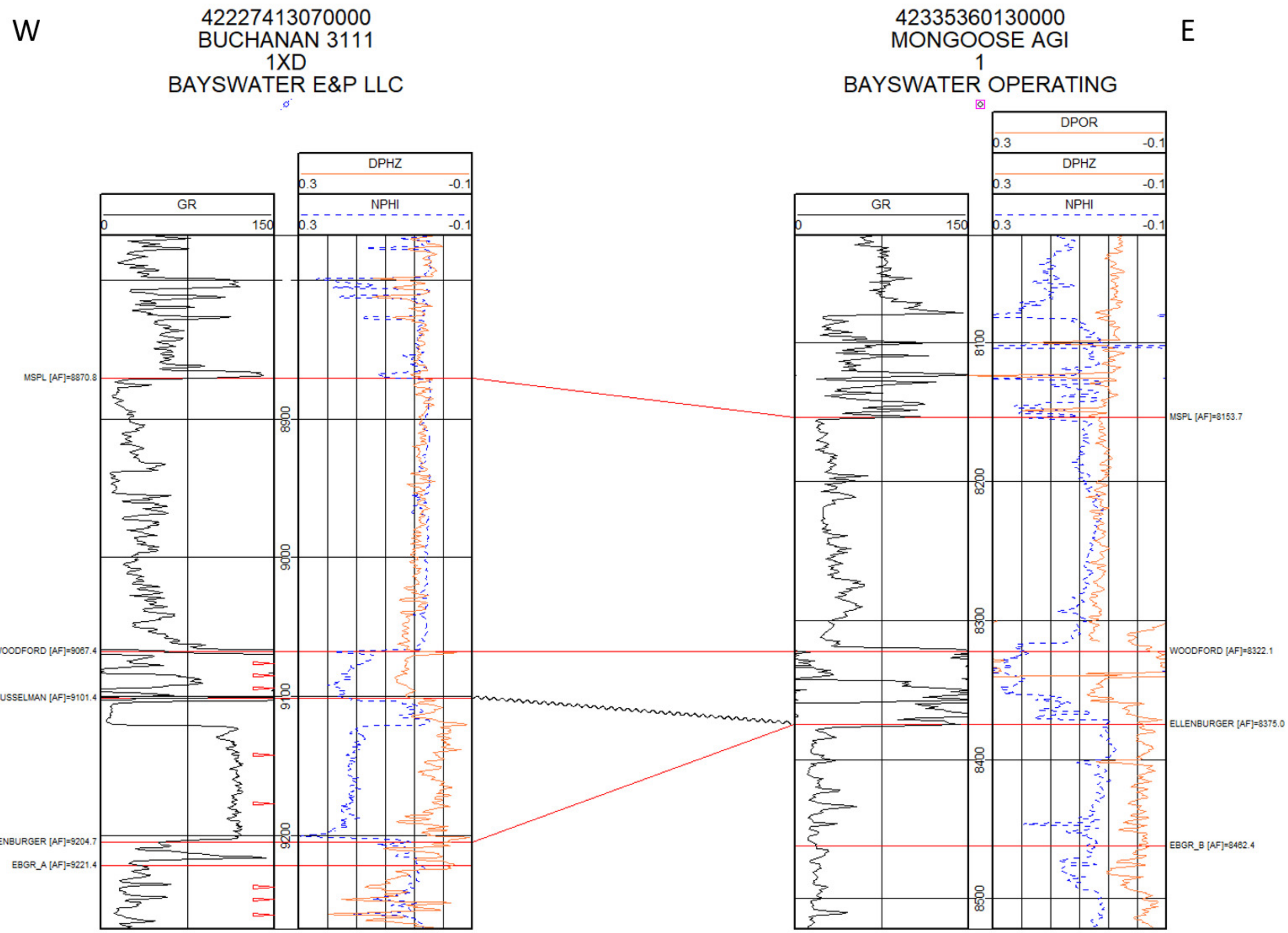


Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.

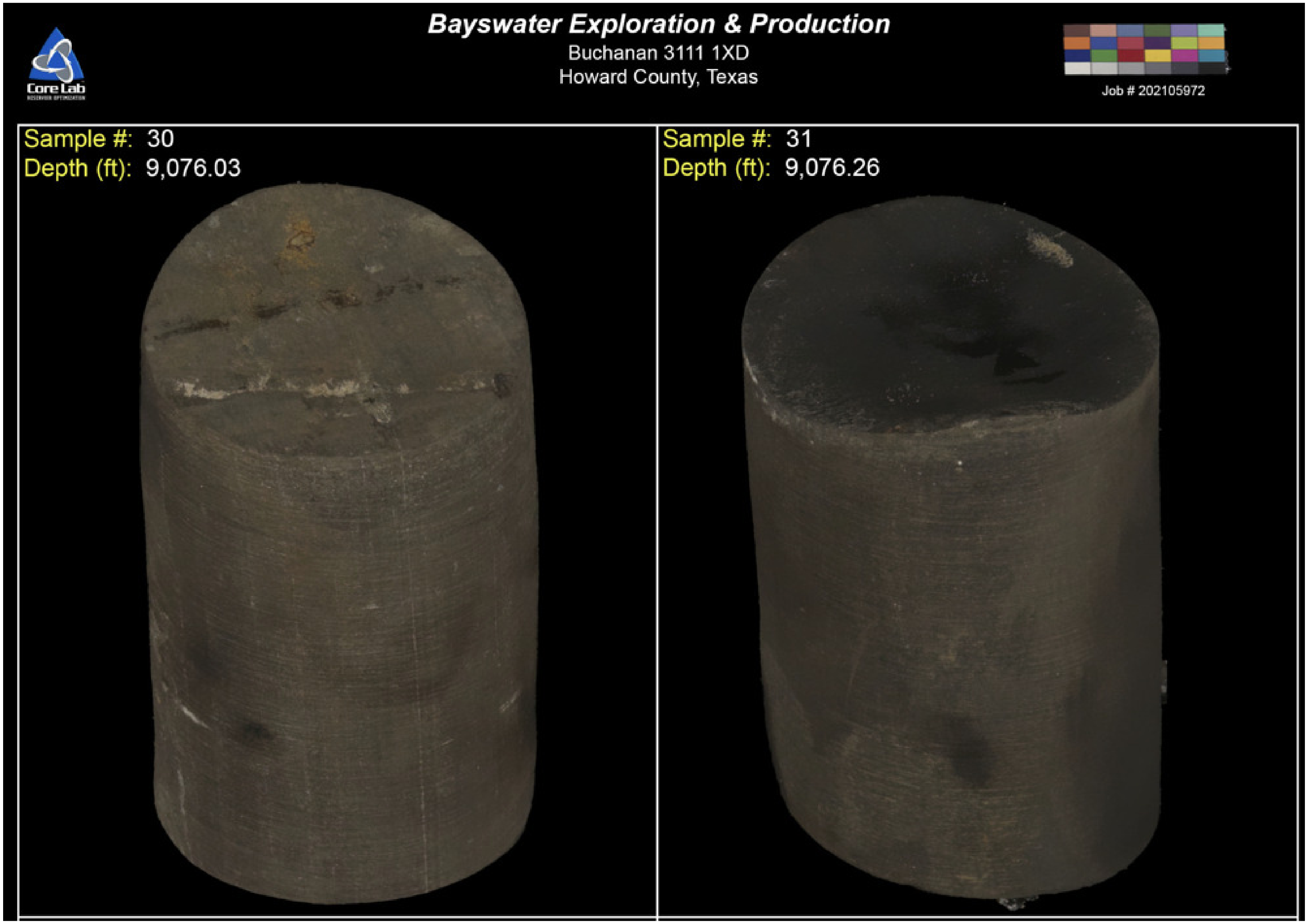


Figure 13 – Core Photo of Samples Within the Woodford Formation

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: February 04, 2022
Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

		As received				Dry & Dean Stark Extracted Conditions (2)				
Sample	**Depth** (ft)	**Bulk Density** (g/cc)	**Matrix Permeability (1)** (mD)	**Gas-filled Porosity** (%)	**Gas Saturation** (%)	**Grain Density** (g/cc)	**Matrix Permeability (5)** (mD)	**Porosity** (%)	**Oil Saturation (3)** (%)	**Water Saturation (4)** (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:
Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.
(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.
(3) Oil volume computed assuming an oil density of 0.844 g/cc
(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc
(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

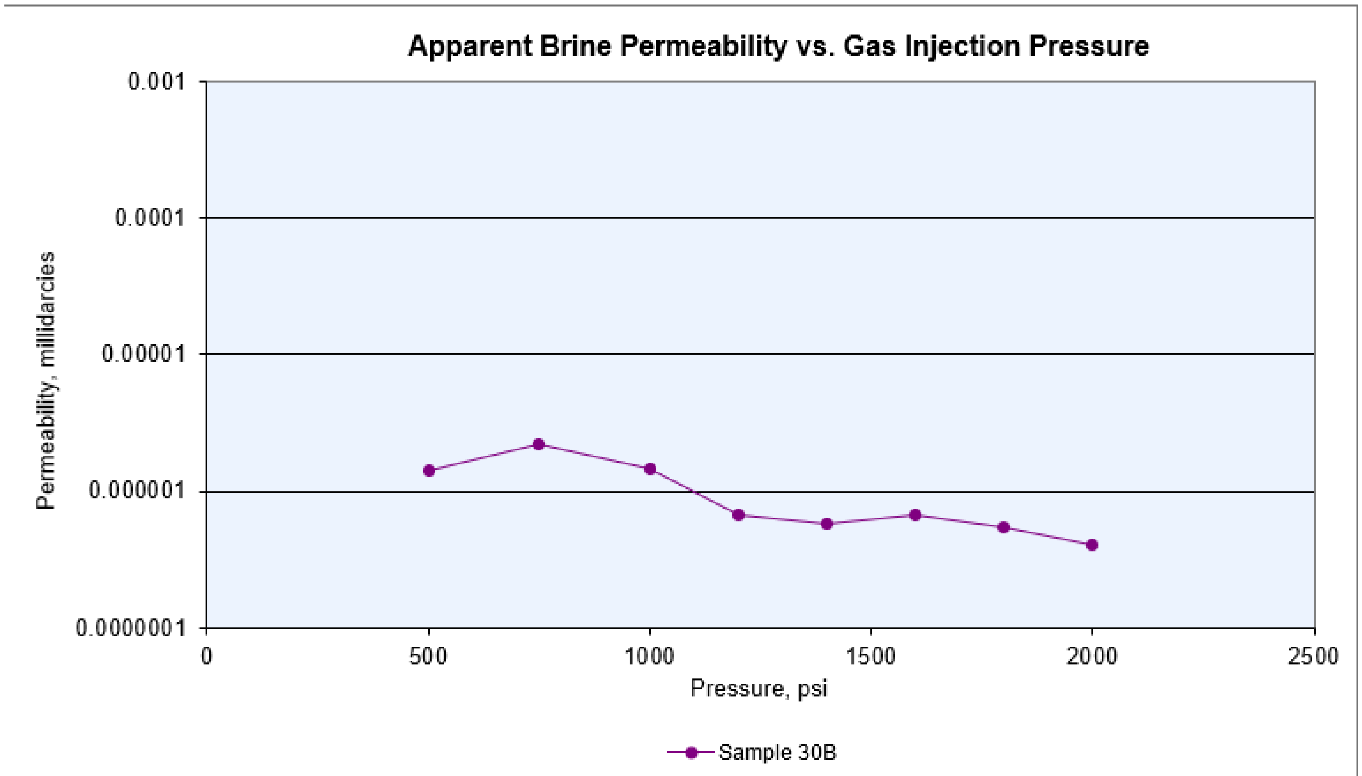


Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi   Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample 30B	
Gas Injection Pressure, psi	Permeability to Brine*, mD
500	1.44E-06
750	2.20E-06
1000	1.46E-06
1200	6.73E-07
1400	5.77E-07
1600	6.72E-07
1800	5.39E-07
2000	4.03E-07

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample Number	Depth, feet	Length, cm	Diameter, cm	Final Permeability to Brine*, millidarcies	Threshold Entry Pressure, psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 <u>Ellenburger</u>

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 <u>Ellenburger Porosity/Permeability Development</u>

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and non-applicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A two-function porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

If Effective Porosity (Φeff) < 6.5%: $K(mD) = 7E{-}08e^{3.3028*\Phi\mathrm{eff}}$

If Effective Porosity (Φeff) > 6.5%: $K(mD) = 277.39\ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: March 31, 2022
Analyst(s): MP

CMS-300 ROTARY SIDEWALL ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Klinkenberg (md)	Permeability Kair (md)	b(air) psi	Beta ft(-1)	Alpha (microns)	Saturation Oil (% Pore Volume)	Saturation Water (% Pore Volume)	Grain Density (g/cm3)	Footnote
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

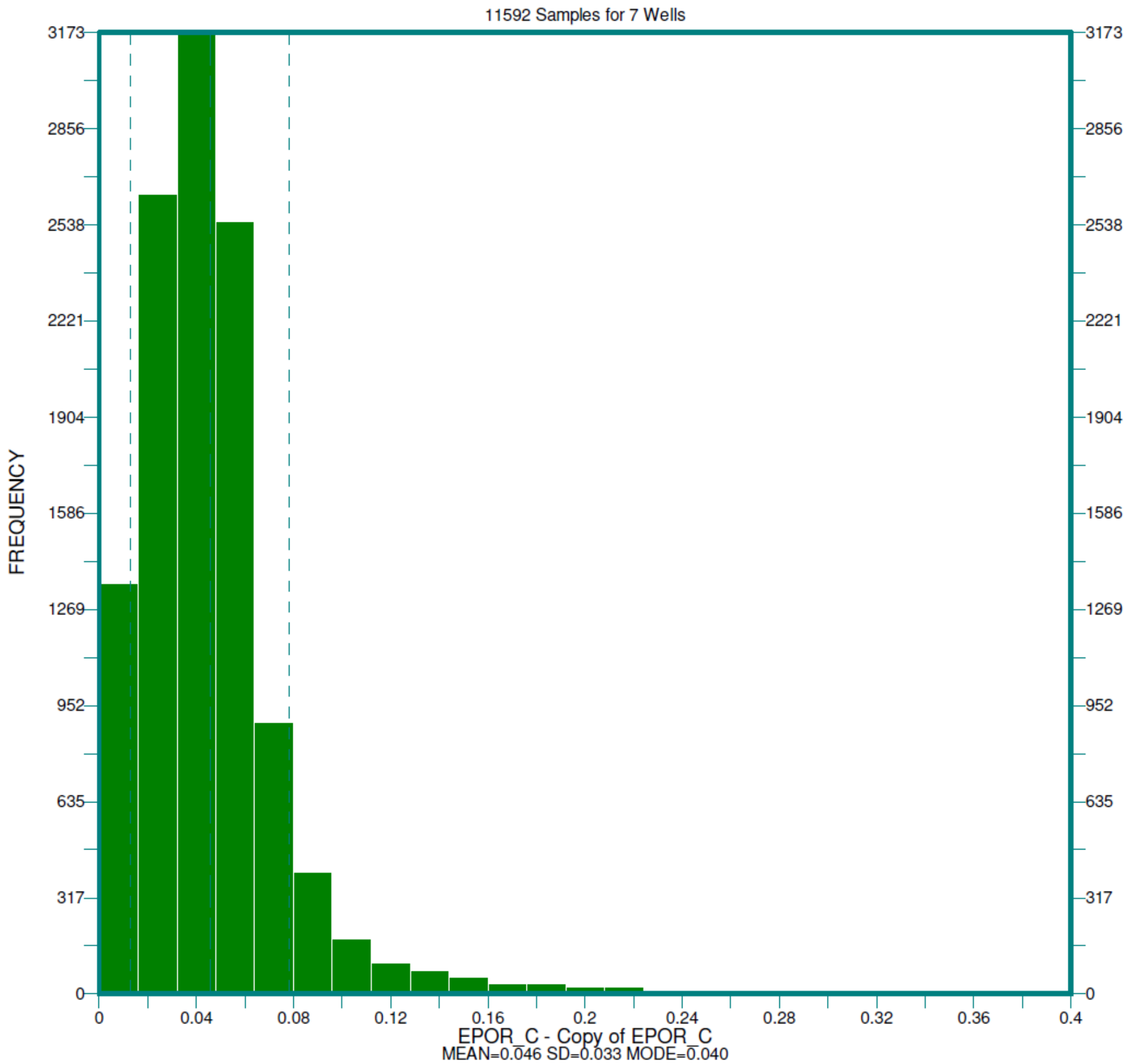


Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

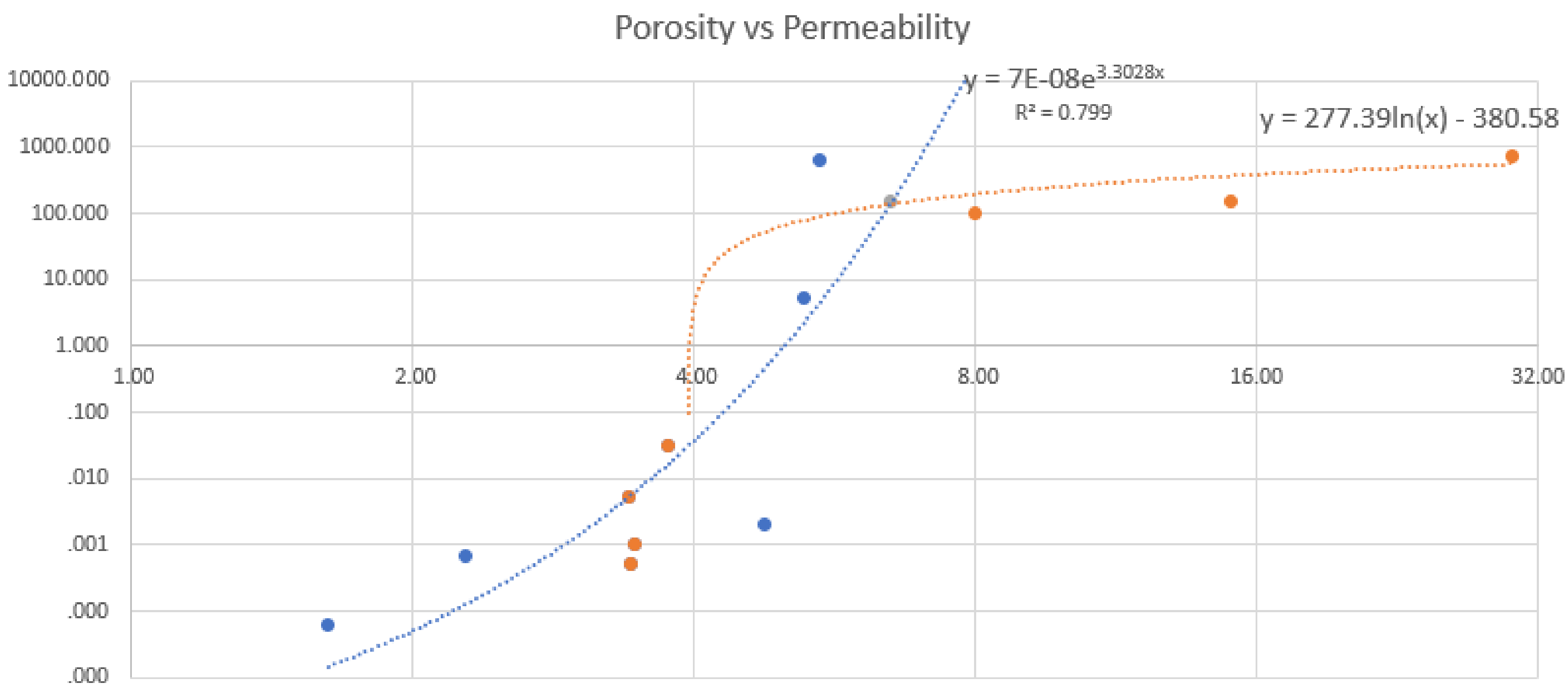


Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data

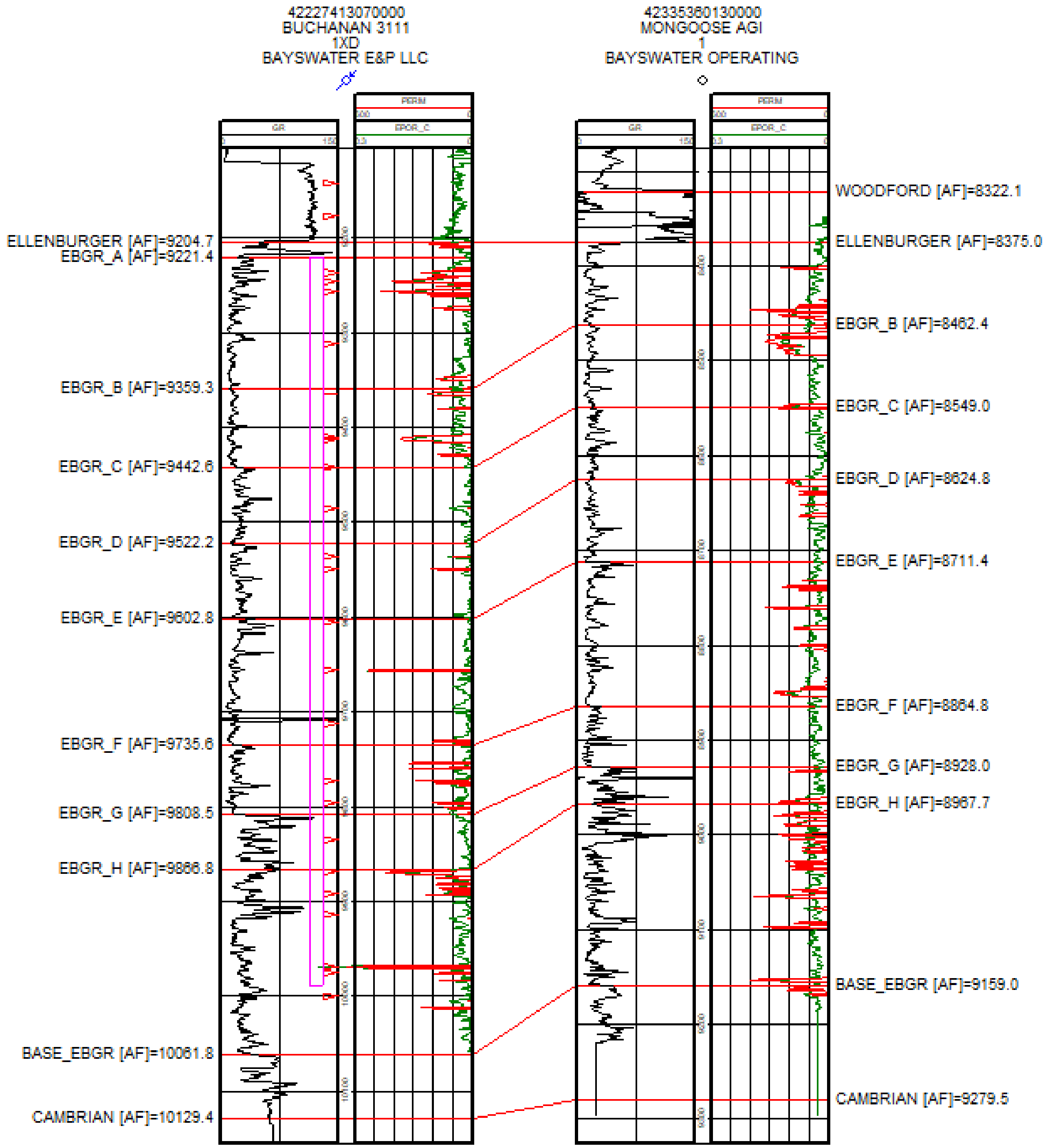


Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.

Figure 23 – Core photo of Ellenburger sample displaying vug features.

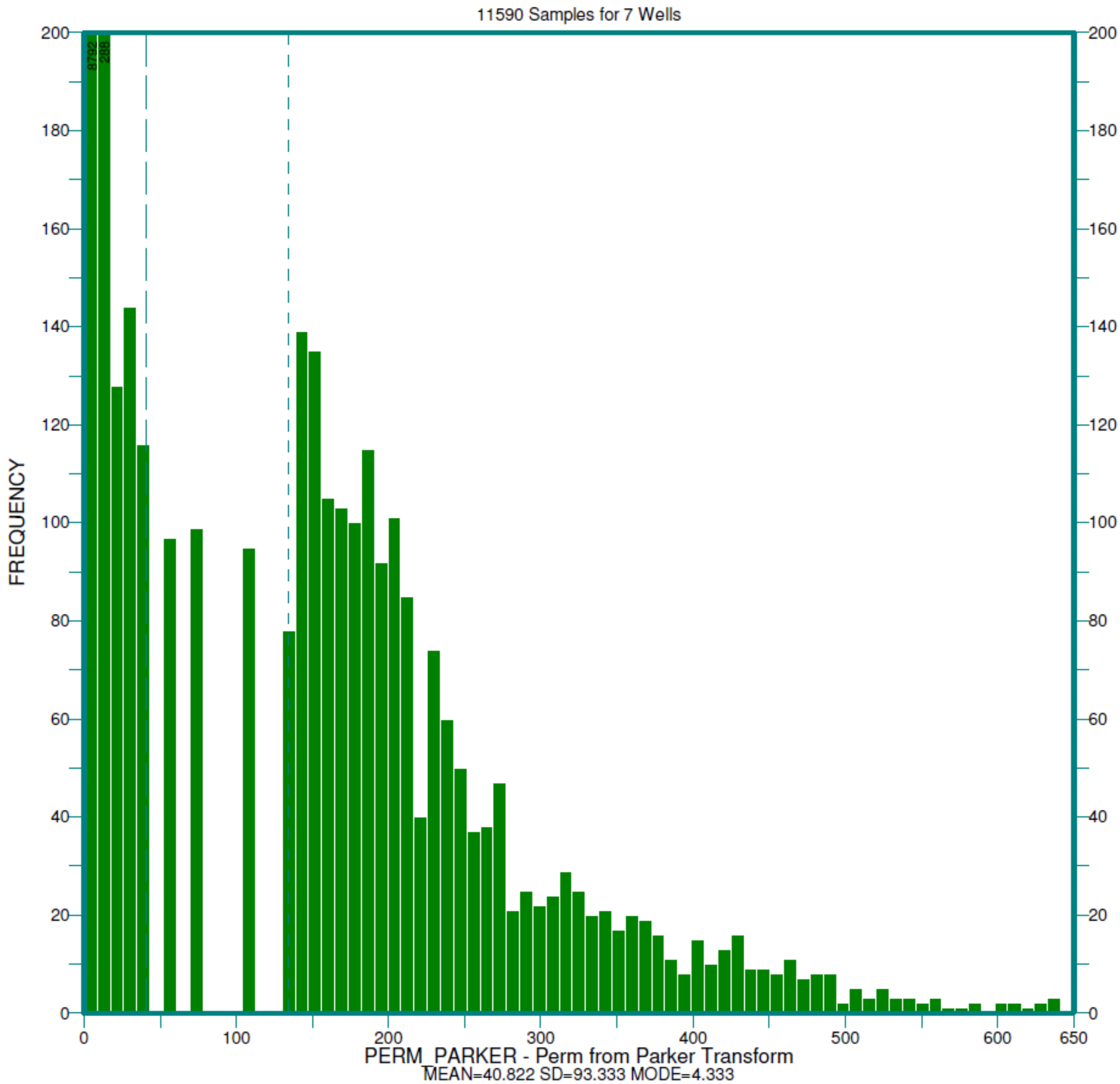


Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oil-field brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.

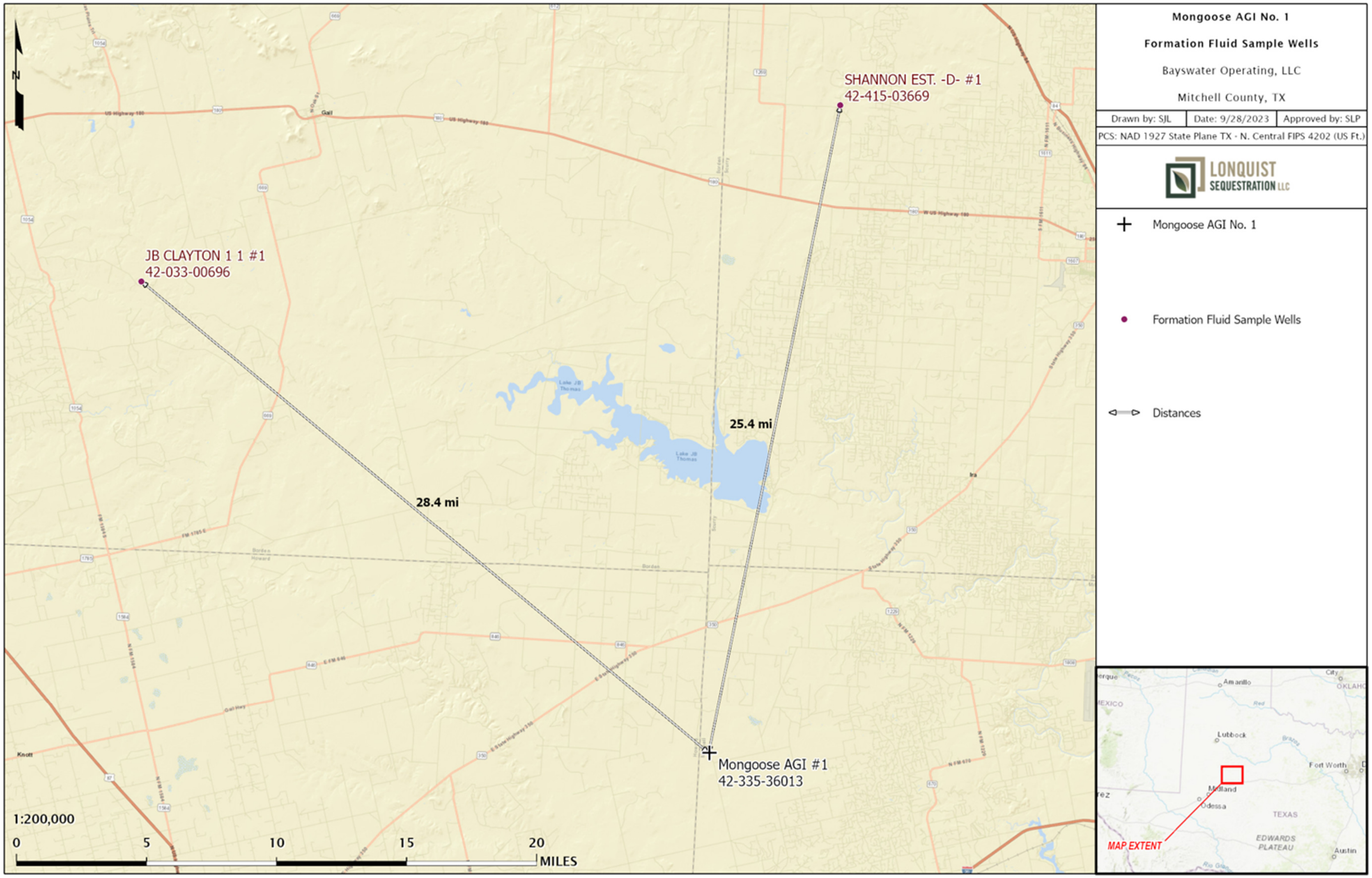


Figure 25 – Offset wells used for formation fluid characterization.

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

	Average	Low	High
Total Dissolved Solids (ppm*)	47,427	42,014	52,840
pH	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

*ppm – parts per million

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian." Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.

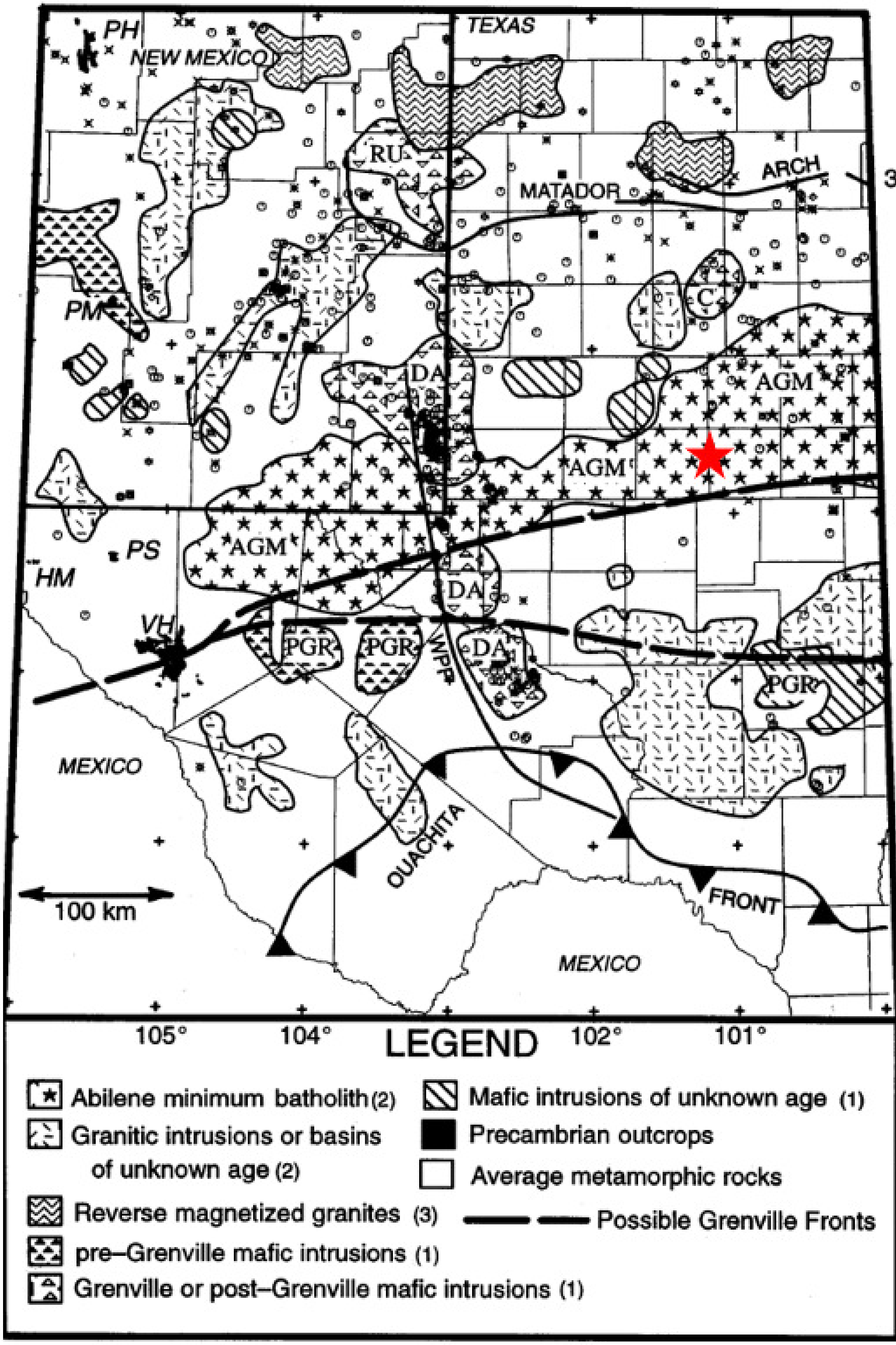


Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Table 4 – Calculated Vertical Stresses

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

*Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. The calculation requires Poisson's ratio (v), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$\nu = \frac{\frac{1}{2}\left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

ν = Poisson's Ratio
v_p = Compressional Velocity
v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1-0.261}(1.029 - 0.465) + 0.465 = 0.664\, psi/ft$$

$$FG\ with\ SF = 0.689\ \times 90\% = \mathbf{0.598}\, \boldsymbol{psi/ft}$$

Table 5 – Fracture Gradient Calculation Inputs and Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix D*.

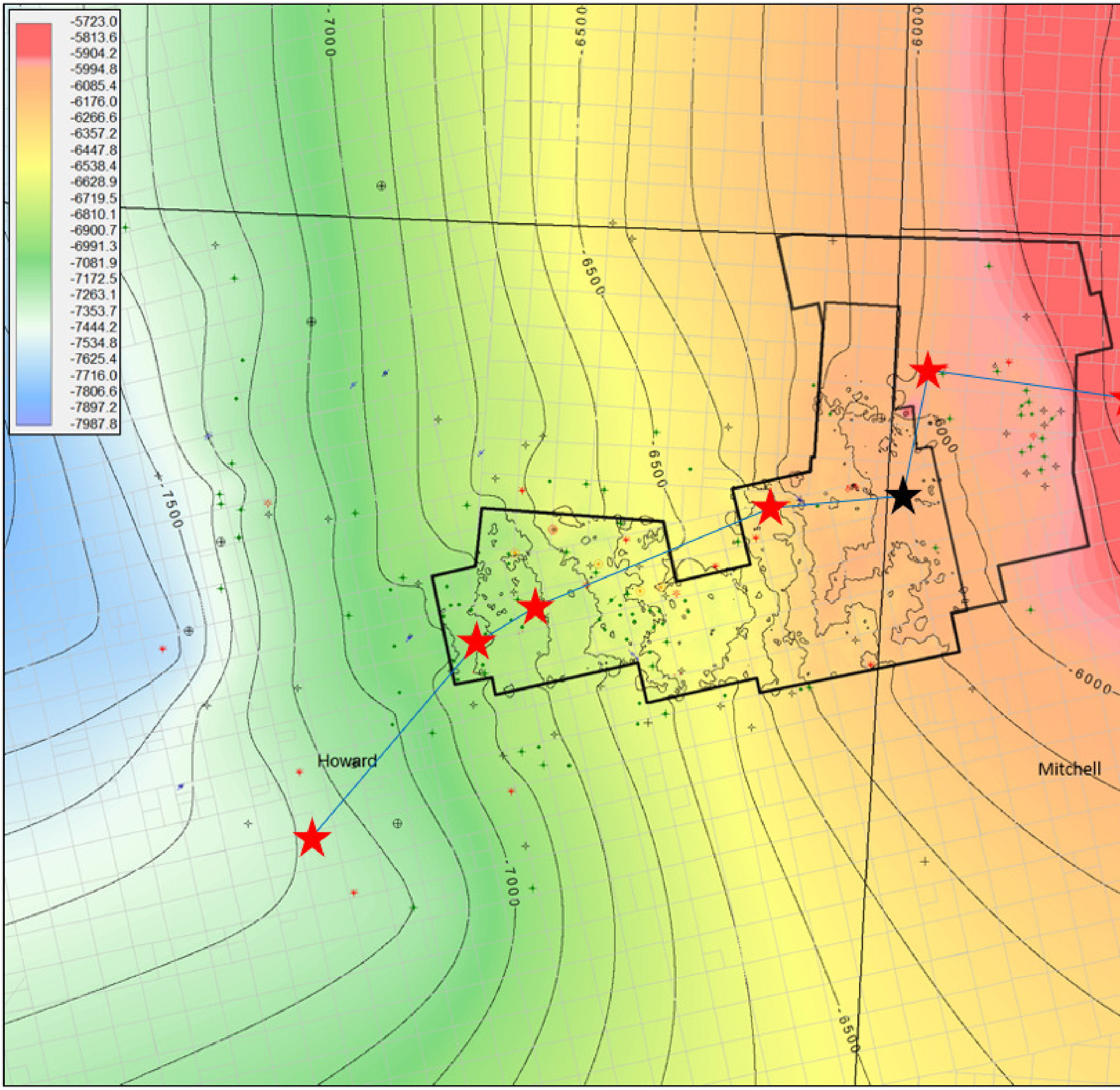


Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.

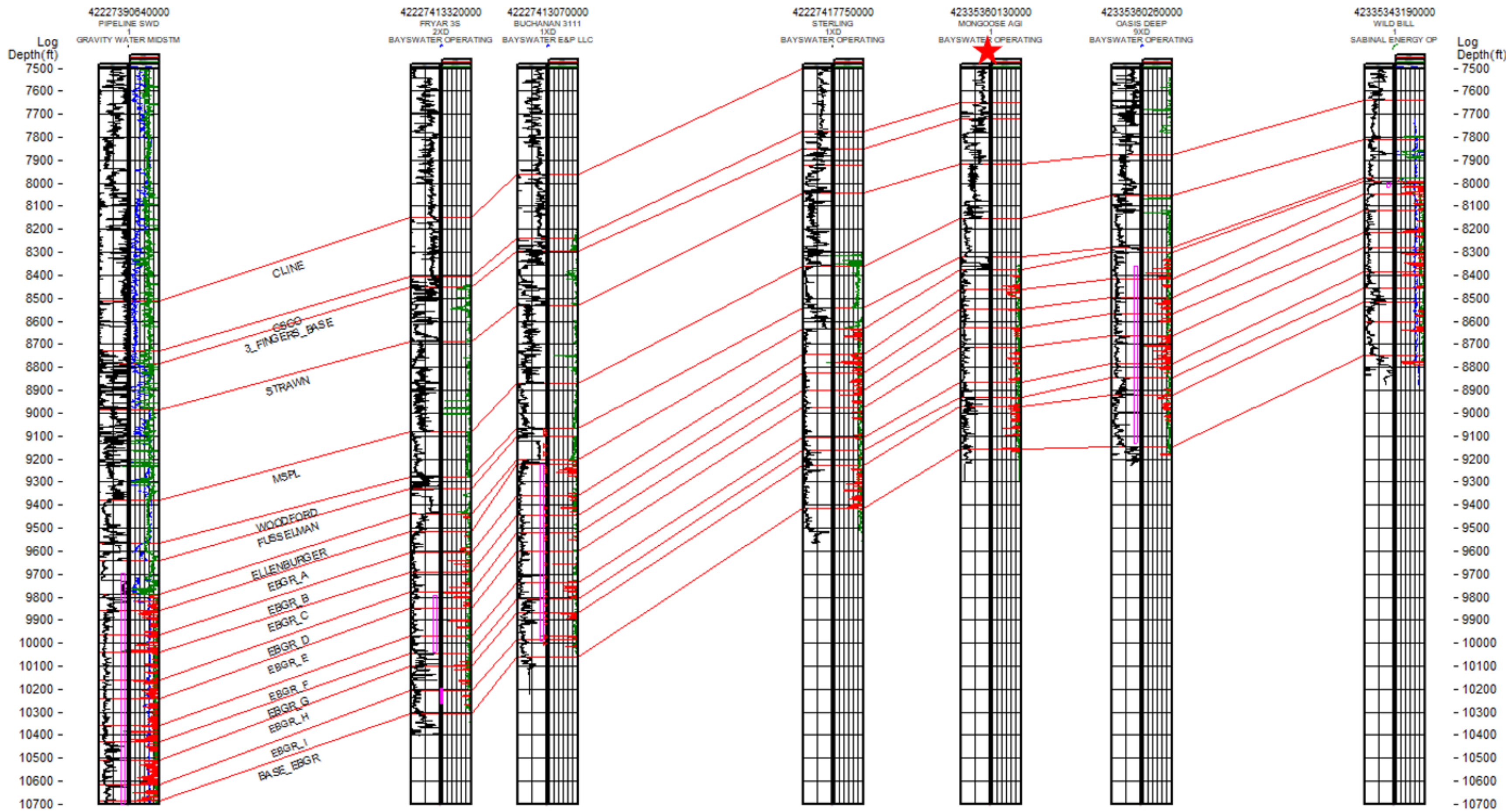


Figure 28 – Structural cross section depicting the Ellenburger.

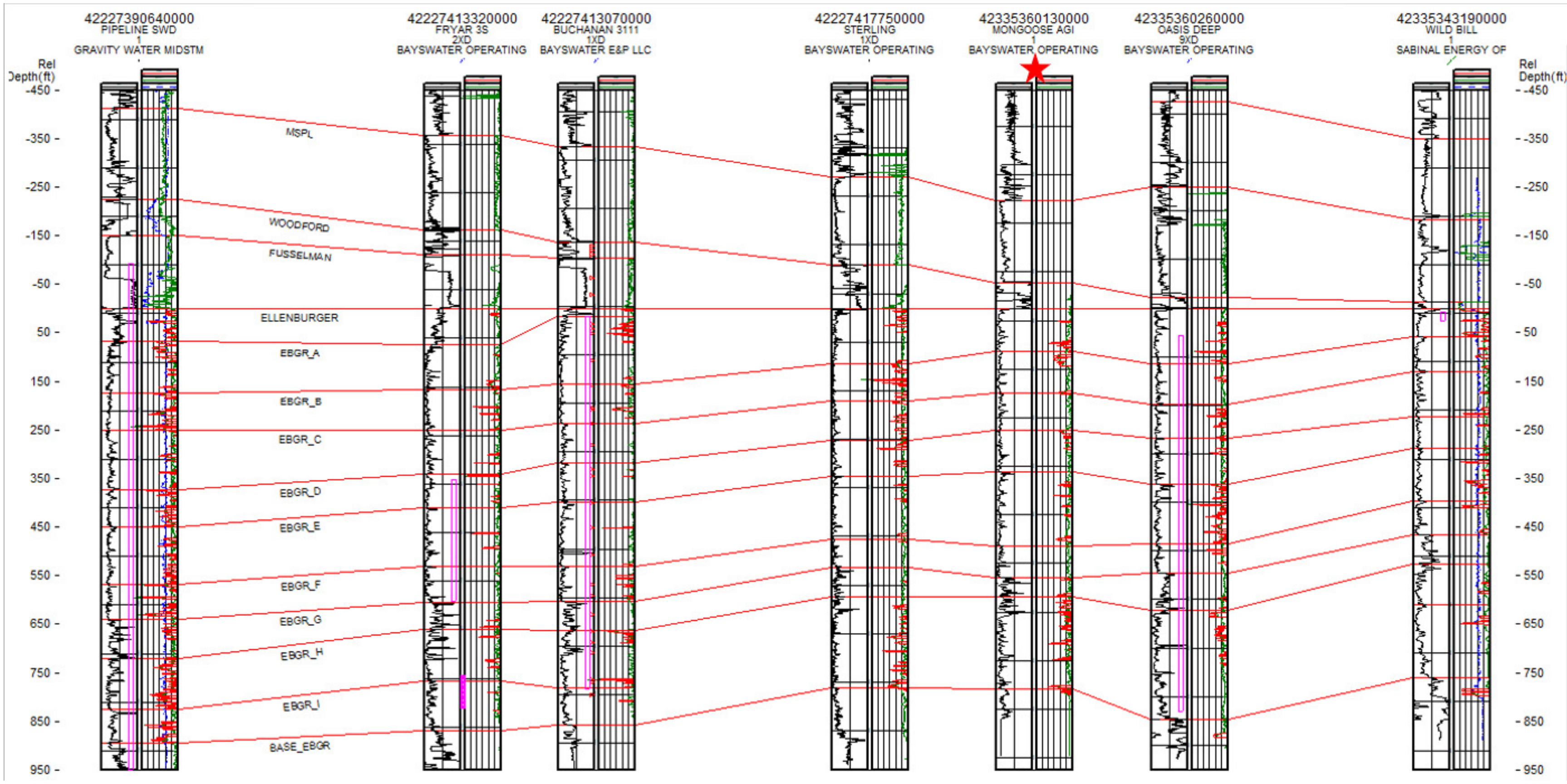


Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colorado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
Cretaceous	Comanche	Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous limestone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potable but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
Triassic		Dockum	Chinle	0-640	Predominantly red to maroon and purplish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sandstone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
			Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaceous and carbonaceous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capacity of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to highly mineralized water to livestock and domestic wells.

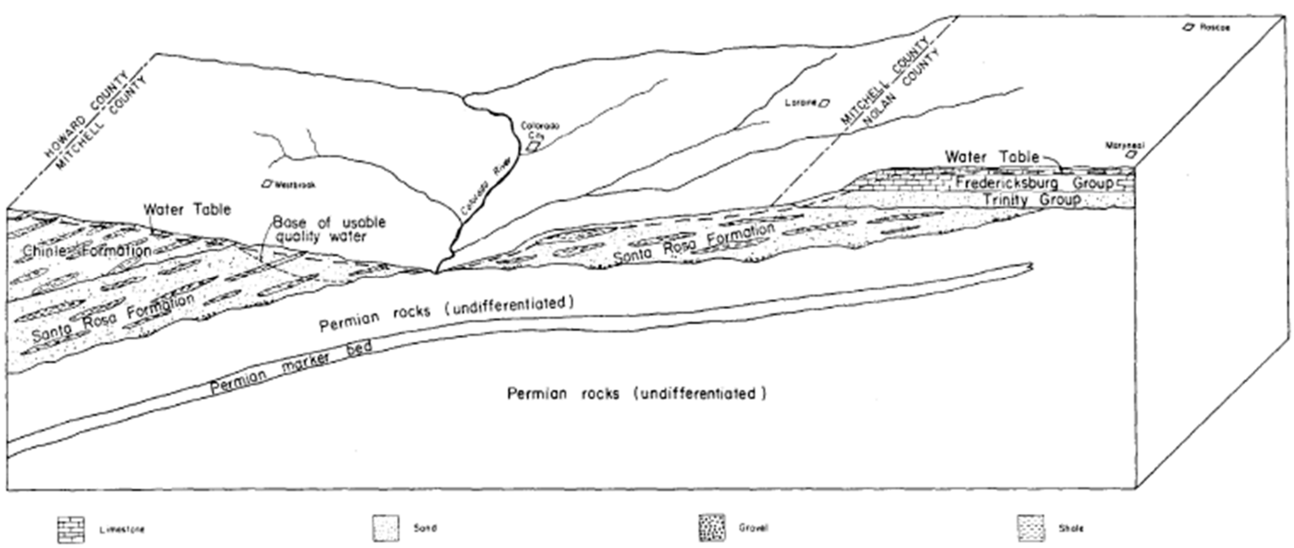


Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.

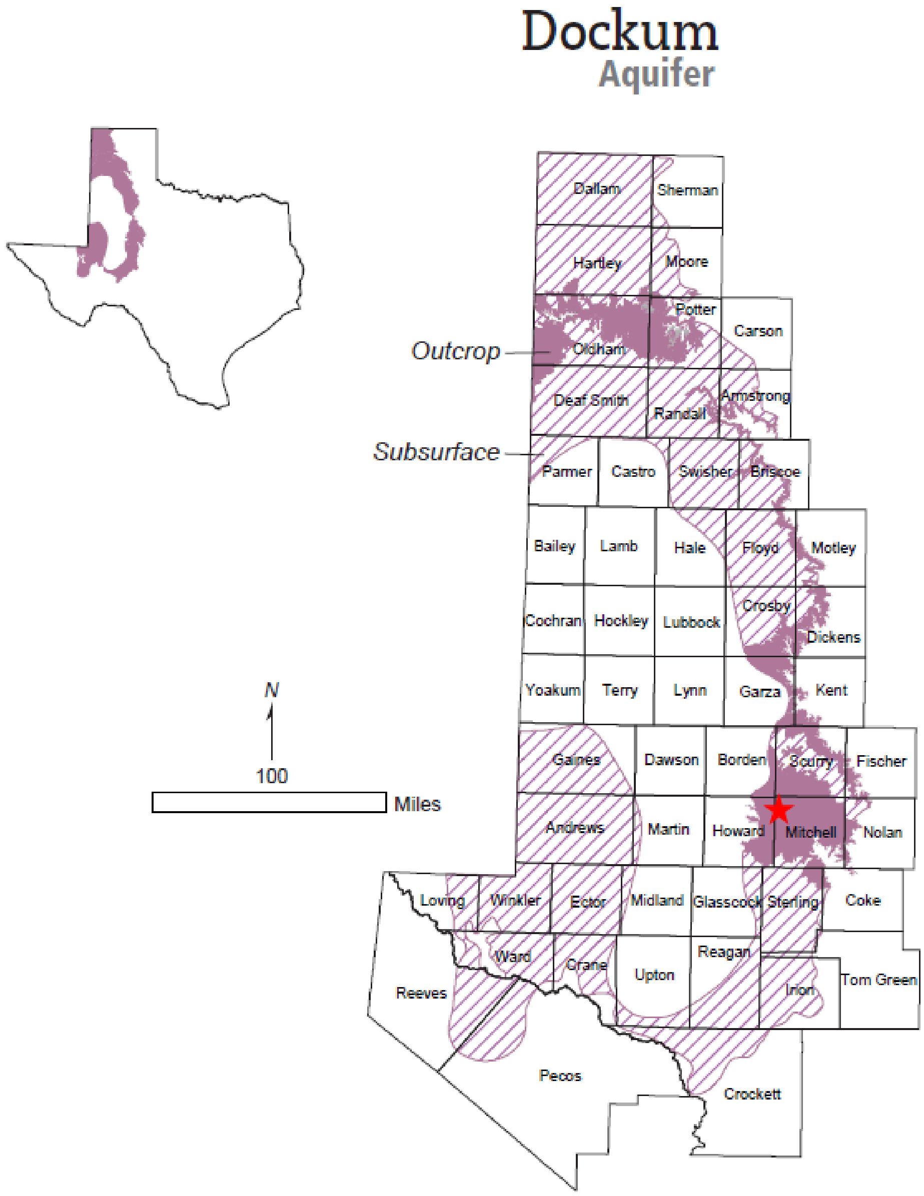


Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).

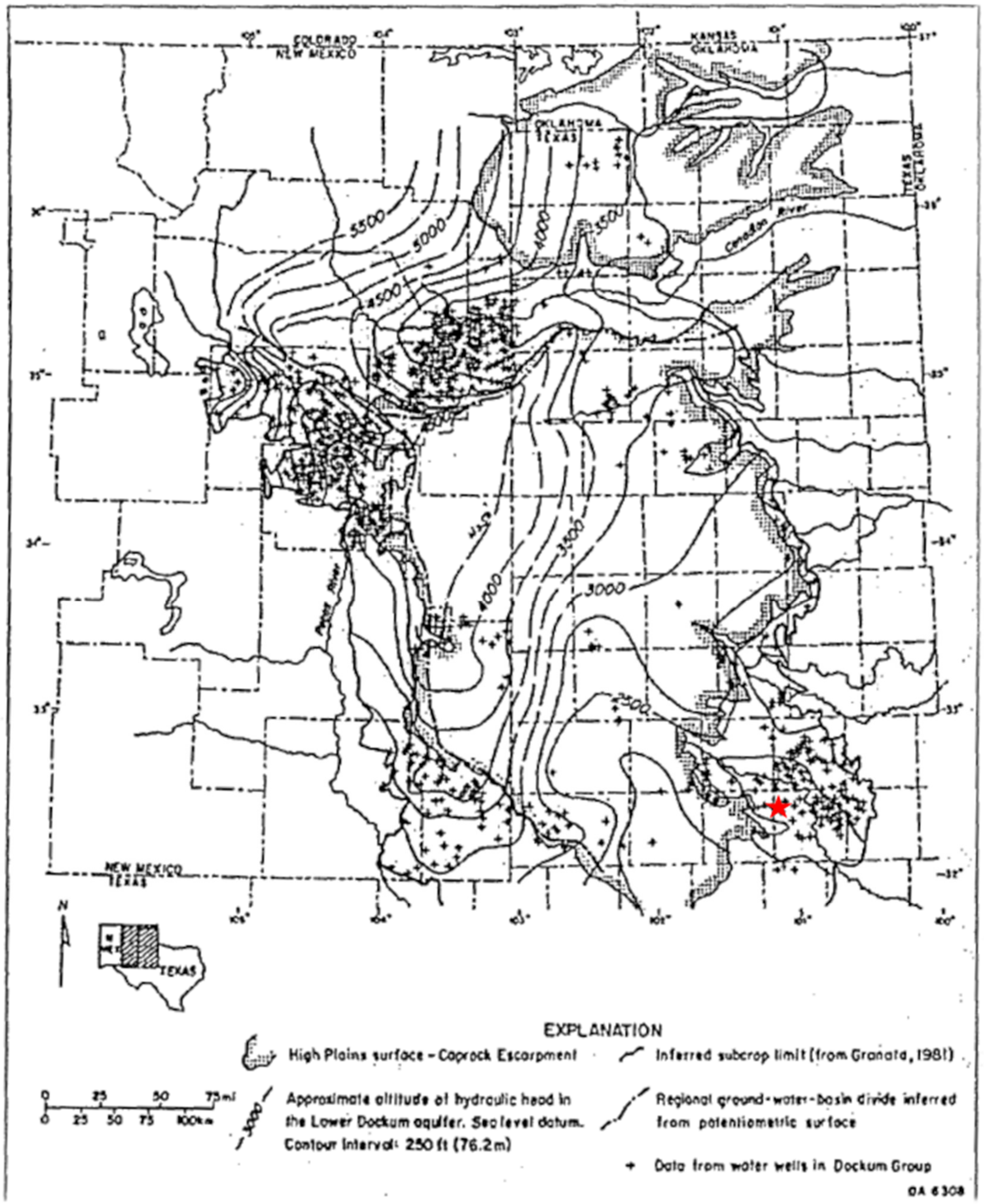


Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).

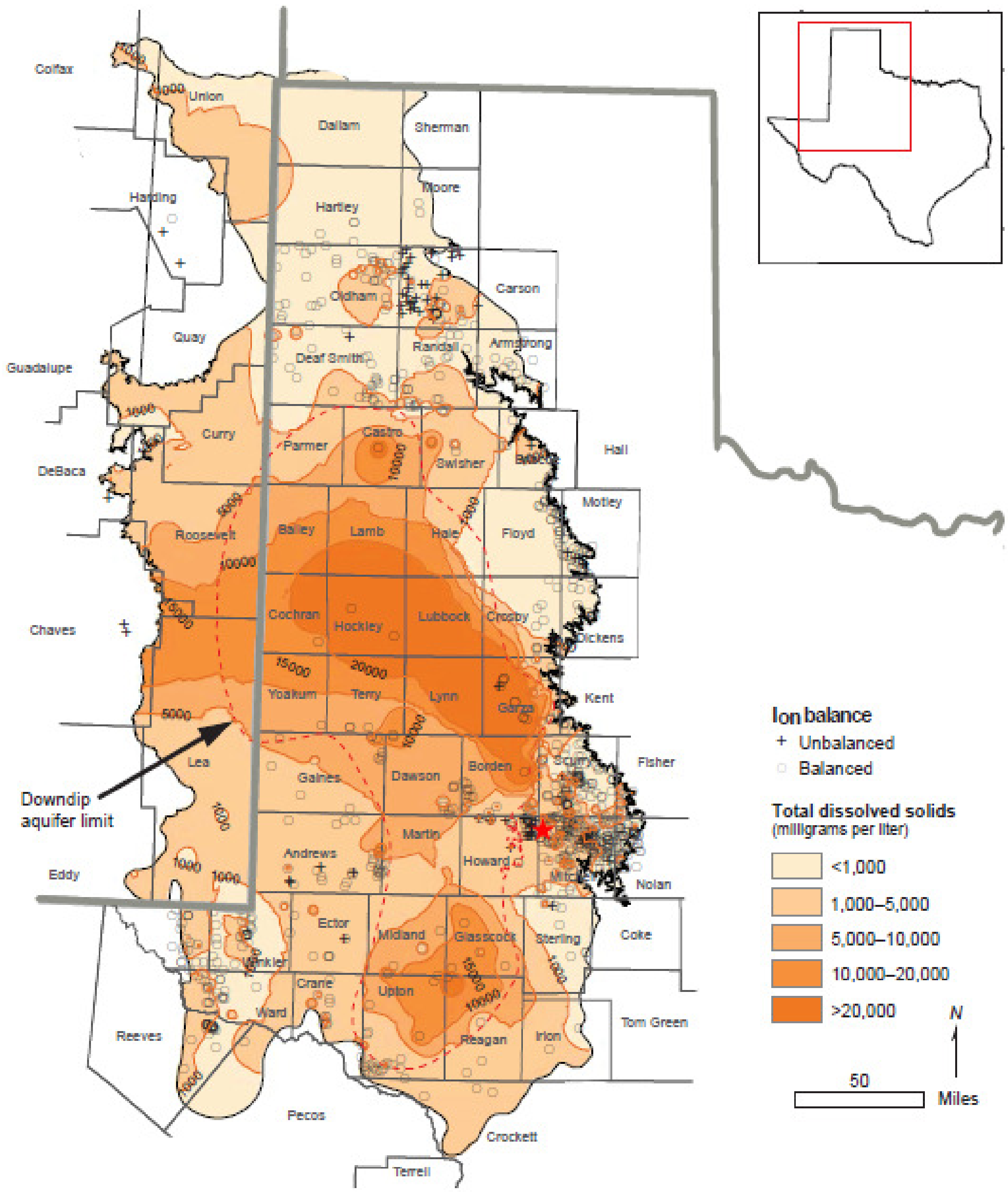


Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 Description of the Injection Process

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/D). The TAG is 41.2% CO_2, which equates to 155.3 MT/yr of CO_2 each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

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

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery.
advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite-acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S and CO_2 based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H_2S and 41.2% CO_2. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H_2S and 41.2% CO_2.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H_2S)	58.8	58.8
Carbon Dioxide (CO_2)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.

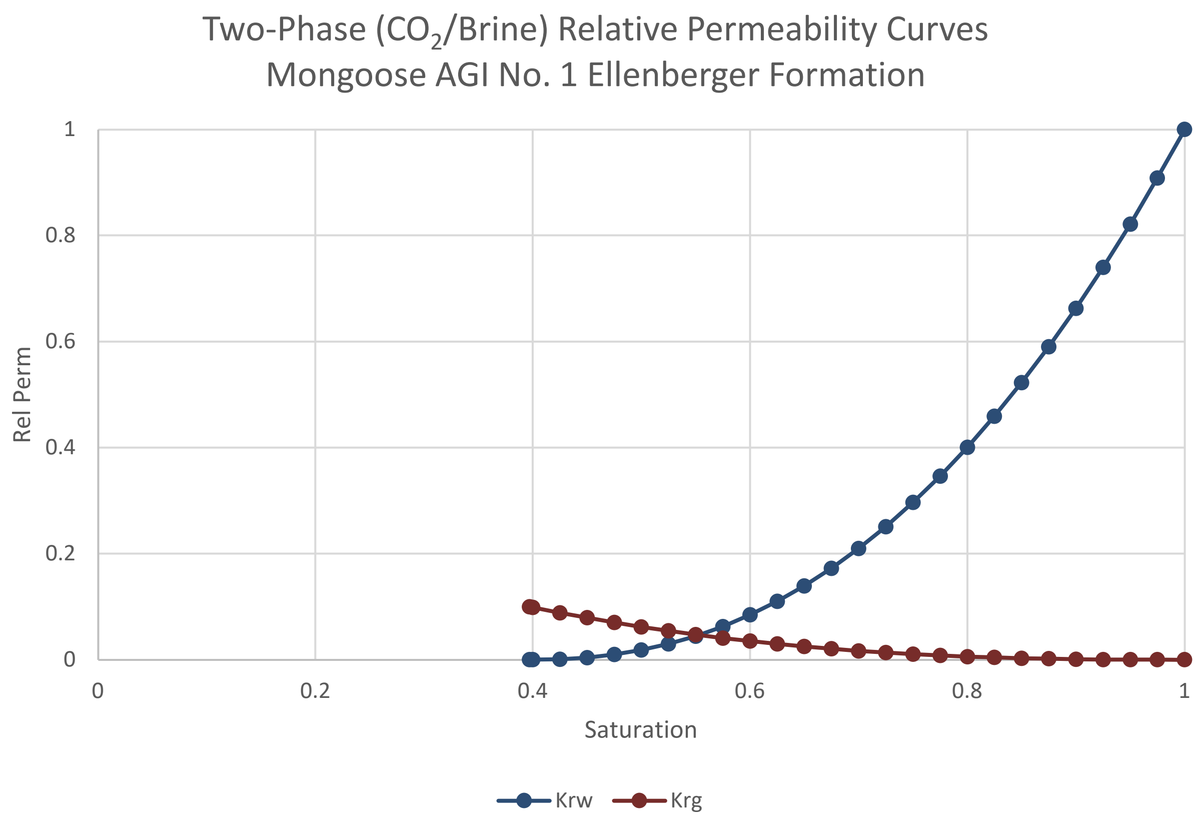


Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (north-south), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Table 9 – GEM Model Layer Package Properties

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

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

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

Table 10 – Offset SWD Wells Included in GEM Model

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.

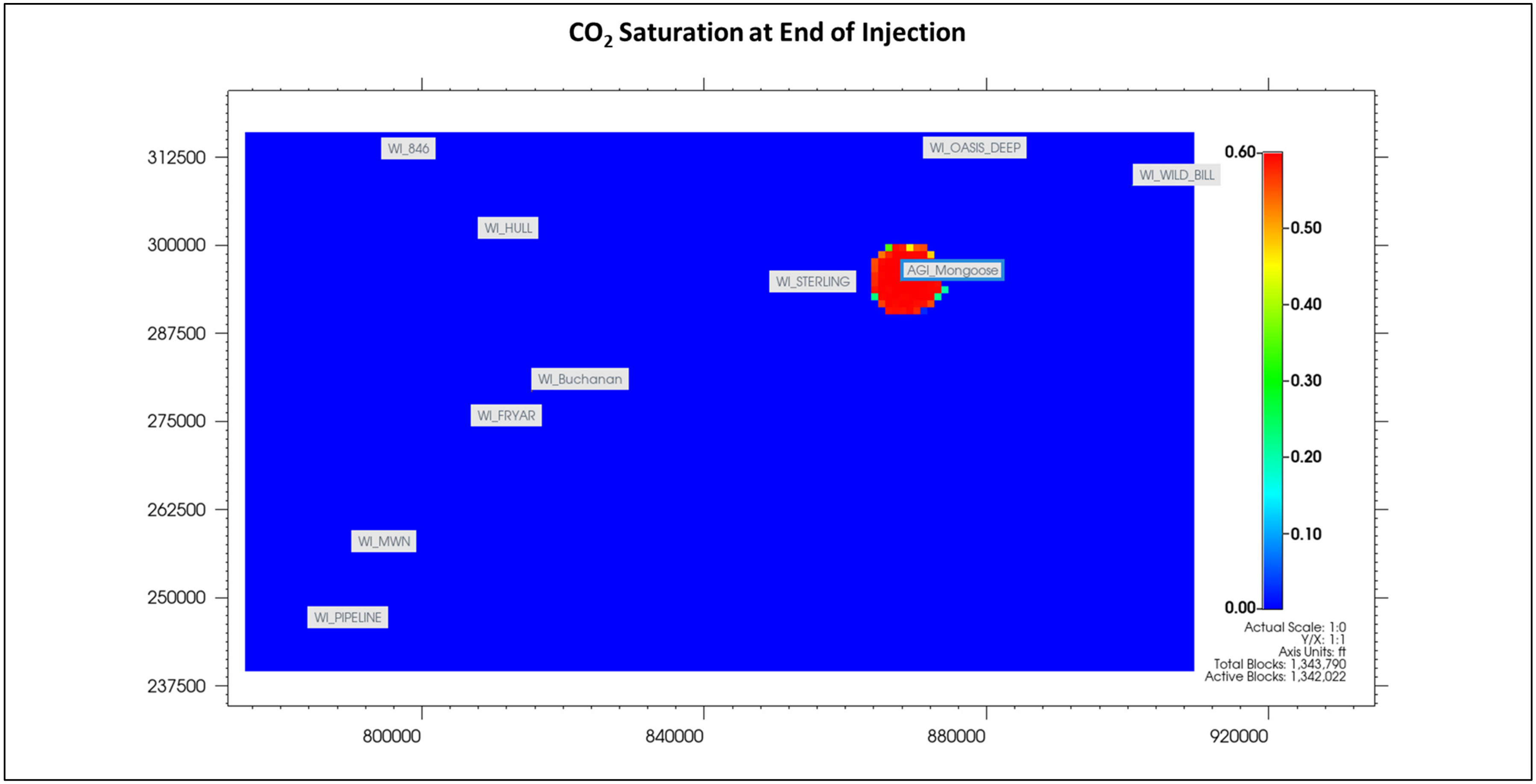


Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)

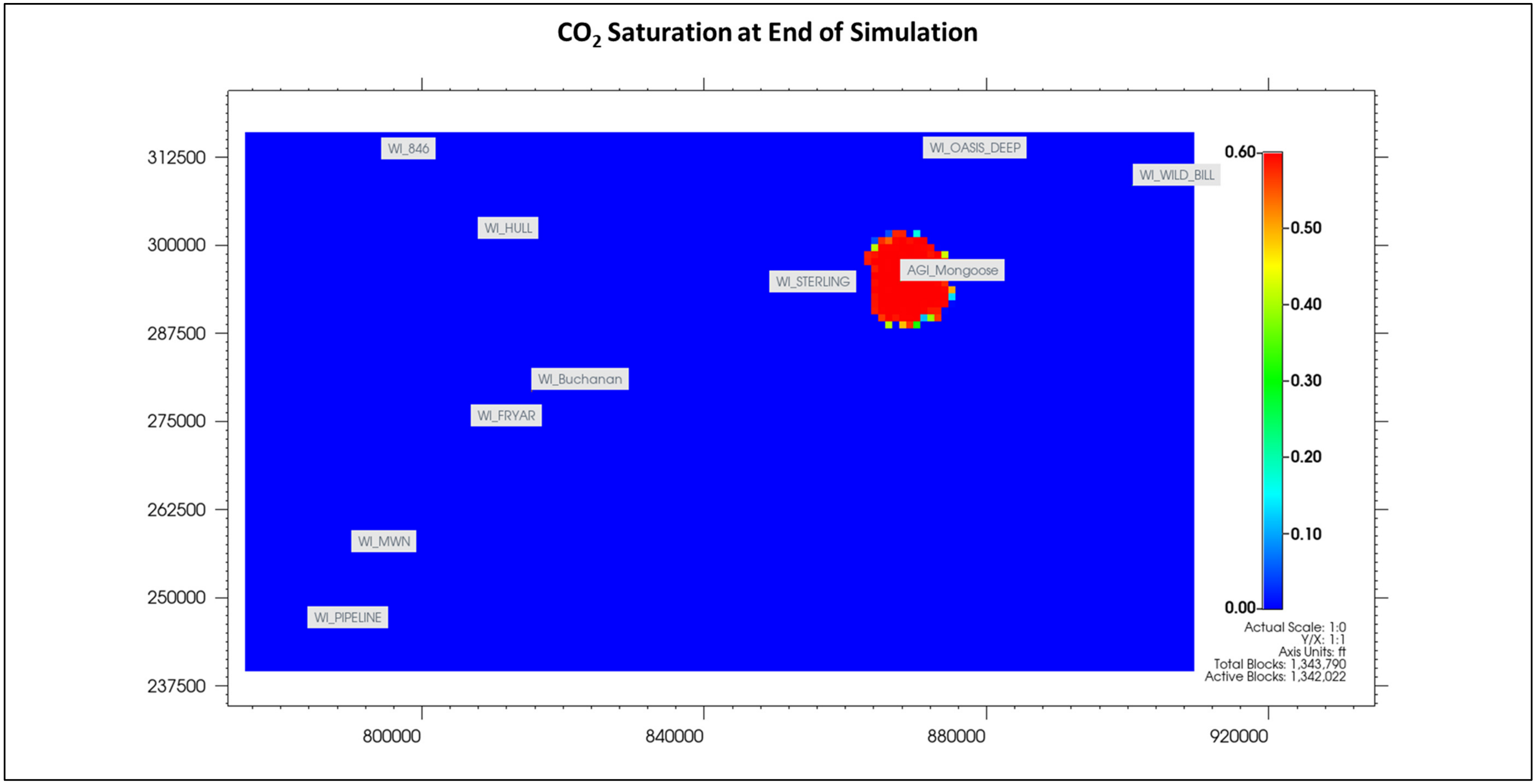


Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

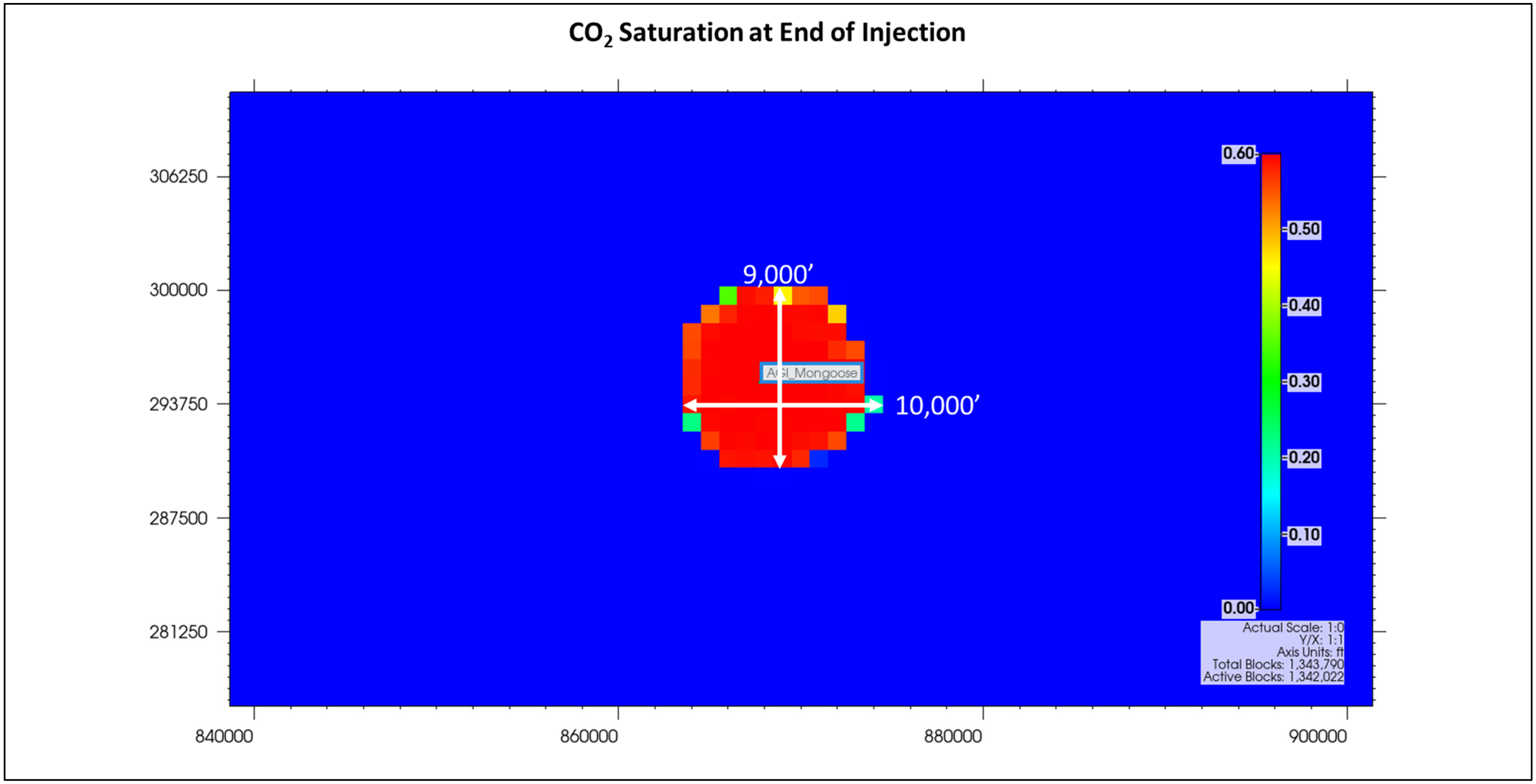


Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)

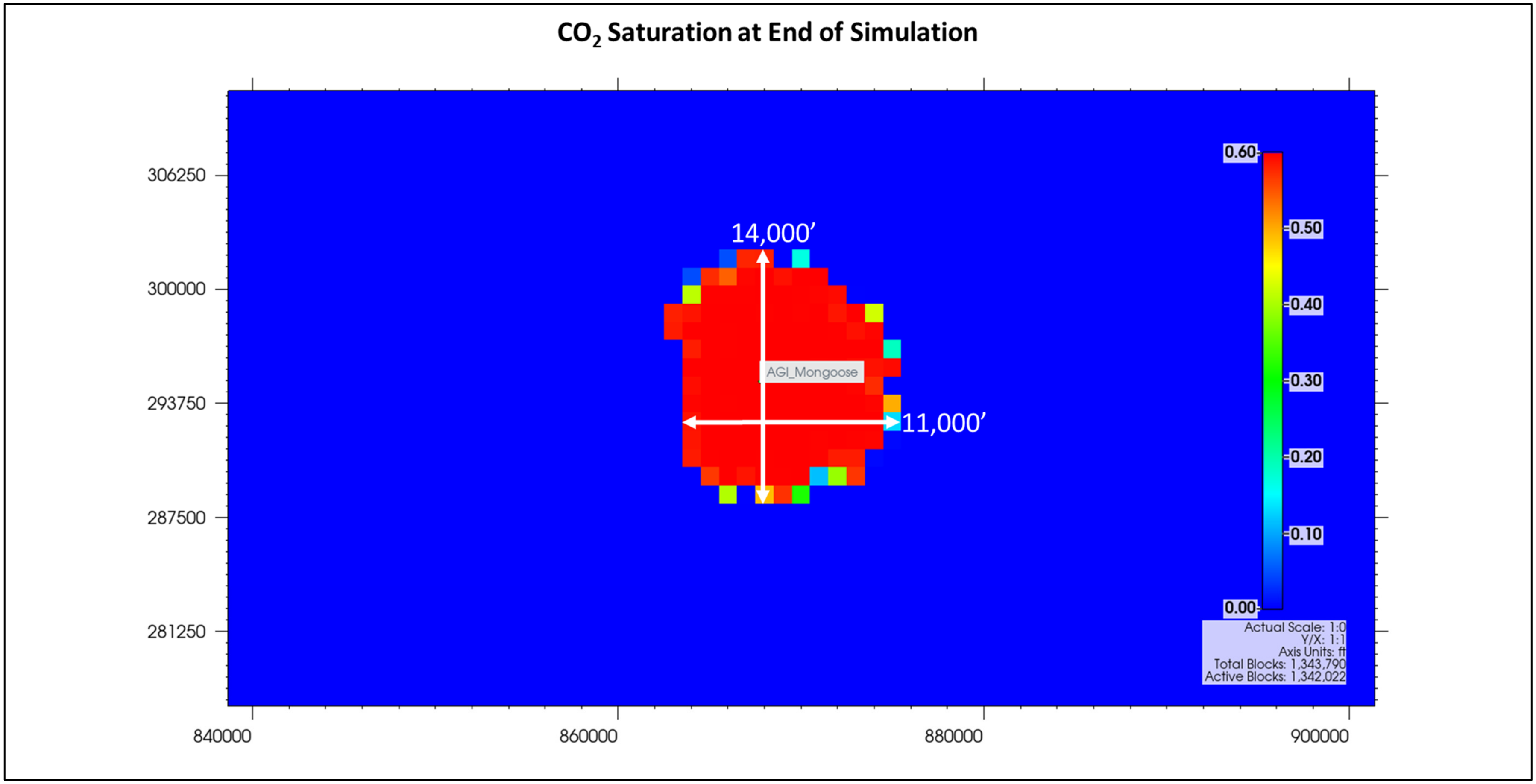


Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.

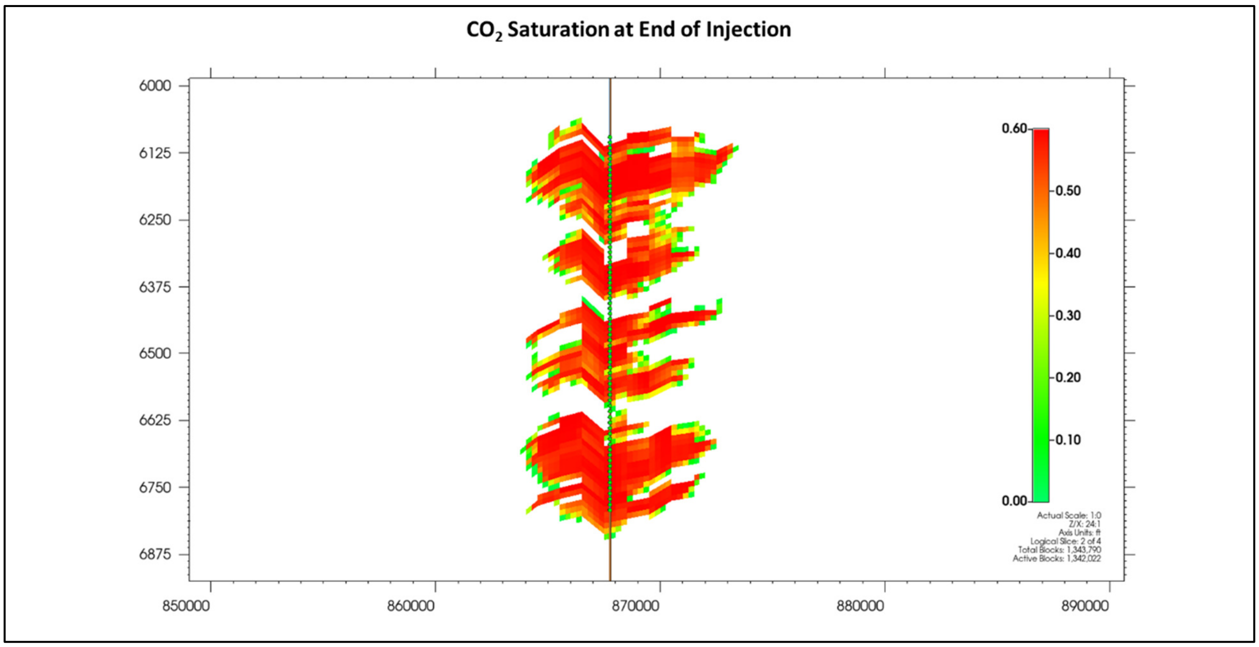


Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

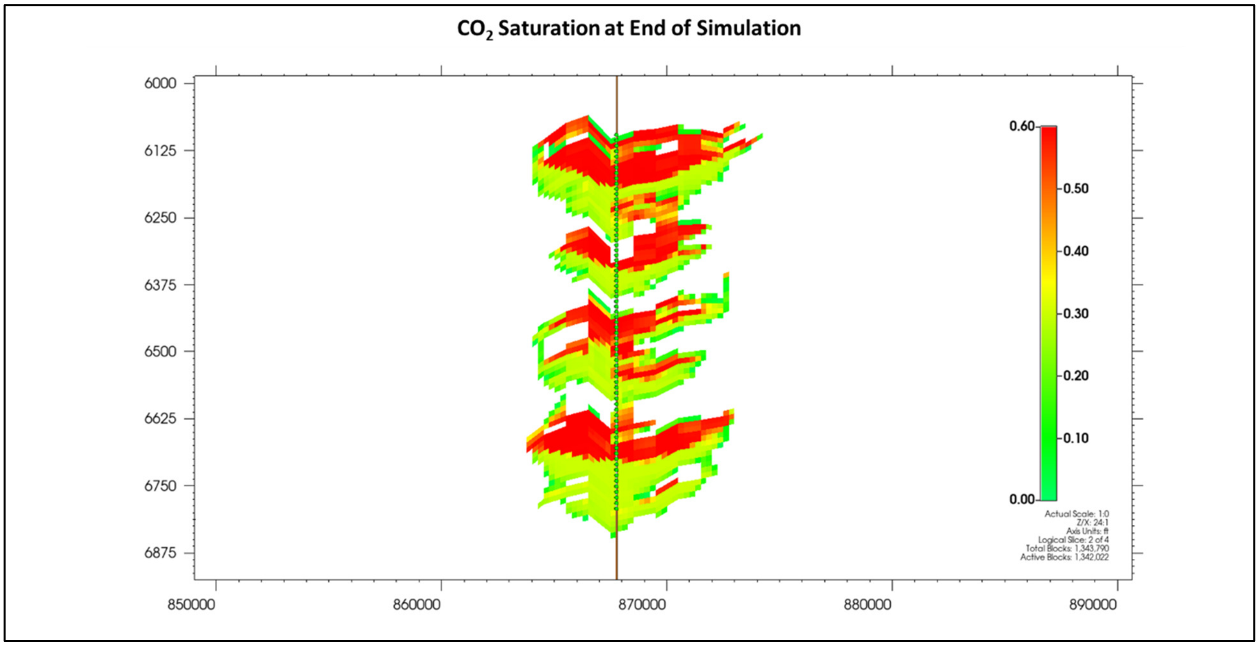


Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.

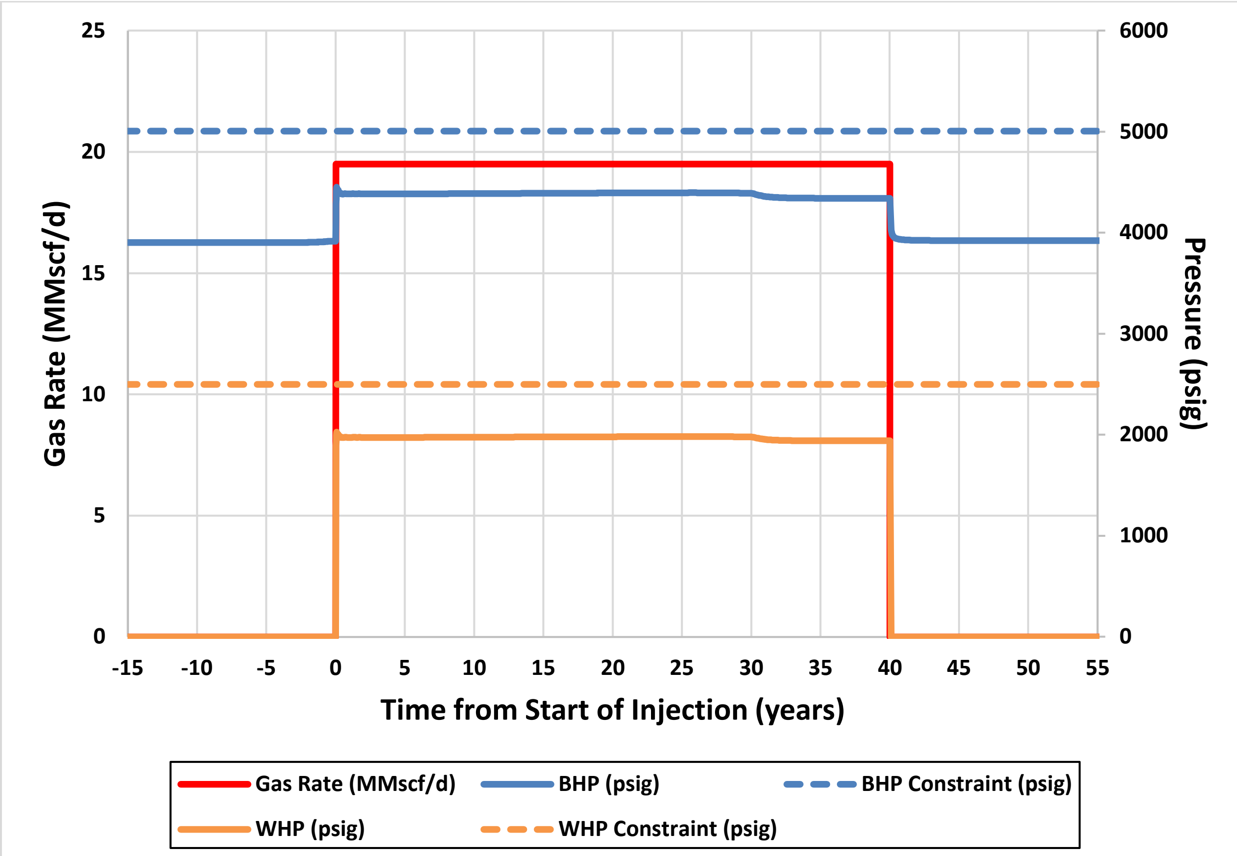


Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H_2S and 41.2% CO_2, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.

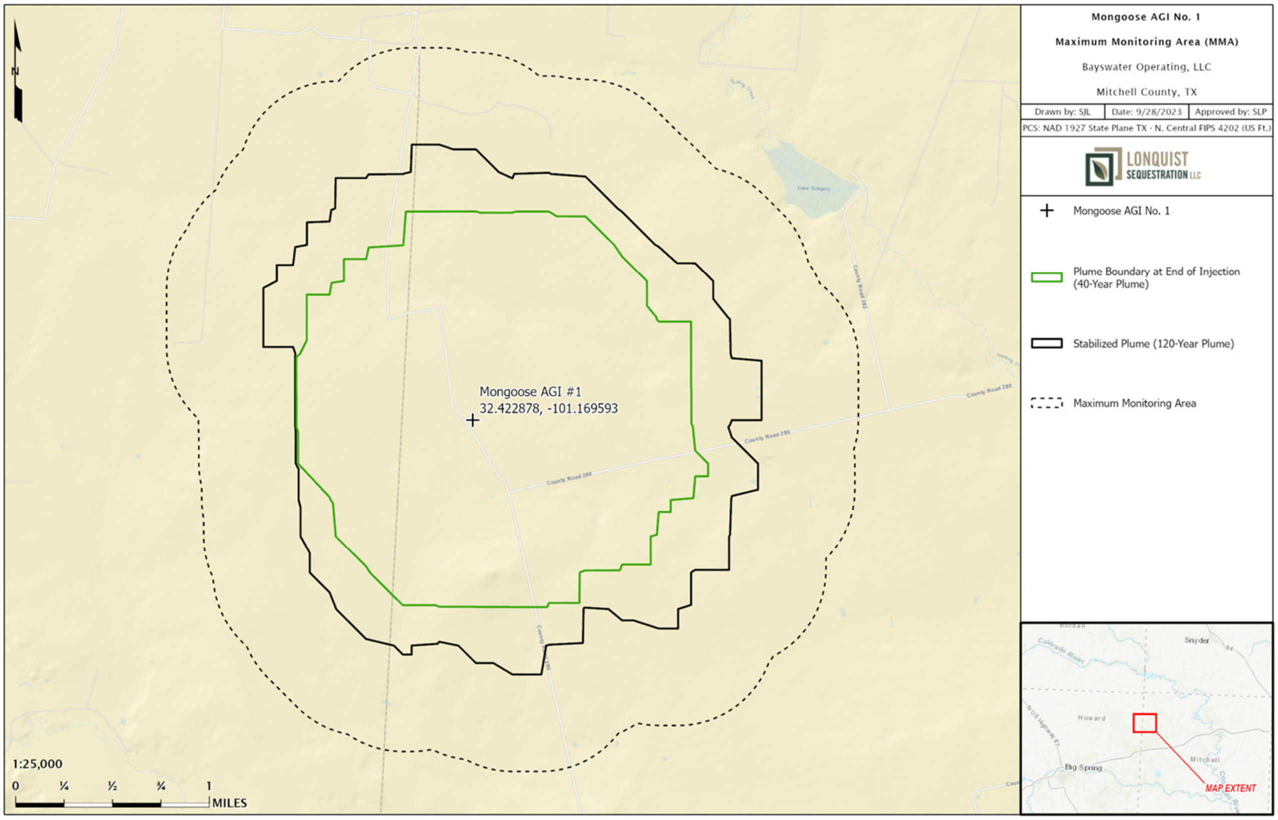


Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.

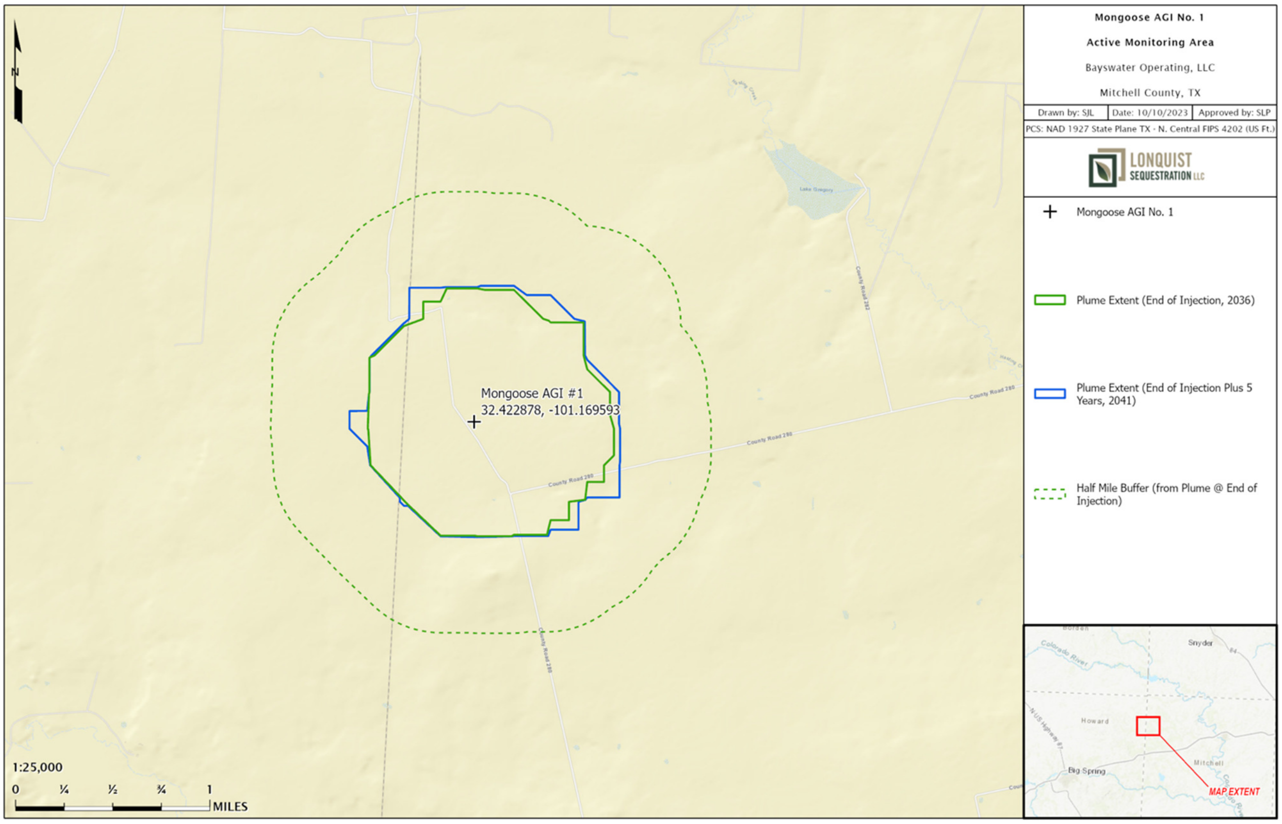


Figure 43 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

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

Table 12 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. Two artificial penetrations were drilled into the gross injection interval. These wells were plugged in accordancee TRRC requirements.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There are no faults within the modeled area. Bayswater monitors the area for seismic activity.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining layer	Unlikely. The lateral continuity of the Woodford Shale blanketing the Ellenburger is recognized as a very competent seal. There is 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There have been no seismic events of 3.0 magnitude or greater detected. There is over 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

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

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H_2S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H_2S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year, per 40 CFR **§98.444(b)**.

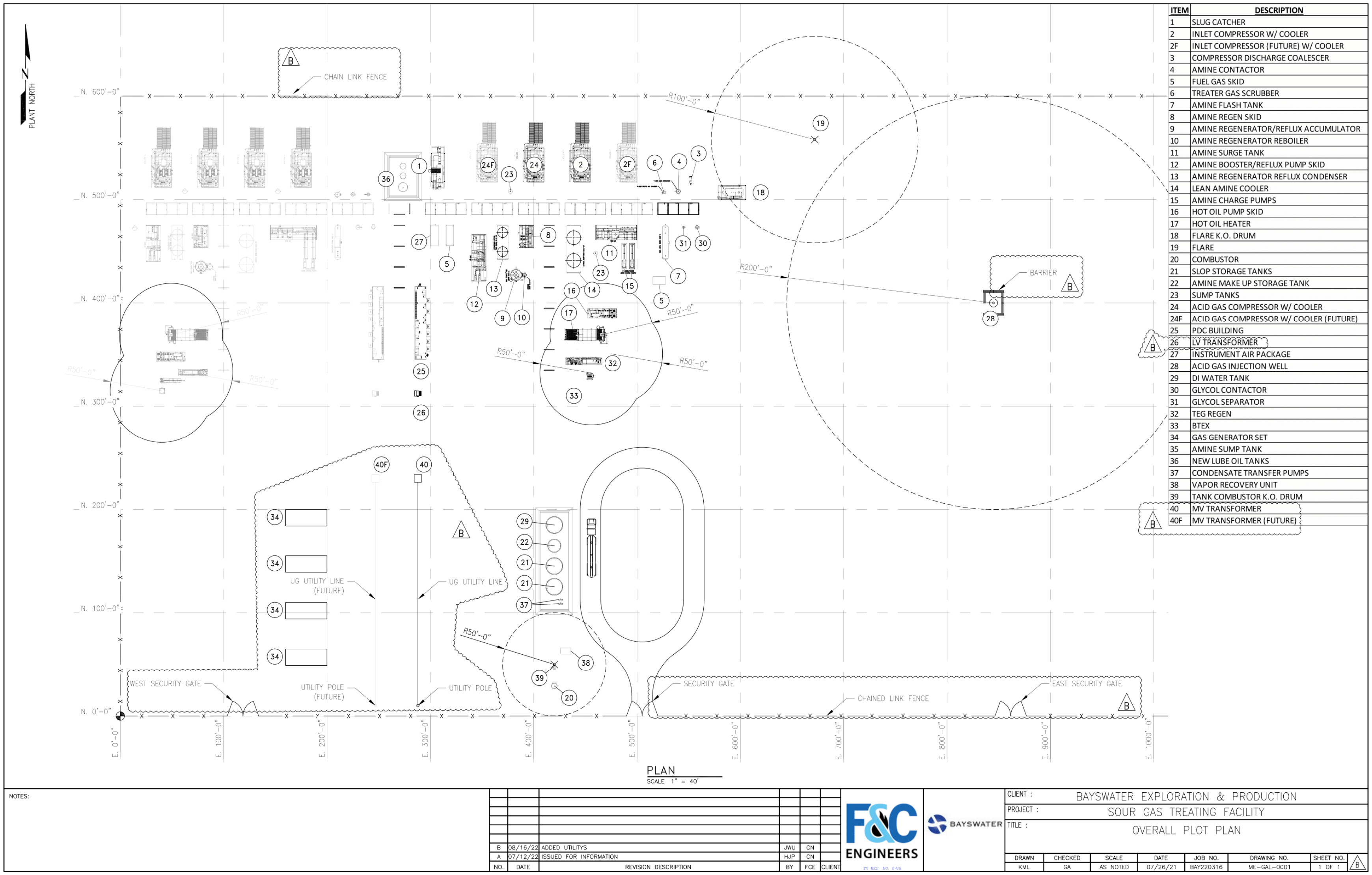
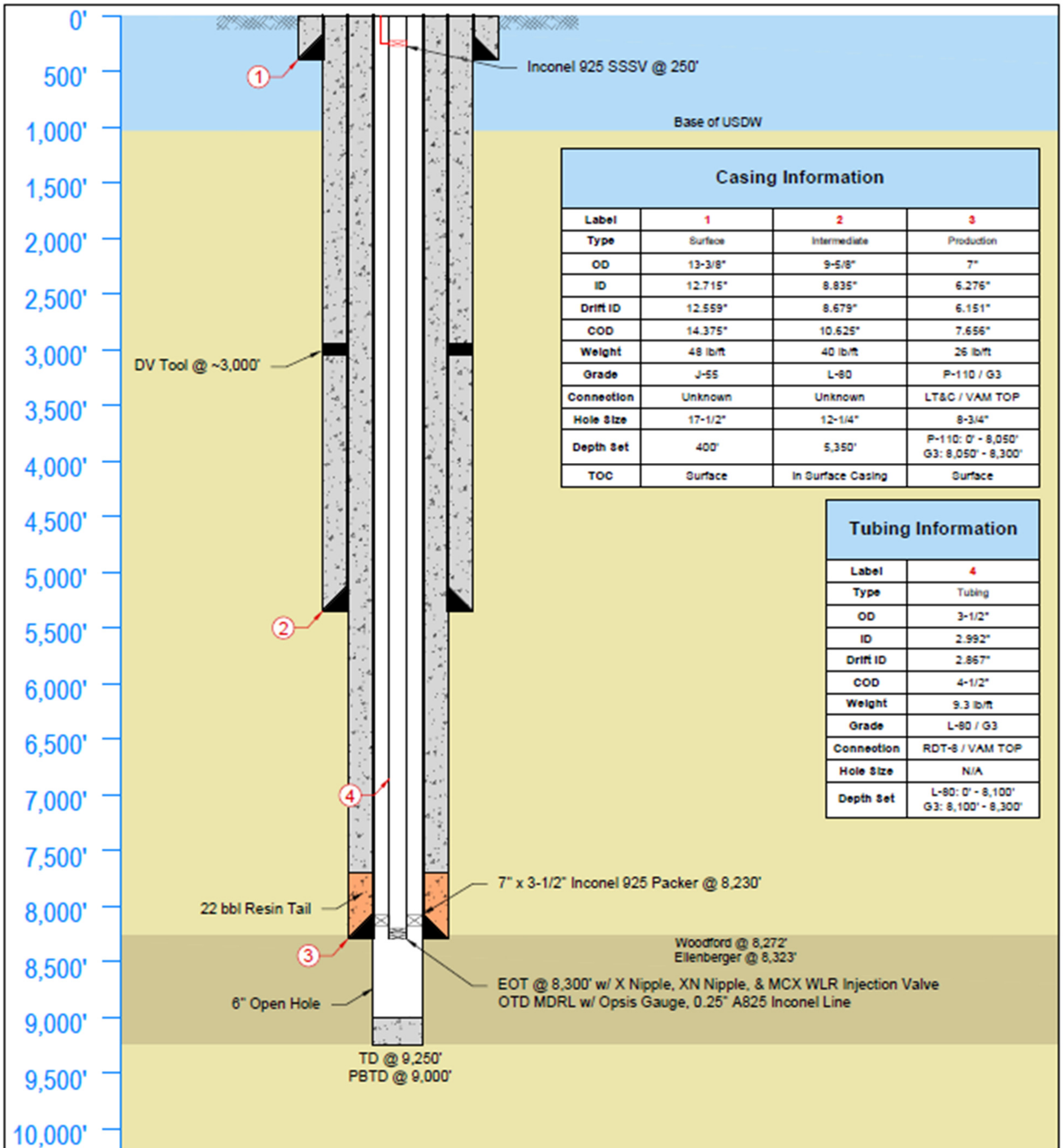


Figure 44 – Site Plan



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
ID	12.715"	8.835"	6.276"
Drift ID	12.559"	8.679"	6.151"
COD	14.375"	10.625"	7.656"
Weight	48 lb/ft	40 lb/ft	26 lb/ft
Grade	J-55	L-80	P-110 / G3
Connection	Unknown	Unknown	LT&C / VAM TOP
Hole Size	17-1/2"	12-1/4"	8-3/4"
Depth Set	400'	5,350'	P-110: 0' - 8,050' G3: 8,050' - 8,300'
TOC	Surface	In Surface Casing	Surface

Tubing Information

Label	4
Type	Tubing
OD	3-1/2"
ID	2.992"
Drift ID	2.867"
COD	4-1/2"
Weight	9.3 lb/ft
Grade	L-80 / G3
Connection	RDT-8 / VAM TOP
Hole Size	N/A
Depth Set	L-80: 0' - 8,100' G3: 8,100' - 8,300'

LONQUIST FIELD SERVICE	Bayswater Operating Company LLC	Mongoose AGI #1	
	Country: USA	State/Province: TX	County/Parish: Mitchell
	API No: 42-335-36013	Field: Sprayberry Trend	Well Type/Status: Acid Gas Injection
Texas License F-9147	RRC District No:	Project No: LS188	Date: 09/07/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved:
	Rev No: 1	Notes:	

Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO_2 will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in *Section 2.2.2*. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset artificial penetrations is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.

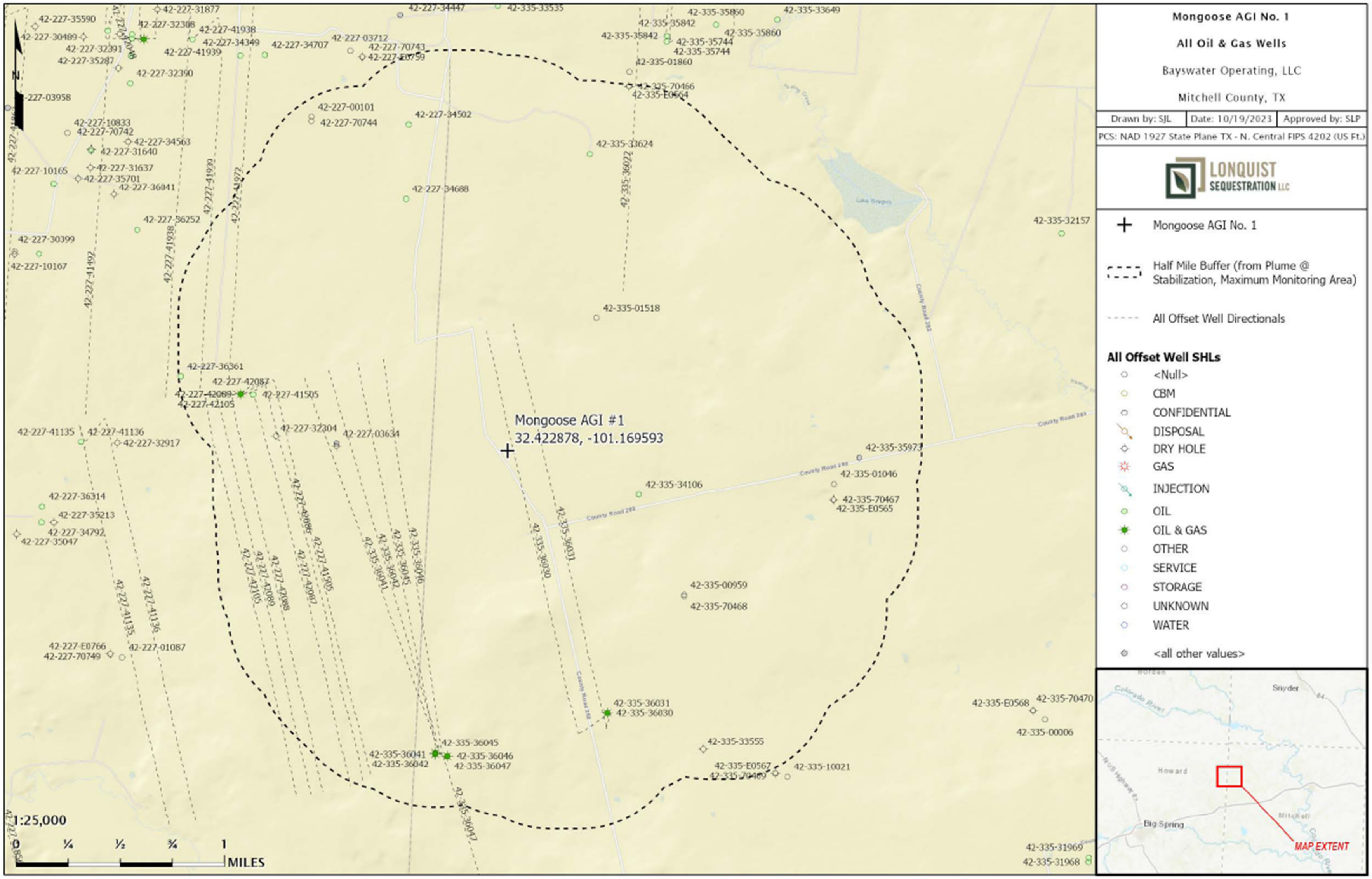


Figure 46 – All Oil and Gas Wells Within the MMA

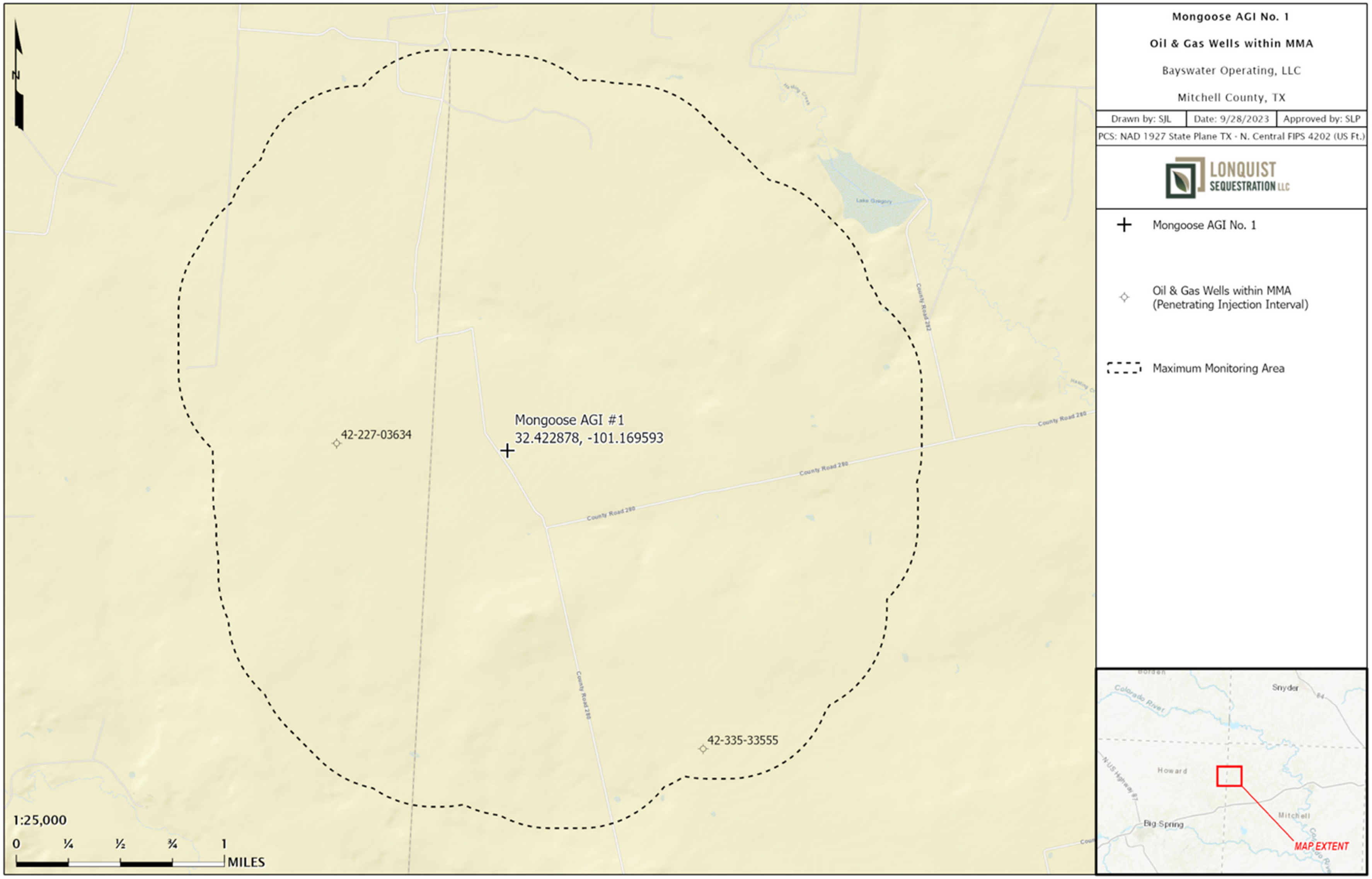


Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Mongoose drilling permit, provided in *Appendix A*, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a quarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued (also provided in the permit in *Appendix A*).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

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

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

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

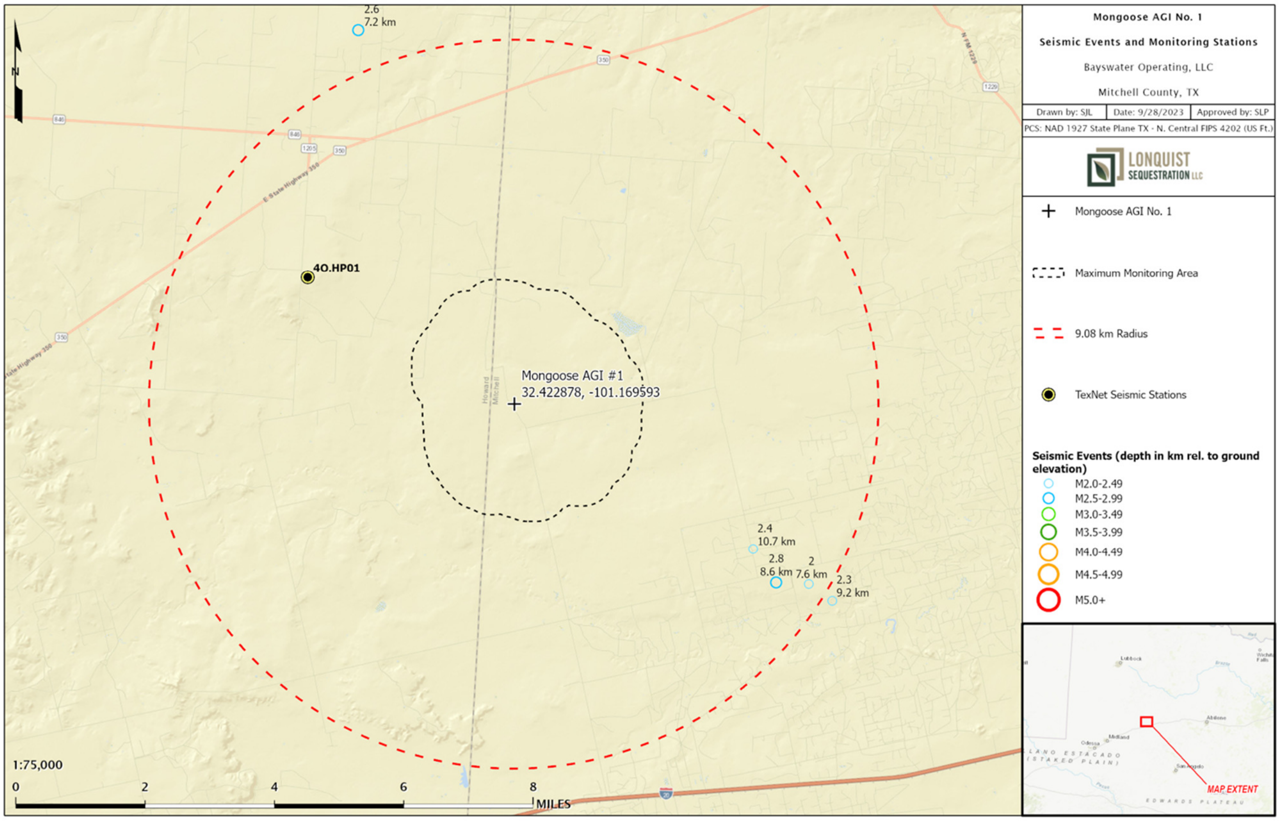


Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Table 13 – Summary of Leakage Monitoring Methods

Leakage Pathway	**Monitoring Method**
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Visual inspections
	SCADA continuous monitoring of the AGI facility
Leakage through existing wells	SCADA continuous monitoring of the AGI well
	Monitor CO_2 levels in Above Zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage from natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established during the commissioning of the Plant. Ambient H_2S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H_2S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

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

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2, migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 Groundwater Quality Monitoring

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 Leakage Through Faults, Fractures, or Confining Seals

Bayswater continuously monitors the operations of the Mongoose well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO_2 content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO_2 content would be an early indicator of a potential issue. Should the CO_2 migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

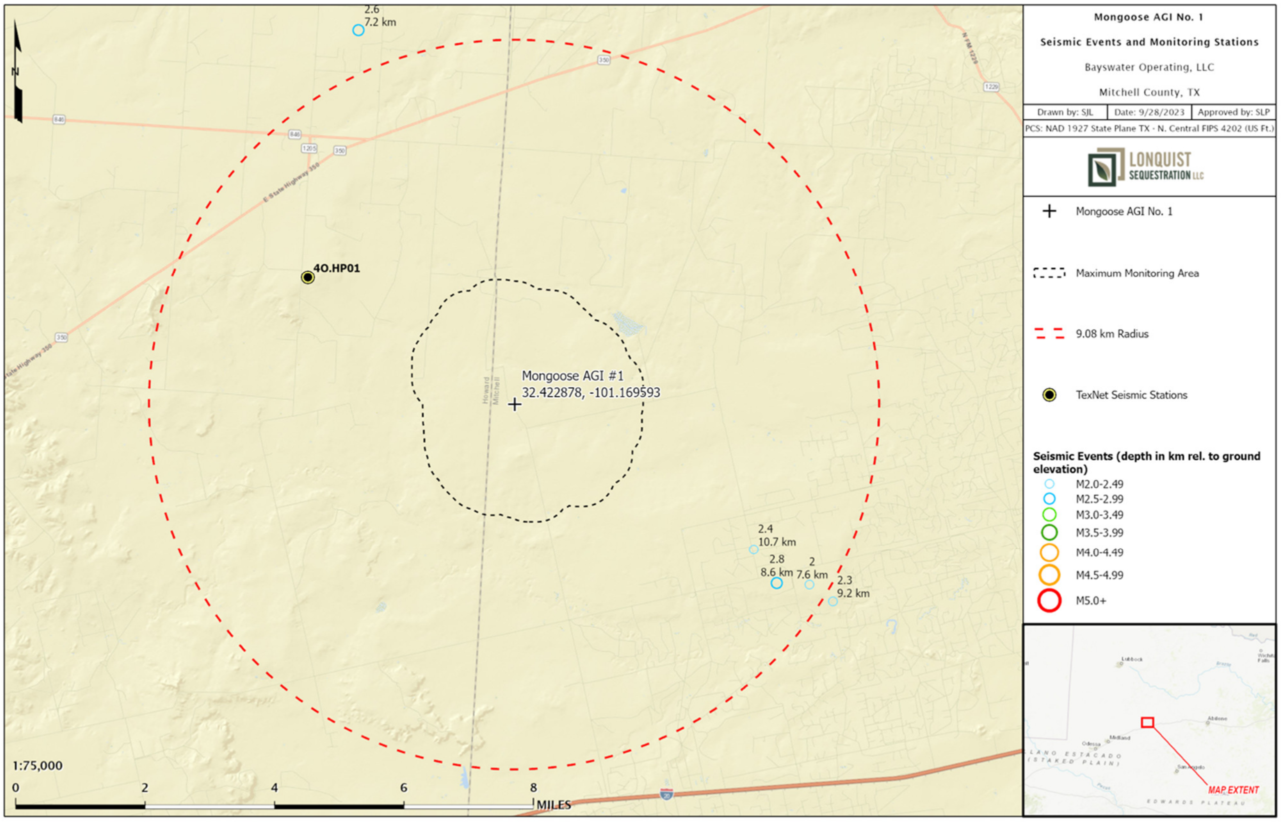


Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

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

6.2 CO_2/H_2S Detection

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H_2S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

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

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

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

7.4 Mass of CO_2 Emitted by Surface Leakage

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

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

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

Where:

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

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

X = Leakage pathway

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

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

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

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

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

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

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

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Bayswater plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

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

CO_2 Emissions from Leaks and Vented Emissions

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

Measurement Devices

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

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

9.2 Missing Data

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

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

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

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Bayswater will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

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

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

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APPENDICES

APPENDICES

APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN
WAYNE CHRISTIAN, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
DEPUTY EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS, P.E.
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17174

BAYSWATER OPERATING COMPANY LLC
730 17TH STREET
SUITE 500
DENVER CO 80202

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE
SPRABERRY (TREND AREA) FIELD
MITCHELL COUNTY
DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33536013	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.** **3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;

Note: This document will only be distributed electronically.

c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON March 10, 2023.

FOR Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	04 March 2022	**GAU Number:**	336979
Attention:	BAYSWATER OPERATING 730 17TH STREET SUITE 500 DENVER, CO 80202	**API Number:**	33536013
		County:	MITCHELL
		Lease Name:	Mongoose AGI
		Lease Number:	
Operator No.:	058827	**Well Number:**	1
		Total Vertical	9250
		Latitude:	32.422884
		Longitude:	-101.169661
		Datum:	NAD27

Purpose: Injection into Non-producing Zone (W-14)

Location: Survey-T&P RR CO; Abstract-1545; Block-29; Township-1N; Section-4

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 350 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 475 feet at the site of the referenced well.

This recommendation is applicable to all wells within a radius of 200 feet of this location.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 03/02/2022. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary. If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER	DATE PERMIT ISSUED OR AMENDED	DISTRICT
876754	Feb 10, 2022	* 08
API NUMBER 42-335-36013	**FORM W-1 RECEIVED** Feb 03, 2022	**COUNTY** MITCHELL
TYPE OF OPERATION NEW DRILL	**WELLBORE PROFILE(S)** Vertical	**ACRES** 40

OPERATOR 058827

BAYSWATER OPERATING COMPANY LLC
730 17TH STREET SUITE 500
DENVER, CO 80202-0000

NOTICE
This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored.
District Office Telephone No:
(432) 684-5581

LEASE NAME	WELL NUMBER
MONGOOSE AGI	1
LOCATION 10.4 miles NW direction from WESTBROOK	**TOTAL DEPTH** 10000

Section, Block and/or Survey
SECTION 4 BLOCK 29 T1N ABSTRACT 1545
SURVEY T&P RR CO/MORRISON, W

DISTANCE TO SURVEY LINES	DISTANCE TO NEAREST LEASE LINE
551 ft. EAST 2164 ft. SOUTH	ft.
DISTANCE TO LEASE LINES 400 ft. EAST 650 ft. SOUTH	**DISTANCE TO NEAREST WELL ON LEASE** See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL # / NEAREST WE	DIST
SPRABERRY (TREND AREA) / MONGOOSE AGI	40.00 / 0	10,000	1	08

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Submitted
Date: 09/11/2023
Tracking No.: 298516

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator BAYSWATER OPERATING COMPANY LLC **Operator** 058827
Operator 730 17TH STREET SUITE 500 DENVER, CO 80202-

WELL INFORMATION

API 42-335-36013 **County:** MITCHELL
Well No.: 1 **RRC District** 08
Lease MONGOOSE AGI **Field** SPRABERRY (TREND AREA)
RRC Lease **Field No.:** 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRISON, W, Abstract: 1545

Latitude 32.423000 **Longitud** -101.170059
This well is 10.4 **miles in a** NW
direction from WESTBROOK,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC **Completion or Recompletion** 04/28/2023

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	02/10/2022	876754
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal		17174
Other:		

COMPLETION INFORMATION

Spud 10/12/2022
Date of first production after rig 04/28/2023
Date plug back, deepening, drilling operation 10/12/2022
Date plug back, deepening, recompletion, drilling operation 04/28/2023
Number of producing wells on this lease this field (reservoir) including this 1
Distance to nearest well in lease & reservoir
Total number of acres in 40.00
Elevation 2252 GL
Total depth TVD 9289
Total depth MD
Plug back depth TVD 9036
Plug back depth MD
Was directional survey made other inclination (Form W- Yes
Rotation time within surface casing 41.0
Is Cementing Affidavit (Form W-15) Yes
Recompletion or No
Multiple No
Type(s) of electric or other log(s) Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease of lease on which this well is
Off Lease : No
400.0 **Feet from the** East **Line and**
650.0 **Feet from the** South **Line of the**
MONGOOSE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

	Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type
PACKET: N/A				

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination	**Depth** 350.0	**Date** 03/04/2022	
SWR 13 Exception	**Depth**		

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		**Production**	
Number of hours	24	**Choke**	
Was swab used during this	No	**Oil produced prior to**	

PRODUCTION DURING TEST PERIOD:

Oil		**Gas**	
Gas - Oil	0	**Flowing Tubing**	
Water			

CALCULATED 24-HOUR RATE

Oil		**Gas**	
Oil Gravity - API - 60.:		**Casing**	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	569			C	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		C	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			C	610	1175.0	3001	Calculation
4	Conventional Production	7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL 925

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	Yes	L 8343	9036.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1	Other	OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H	9036	9289

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

OPERATOR'S CERTIFICATION

Printed	James Clark	**Title:**	Consulting Petroleum Engineer
Telephone	(512) 415-4191	**Date**	09/11/2023

A-5

0 0 0 0 5 7 0 7 0 8

▶ Return each W-1 with plat and $100.00 fee. Make check or money order payable to the State Treasurer of Texas. Address to:
Railroad Commission of Texas
Oil and Gas Division, Drilling Permits
P. O. Drawer 12967, Capitol Station
Austin, Texas 78711
▶ File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

~~Cal 13~~

▶ Read Instructions on Back

Form W-1
Rev. 9/1/83
483-080

080
VMC

Purpose of filing (mark appropriate boxes):
[X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter
[ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ▶ API No. 42-335-33555
▶ Permit No. 379724
▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): Bright & Company 10-18-90
2. Address (including city and zip code): 3200 West Cuthbert, Suite 2-C, Midland, Texas 79701
3. RRC Operator No.: 093125
4. RRC District No.: 8
5. County of Well Site: Mitchell
6. Lease Name (32 spaces maximum): Van Tuyle
7. RRC Lease/ID No.: --
8. Well No.: 1
9. Total Depth: 8500'
10. Location
- Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1-N~~ Abstract No. A-584
- This well is to be located 5 miles in a north direction from Iatan which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.
12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

Granted 10/29/90

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
~~Wolfcamp (Wildcat)~~	~~5200'~~	~~467-1200~~	~~40~~	~~40~~	~~NO~~	~~NA~~	~~0~~	~~1~~	
~~Strawn (Wildcat)~~ Tracy per	~~7800'~~	~~467-1200~~	~~40~~	40	NO	NA	0	1	
~~Ellenburger~~ (Wildcat) 18001	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
- Lease/Unit 1000' FNL & 2500' FEL
- Survey/Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
- Lease/Unit
- Survey/Section

Code C @ 8500

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]
24. Is Item 17 less than Item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]
25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.
26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? If not, and if the well requires a Rule 37 or 38 exception, see Instructions for Rule 37. Yes [X] No [ ]

Remarks
W/C per Cindy 10/26/90

I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison
Signature

Tracy D. Tenison, Engineer
Name and title of operator's representative

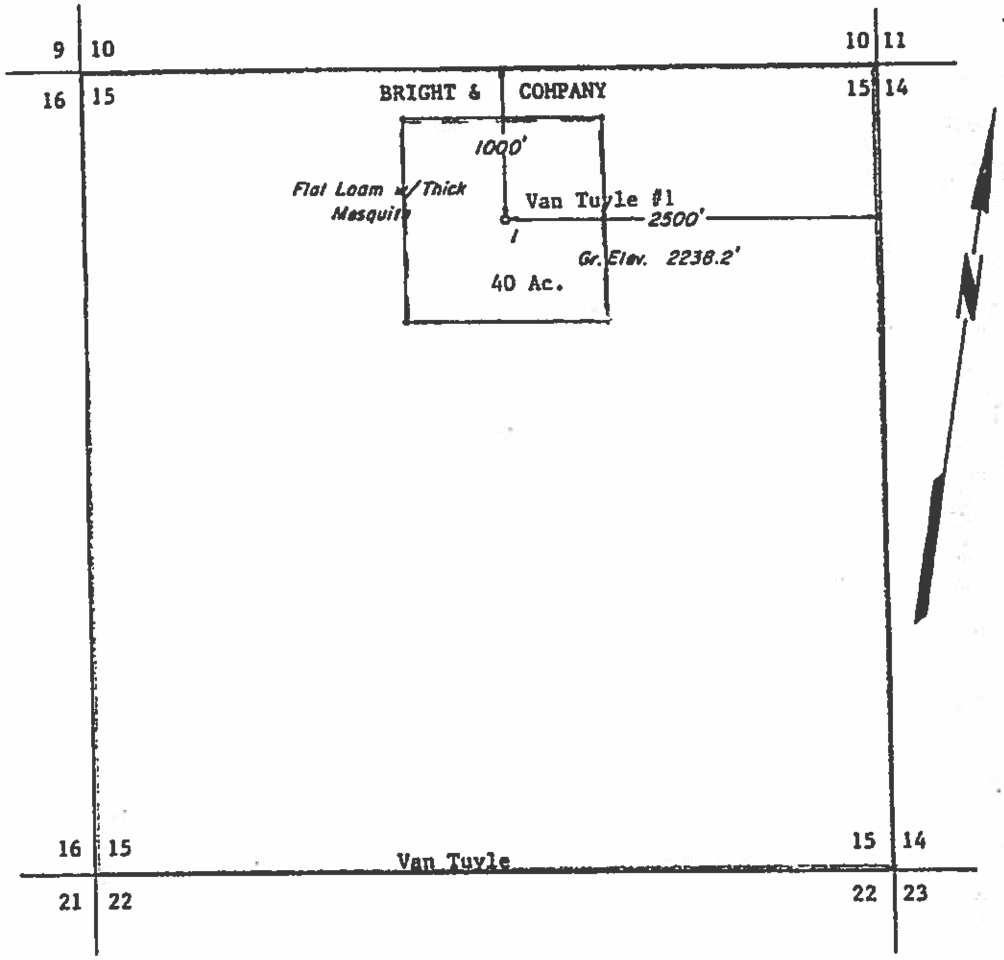
Date: 9/26/90 (mo. day yr.)
Tel: 915-697-2214 (Area Code Number)

▶ RRC Use Only ●

203091 OCT 1890

379724

335-33555



THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

OCT 1990

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL
LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON	TEXAS P.L.S. NO. 1883
GARY G. EIDSON	TEXAS P.L.S. NO. 4735
JERRY A. DUNN	TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1"= 1000'	Drawn by: KED
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

0 9 0 5 7 0 7 1 0

▶ Return each W-1 with plat and $100.00 fee. Make a check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas, Oil and Gas Division, Drilling Permits, P. O. Drawer 12967, Capitol Station, Austin, Texas 78711

▶ File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1
Rev. 9/1/83
483-080

020

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ▶ API No. 42- ▶ Permit No. ▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): Bright & Company
3. RRC Operator No.: 093125
4. RRC District No.: 8
5. County of Well Site: Mitchell

2. Address (including city and zip code): 3200 West Cuthbert, Suite 2-C, Midland, Texas 79701

6. Lease Name (32 spaces maximum): Van Tuyle
7. RRC Lease/ID No.: --
8. Well No.: 1
9. Total Depth: 8500'

10. Location
- Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1-N~~ Abstract No. A-584
- This well is to be located 5 miles in a north direction from Iatan which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.

12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well (Specify)	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
Wolfcamp (Wildcat)	5200'	467-1200	40	40	NO	NA	0	1	
Strawn (Wildcat)	7800'	467-1200	40	40	NO	NA	0	1	
Ellenburger (Wildcat)	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
- Lease/Unit 1000' FNL & 2500' FEL
- Survey Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
- Lease/Unit
- Survey/Section

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]

24. Is item 17 less than item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]

25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.

26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? Yes [X] No [ ] If not, and if the well requires a Rule 37 or 38 exception, see instructions for Rule 37.

Remarks

I certify that information stated in this application is true and complete, to the best of my knowledge.

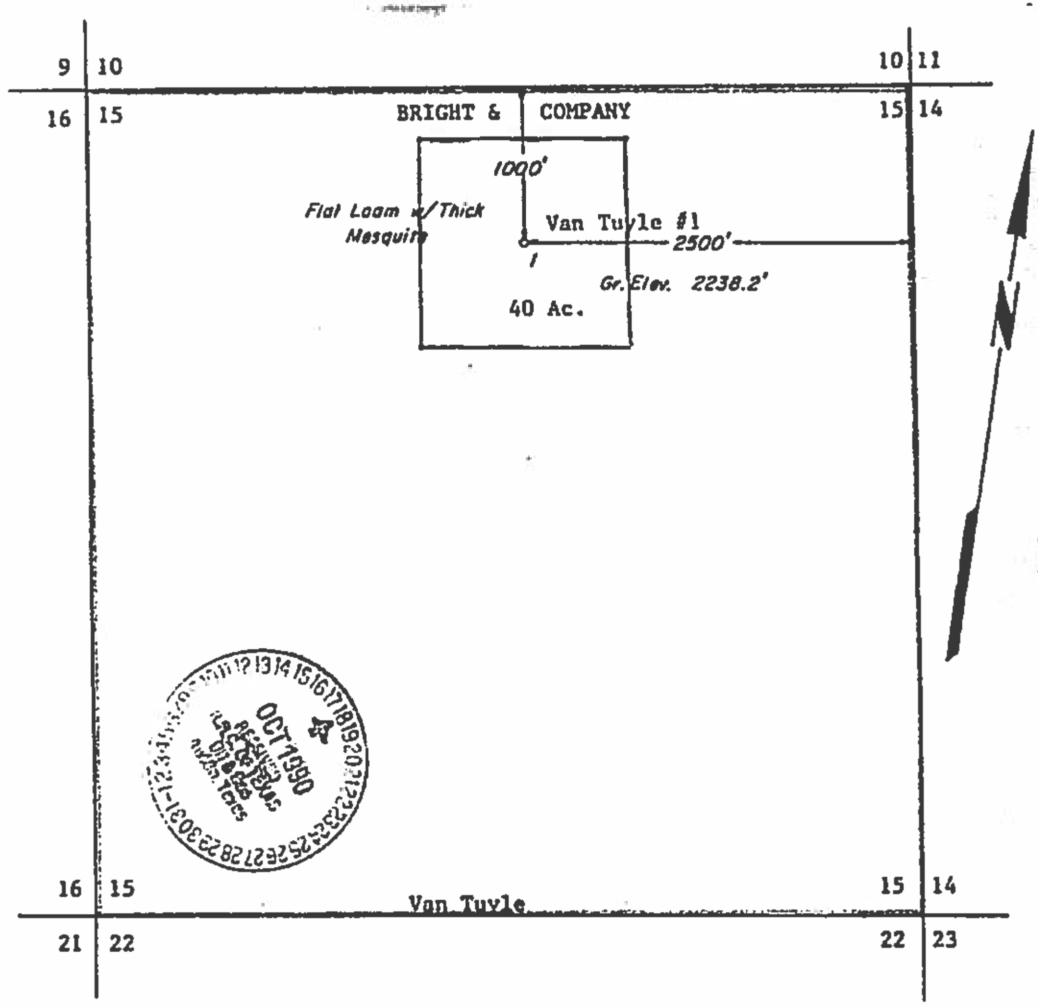
Tracy D. Tenison
Signature

Tracy D. Tenison, Engineer
Name and title of operator's representative

Date: 9/26/90 (mo. day yr.)

Tel: 915-697-2214 (Area Code Number)

• RRC Use Only •



THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON TEXAS P.L.S. NO. 1883
GARY G. EIDSON TEXAS P.L.S. NO. 4735
JERRY A. DUNN TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1" = 1000'	Drawn by: NEG
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

WATER BOARD LETTER DATED 10-1990 1 2

Plugging Record Depth 350

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

13(A) Exception Dated N/A

13 3/8 - 361

API NO. 42-335-33555 (if available)

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

1. RRC District: 8

4. RRC Lease or Id. Number:

2. FIELD NAME (as per RRC Records): Wildcat

3. Lease Name: Van Tuyle

5. Well Number: 1

6. OPERATOR: Bright & Company

6a. Original Form W-1 Filed in Name of:

10. County: Mitchell

7. ADDRESS: 2911 Turtle Creek Blvd #700 Dallas, TX 75219

6b. Any Subsequent W-1's Filed in Name of:

11. Date Drilling Permit Issued: 10/18/90

8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 1000 Feet From north Line and 2500 Feet From east Line of the Van Tuyle Lease

12. Permit Number: 379724

9a. SECTION, BLOCK, AND SURVEY: Sec 15, Blk 29, T1N, T&P RR Co

9b. Distance and Direction From Nearest Town in this County: 8.7 miles NW of Westbrook

13. Date Drilling Commenced: 11/26/90

16. Type Well (Oil, Gas, Dry): Dry

Total Depth: 8360'

17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s

	GAS ID or OIL LEASE #	Oil-O Gas-G	WELL #

14. Date Drilling Completed: 12/18/90

18. If Gas, Amt. of Cond. on Hand at time of Plugging:

15. Date Well Plugged: 12-17-90

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	12-17	12-17	12-17	12-17	12-17			
20. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8			
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15			
*22. Sacks of Cement Used (each plug)	50	50	160	50	10			
*23. Slurry Volume Pumped (cu. ft.)	59	59	189	59	11.8			
*24. Calculated Top of Plug (ft.)	8076	2526	1792	325	Surf.			
25. Measured Top of Plug (if tagged) (ft.)			1790					
*26. Slurry Wt. #/Gal.	15.6	15.6	15.6	15.6	15.6			
*27. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.			

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
13-3/8	48	361	361	17-1/2
8-5/8	32	2274	2274	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well: [ ] Yes [X] No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
2274	8360		

APR 15 1991

Return to Central Records

RECEIVED RRC OF TEXAS JAN 14 1991 MIDLAND, TEXAS

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

D L Hammell

Signature of Cementer or Authorized Representative

Halliburton Services, Big Spring, TX

Name of Cementing Company

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

W J Morris — W. J. Morris — REPRESENTATIVE OF COMPANY

Agent — TITLE

1/11/91 — DATE

Phone 214 550-0889 (A/C NUMBER)

Did not Witness

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

RECEIVED RRC OF TEXAS MAR 05 1991 OIL & GAS MIDLAND, TEXAS

/38

335-33555

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission [X] Yes [ ] No	32. How was Mud Applied? Drilling Rig	33. Mud Weight 9.1 LBS/GAL
34. Total Depth 8360 Depth of Deepest Fresh Water 210	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No 36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Halliburton, P. O. Box 380, Snyder, Texas 79549

Date RRC District Office notified of plugging 12/15/90

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Ben Van Tuyle, 432 Hilldale Dr, Ann Arbor, MI 48105

39. Was Notice Given Before Plugging to Each of the Above?

Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ________ Date ________

Type Logs:

[ ] Driller's [X] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging ________ bbls*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ________

REMARKS ________

000 57 0713

Operator: Fill in other items.

Form W-15
Cementing Report
Rev. 4/1/83

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1. Operator's Name (As shown on Form P-5, Organization Report)	2. RRC Operator No.	3. RRC District No.	4. County of Well Site
Bright & Co.	093125	8	Mitchell

5. Field Name (Wildcat or exactly as shown on RRC records)	6. API No.	7. Drilling Permit No.
Wildcat	42- 335-33555	379724

8. Lease Name	9. Rule 37 Case No.	10. Oil Lease/Gas ID No.	11. Well No.
Van Tuyle			1

CASING CEMENTING DATA:		SURFACE CASING	INTERMEDIATE CASING	PRODUCTION CASING: Single String	PRODUCTION CASING: Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS: Tool	MULTI-STAGE CEMENTING PROCESS: Shoe
12. Cementing Date		[illegible]	[illegible]				
13. •Drilled hole size		17-1/2	11				
•Est. % wash or hole enlargement							
14. Size of casing (in. O.D.)		13-3/8	8-5/8				
15. Top of liner (ft.)							
16. Setting depth (ft.)		361	2274				
17. Number of centralizers used		3	3				
18. Hrs. waiting on cement before drill out		12	12				
1st Slurry	19. API cement used: No. of sacks	390	300				
	Class	Premium Plus	Hall.Light Prem Plus				
	Additives	2% Calcium Chloride	2% CaCl2				
2nd Slurry	No. of sacks						
	Class						
	Additives						
3rd Slurry	No. of sacks						
	Class						
	Additives						
1st	20. Slurry pumped: Volume (cu. ft.)	514.8	591				
	Height (ft.)	Surface	2268				
2nd	Volume (cu. ft.)						
	Height (ft.)						
3rd	Volume (cu. ft.)						
	Height (ft.)						
Total	Volume (cu. ft.)	514.8	591				
	Height (ft.)	Surface	2268				
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?		Yes	No				

22. Remarks

RECEIVED
R.R.C. OF TEXAS
JAN 14 1991
O.G.
MIDLAND, TEXAS

RECEIVED
R.R.C. OF TEXAS
MAR 05 1991
OIL & GAS DIV
MIDLAND TEXAS

OVER ▶

[illegible] TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
[illegible]								
[illegible]. Size of hole or pipe plugged (in.)								
[illegible]. Depth to bottom of tubing or drill pipe (ft.)								
[illegible]								
[illegible]								
[illegible] top of plug (ft.)								
[illegible]. Measured top of plug, if tagged (ft.)								
[illegible]								
[illegible]								

[illegible] under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this [illegible] the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my [illegible] and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This [illegible]

[illegible], Jr. - Cementer | Halliburton | [signature]
[illegible] | Cementing Company | Signature

[illegible] 300 | Snyder, Texas 79549 | 915-573-3526 | 11-26-90
[illegible] | City, State, Zip Code | Tel.: Area Code Number | Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data.

W. J. Morris | Agent | [signature]
Typed or printed name of operator's representative | Title | Signature

2911 Turtle Creek Blvd, #700, Dallas, TX 75219 | 214-559-0889 | 1/11/91
Address | City, State, Zip Code | Tel.: Area Code Number | Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For offshore operations, see the requirements of Rule 13 (c).

A. What to file. An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, Form W-2 or G-1, as required by Statewide or special field rules;
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form **W-15, in addition to Form W-3, to show any casing cemented in the hole.**

B. Where to file. The appropriate Commission District Office for the county in which the well is located.

C. Surface casing. An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. Centralizers. Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. Exceptions and alternative casing programs. The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F. Intermediate and production casing. For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. Plugging and abandoning. Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

R.R.C. Midland

Please Refer
to File No..........

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2A

APPLICATION TO PLUG AND WELL RECORD
FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH
WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Name of Company or Operator The Texas Company Address Box 1720, Fort Worth, Texas

County Howard Survey T&P RRCo. Blk 29 T-1-N Sec 4

Name of Lease A. L. Wasson No. of Acres 1760 Well No. 1 Elev. 2300 (DF)

Located Approx. 21 Miles NE Direction from Big Spring, Texas (Nearest P. O. or Town)

Name of Field in which well is located Wildcat

Form 1, "Notice of Intention to Drill," was filed in name of The Texas Company

Drilling Commenced 12-28, 19 52, Drilling Completed 3-28, 19 52

Has this well ever produced oil? No or Gas? No

Character of Well (Oil, Gas or Dry) Dry Total Depth 8670'

Date you wish to Plug 3-27-, 19 52

Name of Party Plugging Well Livermore Drilling Address 610 Lubbock Nat'l Bank Lubbock, Texas

Correspondence regarding this well should be sent to: Name The Texas Company

Address Box 1720, Fort Worth, Texas

CASING RECORD

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
13 3/8"	196		None		196		Texas Pattern
9 5/8"	2115		100		2015		Halliburton F & S

IF CASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS

Initial Production of Gas: Volume (MCF) None 24 hrs. Pressure None

Initial Production of Oil: Barrels None

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to, to the Deputy Supervisor of district in which well is located. All necessary forms will be furnished by Railroad Commission of Texas

RECEIVED
MIDLAND, TEXAS
APR 10 1952
OIL & GAS DIVISION

NOTE: If no log available, so state and give all information that can be obtained as to total depth, casing record, formation, water sands, and as near as possible date well was drilled.

General Remarks: This well drilled to a total depth of 8670' without encountering oil or gas. We therefore desire to abandon salvage and plug well in the following manner: (Cut 9 5/8" casing at 100' and pull same) (Over)

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Caliche	0	100	At depth 206' cemented 13 3/8"
Red Beds	100	206	casing at 206' with 250 sacks.
Shale & Anhy	206	945	Cement circulated.
Anhy	945	1254	
Anhy & Shale	1254	1499	At depth 2125' cemented 9 5/8" casing
Anhy & Salt	1499	1750	at 2125' with 600 sacks.
Anhy & Shale	1750	1837	
Anhy	1837	1955	
Anhy & Lime	1955	2125	
Lime	2125	2290	
Lime & Shale	2290	2322	
Lime	2322	3116	
Lime & Shale	3116	3612	
Lime & Chert	3612	3820	
Lime & Sand	3820	3979	
Lime & Chert	3979	4155	
Lime & Sand	4155	4538	
Lime & Chert	4538	4900	
Lime & Sand	4900	5114	
Lime & Chert	5114	5232	
Lime & Shale	5232	6203	
Shale	6203	7953	
Lime & Chert	7953	8670	
Total Depth		8670	

All Measurements from Rotory Table or 12' above ground.

Remarks Cont'd

Using Heavy mud between plugs, spot the following cement plugs, 95 sacks 8670'-8373';15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7655'; 15 sacks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sacks 4680'-4630'; 15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1070'; 40 sacks. 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing.

Drill Stem Tests

DST # 1: Pkr. failed

DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 2250' salt water cut with drlg. mud.

DST # 3: 5100-5210, Tool open 1 1/2 hrs. Recovered 300' drlg. mud.

DST # 4: 5440-5485, Tool open 1 hr. Recovered 75' slightly gas cut drlg. mud.

DST # 5: 5902-6000, Tool open 1 hr. Recovered 100' drlg. mud, [illegible]

DST # 6: 780[illegible]-7870, Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120' [illegible] gas cut drlg. mud.

DST # 7: 78[illegible] [illegible] hrs., Recovered 5' drlg. mud & 180' slightly [illegible] mud.

Method of shutting off water Cased off Is water completely shut off? Yes

Amount of water with oil None per cent None

I, T. P. [illegible] being first duly sworn [illegible] that I have knowledge of the facts and matter herein [illegible] and that the same are true and correct.

[signature]

Representative of Company.

Subscribed and sworn to before me this 7 day of April, 1952

[signature] W. E. BRUZEK

Notary Public

Midland County, Texas.

RECEIVED

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.

DST # 10: 8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

Please Refer to
File No.........................

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 4
Plugging Record

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company The Texas Company Address Box 1720, Ft. Worth, Texas

Sec. No. 4 Block No. 29 T-I-N Survey T & P RRCO County Howard

Well No. 1 Name of Lease A. L. Wasson No. of Acres 1760

Name of Field in which well is located Wildcat Date well was plugged 3-27- 19 52

Form 1 (Notice of Intention to Drill) Was Filed in Name of The Texas Company

Character of Well at the time of completion: Oil - bbls.; (Initial Production) Gas - Cu. ft.; (Initial Production) Dry Yes

Amount well producing when plugged: Oil None bbls.; Gas None Cu. ft.; Water None bbls.

Has this well ever produced oil or gas? No

Total Depth 8670 feet. Top of each producing sand - feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Thru drill pipe

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depths placed. Also amount of cement and rock. Was well shot? No

Spotted the following plugs: 95 sx 8670-8373, 15 sx 8213-8163, 15 sx 7860-7810, 15 sx 7705-7655, 15 sx 5600-5550, 15 sx 5430-5380, 15 sx [redacted] 50-25-4975, 15 sx 4680-4630, 15 sx 2810-2760, 15 sx 2093-2043, Cut off 9 5/8" casing @ 100' and pulled, spot 40 sx 1125-1070, 40 sx 1025-975, 40 sx 875-825, 30 sx in top of casing.

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: All 13 3/8" casing left in hole & 2015' 9 5/8" casing left in hole. All strata protected by casing left in hole or cassed of with cement.

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:

All adjacent property leased by The Texas Company

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, T. P. Drew, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name T P Drew Dist. Supt.

Subscribed and sworn to before me this 15 day of May, 19 52

Notary Public Midland County, Texas

Correspondence regarding this well should be addressed to:

Name The Texas Company Address Box 1720, Ft. Worth, Texas

0 0 0 2 2 0 7 7 7

FORM W-1 (6/78)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

API Well No. 42
Instruction (7a & b) on back side.

☐ Directional Well ☐ Amended or Corrected Permit

RRC Permit Number, if previously assigned. 084247

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

Check one: ☐ DRILL ☐ DEEPEN (Below Casing) ☐ DEEPEN (Within Casing) ☐ PLUG BACK ☒ OTHER (Specify) re-entry

If Amended Application, explain fully in Remarks or Attach Separate Page.

7. RRC District: 8

8. County: Howard

1. Operator: McCann Corporation 538853

2. Address (Including City and Zip Code): P. O. Box 448, Big Spring, TX 79720

3. Is Form P-5 (Organization Report) in Exact Operator Name Filed? YES ☒ NO ☐ (Instruction (2) on back side.)

4. Lease Name and RRC Lease or ID No. (If Assigned): Stewart

5. Location (Sec., Blk., Survey): Sec. 4, Blk. 29, T-1-N, T & P RR Co.

6. This well is to be located 4 miles Southeast Direction from Vincent, TX Nearest Post Office or Town.

9. Well Number: 1

10. Number of Acres in Lease: 640

11. Distance from Proposed Location to Nearest Property or Lease Line (ft.): 660'

12. Total Depth: 4600'

EACH PROPOSED COMPLETION

REFER TO INSTRUCTIONS ON BACK SIDE. READ CAREFULLY AND FURNISH COMPLETE DATA.

13. FIELD NAME (Exactly as shown on R.R.C. Proration Schedule including Reservoir if applicable.) If Wildcat, so state below. 00018 001	14. Completion Depth	15. All Prior Rule 37 Exc. Case Numbers for this wellbore. If none, State None.	16. Applicable Field Rules Spacing Pattern. If no Rules, State 467-1200. (ft.)	17. Applicable Field Rules Density Pattern. If no Rules, State 40. (acres)	18. Number of Acres in Drilling Unit for this Well AND DESIGNATE ON PLAT.	19. Is this acreage presently assigned to another well in same field? (Yes or No; If yes explain in remarks.)	20. Distance and Direction from proposed location to nearest drilling completed or applied for well in same res. on same lease (ft.)	21. Is this a 1. Regular or 2. Rule 37 Exc. Location? Check the appropriate box.	22. Oil, Gas, or other Type Well (Specify)	23. Number of Wells or Permitted locations on this Lease in same Reservoir for which this Permit is Requested? OIL	GAS
Wildcat	4210'	None	467/1200	40	40	No	None	Regular 1 ☒ Rule 37 2 ☐	Oil	0	0
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			

RECEIVED R.R.C. OF TEXAS JUN 16 1980 OIL & GAS DIV. TEXAS

24. PERPENDICULAR LOCATION FROM TWO DESIGNATED:
A. Lease Lines: 660' FWL & 1980' FNL
B. Survey Lines: 660' FWL & 1980' FNL

25. (a) Is this wellbore subject to SWR 36? Yes ☒ No ☐
(b) If subject to SWR 36, has Form H-9 been filed? Yes ☒ No ☐
(If no, attach explanation.)

NOTICE
NO ALLOWABLE WILL BE ASSIGNED to any well which does not have sufficient surface casing to protect all fresh water sands. Where Commission rules do not specify surface casing requirements, it will be necessary to contact Texas Water Development Board, Austin, Texas, to ascertain the depth to which fresh water sands must be protected.

REMARKS: Original Operator: The Texas Company
Original Lease Name: A.L. Wasson, Well #1.
Plugged and Abandoned: 3-27-52

CERTIFICATE
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Signature: Ellie W. Bulls
Title: Administrative Assistant
Date: June 12, 1980
Telephone: Area Code 915 267-7[illegible]

READ INSTRUCTIONS ON BACK SIDE AND FURNISH COMPLETE DATA.

0 0022 0775

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. (if available) 42-227-00000

RRC District: 08

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or ID Number:

2. FIELD NAME (as per RRC Records): Wildcat	3. Lease Name: Stewart	5. Well Number: 1
6. OPERATOR: McCann Corporation	6a. Original Form W-1 Filed in Name of: McCann Corporation	10. County: Howard
7. ADDRESS: P. O. Box 448, Big Spring, TX	6b. Any Subsequent W-1's Filed in Name of:	11. Date Drilling Permit Issued: 6-17-80
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located	660 Feet From West Line and 1980 Feet From North Line of the Stewart Lease	12. Permit Number: 084247
9a. SECTION, BLOCK, AND SURVEY: Sec. 4, Blk. 29, T-1-N, T&P RR Co	9b. Distance and Direction From Nearest Town in this County: 4 miles SE of Vincent	13. Date Drilling Commenced: 10-10-80

16. Type Well (Oil, Gas, Dry): DRY
Total Depth: 1100
17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s — GAS ID or OIL LEASE # | Oil-O Gas-G | WELL #
18. If Gas, Amt. of Cond. on Hand at time of Plugging:
14. Date Drilling Completed: 10-12-
15. Date Well Plugged: 10-12-

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	10-12-80	10-13	10-13					
20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8					
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1100	250	Top Out					
*22. Sacks of Cement Used (each plug)	50	100	10					
*23. Slurry Volume Pumped (cu. ft.)	66	133	13					
*24. Calculated Top of Plug (ft.)	990	70	Surf.					
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	1.33	1.33	1.33					
*27. Type Cement	C	C	C					

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
8 5/8	24#	200	200	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well? ☐ Yes ☒ No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

Signature of Cementer or Authorized Representative

Dowell Division of Dow Chemical Co.
Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Tom McCann | President | April 9, 1981 | Phone 915 267-7488
REPRESENTATIVE OF COMPANY | TITLE | DATE | A/C NUMBER

Did Not Witness
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

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R.R.C. OF TEXAS
APR 20 1981
O.G.
MIDLAND, TEXAS

DR-80

31. Was Hole filled with Mud-Laden Fluid, according to the regulations of the Commission? [X] Yes [ ] No	32. How was Mud Applied? Circulated		33. Mud Weight 8.6 LBS/GAL
34. Total Depth 1100	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No	
Depth of Deepest Fresh Water 150		36. If NO, Explain	

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Dowell Division of Dow Chemical Co. - Colorado City, TX

Date RRC District Office notified of plugging 10-1-85

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Danny Stewart - P. O. Box 26, Sterling City, Tx. 76951

39. Was Notice Given Before Plugging to Each of the Above?
Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______ Date ______

Type Logs:
[ ] Driller's [ ] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Was FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging None bbls*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ______

REMARKS ______

APR 2 0 1990

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form W-2
(Rev. [illegible])

CEMENTING REPORT

*1. Field Name (as per RRC Records or Wildcat): Wildcat	*2. RRC District: 08
*3. Operator: Mc Cann Corporation	*4. County: Howard
*5. Lease Name(s) and RRC Lease Number(s) or I. D. Number(s): Stewart	*6. Well Number: 1
*7. Location (Section, Block, and Survey): Sec. 4, Blk. 29, T-1-N, T&P RR Co. Survey	

CASING CEMENTING DATA:	SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
8. Cementing Date						
*9. (a) Size of Drill Bit (inches)						
(b) Estimated % Wash or Hole Enlargement Used in Calculations.						
*10. Size of Casing (inches O.D.)						
*11. Top of Liner (if liner used) (ft.)						
*12. Setting Depth of Casing (ft.)						
13. Type API Class Cement & Amount of Additives Used: (a) In First (Lead) or Only Slurry (If additional space is needed, use "REMARKS" on reverse side.)						
(b) In Second Slurry						
(c) In Third Slurry						
14. Sacks of Cement Used: (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Sacks of Cement Used						
15. Slurry Volume per Sack of Cement (cu.ft./sack): (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
16. Volume of Slurry Pumped: (cu.ft.) (Item 14 x Item 15) (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Slurry Volume Pumped (cu.ft.)						
17. Calculated Annular Height of Cement Slurry behind Pipe (ft.)						
18. Was cement circulated to ground surface (or bottom of cellar) outside casing? (Yes or No)						

CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6
19. Cementing Date	10-12-80	10-13-80	10-13			
*20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8			
*21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1000	250	Top Out			
22. Sacks of Cement Used (each plug)	50	100	10			
23. Slurry Volume Pumped (cu. ft.)	66	133	13			
24. Calculated Top of Plug (ft.)	990	70	Surf.			
*25. Measured Top of Plug (if tagged) (ft.)						

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R.R.C. OF TEXAS
APR 20 1981
MIDLAND, TEXAS

(CEMENTING COMPANY AND OPERATOR MUST COMPLY WITH THE INSTRUCTIONS ON REVERSE SIDE HEREOF.)

– OVER –

* Designated items to be completed by Operator. Items not so designated shall be completed by Cementing Company.

Remarks:	*27. Remarks:

CEMENTING COMPANY	*OPERATOR
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.	I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data and information presented herein.
P.N. Shackelford	Tom McCann
Signature of Cementer or Authorized Representative	*Signature of Operator or Authorized Representative
P. N. Shackelford, Sr.District Clerk	Tom McCann - President
Name of Person and Title (type or print)	*Name of Person and Title (type or print)
Dowell Division of Dow Chemical Co.	McCann Corporation
Cementing Company	*Operator
Route 3, Box 178	P. O. Box 448
Street Address or P.O. Box	*Street Address or P.O. Box
Colorado City, Tx 79512	Big Spring, Texas 79720
City, State Zip Code	*City, State Zip Code
Telephone 915 728-5291	*Telephone 915 267-7488
Area Code	Area Code
10-14-80	4-6-81
Date	*Date

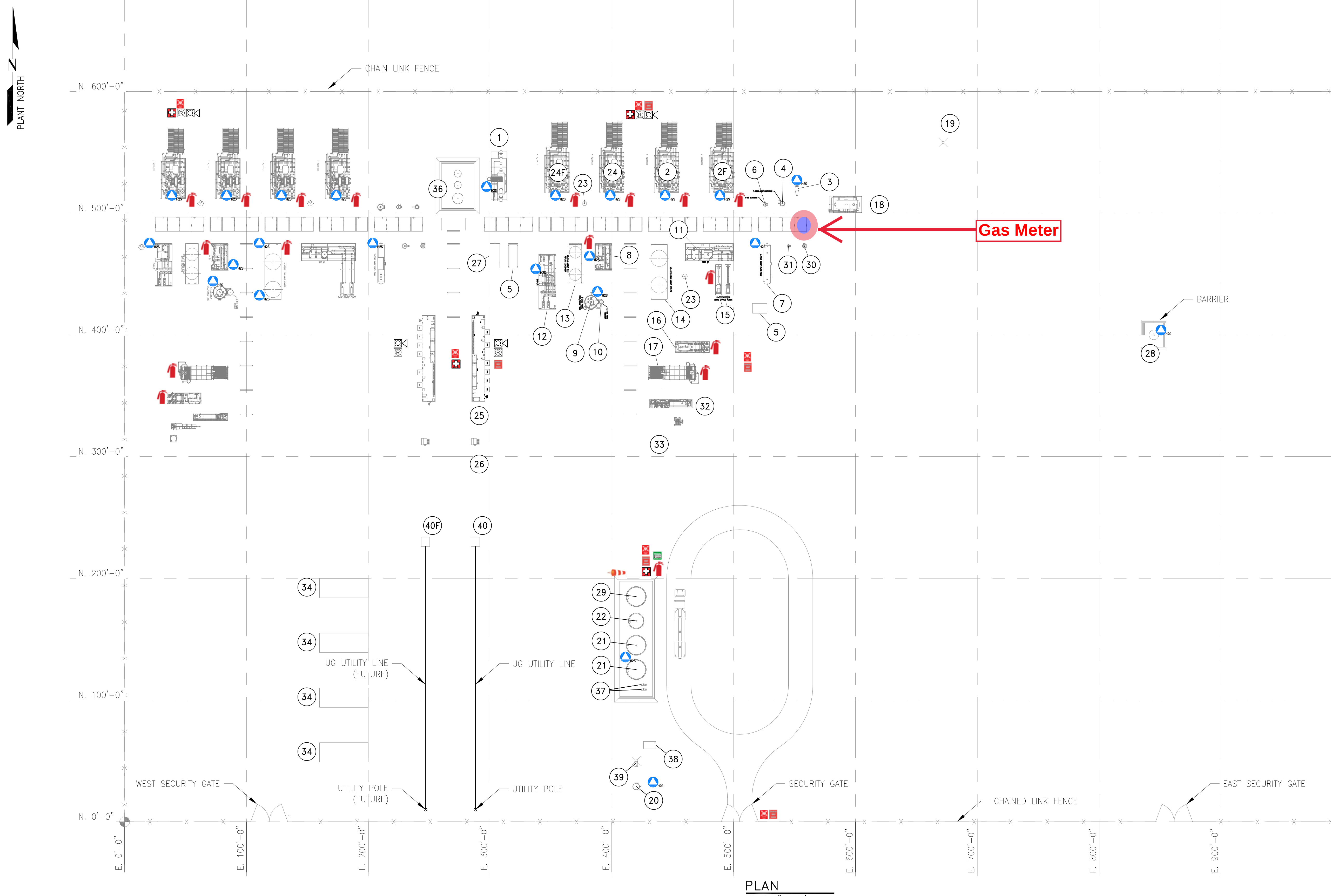
INSTRUCTIONS

1. A. This form shall be filed by the operator in the RRC District Office with:
   (1) Each copy of an initial Form G-1 or W-2 if a cementing report is required by Statewide or Special Rules, or if exception is needed to cementing requirements in Statewide or Special Rules;
   (2) Each copy of Form W-3;
   (3) Each copy of Form W-4 if a multiple parallel casing completion.
   B. At least an original and one copy of this form shall be filed for each cementing company used on a well.
   C. The cementing of different casing strings on a well by one cementing company may be consolidated on one form (to be filed in duplicate)
2. Cementing Company and Operator shall comply with the applicable portions of Statewide Rules 8, 13, and 14. For offshore operations, Cementing Company and Operator shall comply with Statewide Rule 13(E).
3. If setting FULL AMOUNT OF SURFACE CASING:
   A. Depth to protect fresh water determined by:
   (1) Field Rule
   (2) Texas Water Development Board, if no Field Rule
   B. Set surface casing below depth to be protected and cement from casing shoe to ground surface.
4. IF SETTING ANYTHING OTHER THAN THE FULL AMOUNT OF SURFACE CASING, PERMISSION SHALL BE OBTAINED FROM THE RAILROAD COMMISSION.
5. If setting NO SURFACE CASING (See Item 4 above.):
   A. If no multi-stage tool is used, the next deeper casing string shall be cemented from the casing shoe to the surface.
   B. If using the multi-stage tool on the next deeper string, cement from the depth that protects fresh water sands to the surface.
6. If setting SHORT SURFACE CASING (See Item 4 above.):
   A. Cement short surface casing from the shoe to the surface.
   B. Whether the multi-stage tool is or is not used on the next deeper casing string, cement from the depth that protects fresh water sands to
   (1) the surface, or
   (2) a point midway between shoe of surface string and the surface. Compliance will be considered if a temperature survey shows that the top of the cement is at least one-third of the distance from the shoe of the surface string to the surface.
7. Setting PRODUCTION STRING of Casing: (Statewide Rules, Special Rules may vary.)
   A. Cement to a point at least 600 feet above the casing shoe.
   B. When 3,000 feet or more of pipe is set for the production or protecting string, a minimum of 30 feet of cement shall be left inside the pipe
8. PLUGGING and ABANDONING:
   A. Cement plugs shall be placed in the well bore as required by Rules and Regulations of the Commission plus any additional plugs as may be specified by the RRC District Director.
   B. The minimum amount of cement normally used in each plug shall be a slurry volume equal to the amount necessary to fill the calculated volume of 100 feet of the hole in which the plug is placed.
   C. A 10 foot cement plug is required to be placed in the top of the well.

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H_2S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



ITEM	DESCRIPTION
1	SLUG CATCHER
2	INLET COMPRESSOR W/ COOLER
2F	INLET COMPRESSOR (FUTURE) W/ COOLER
3	COMPRESSOR DISCHARGE COALESCER
4	AMINE CONTACTOR
5	FUEL GAS SKID
6	TREATER GAS SCRUBBER
7	AMINE FLASH TANK
8	AMINE REGEN SKID
9	AMINE REGENERATOR/REFLUX ACCUMULATOR
10	AMINE REGENERATOR REBOILER
11	AMINE SURGE TANK
12	AMINE BOOSTER/REFLUX PUMP SKID
13	AMINE REGENERATOR REFLUX CONDENSER
14	LEAN AMINE COOLER
15	AMINE CHARGE PUMPS
16	HOT OIL PUMP SKID
17	HOT OIL HEATER
18	FLARE K.O. DRUM
19	FLARE
20	COMBUSTOR
21	SLOP STORAGE TANKS
22	AMINE MAKE UP STORAGE TANK
23	SUMP TANKS
24	ACID GAS COMPRESSOR W/ COOLER
24F	ACID GAS COMPRESSOR W/ COOLER (FUTURE)
25	PDC BUILDING
26	LV TRANSFORMER
27	INSTRUMENT AIR PACKAGE
28	ACID GAS INJECTION WELL
29	DI WATER TANK
30	GLYCOL CONTACTOR
31	GLYCOL SEPARATOR
32	TEG REGEN
33	BTEX
34	GAS GENERATOR SET
35	AMINE SUMP TANK
36	NEW LUBE OIL TANKS
37	CONDENSATE TRANSFER PUMPS
38	VAPOR RECOVERY UNIT
39	TANK COMBUSTOR K.O. DRUM
40	MV TRANSFORMER
40F	MV TRANSFORMER (FUTURE)

LEGEND

- FIRE EXTINGUISHER = 9 ea.
- HYDROGEN SULFIDE DETECTOR = 10 ea.
- AUDIBLE ALARM SOUNDER = 4 ea.
- STROBE LIGHT (RED) – FIRE = 4 ea.
- PLANT EMERGENCY SHUTDOWN = 6 ea.
- FIRST AID & SCBA KIT = 3 ea.
- EYE WASH STATION = 3 ea.
- WIND SOCK = 1 ea.
- MUSTER POINT = 3 ea.

NOTES:

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
C	08/16/22	ISSUED FOR INFORMATION	HJP	CN	–
B	07/12/22	ISSUED FOR INFORMATION	RDC	CN	–
A	06/13/22	ISSUED FOR INFORMATION	RDC	RAF	–

F&C ENGINEERS
TX REG. NO. 8419

BAYSWATER

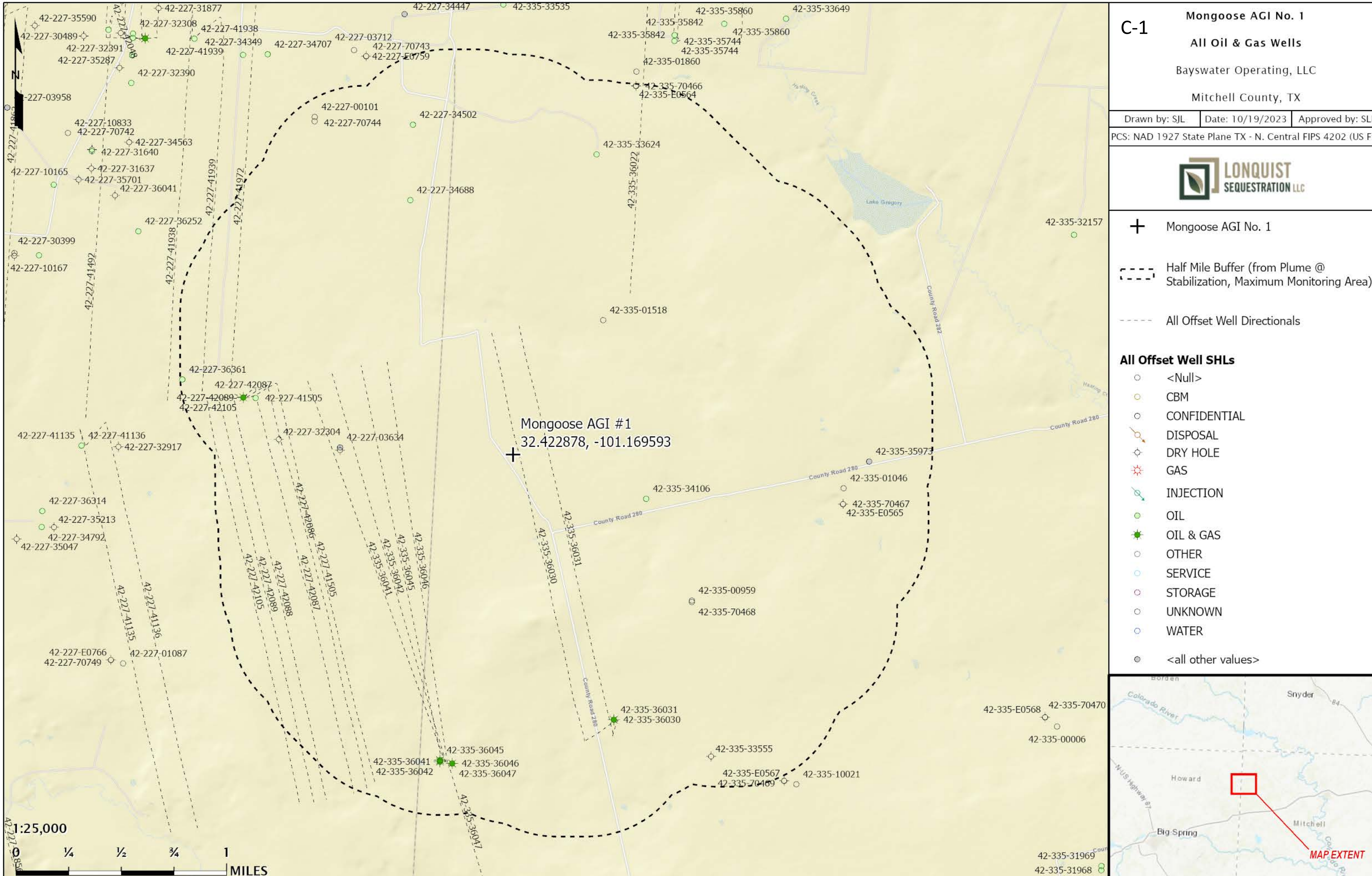
CLIENT : BAYSWATER EXPLORATION & PRODUCTION
PROJECT : SOUR GAS TREATING FACILITY
TITLE : INSTRUMENTATION FACILITY SAFETY LOCATION PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.	SHEET NO.	
RDC	GA	AS NOTED	06/09/22	BAY220316	IN-PLN-0790	1 OF 1	C

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST



C-1
Mongoose AGI No. 1
All Oil & Gas Wells
Bayswater Operating, LLC
Mitchell County, TX
Drawn by: SJL
Date: 10/19/2023
Approved by: SLP
PCS: NAD 1927 State Plane TX - N. Central FIPS 4202 (US Ft.)
LONQUIST SEQUESTRATION LLC
Mongoose AGI No. 1
Half Mile Buffer (from Plume @ Stabilization, Maximum Monitoring Area)
All Offset Well Directionals
All Offset Well SHLs
<Null>
CBM
CONFIDENTIAL
DISPOSAL
DRY HOLE
GAS
INJECTION
OIL
OIL & GAS
OTHER
SERVICE
STORAGE
UNKNOWN
WATER
<all other values>
Mongoose AGI #1
32.422878, -101.169593
N
1:25,000
0
¼
½
¾
1
MILES
County Road 280
County Road 282
Lake Gregory
Borden
Snyder
Howard
Mitchell
Big Spring
Colorado River
MAP EXTENT
42-227-35590
42-227-31877
42-227-32308
42-227-41938
42-227-30489
42-227-32391
42-227-34349
42-227-41939
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42-227-34707
42-227-03712
42-227-70743
42-227-E0759
42-227-34447
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42-335-35842
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42-335-01860
42-335-70466
42-335-E0564
42-227-32390
42-227-03958
42-227-00101
42-227-70744
42-227-34502
42-227-10833
42-227-70742
42-227-34563
42-227-31640
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42-335-36022
42-227-31637
42-227-10165
42-227-35701
42-227-36041
42-227-41939
42-227-41972
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42-227-36252
42-227-30399
42-227-10167
42-227-41492
42-227-41938
42-335-32157
42-335-01518
42-227-36361
42-227-42087
42-227-42089
42-227-41505
42-227-42105
42-227-41135
42-227-41136
42-227-32917
42-227-32304
42-227-03634
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42-335-01046
42-335-34106
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42-335-E0565
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42-227-70749
42-227-01087
42-335-36047
42-335-33555
42-335-E0567
42-335-70469
42-335-10021
42-335-E0568
42-335-70470
42-335-00006
42-335-31969
42-335-31968

Mongoose AGI No. 1

Area of Review: Oil & Gas Wells List										
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022
4222741505	KAMIKAZE 5-8-17-20	3W	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023

Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.

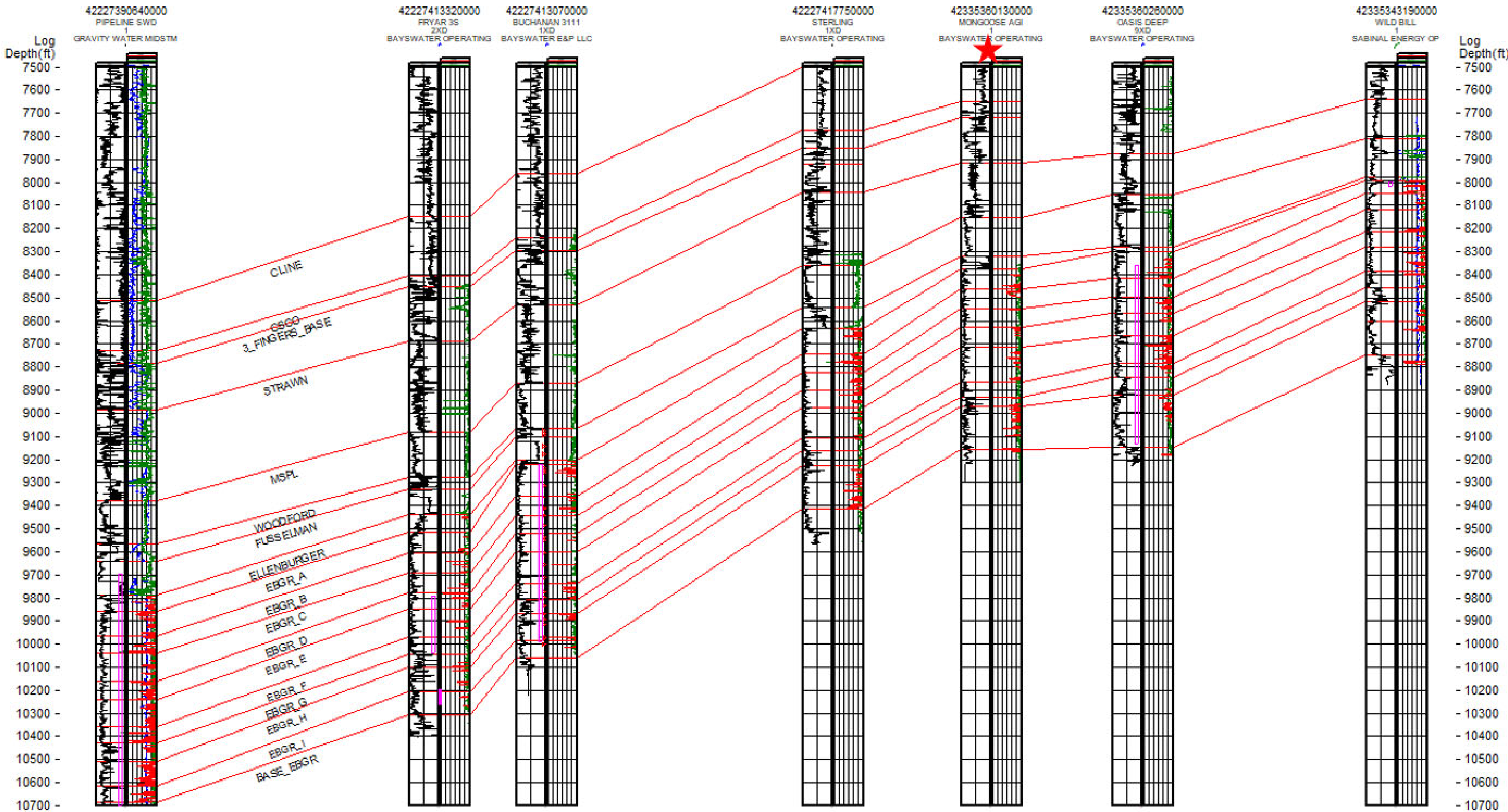
LONQUIST SEQUESTRATION LLC

APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 28 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 29 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER

D-1



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GRAVITY WATER MIDSTM
42227413320000
FRYAR 3S
2XD
BAYSWATER OPERATING
42227413070000
BUCHANAN 3111
1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Log Depth(ft)
7500
7600
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7800
7900
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10000
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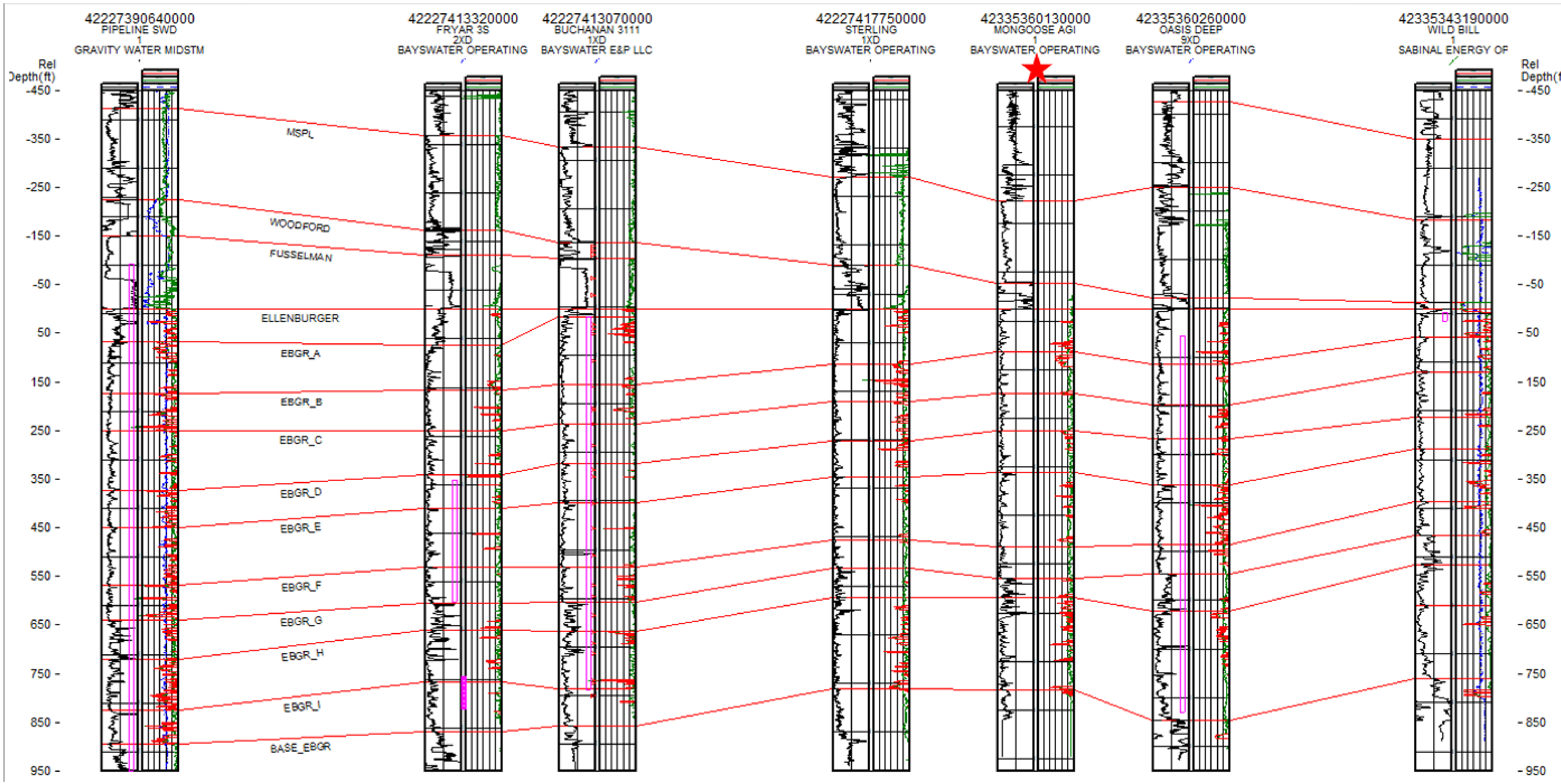
10200
10300
10400
10500
10600
10700
CLINE
CISCO
3_FINGERS_BASE
STRAWN
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR

D-2



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42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
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WILD BILL
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SABINAL ENERGY OP
Rel Depth(ft)
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650
750
850
950
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR

Appendix B: Submissions and Responses to Requests for Additional Information

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC*
Denver, CO

By

Lonquist Sequestration, LLC
Austin, TX

Version 4.0
August 2024

INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.

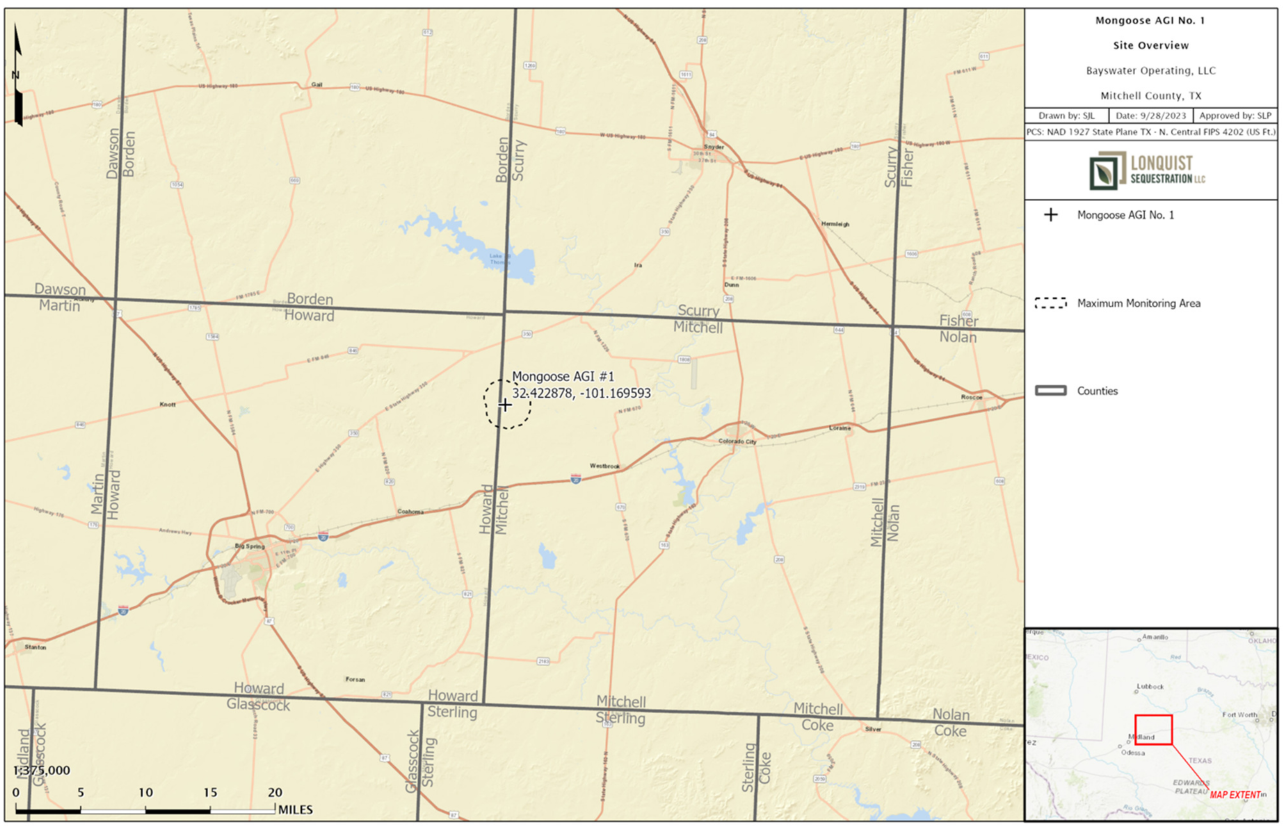

Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years up to a maximum of 19.5 MMscf/D. The primary source of this injected CO_2 gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NAD	North American Datum
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
pH	Scale of Acidity
PISC	Post Injection Site Care
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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Figures

Tables

Appendices

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 Reporter Number

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
  - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility
1625 County Road 280
Westbrook, Texas 79565

Coordinates in North American Datum of 1983 (NAD 83) for this facility:

Latitude: 32.4225396641
Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).

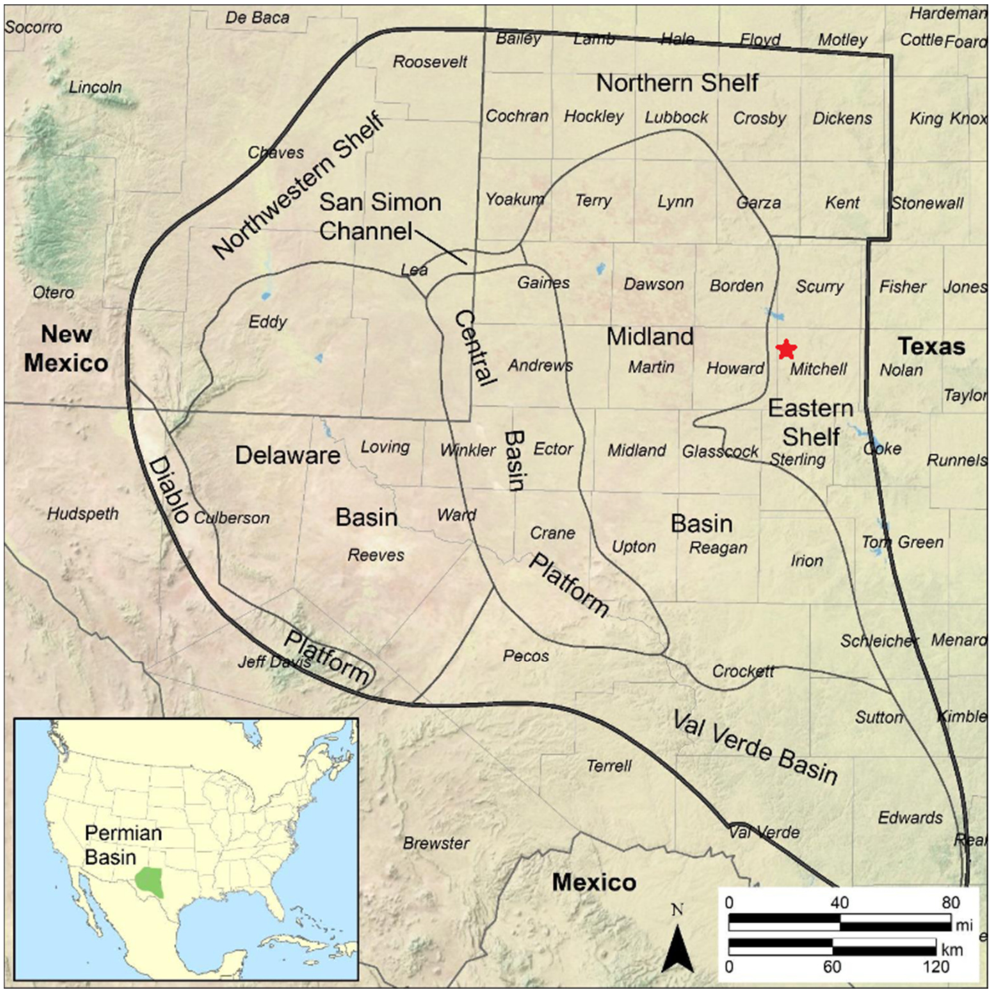


Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).

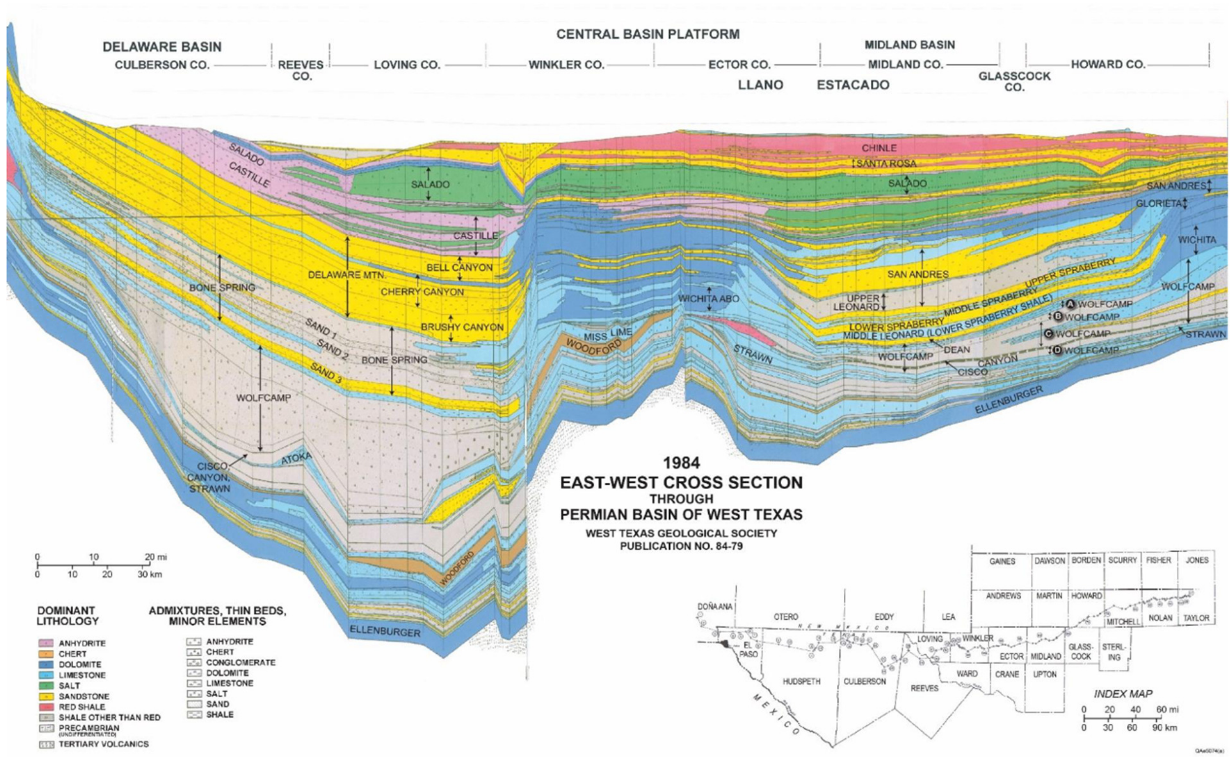


Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are “ooid grainstone; ooid-peloid packstone-grainstone”

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).

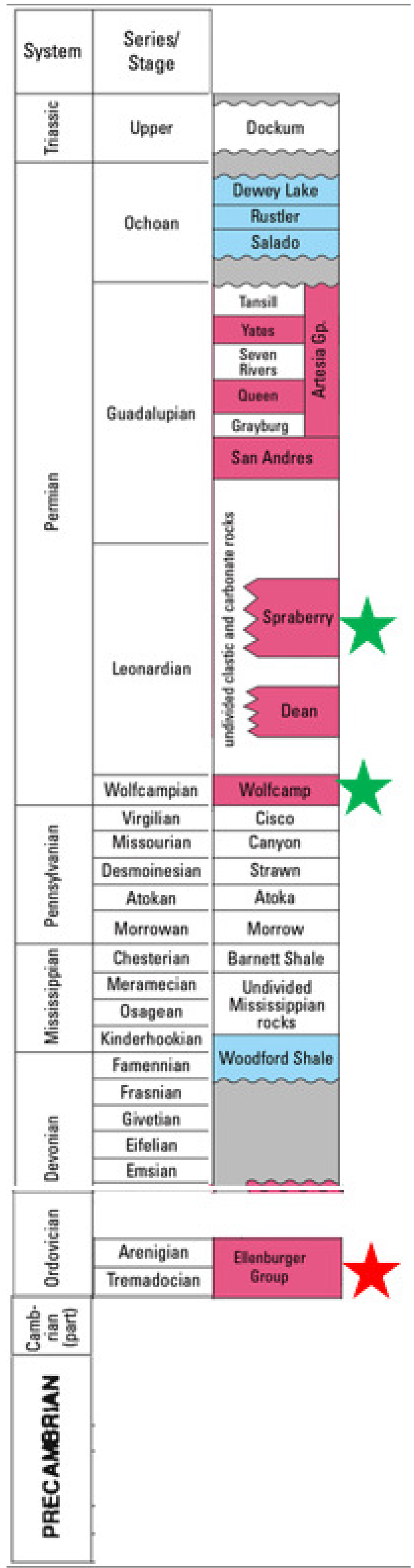


Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf

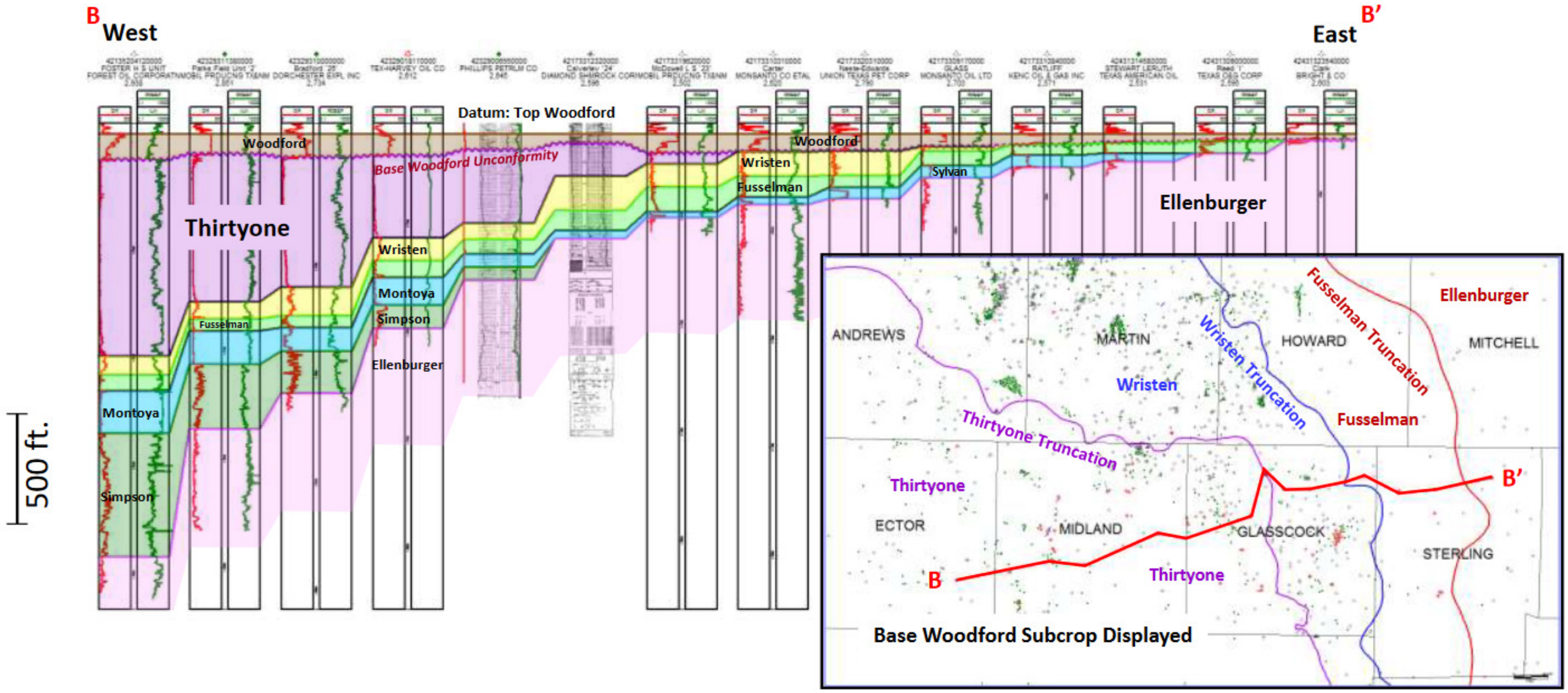


Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).

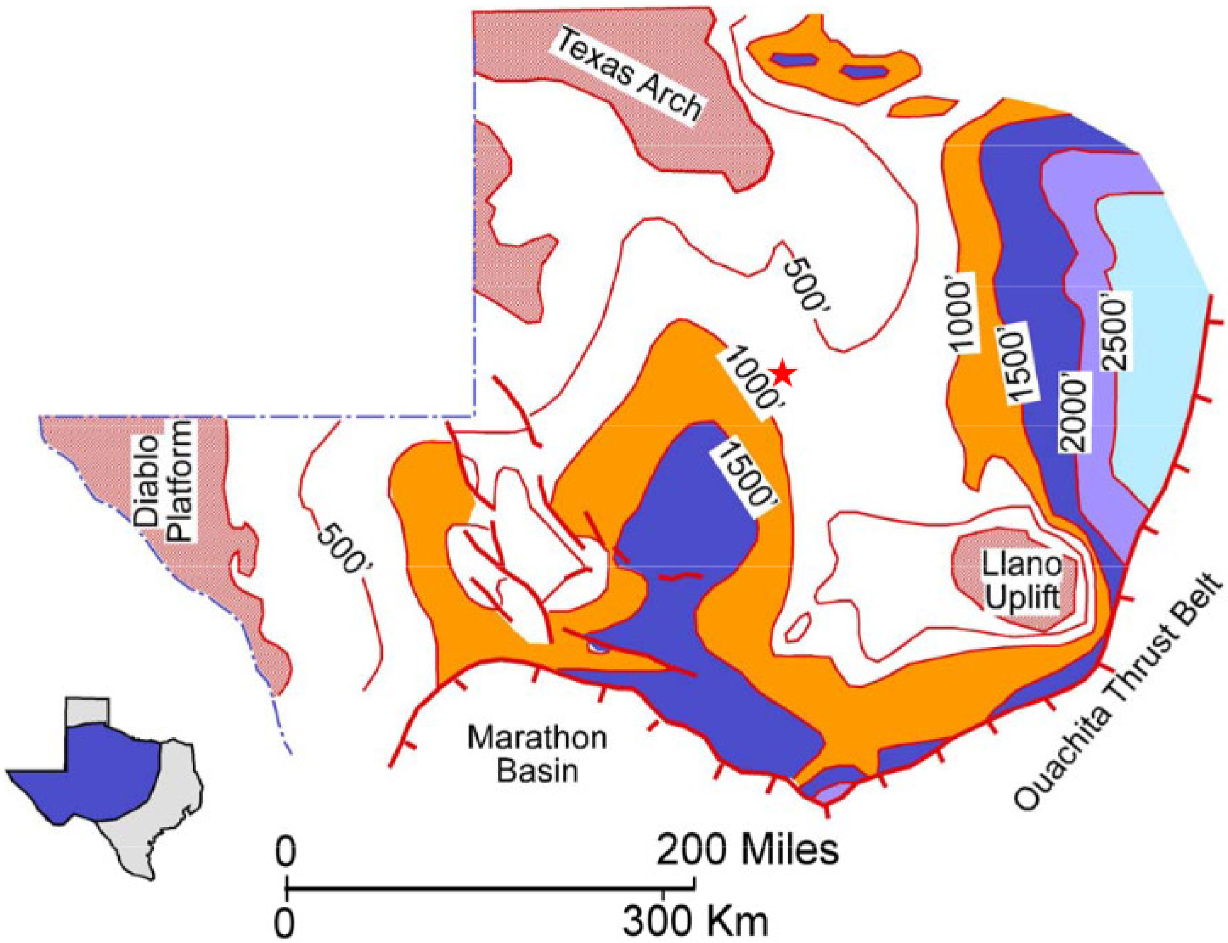


Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)

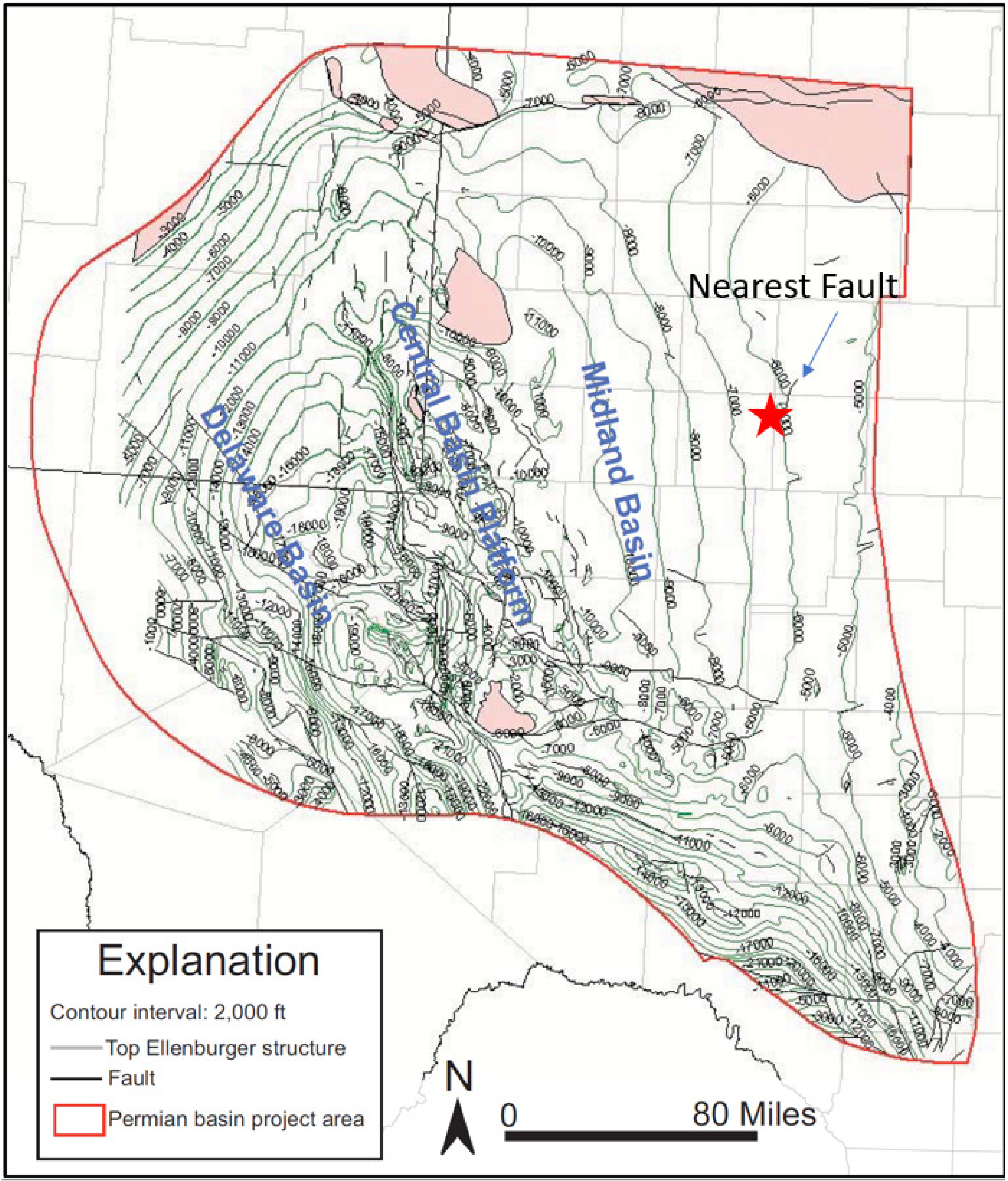


Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant “karsting” and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).

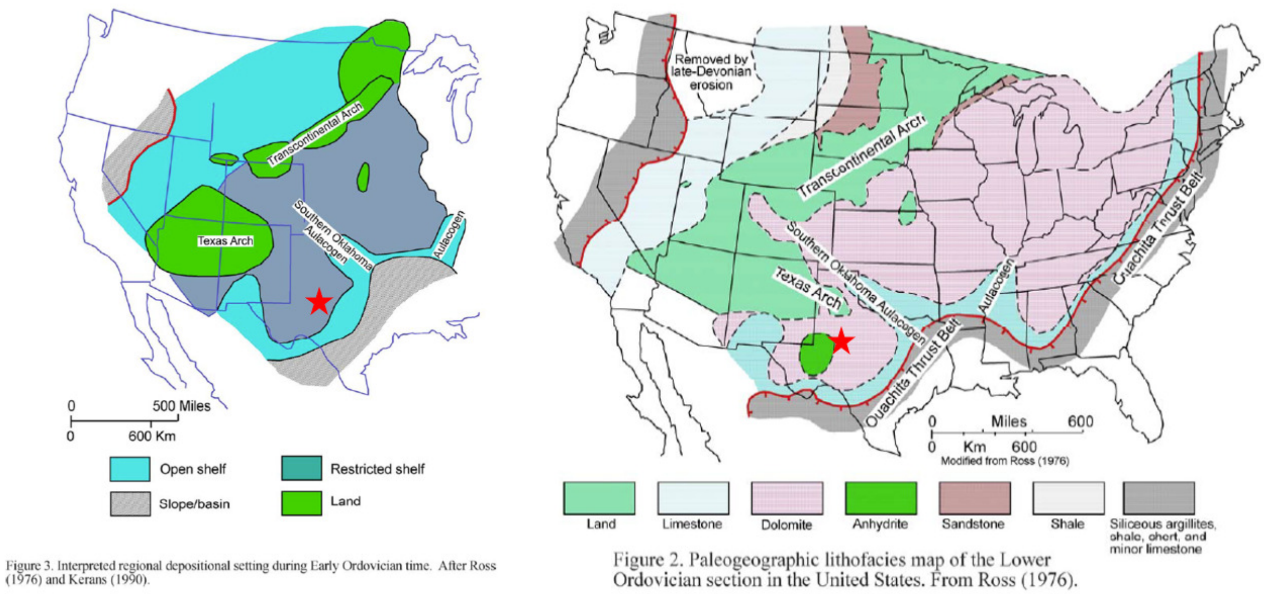


Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).

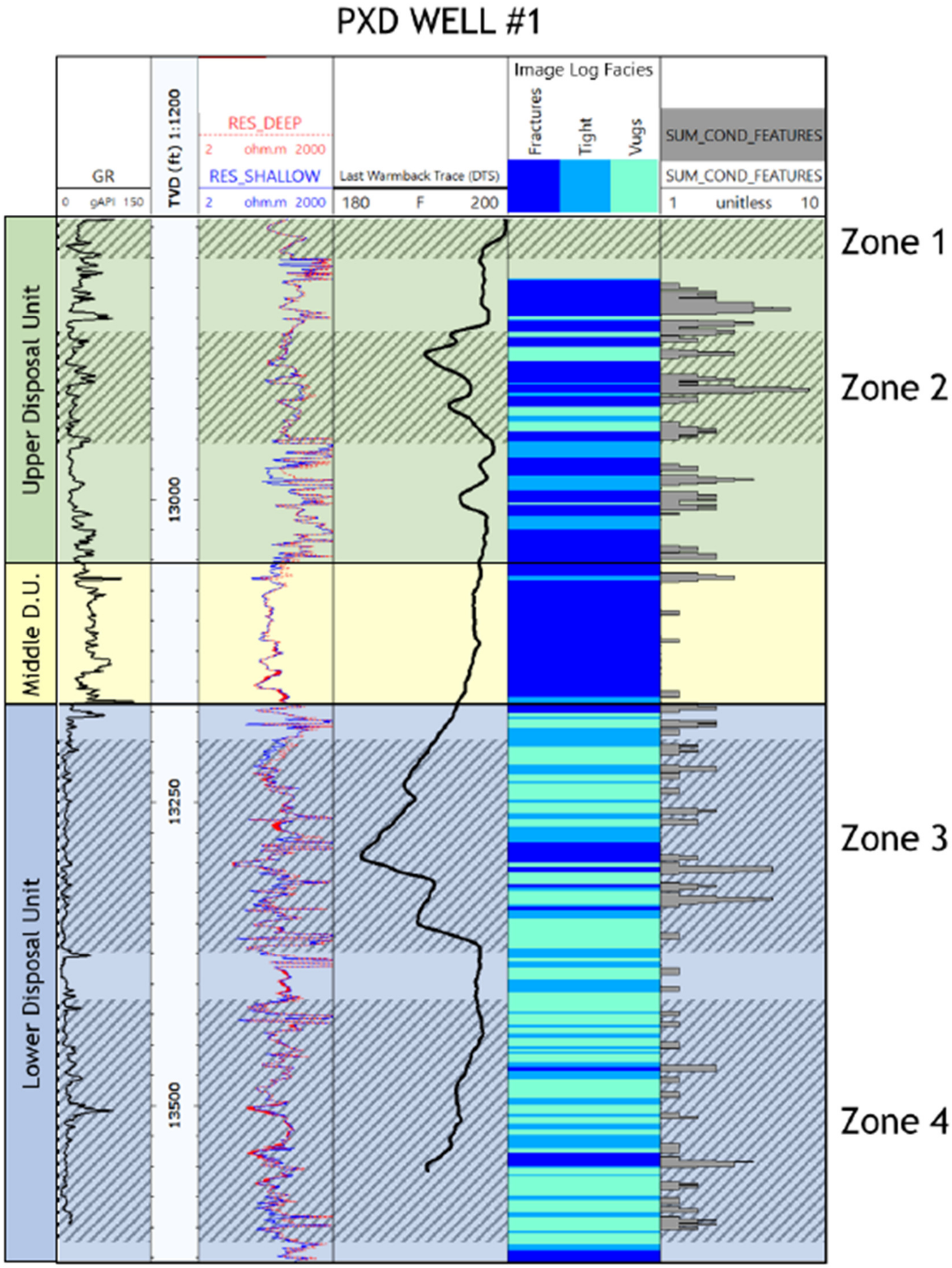


Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, & Coringrato, 2019)

2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displayed this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.

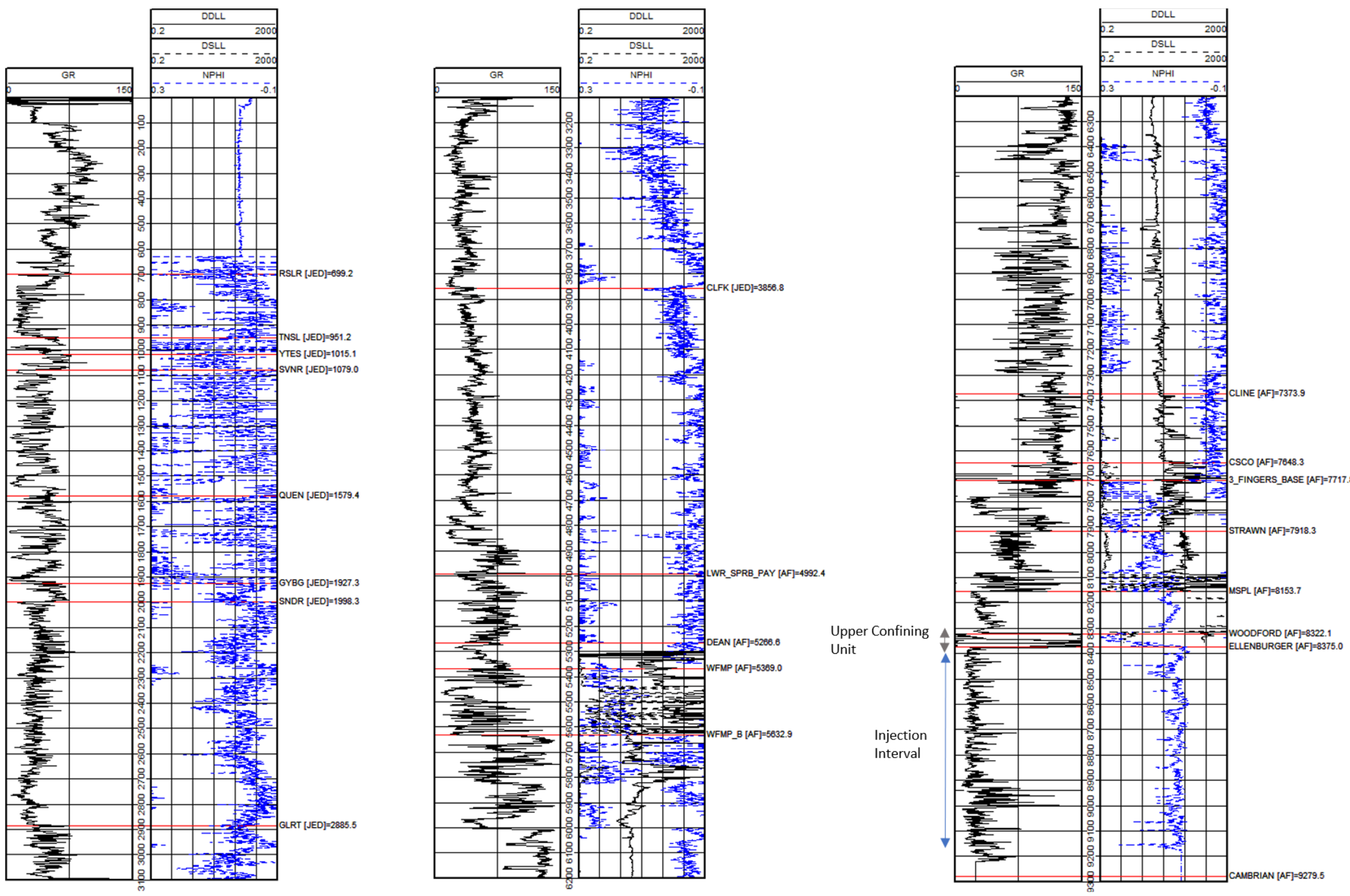


Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO_2 Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.

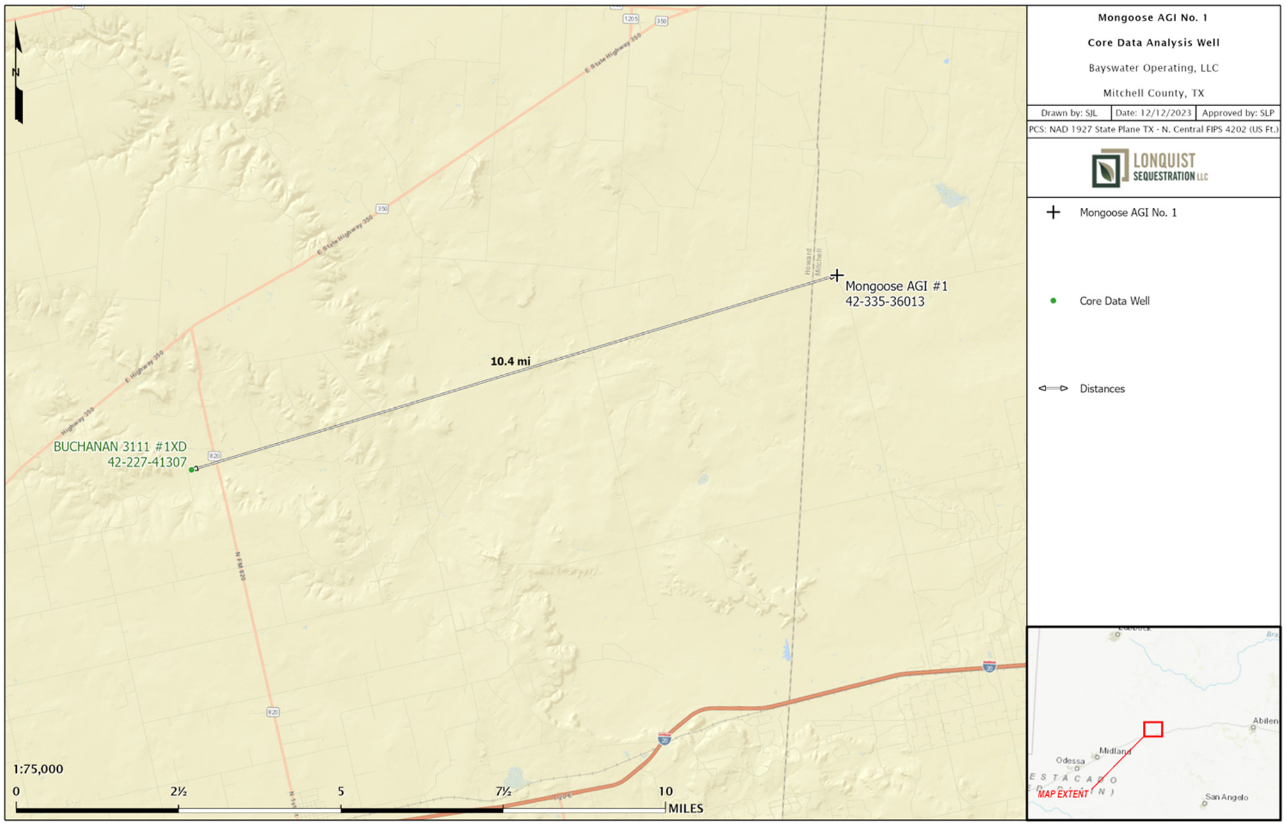


Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data

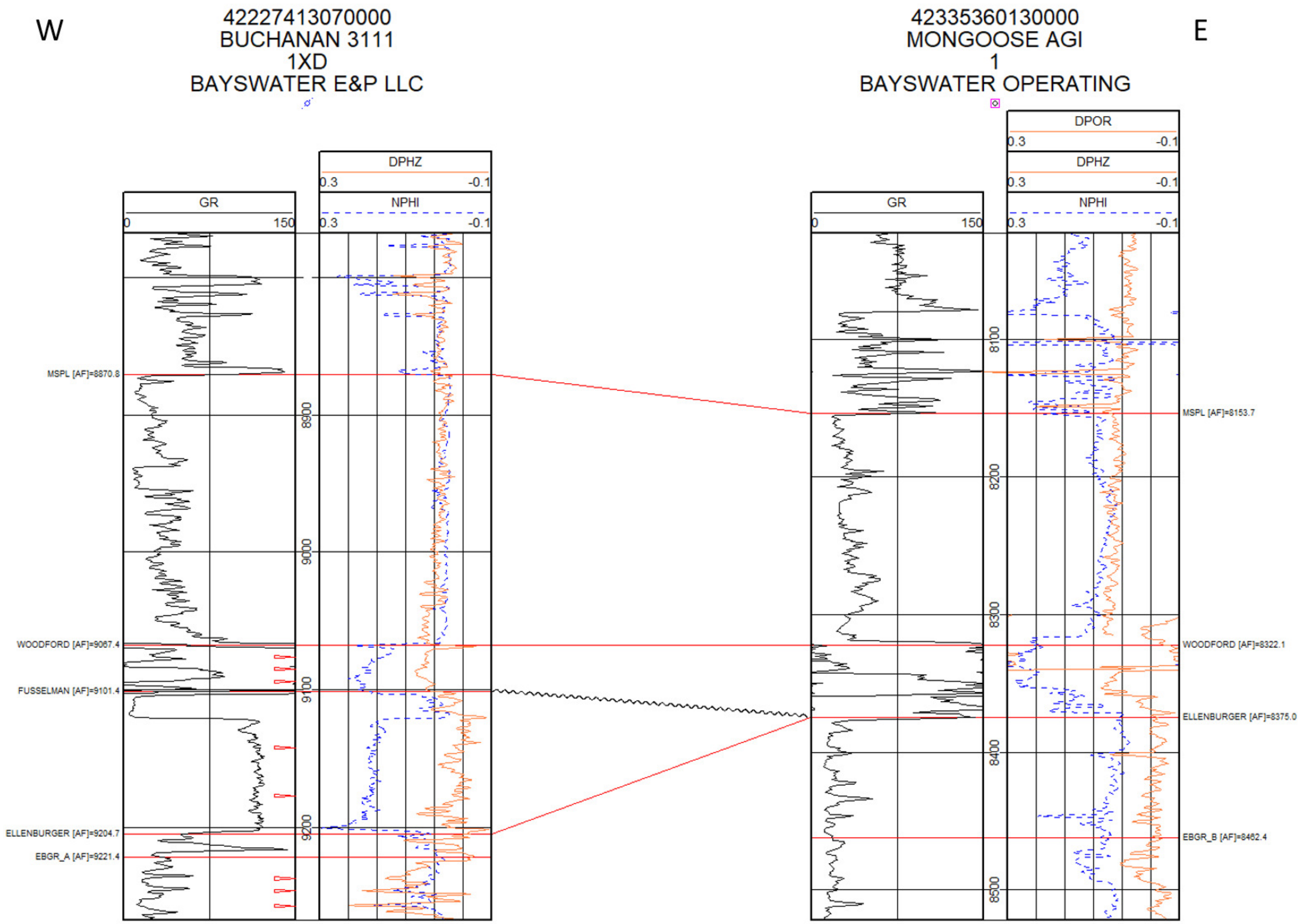


Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.

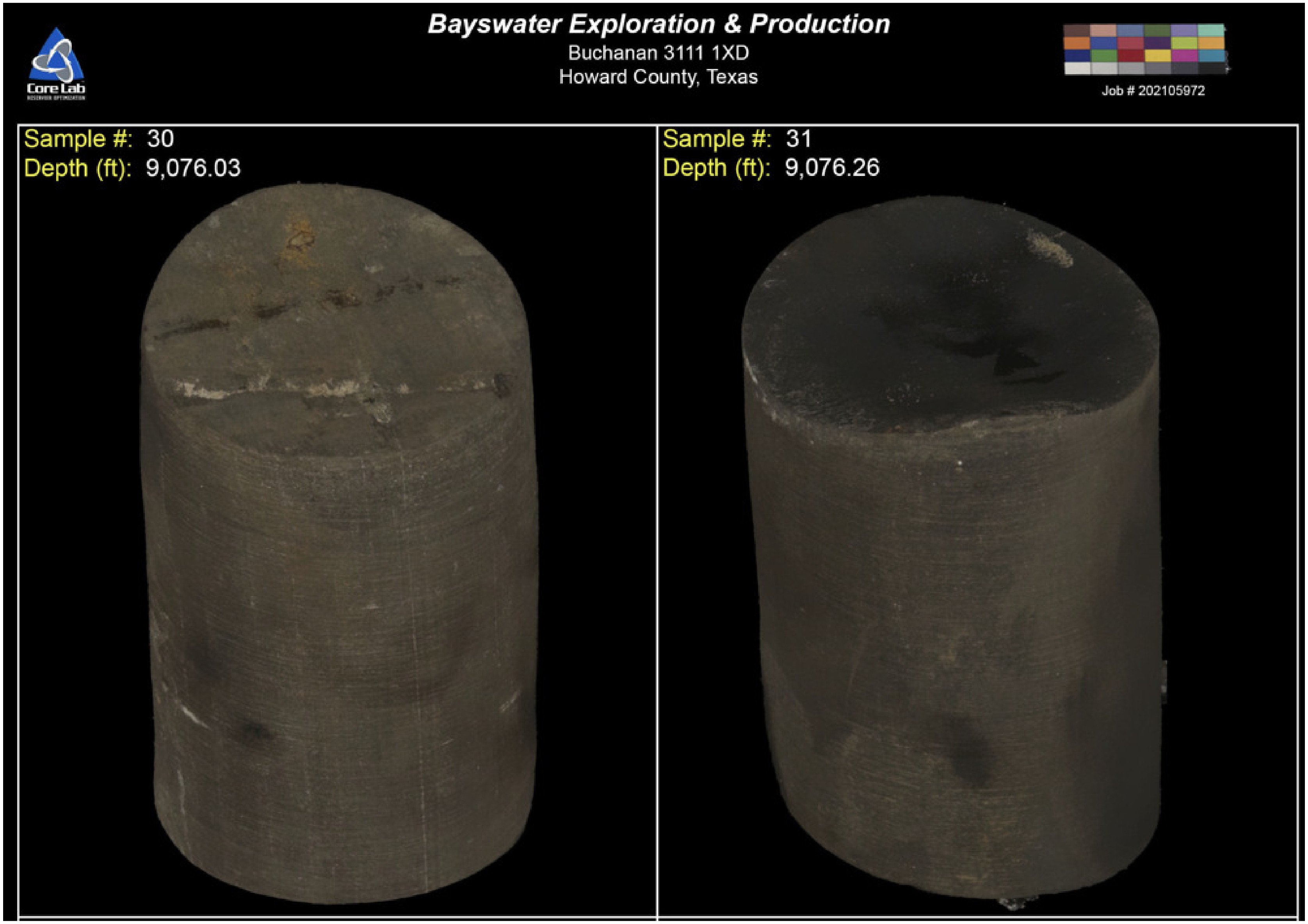


Figure 13 – Core Photo of Samples Within the Woodford Formation

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: February 04, 2022
Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

		As received				Dry & Dean Stark Extracted Conditions [2]				
Sample	**Depth** (ft)	**Bulk Density** (g/cc)	**Matrix Permeability** [1] (mD)	**Gas-filled Porosity** (%)	**Gas Saturation** (%)	**Grain Density** (g/cc)	**Matrix Permeability** [5] (mD)	**Porosity** (%)	**Oil Saturation** [3] (%)	**Water Saturation** [4] (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.
(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.
(3) Oil volume computed assuming an oil density of 0.844 g/cc
(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc
(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS
Net Confining Stress: 2960 psi   Temperature: 68°F
Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

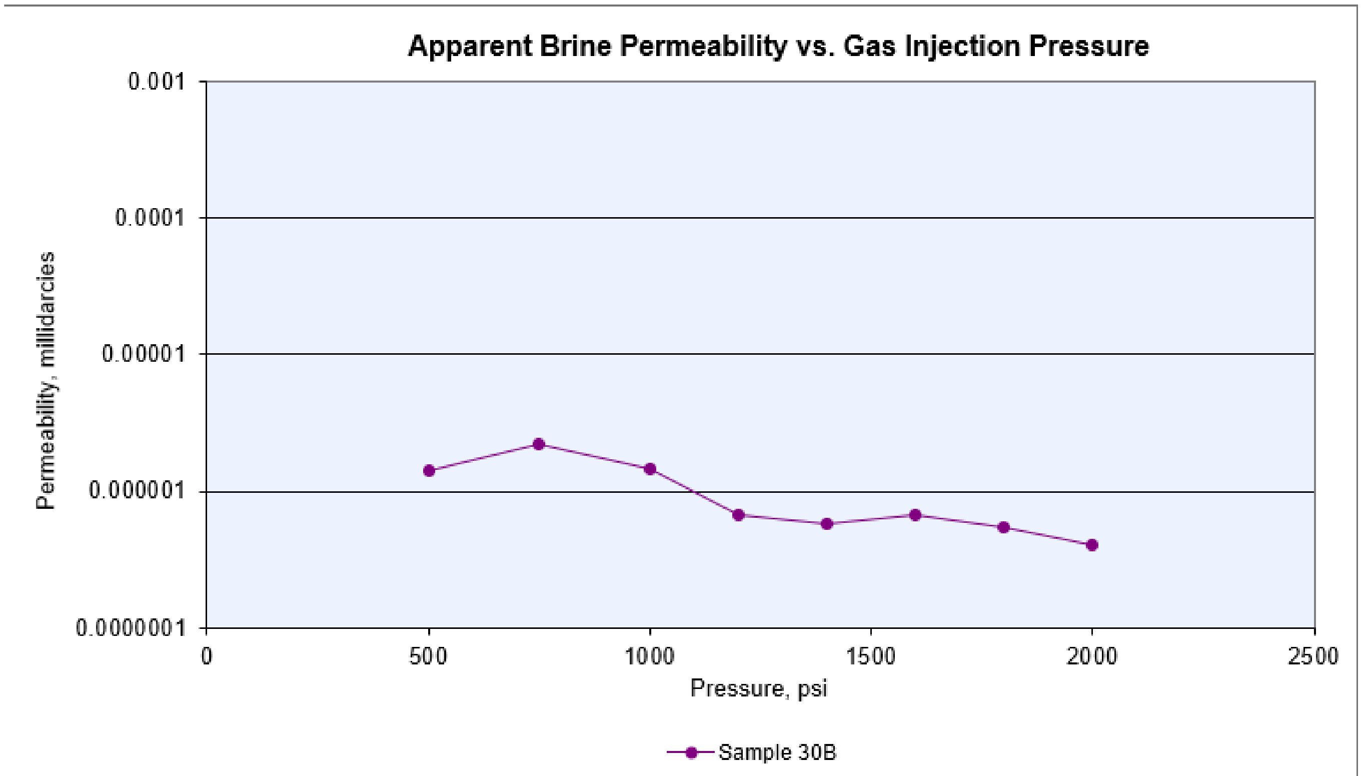


Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi   Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample 30B	
Gas Injection Pressure, psi	Permeability to Brine*, mD
500	1.44E-06
750	2.20E-06
1000	1.46E-06
1200	6.73E-07
1400	5.77E-07
1600	6.72E-07
1800	5.39E-07
2000	4.03E-07

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi   Temperature: 68°F
Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample Number	Depth, feet	Length, cm	Diameter, cm	Final Permeability to Brine*, millidarcies	Threshold Entry Pressure, psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and non-applicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A two-function porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

If Effective Porosity (Φeff) < 6.5%: $K(mD) = 7E{-}08e^{3.3028*\Phi \mathrm{eff}}$

If Effective Porosity (Φeff) > 6.5%: $K(mD) = 277.39\ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: March 31, 2022
Analyst(s): MP

CMS-300 ROTARY SIDEWALL ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Klinkenberg (md)	Permeability Kair (md)	b(air) psi	Beta ft(-1)	Alpha (microns)	Saturation Oil (% Pore Volume)	Saturation Water (% Pore Volume)	Grain Density (g/cm3)	Footnote
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

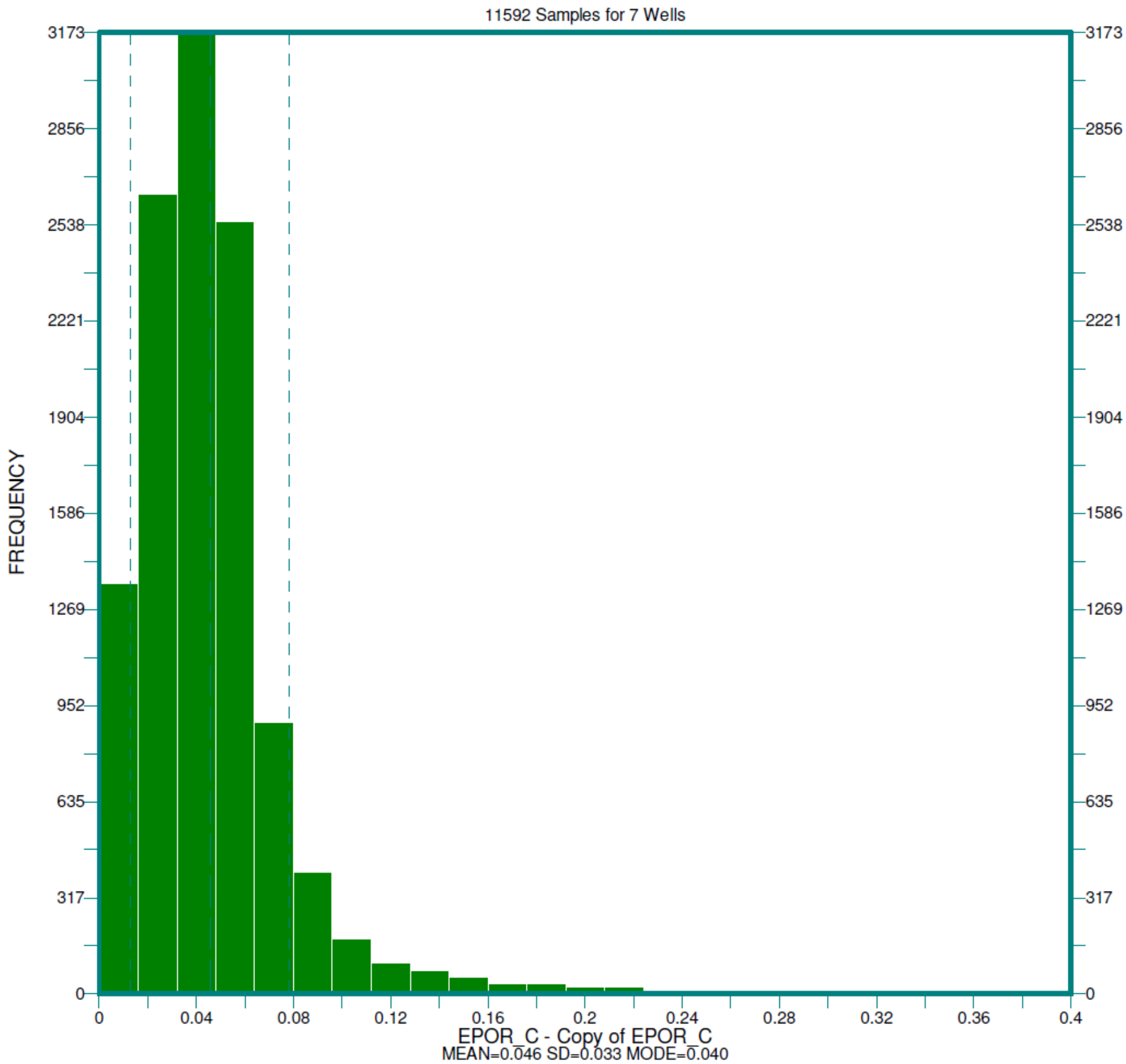


Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

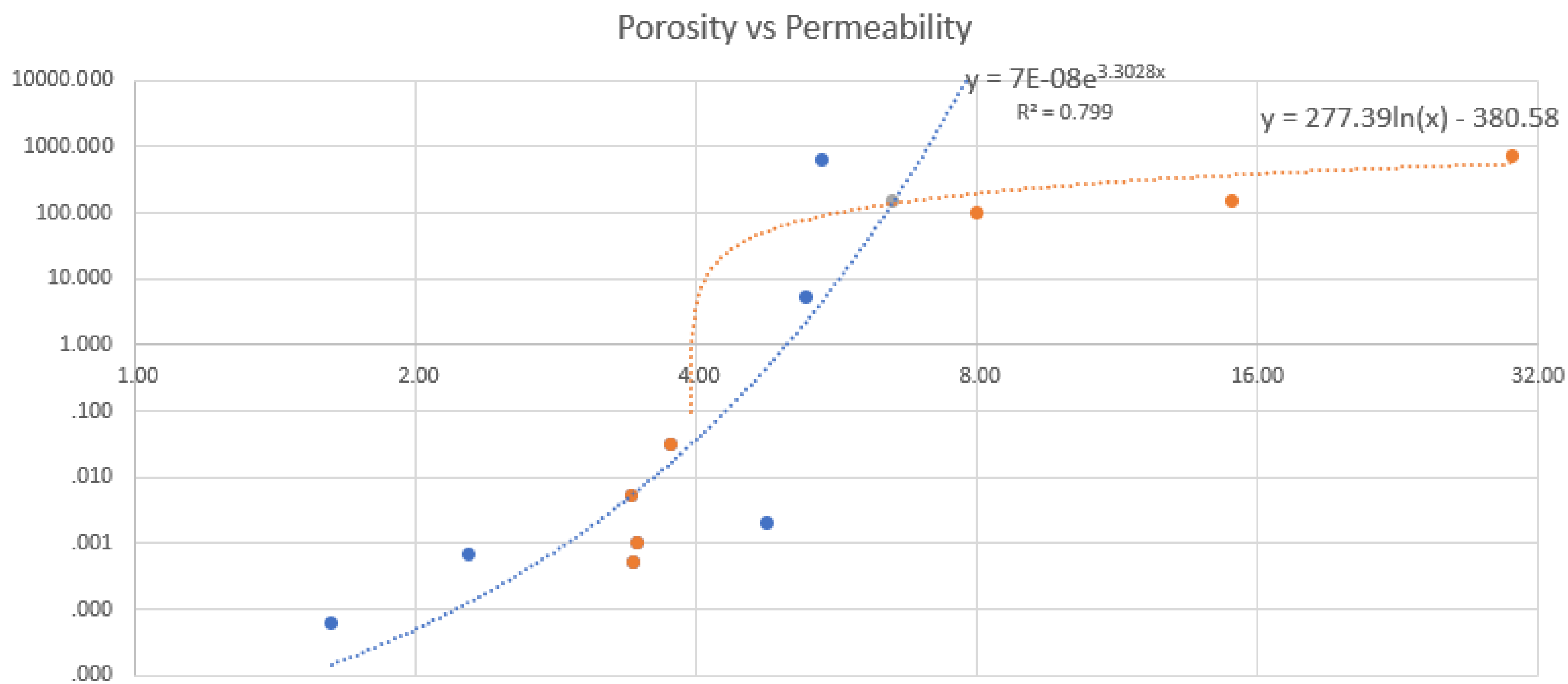


Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data

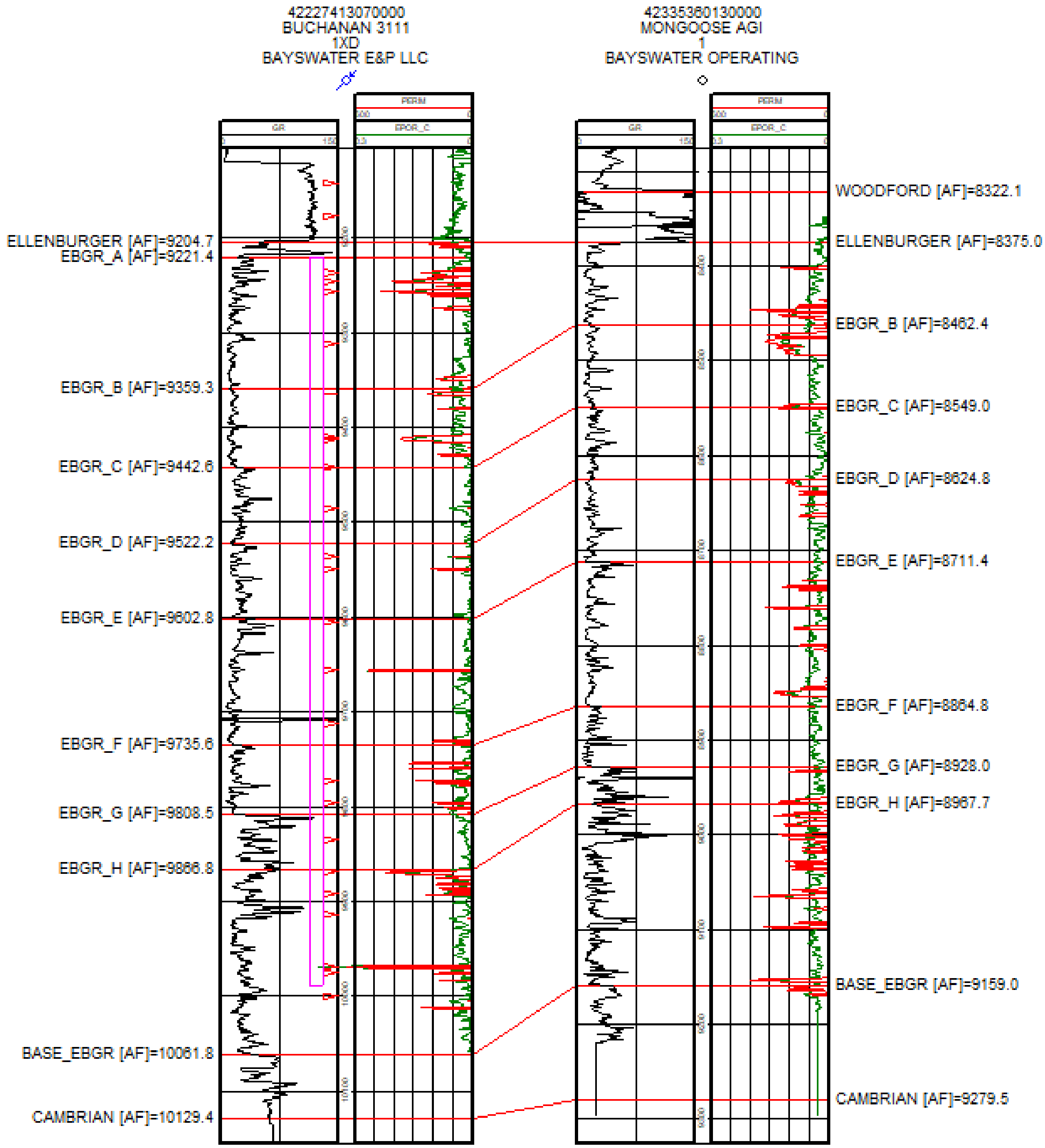


Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.

Figure 23 – Core photo of Ellenburger sample displaying vug features.

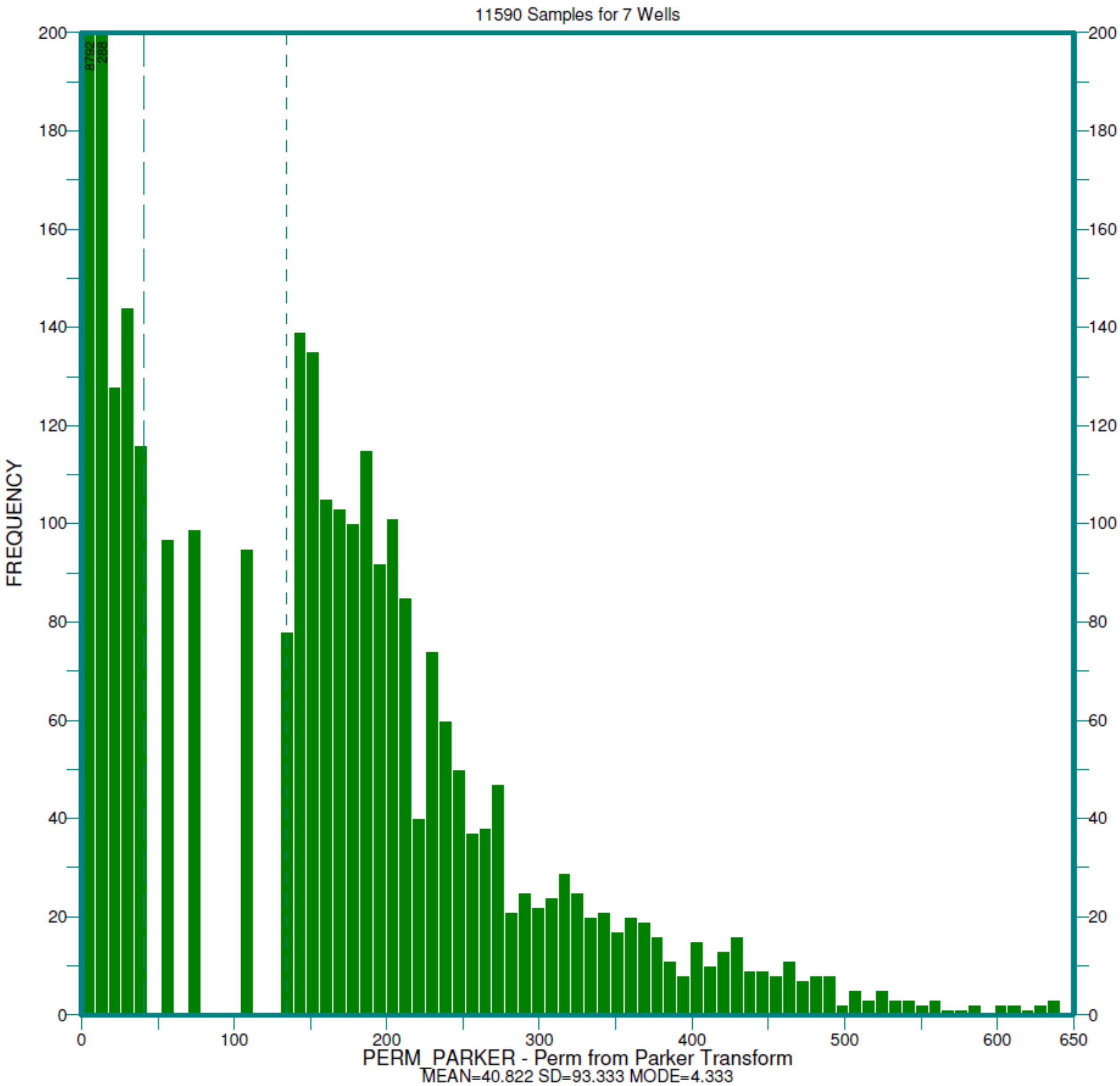


Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oil-field brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.

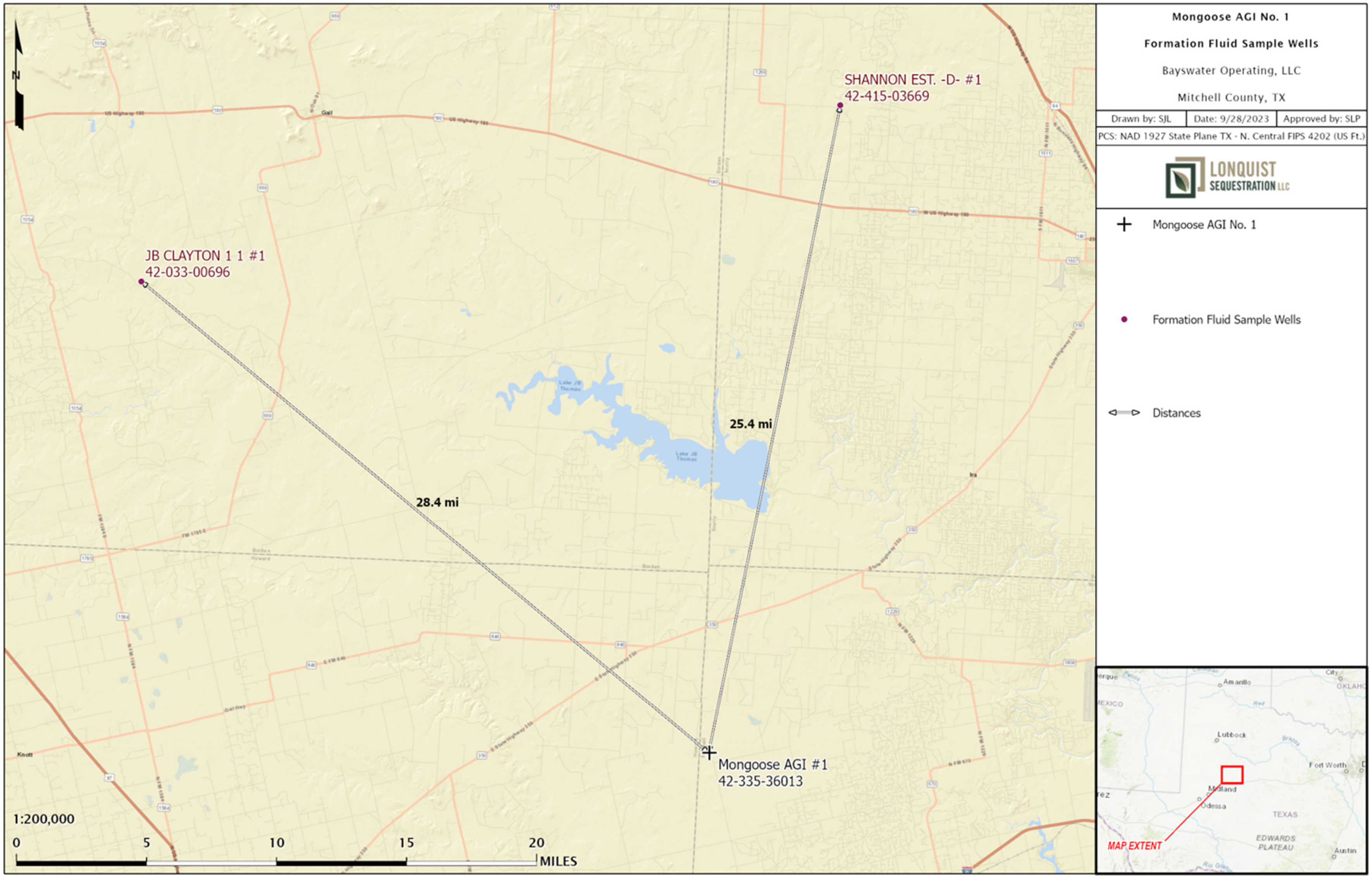


Figure 25 – Offset wells used for formation fluid characterization.

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

	Average	Low	High
Total Dissolved Solids (ppm*)	47,427	42,014	52,840
pH	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

*ppm – parts per million

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian." Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.

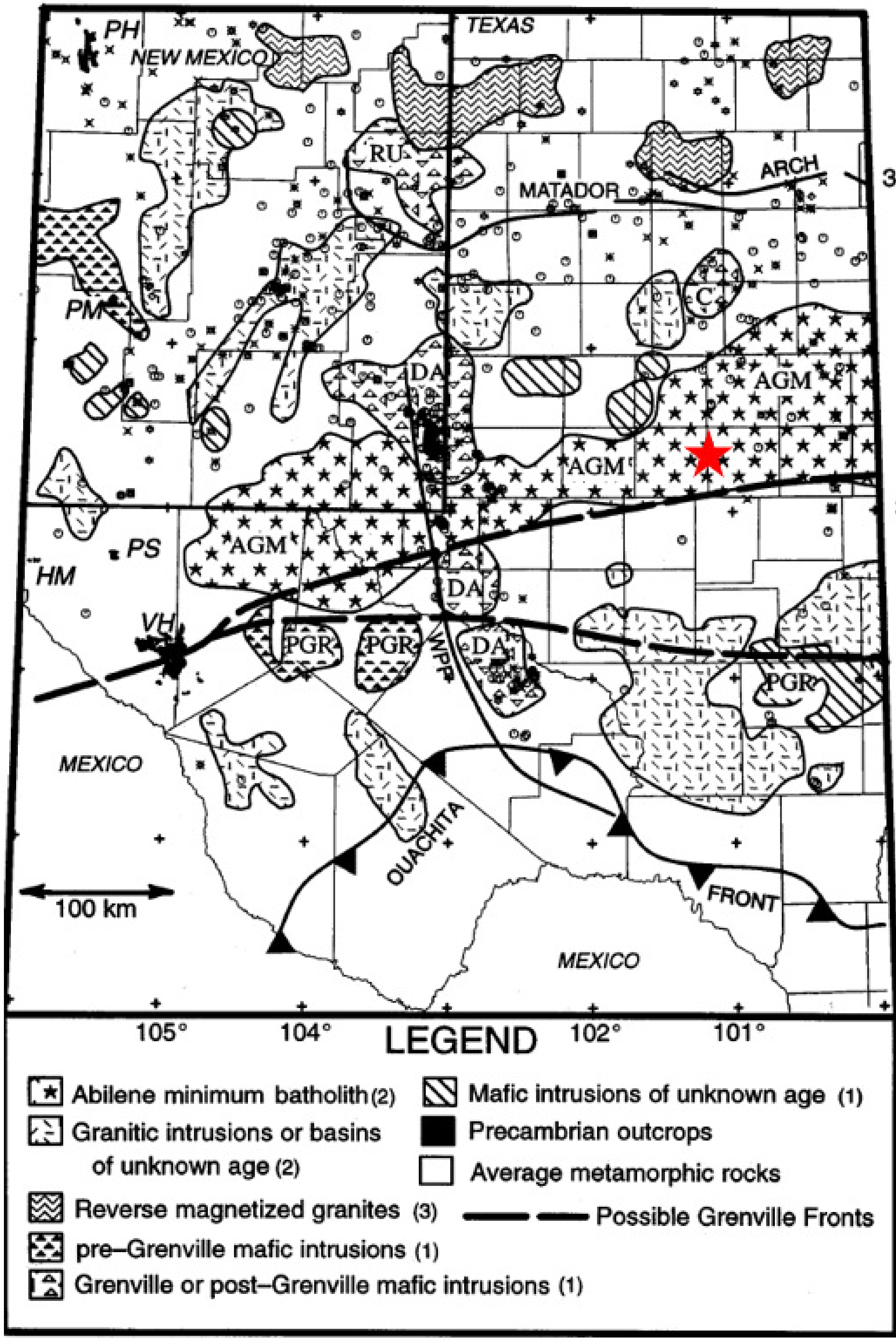


Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Table 4 – Calculated Vertical Stresses

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

*Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. The calculation requires Poisson's ratio (v), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$\nu = \frac{\frac{1}{2}\left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

ν = Poisson's Ratio
v_p = Compressional Velocity
v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1-0.261}(1.029 - 0.465) + 0.465 = 0.664\ psi/ft$$

$$FG\ with\ SF = 0.689\ \times 90\% = \mathbf{0.598\ psi/ft}$$

Table 5 – Fracture Gradient Calculation Inputs and Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix D*.

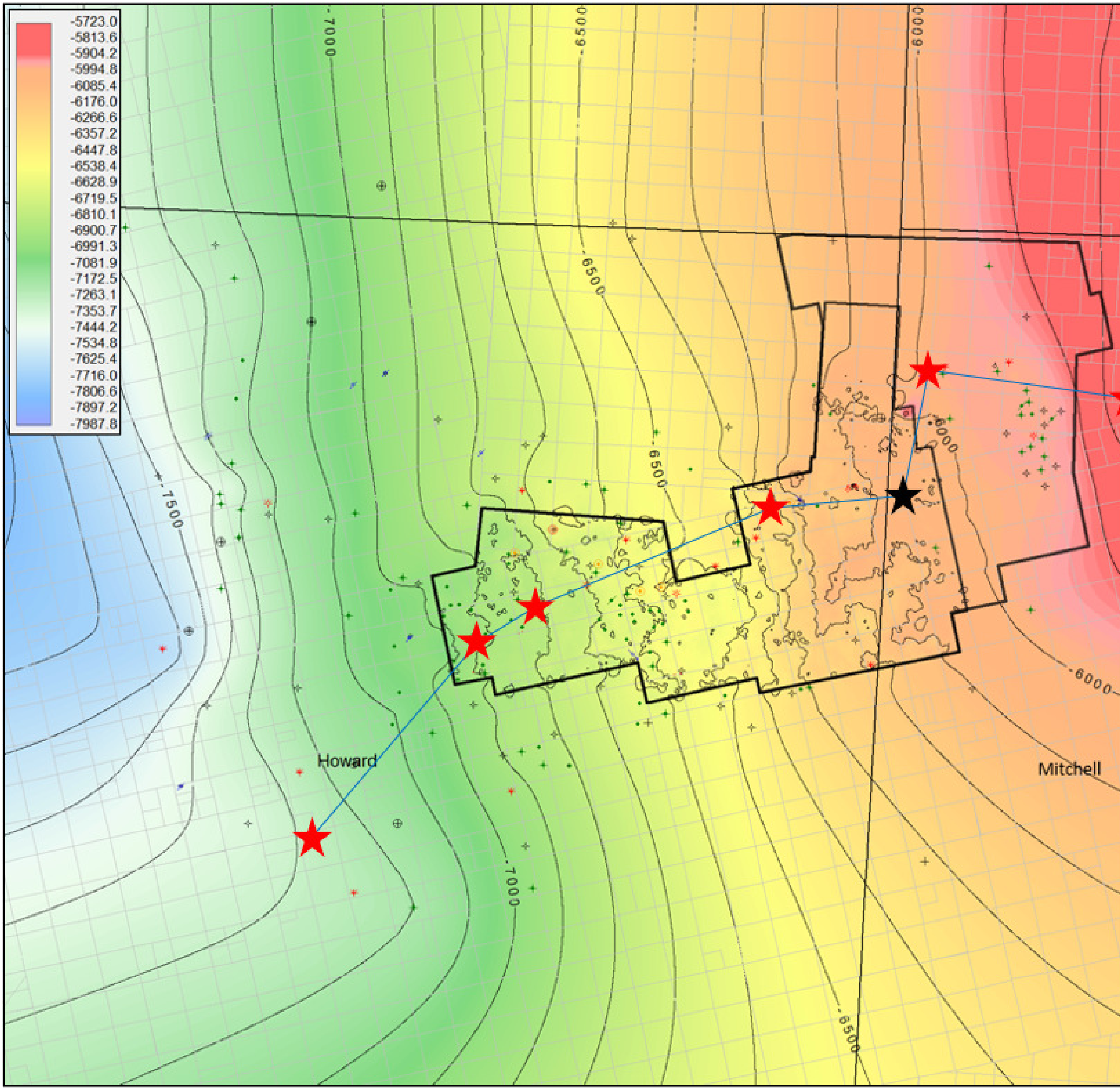


Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.

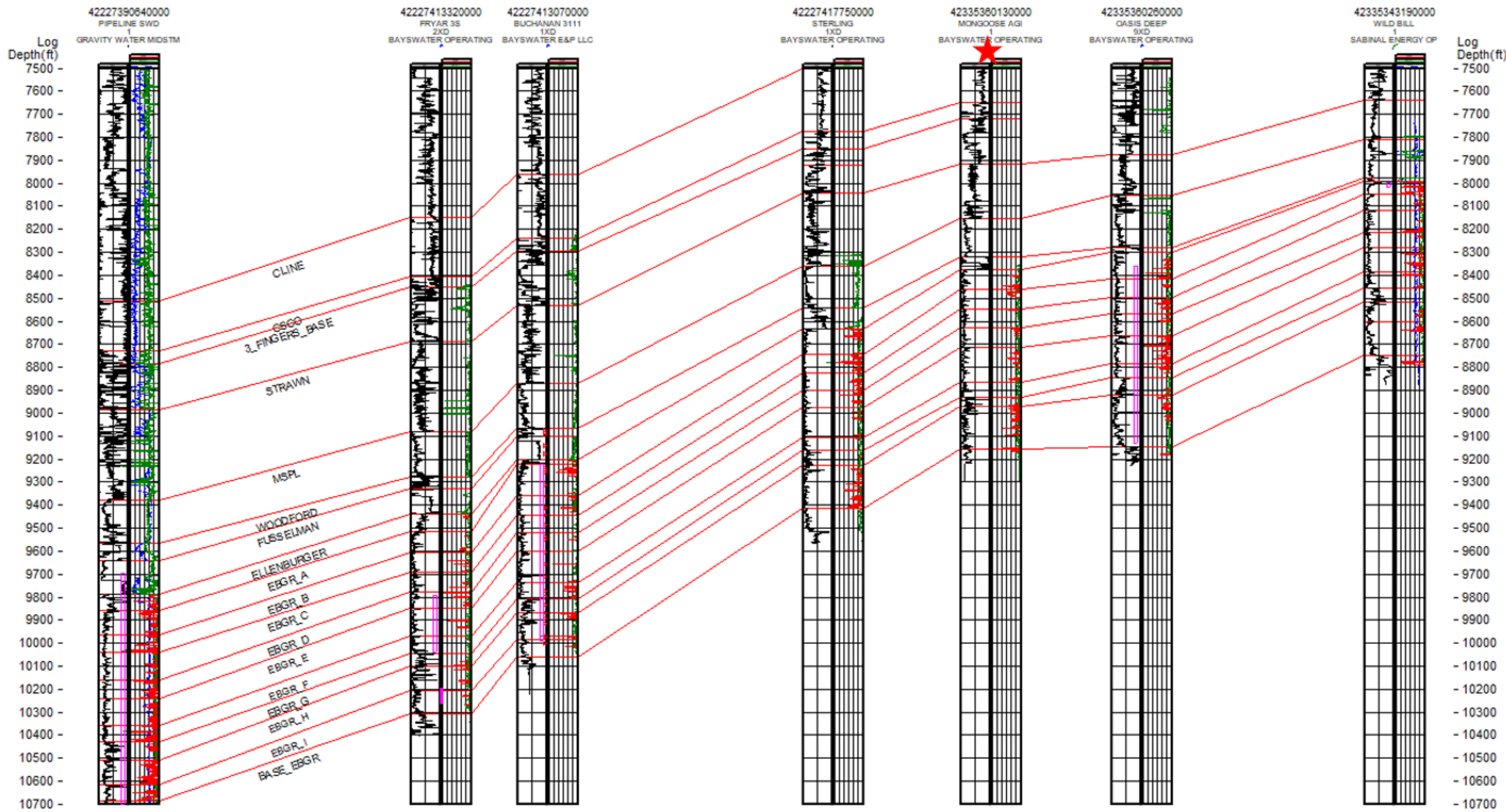


Figure 28 – Structural cross section depicting the Ellenburger.

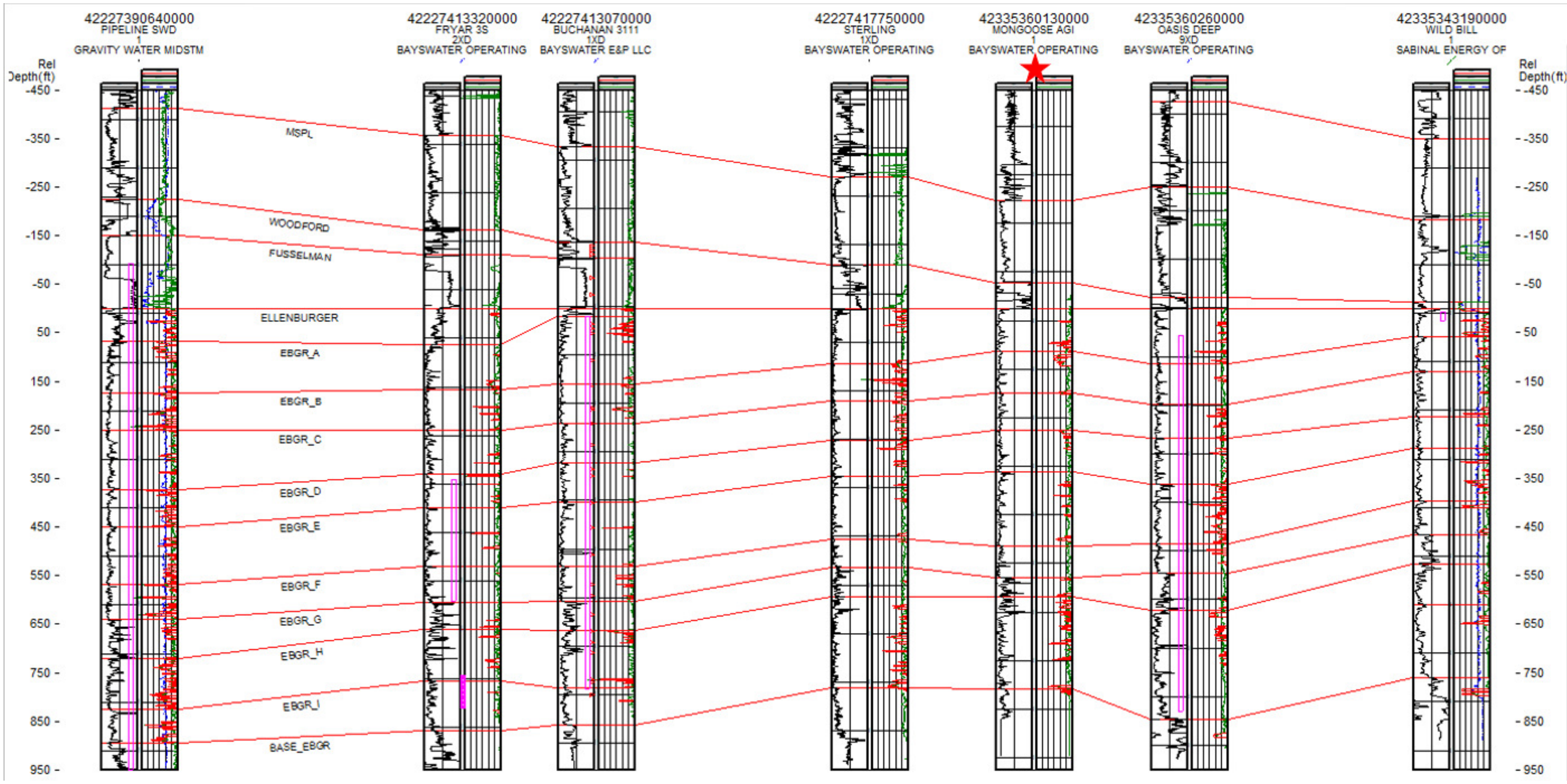


Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colorado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
Cretaceous	Comanche	Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous limestone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potable but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
Triassic		Dockum	Chinle	0-640	Predominantly red to maroon and purplish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sandstone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
			Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaceous and carbonaceous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capacity of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to highly mineralized water to livestock and domestic wells.

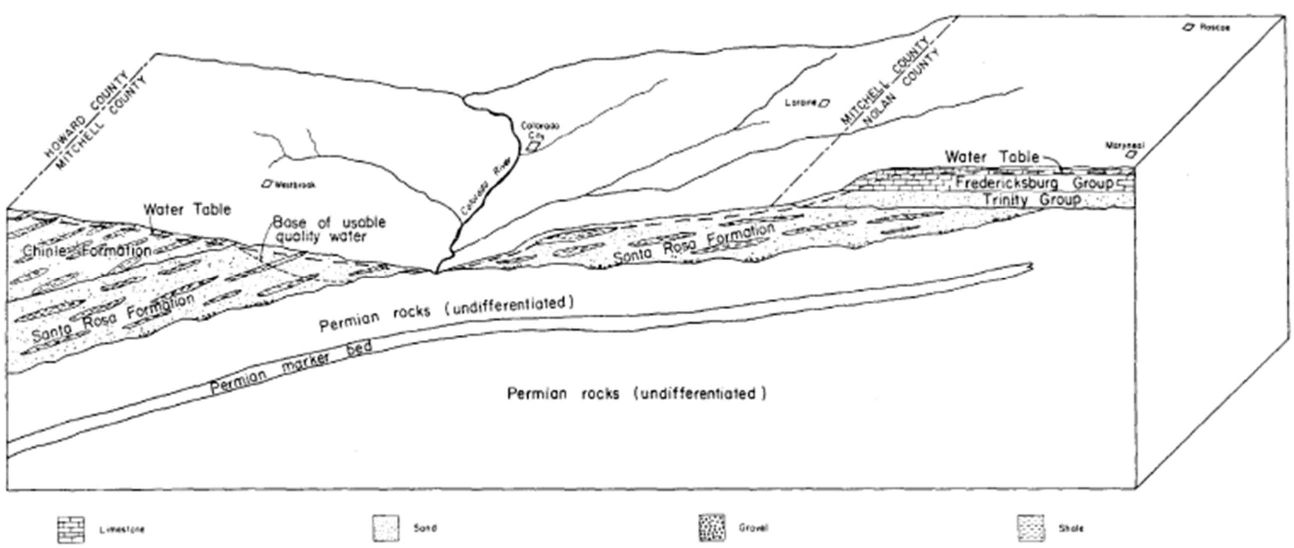


Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of “red beds,” dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into “fluvial, deltaic, and lacustrine environments within a closed continental basin” (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.

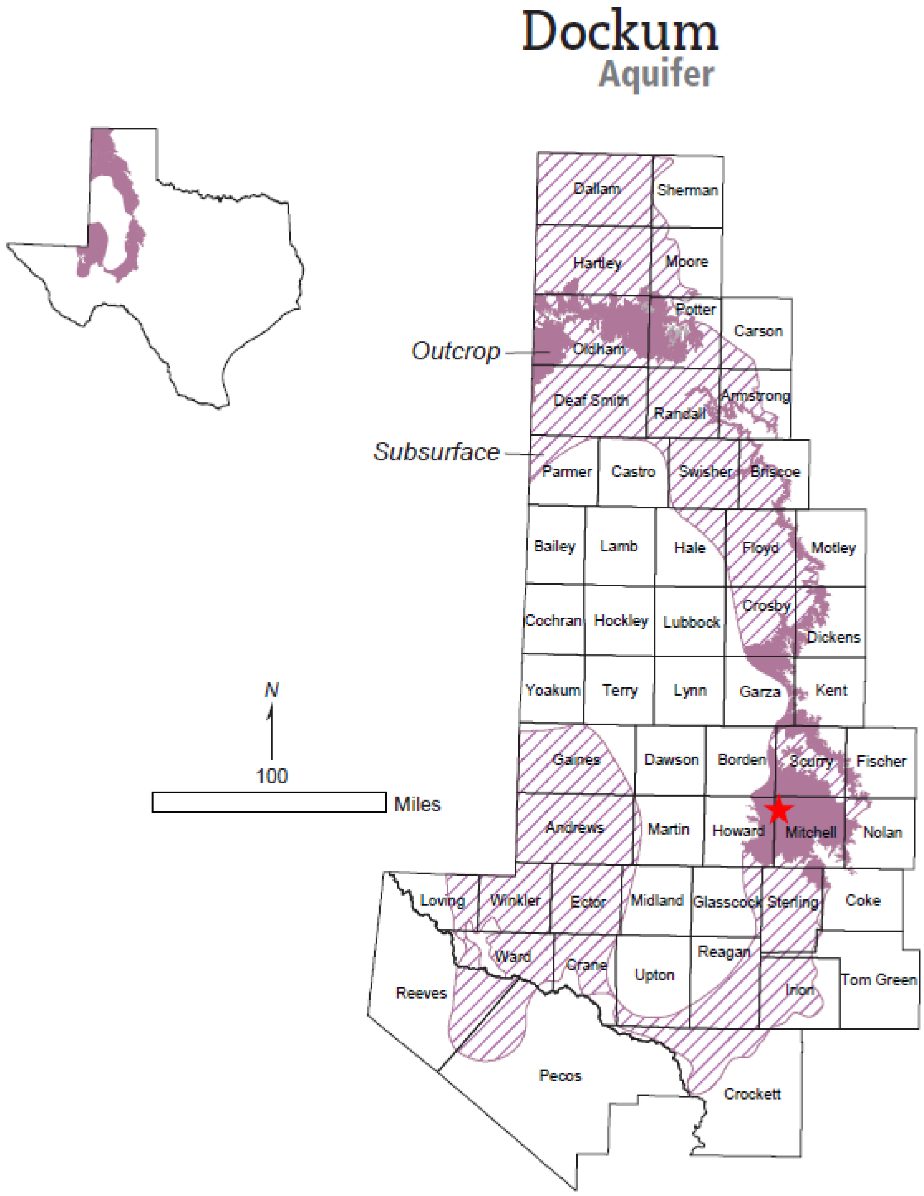


Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).

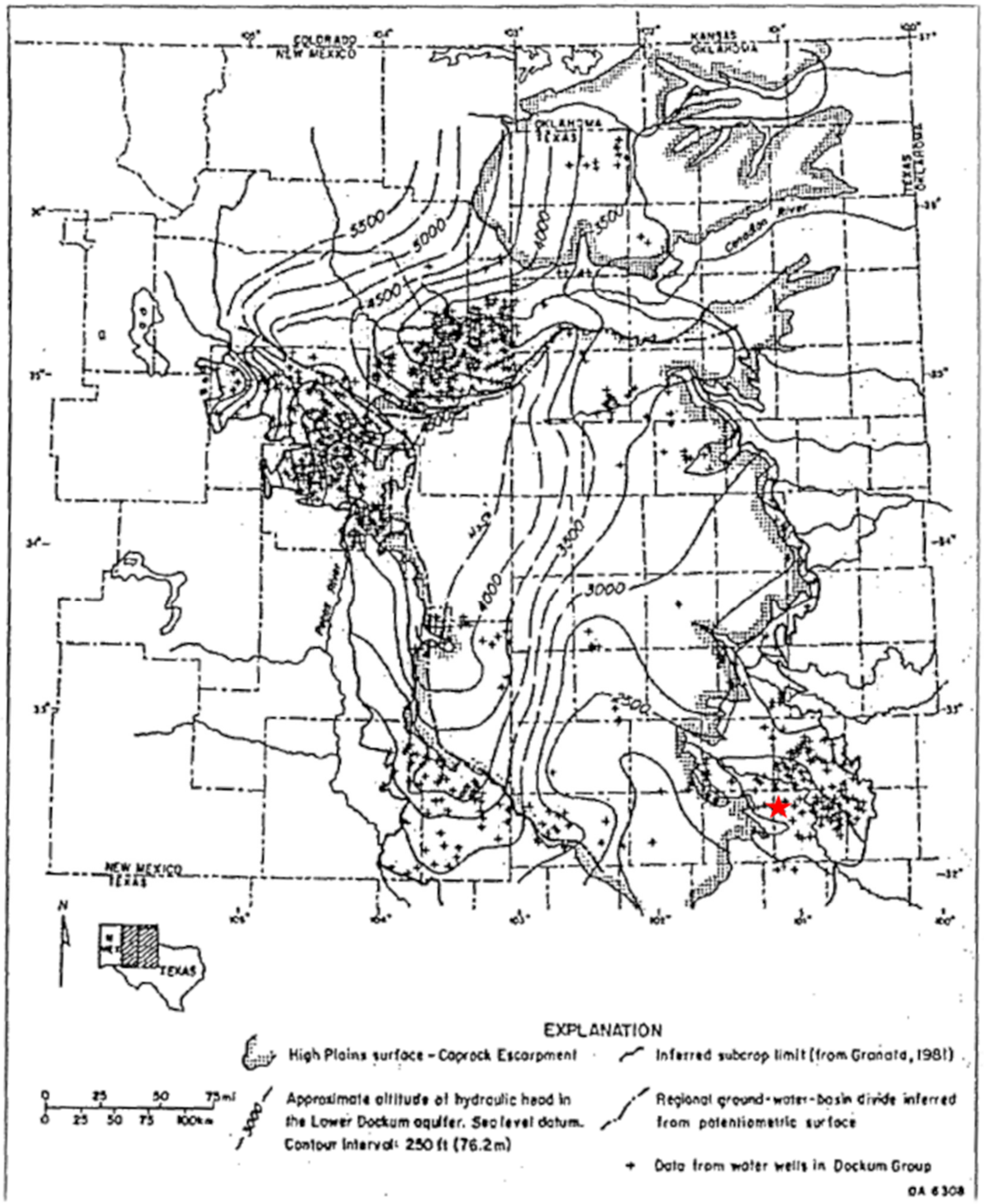


Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).

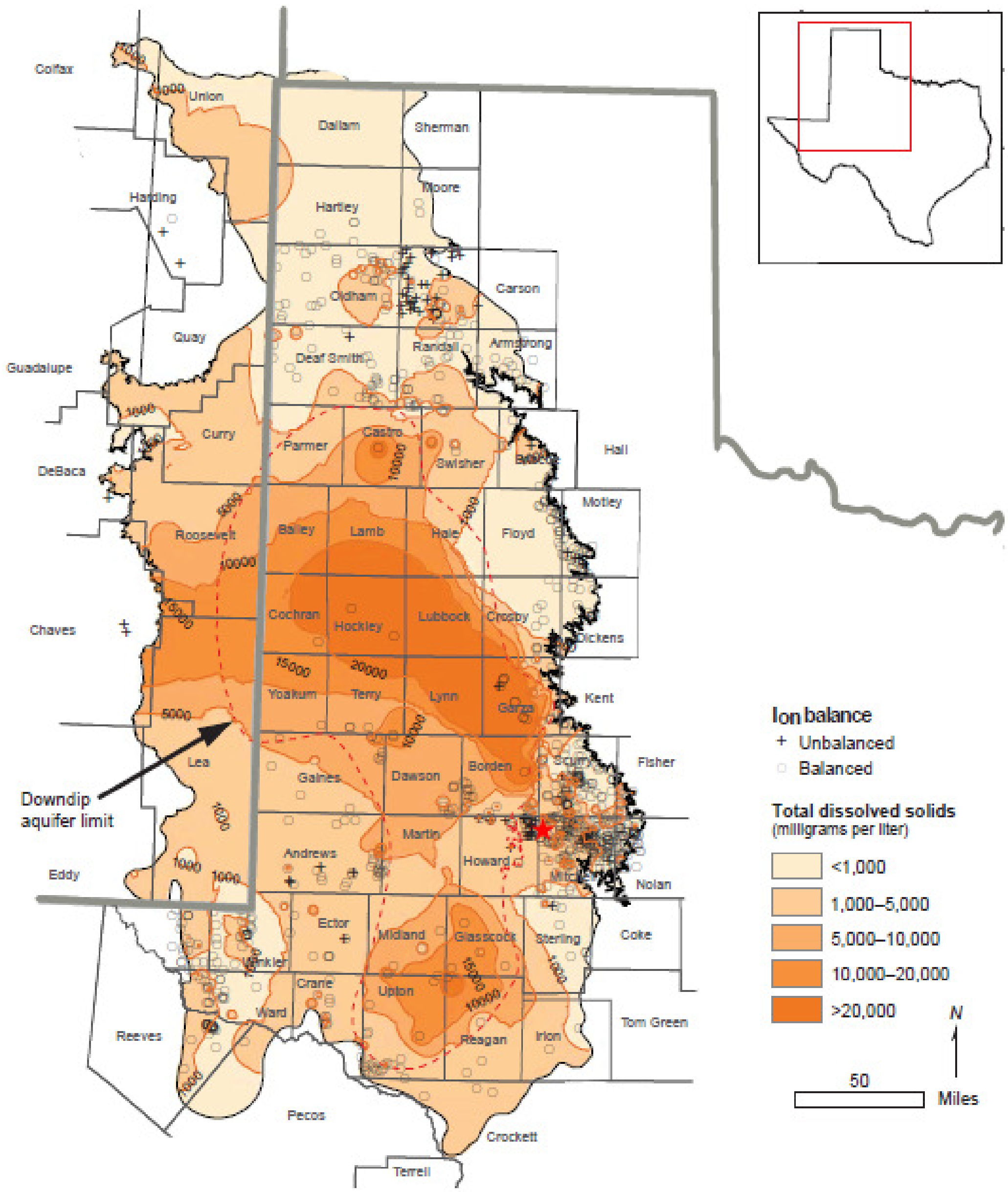


Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 Description of the Injection Process

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/D). The TAG is 41.2% CO_2, which equates to 155.3 MT/yr of CO_2 each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

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

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery.
advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite-acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S and CO_2 based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H_2S and 41.2% CO_2. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H_2S and 41.2% CO_2.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H_2S)	58.8	58.8
Carbon Dioxide (CO_2)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.

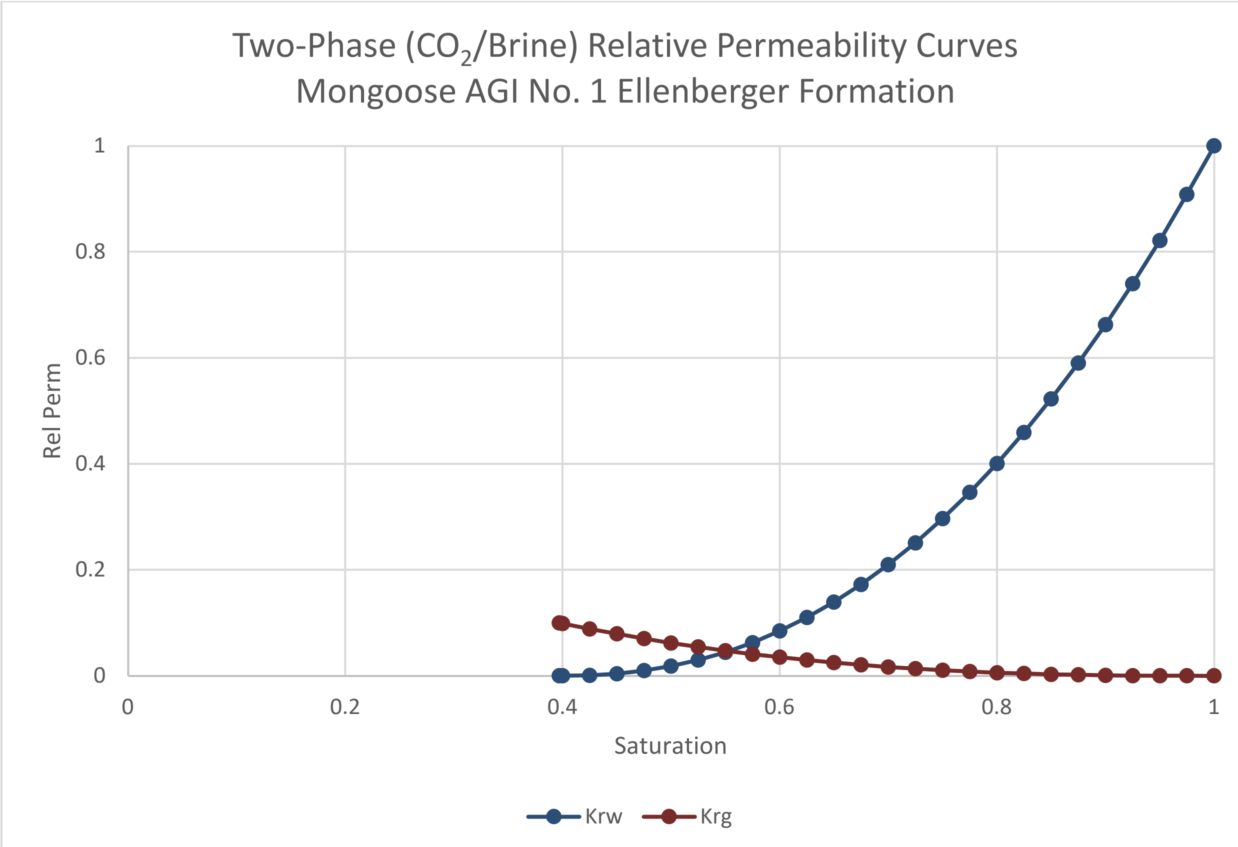


Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (north-south), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Table 9 – GEM Model Layer Package Properties

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

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

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

Table 10 – Offset SWD Wells Included in GEM Model

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.

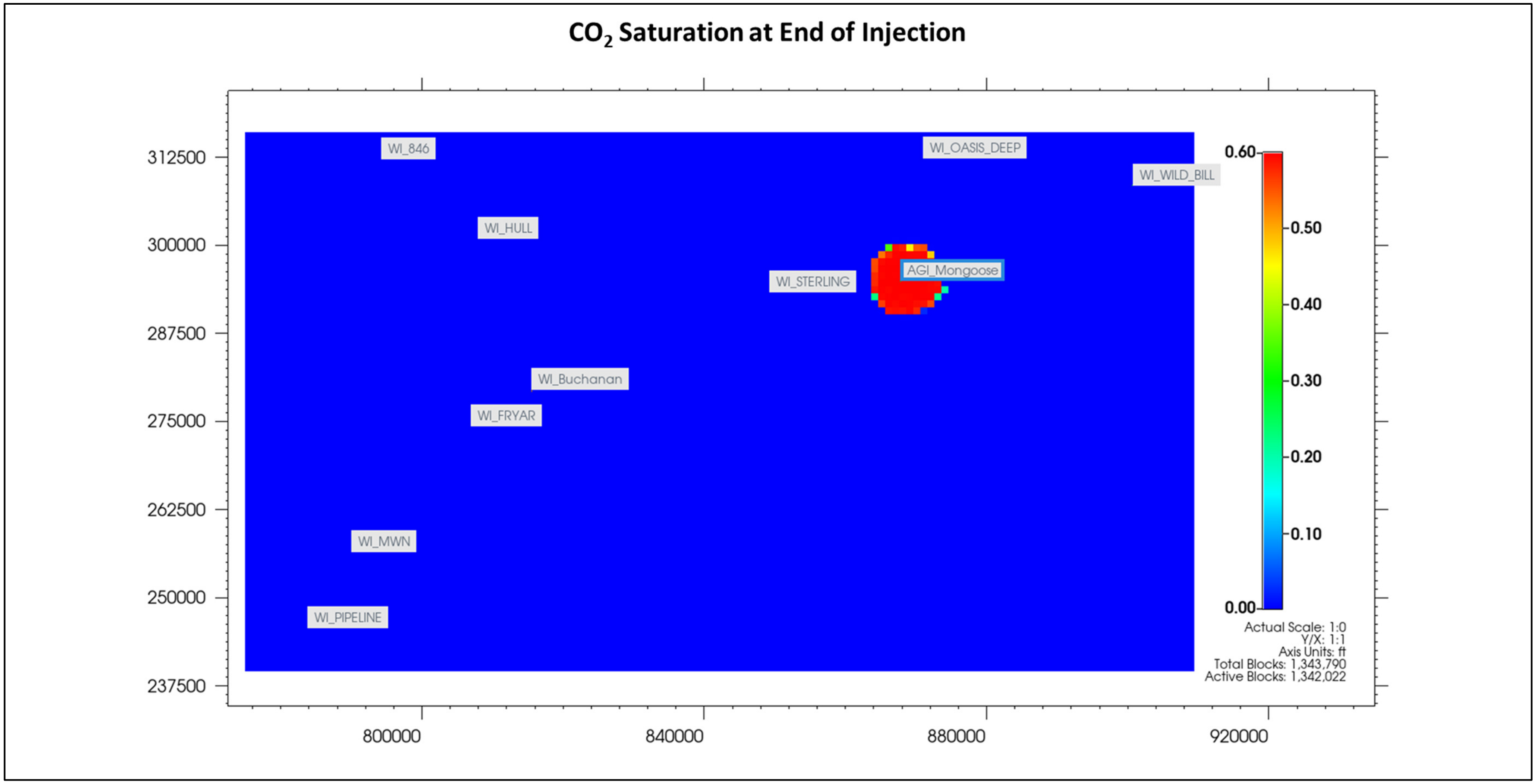


Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)

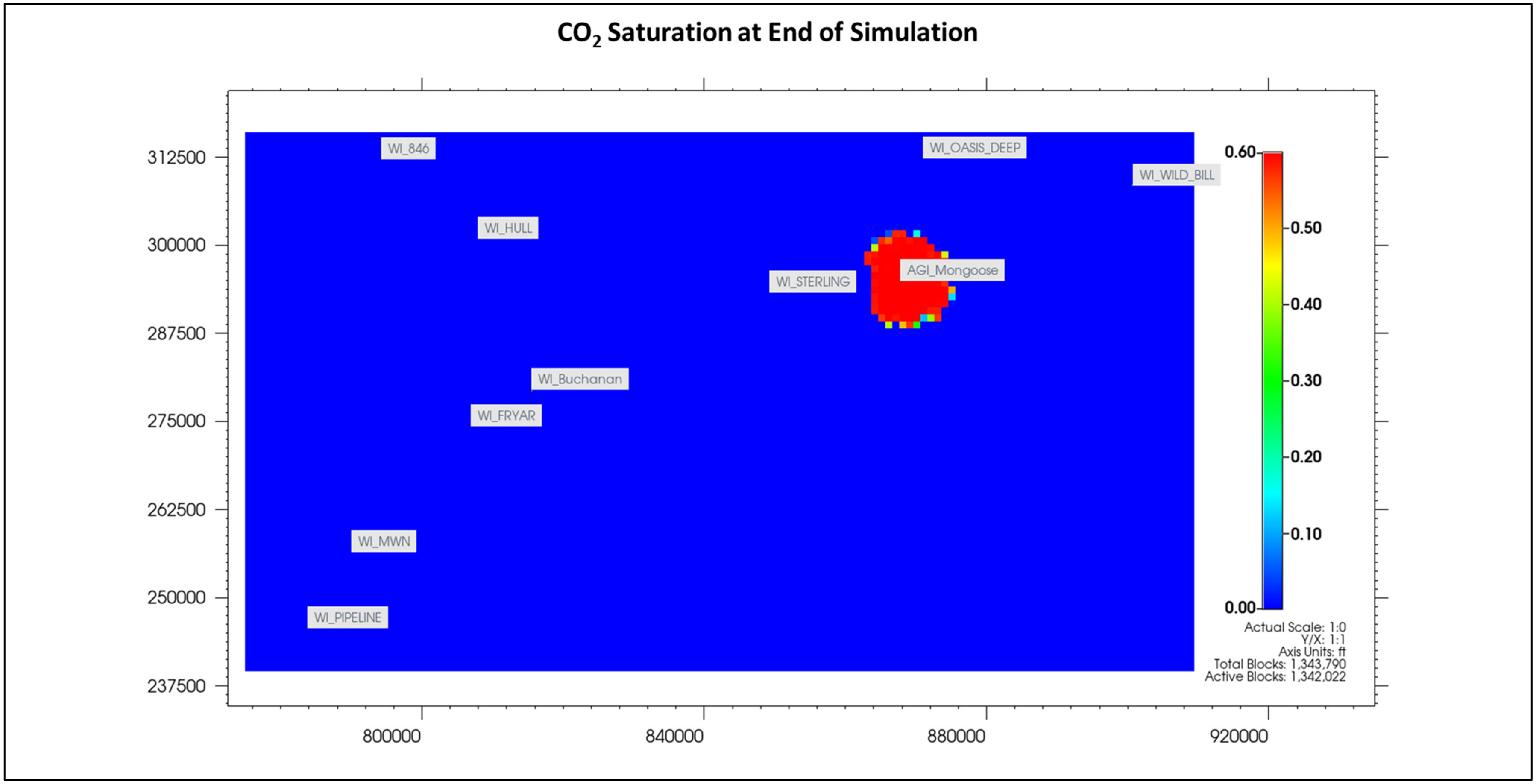


Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

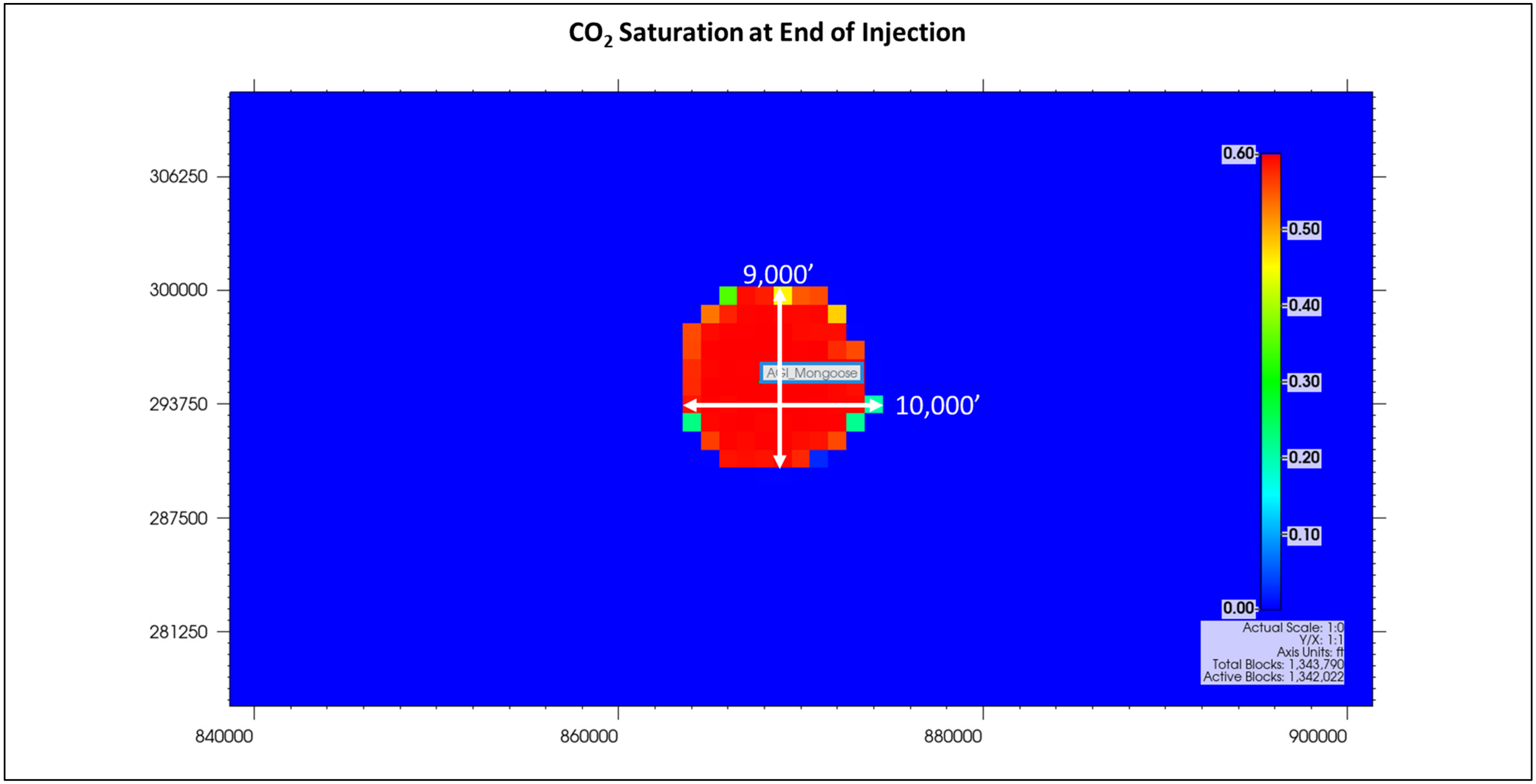


Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)

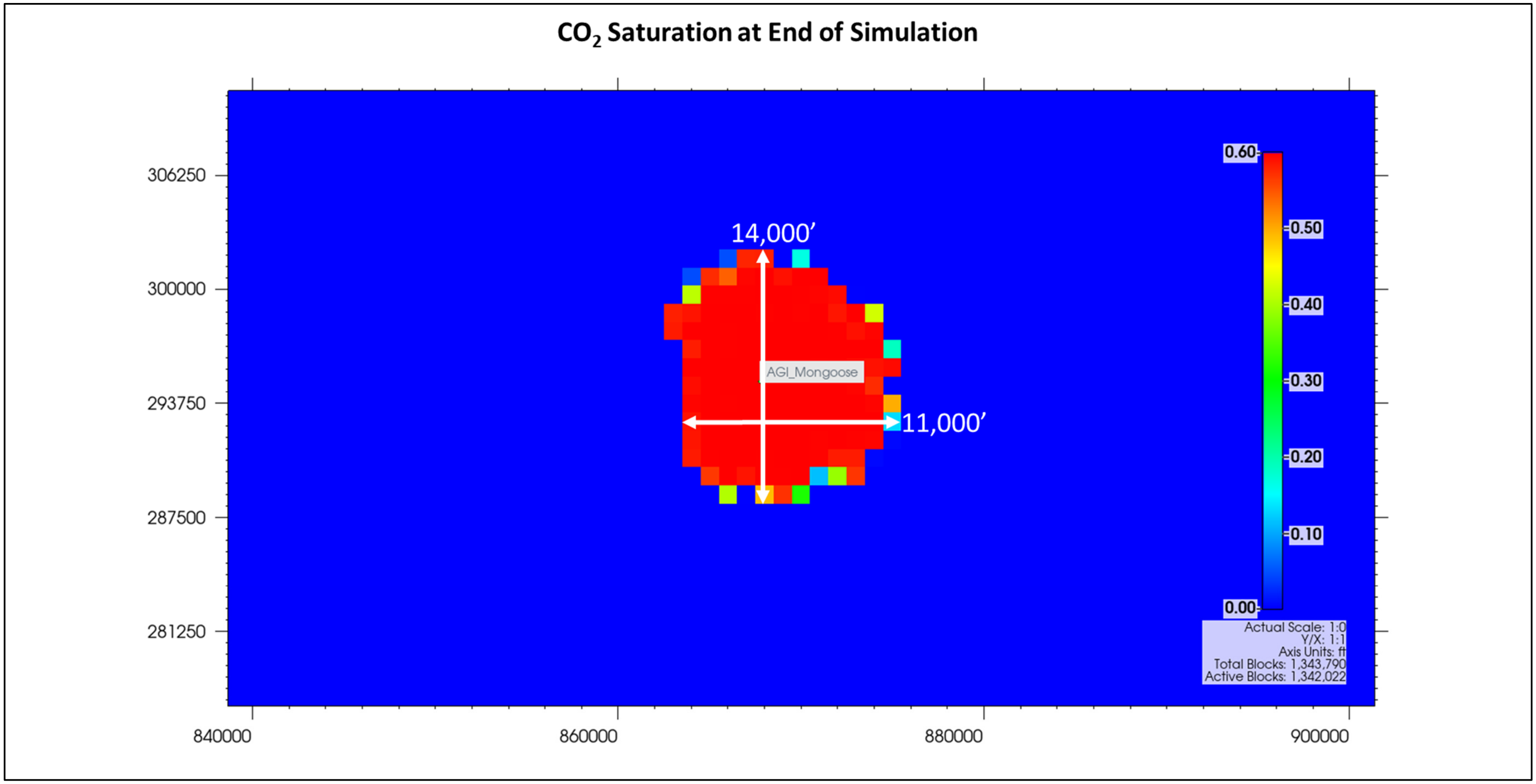


Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.

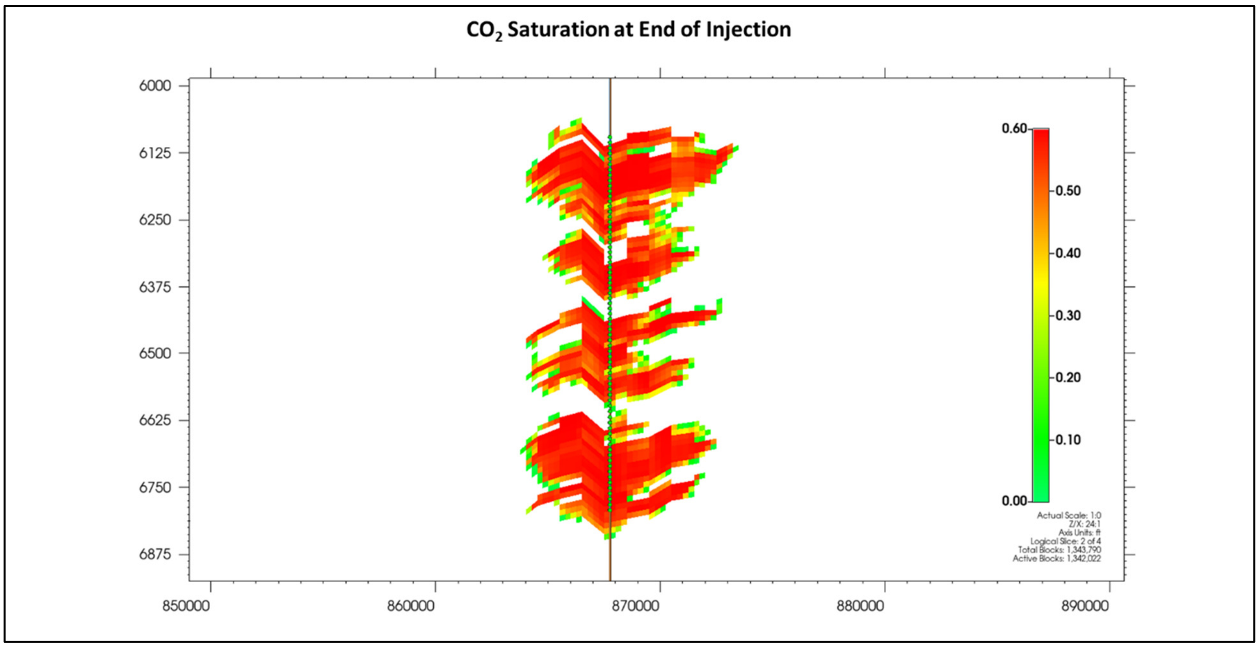


Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

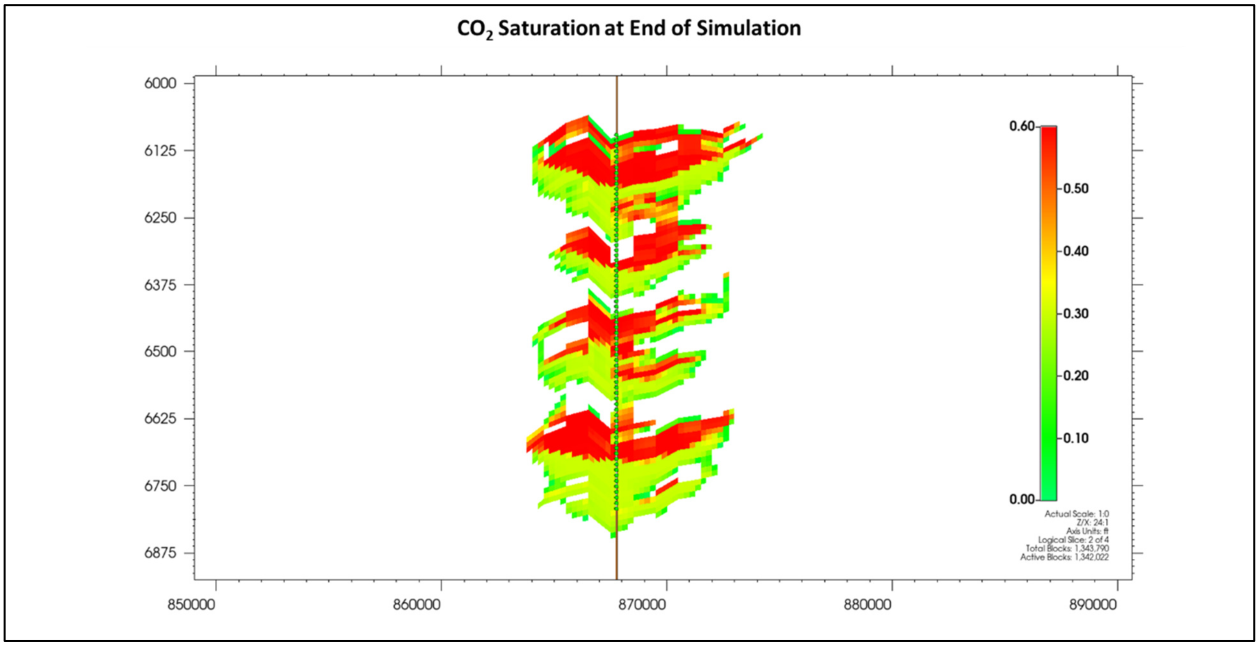


Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.

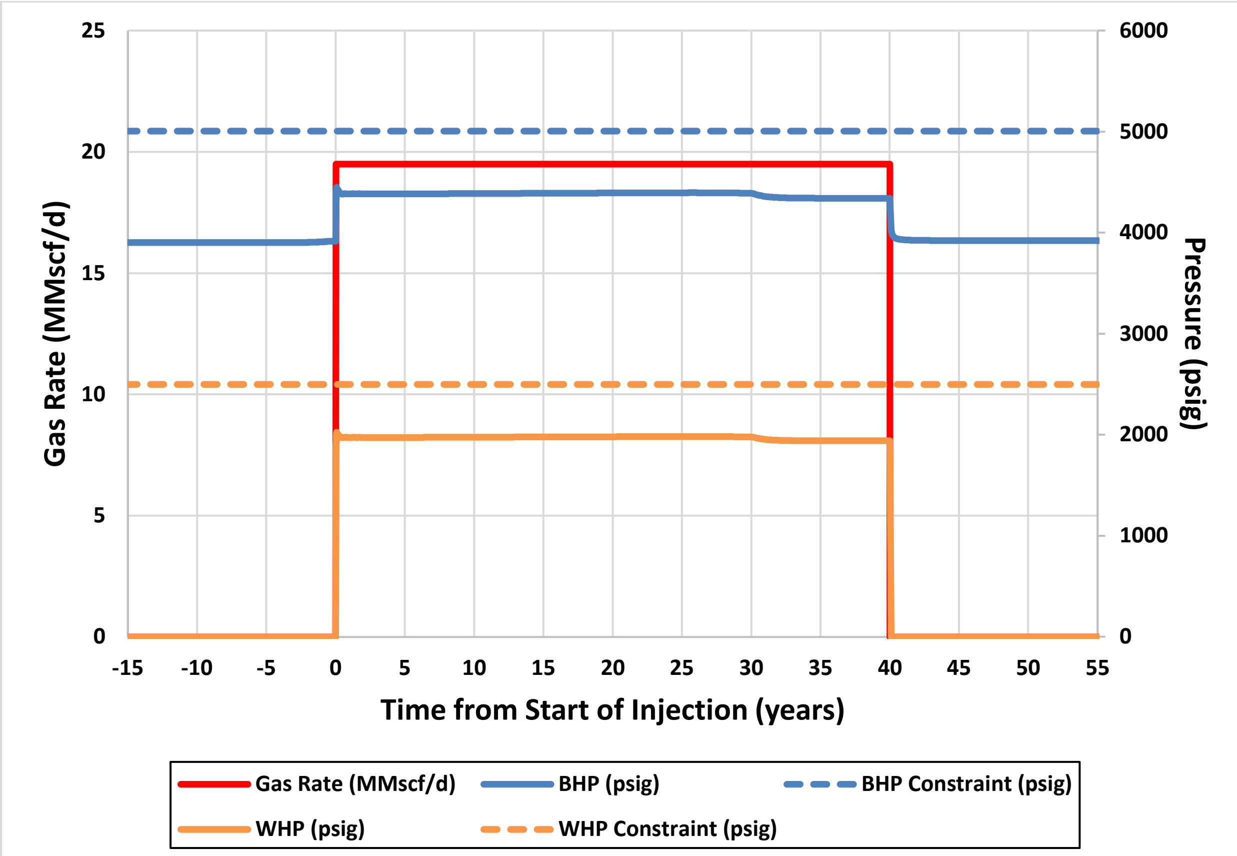


Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H_2S and 41.2% CO_2, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.

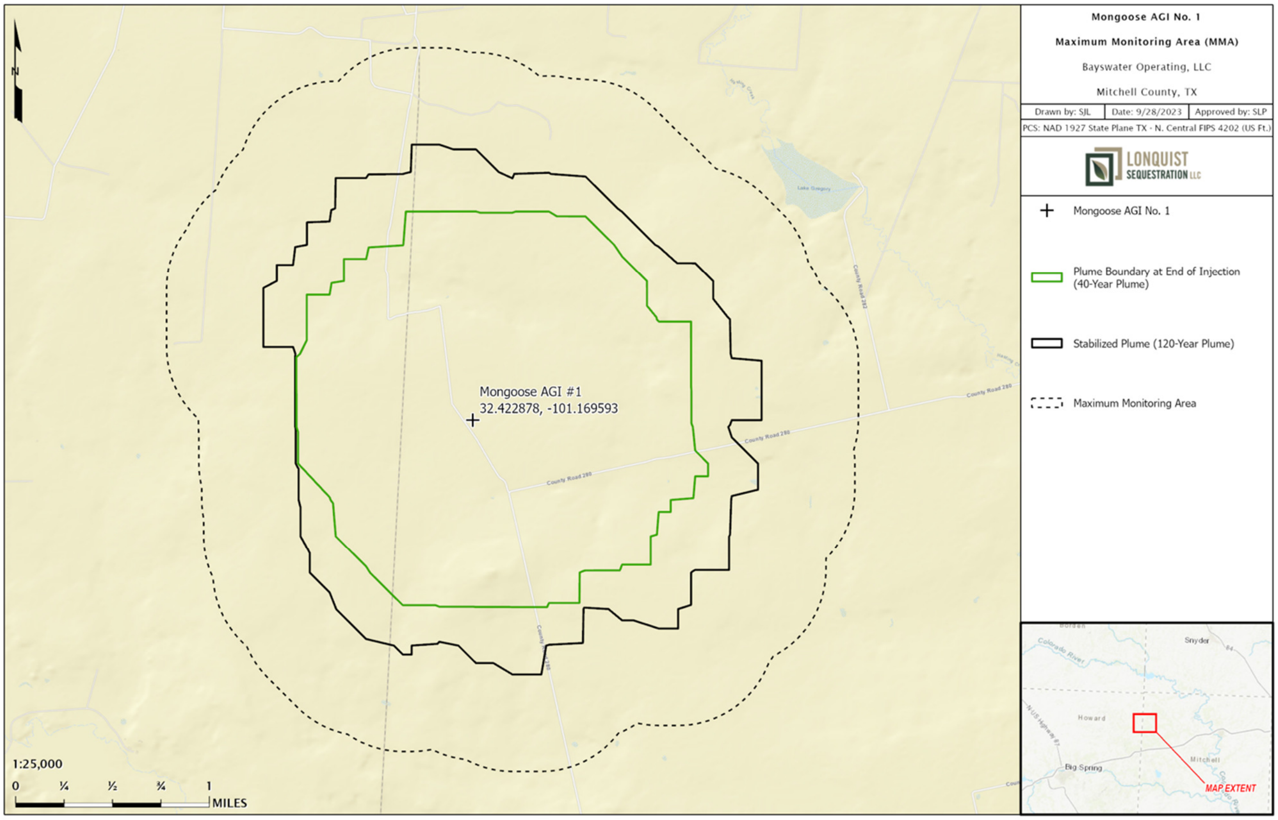


Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.

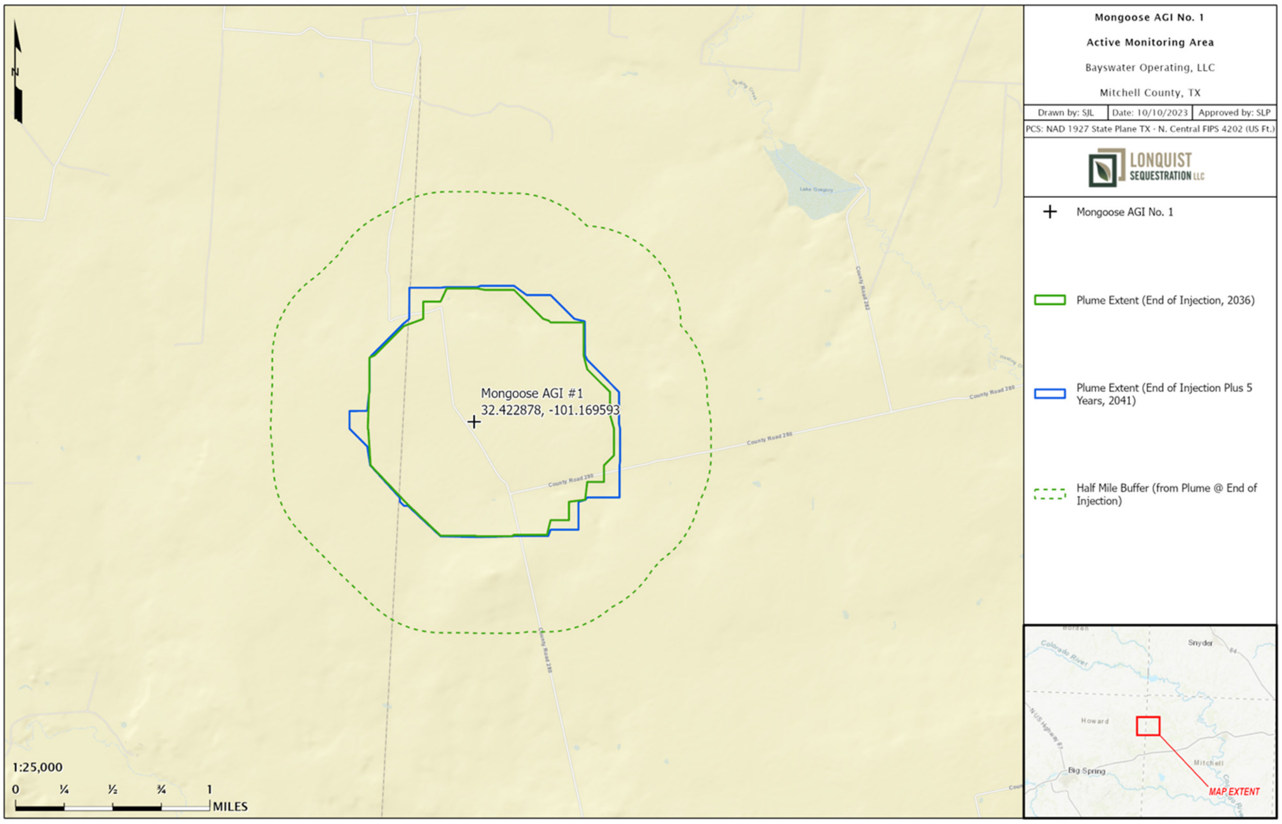


Figure 43 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

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

Table 12 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. Two artificial penetrations were drilled into the gross injection interval. These wells were plugged in accordancee TRRC requirements.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There are no faults within the modeled area. Bayswater monitors the area for seismic activity.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining layer	Unlikely. The lateral continuity of the Woodford Shale blanketing the Ellenburger is recognized as a very competent seal. There is 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There have been no seismic events of 3.0 magnitude or greater detected. There is over 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

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

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H_2S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H_2S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year, per 40 CFR **§98.444(b)**.

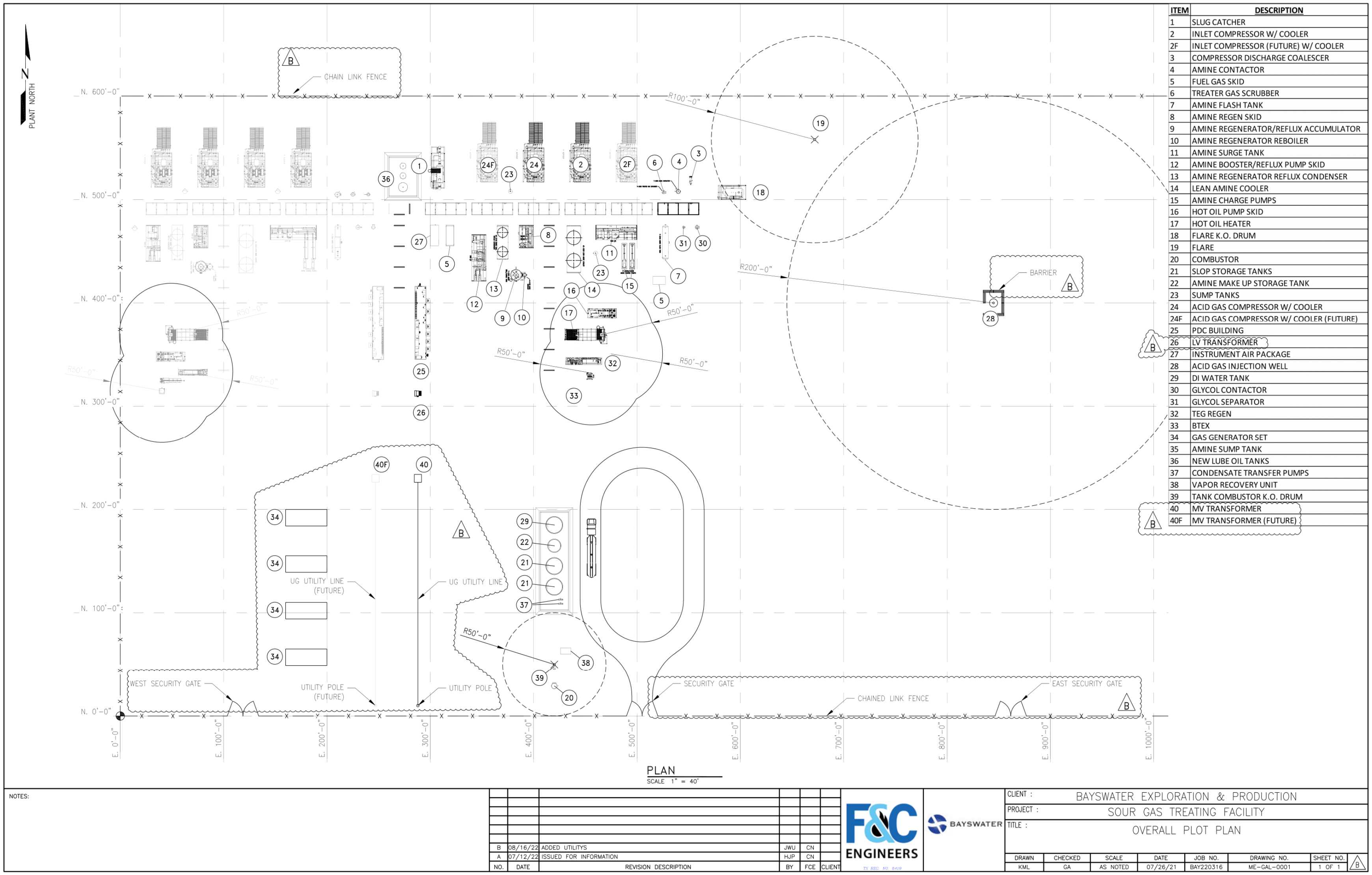
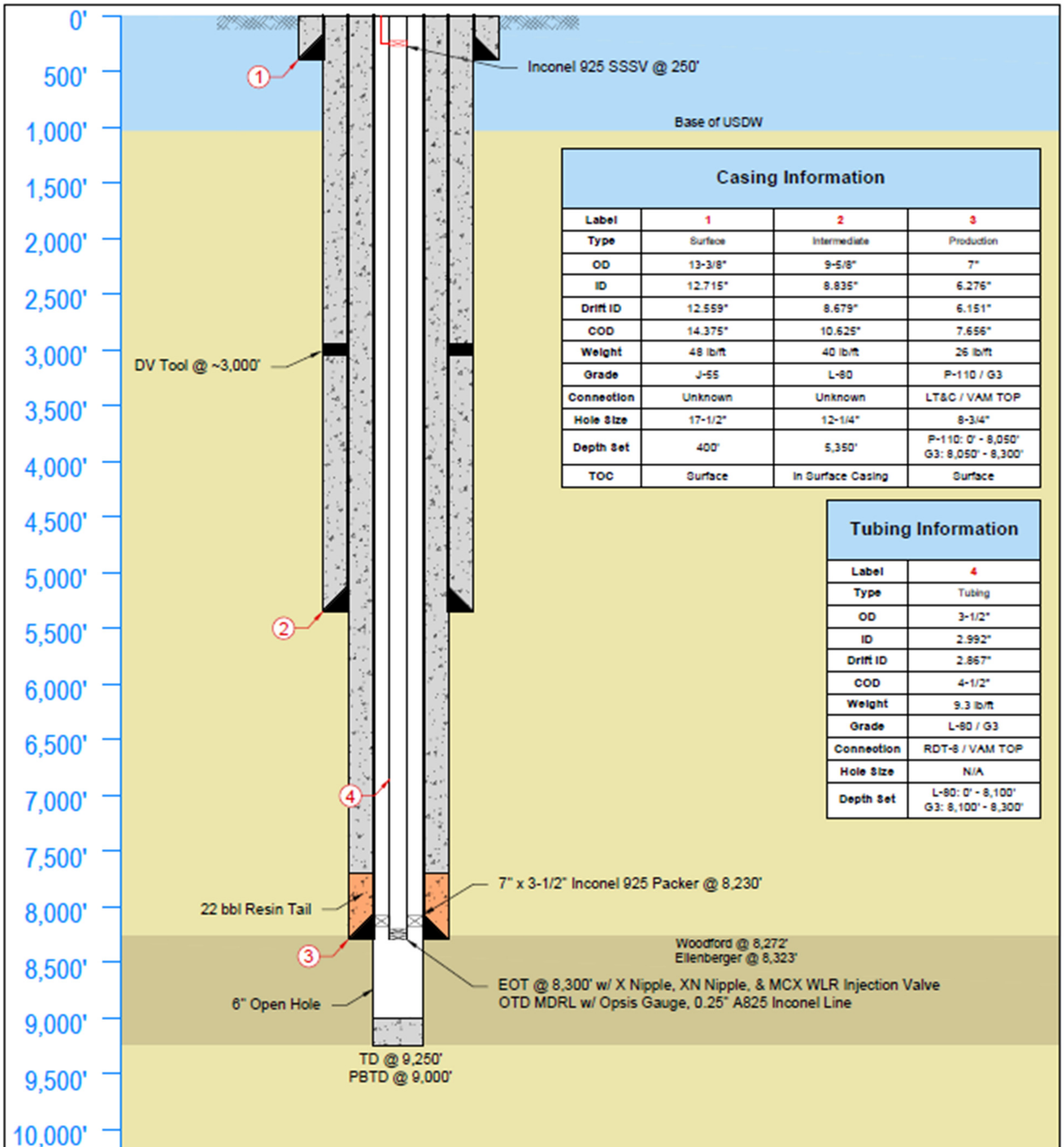


Figure 44 – Site Plan



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
ID	12.715"	8.835"	6.276"
Drift ID	12.559"	8.679"	6.151"
COD	14.375"	10.625"	7.656"
Weight	48 lb/ft	40 lb/ft	26 lb/ft
Grade	J-55	L-80	P-110 / G3
Connection	Unknown	Unknown	LT&C / VAM TOP
Hole Size	17-1/2"	12-1/4"	8-3/4"
Depth Set	400'	5,350'	P-110: 0' - 8,050' G3: 8,050' - 8,300'
TOC	Surface	In Surface Casing	Surface

Tubing Information

Label	4
Type	Tubing
OD	3-1/2"
ID	2.992"
Drift ID	2.867"
COD	4-1/2"
Weight	9.3 lb/ft
Grade	L-80 / G3
Connection	RDT-8 / VAM TOP
Hole Size	N/A
Depth Set	L-80: 0' - 8,100' G3: 8,100' - 8,300'

LONQUIST FIELD SERVICE	Bayswater Operating Company LLC	Mongoose AGI #1	
	Country: USA	State/Province: TX	County/Parish: Mitchell
	API No: 42-335-36013	Field: Sprayberry Trend	Well Type/Status: Acid Gas Injection
Texas License F-9147	RRC District No:	Project No: LS188	Date: 09/07/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved:
	Rev No: 1	Notes:	

Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO_2 will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in *Section 2.2.2*. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset artificial penetrations is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.

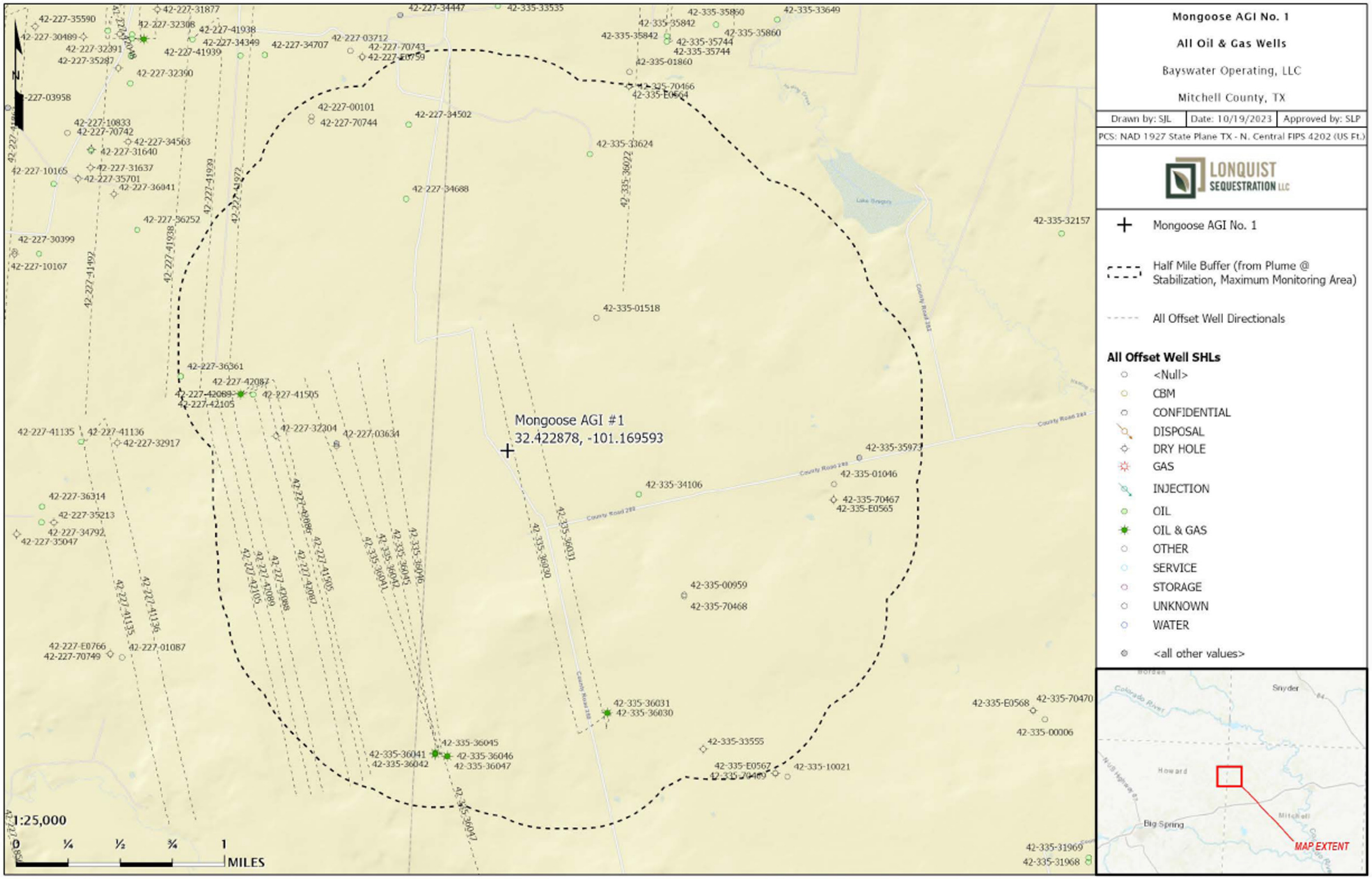


Figure 46 – All Oil and Gas Wells Within the MMA

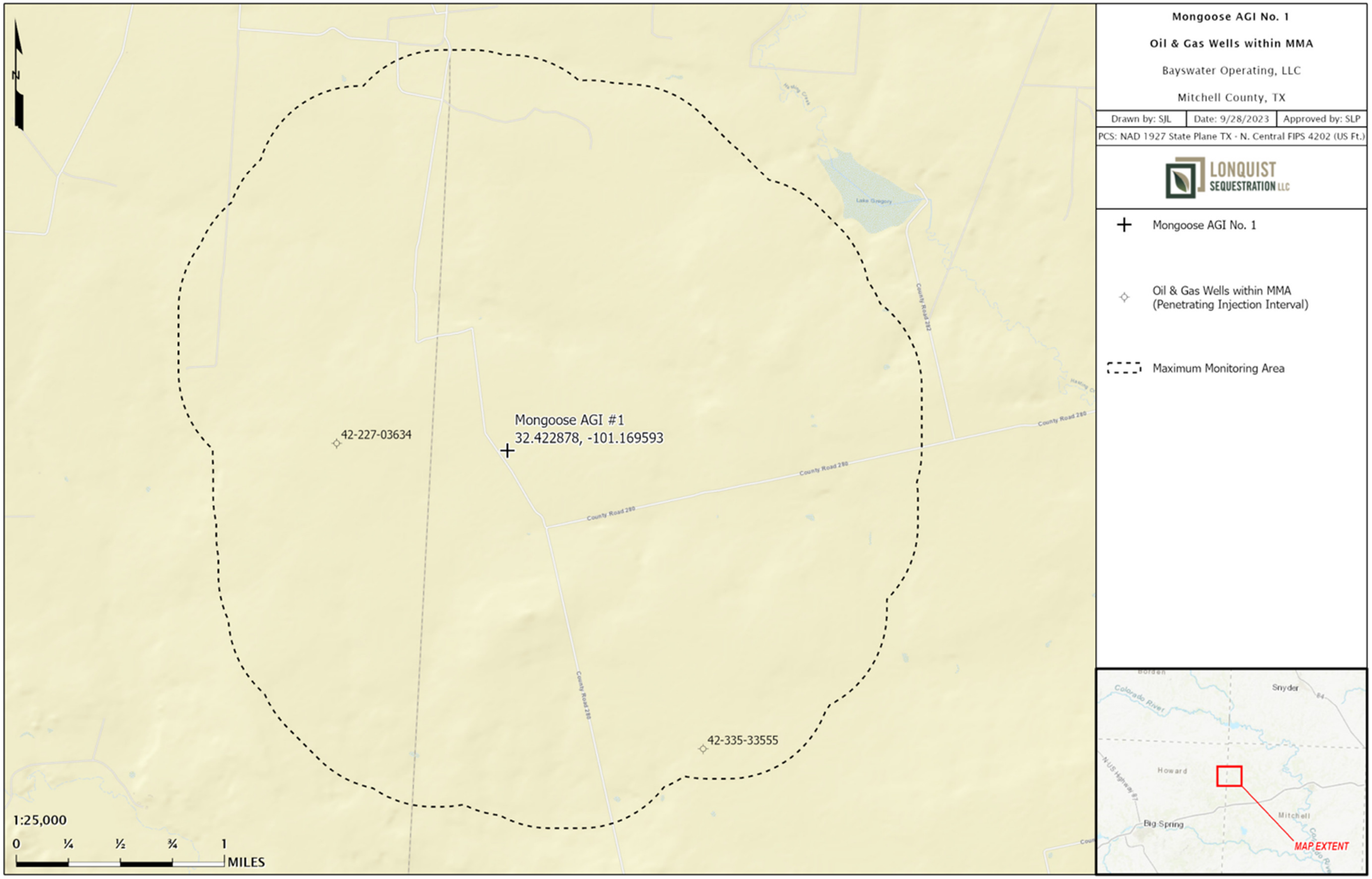


Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Mongoose drilling permit, provided in *Appendix A*, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a quarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued (also provided in the permit in *Appendix A*).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 <u>Leakage Through Faults and Fractures</u>

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

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

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

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

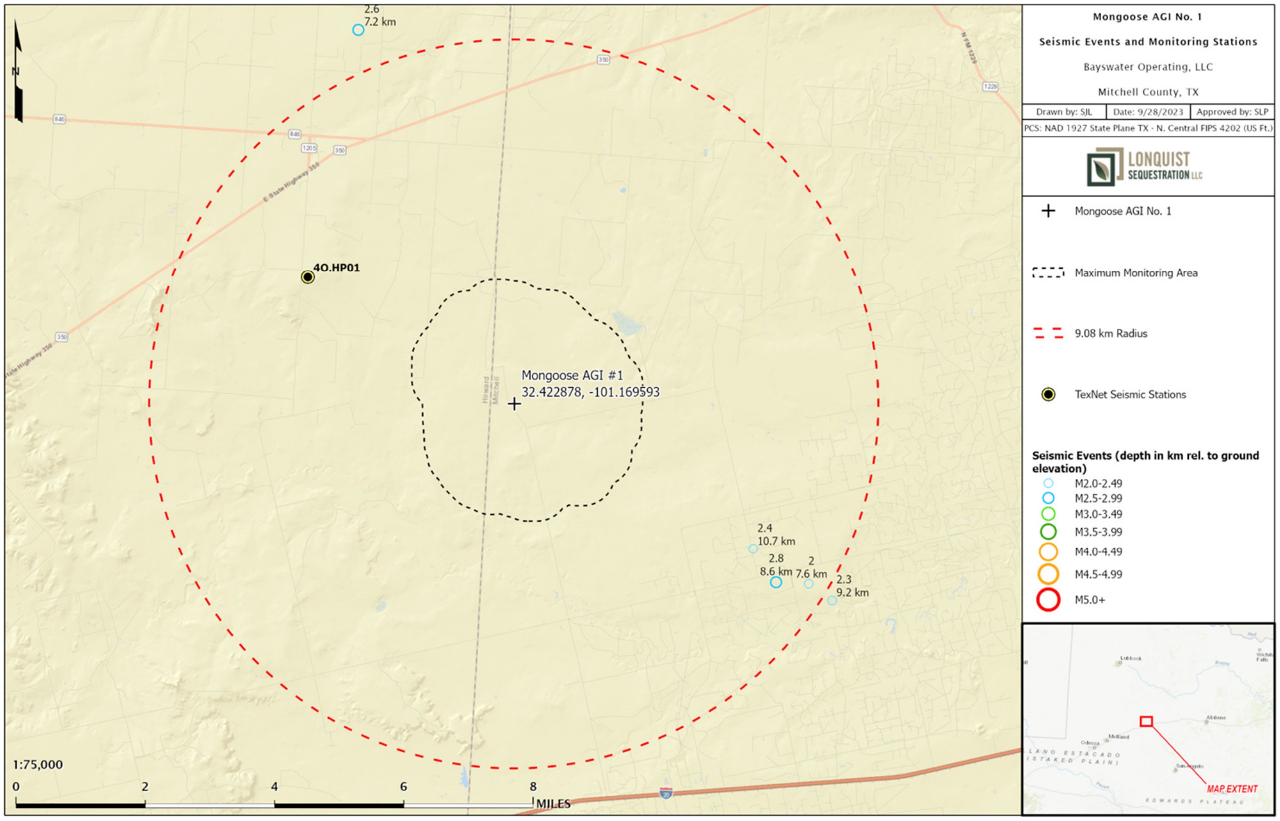


Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Table 13 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Visual inspections
	SCADA continuous monitoring of the AGI facility
Leakage through existing wells	SCADA continuous monitoring of the AGI well
	Monitor CO_2 levels in Above Zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage from natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established during the commissioning of the Plant. Ambient H_2S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H_2S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

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

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2, migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 Groundwater Quality Monitoring

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 Leakage Through Faults, Fractures, or Confining Seals

Bayswater continuously monitors the operations of the Mongoose well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO_2 content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO_2 content would be an early indicator of a potential issue. Should the CO_2 migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

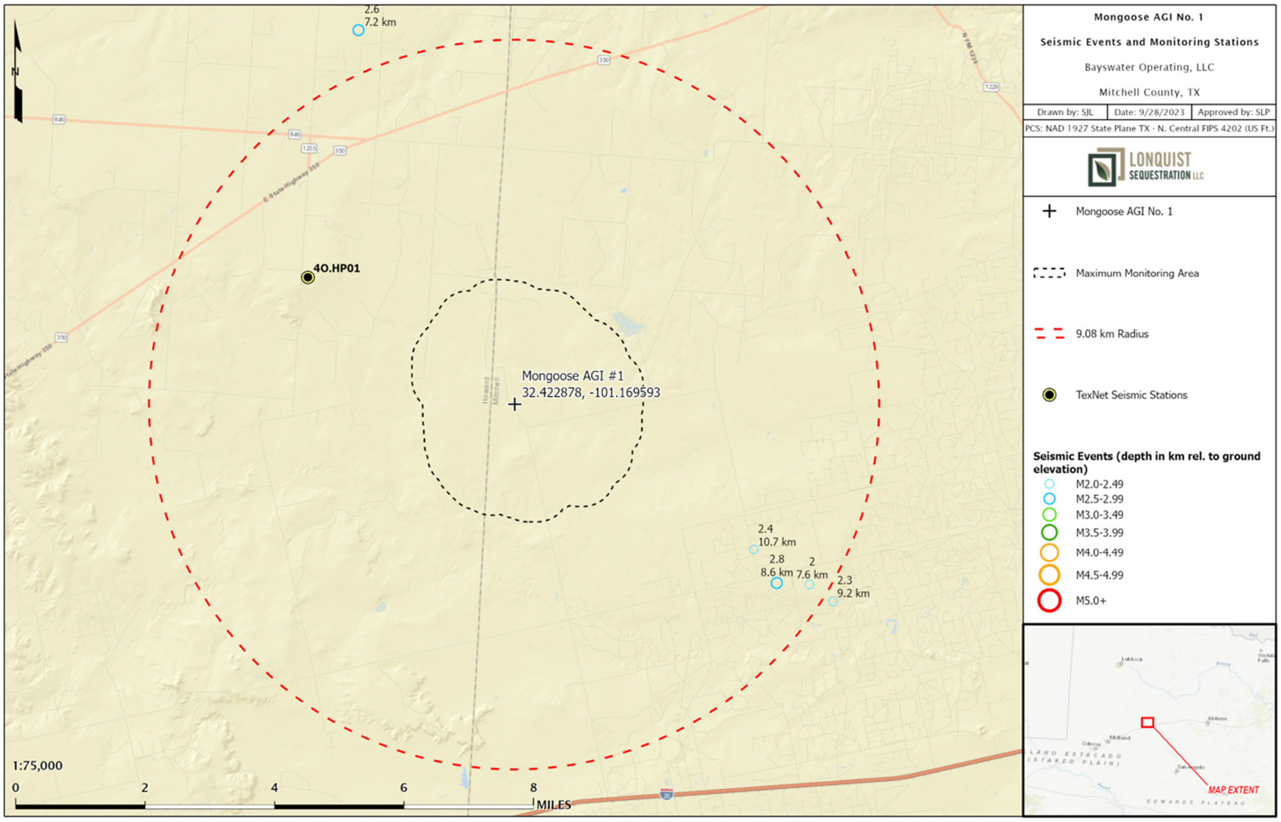


Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

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

6.2 CO_2/H_2S Detection

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H_2S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

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

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

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

7.4 Mass of CO_2 Emitted by Surface Leakage

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

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

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

Where:

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

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

X = Leakage pathway

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

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

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

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

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

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

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

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Bayswater plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

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

CO_2 Emissions from Leaks and Vented Emissions

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

Measurement Devices

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

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

9.2 Missing Data

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

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

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

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Bayswater will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

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

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

SECTION 11 - REFERENCES

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APPENDICES

APPENDICES

APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN
WAYNE CHRISTIAN, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
DEPUTY EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS, P.E.
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17174

BAYSWATER OPERATING COMPANY LLC
730 17TH STREET
SUITE 500
DENVER CO 80202

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE
SPRABERRY (TREND AREA) FIELD
MITCHELL COUNTY
DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33536013	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.** **3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;

Note: This document will only be distributed electronically.

c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON March 10, 2023.

FOR Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	04 March 2022	**GAU Number:**	336979

Attention:	BAYSWATER OPERATING 730 17TH STREET SUITE 500 DENVER, CO 80202	**API Number:**	33536013
		County:	MITCHELL
		Lease Name:	Mongoose AGI
		Lease Number:	
Operator No.:	058827	**Well Number:**	1
		Total Vertical	9250
		Latitude:	32.422884
		Longitude:	-101.169661
		Datum:	NAD27

Purpose: Injection into Non-producing Zone (W-14)

Location: Survey-T&P RR CO; Abstract-1545; Block-29; Township-1N; Section-4

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 350 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 475 feet at the site of the referenced well.

This recommendation is applicable to all wells within a radius of 200 feet of this location.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 03/02/2022. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary. If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRICT * 08
API NUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03, 2022	COUNTY MITCHELL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 40
OPERATOR 058827 BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER, CO 80202-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (432) 684-5581
LEASE NAME MONGOOSE AGI		WELL NUMBER 1
LOCATION 10.4 miles NW direction from WESTBROOK		TOTAL DEPTH 10000
Section, Block and/or Survey SECTION 4 BLOCK 29 T1N ABSTRACT 1545 SURVEY T&P RR CO/MORRISON, W		
DISTANCE TO SURVEY LINES 551 ft. EAST 2164 ft. SOUTH		DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 400 ft. EAST 650 ft. SOUTH		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME / LEASE NAME	ACRES	DEPTH	WELL #	DIST
	NEAREST LEASE		NEAREST WE	
SPRABERRY (TREND AREA)	40.00	10,000	1	08
MONGOOSE AGI		0		

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Submitted
Date: 09/11/2023
Tracking No.: 298516

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator BAYSWATER OPERATING COMPANY LLC **Operator** 058827
Operator 730 17TH STREET SUITE 500 DENVER, CO 80202-

WELL INFORMATION

API 42-335-36013 **County:** MITCHELL
Well No.: 1 **RRC District** 08
Lease MONGOOSE AGI **Field** SPRABERRY (TREND AREA)
RRC Lease **Field No.:** 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRISON, W, Abstract: 1545

Latitude 32.423000 **Longitud** -101.170059
This well is 10.4 **miles in a** NW
direction from WESTBROOK,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC **Completion or Recompletion** 04/28/2023

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	02/10/2022	876754
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal		17174
Other:		

COMPLETION INFORMATION

Spud 10/12/2022
Date of first production after rig 04/28/2023
Date plug back, deepening, drilling operation 10/12/2022
Date plug back, deepening, recompletion, drilling operation 04/28/2023
Number of producing wells on this lease this field (reservoir) including this 1
Distance to nearest well in lease & reservoir
Total number of acres in 40.00
Elevation 2252 GL
Total depth TVD 9289
Total depth MD
Plug back depth TVD 9036
Plug back depth MD
Was directional survey made other inclination (Form W- Yes
Rotation time within surface casing 41.0
Is Cementing Affidavit (Form W-15) Yes
Recompletion or No
Multiple No
Type(s) of electric or other log(s) Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease of lease on which this well is
Off Lease : No
400.0 **Feet from the** East **Line and**
650.0 **Feet from the** South **Line of the**
MONGOOSE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

	Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type
PACKET: N/A				

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:				
GAU Groundwater Protection Determination	**Depth**	350.0	**Date**	03/04/2022
SWR 13 Exception	**Depth**			

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		**Production**	
Number of hours	24	**Choke**	
Was swab used during this	No	**Oil produced prior to**	

PRODUCTION DURING TEST PERIOD:

Oil		**Gas**	
Gas - Oil	0	**Flowing Tubing**	
Water			

CALCULATED 24-HOUR RATE

Oil		**Gas**	
Oil Gravity - API - 60.:		**Casing**	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	569			C	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		C	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			C	610	1175.0	3001	Calculation
4	Conventional Production	7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL 925

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	Yes	L 8343	9036.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1	Other	OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H	9036	9289

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

OPERATOR'S CERTIFICATION

Printed	James Clark	**Title:**	Consulting Petroleum Engineer
Telephone	(512) 415-4191	**Date**	09/11/2023

A-5

- Return each W-1 with plat and $100.00 fee. Make check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas Oil and Gas Division, Drilling Permits P. O. Drawer 12967, Capitol Station Austin, Texas 78711
- File a copy of W-1 and plat in RRC District Office.

~~Cal 13~~

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1 Rev. 9/1/83 483-080

080 VMC

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: API No. 42-335-33555 ▶ Permit No. 379724 ▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): Bright & Company 10-18-90
2. Address (including city and zip code): 3200 West Cuthbert, Suite 2-C Midland, Texas 79701
3. RRC Operator No.: 093125
4. RRC District No.: 8
5. County of Well Site: Mitchell
6. Lease Name (32 spaces maximum): Van Tuyle
7. RRC Lease/ID No.: --
8. Well No.: 1
9. Total Depth: 8500'
10. Location
- Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1-N~~ Abstract No. A-584
- This well is to be located 5 miles in a north direction from Iatan which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.

12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

Granted 10/29/90

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
~~Wolfcamp (Wildcat)~~	~~5200'~~	~~467-1200~~	~~40~~	~~40~~	~~NO~~	~~NA~~	~~0~~	~~1~~	
~~Strawn (Wildcat)~~ per Tracy	~~7800'~~	~~467-1200~~	~~40~~	40	NO	NA	0	1	
~~Ellenburger~~ (Wildcat) 18001	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
- Lease/Unit 1000' FNL & 2500' FEL
- Survey/Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
- Lease/Unit
- Survey/Section

Code C 0 8500

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]

24. Is Item 17 less than Item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]

Code C

25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.

26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? Yes [X] No [ ] If not, and if the well requires a Rule 37 or 38 exception, see Instructions for Rule 37.

Remarks
W/C per Cindy 10/26/90

I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison
Signature

Tracy D. Tenison, Engineer
Name and title of operator's representative

Date: 9/26/90 (mo. day yr.)
Tel: 915-697-2214 (Area Code Number)

RRC Use Only
203091 OCT 1890
379724

335-33555

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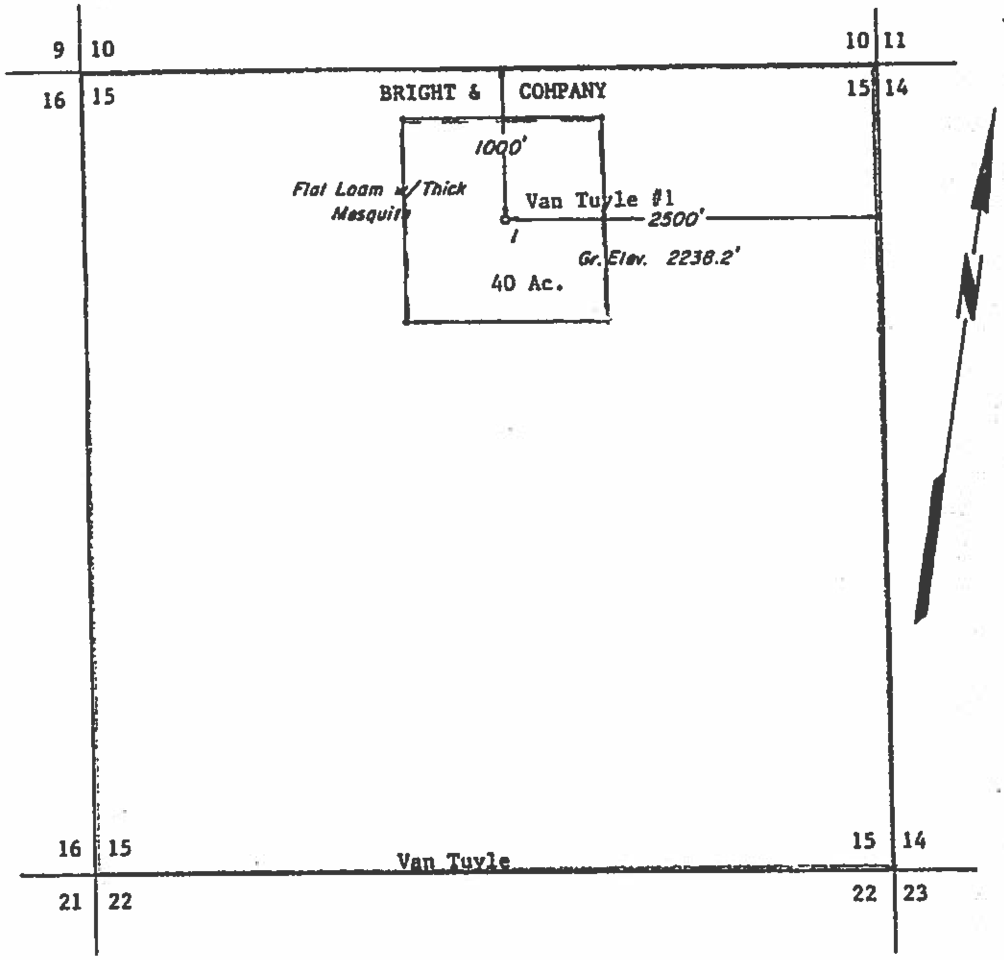

THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

OCT 1990

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON	TEXAS P.L.S. NO. 1883
GARY G. EIDSON	TEXAS P.L.S. NO. 4735
JERRY A. DUNN	TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1" = 1000'	Drawn by: NED
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

0 9 0 5 7 0 7 1 0

▶ Return each W-1 with plat and $100.00 fee. Make a check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas, Oil and Gas Division, Drilling Permits, P. O. Drawer 12967, Capitol Station, Austin, Texas 78711

▶ File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1
Rev. 9/1/83
483-060

020

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ▶ API No. 42- ▶ Permit No. ▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): Bright & Company
3. RRC Operator No.: 093125
4. RRC District No.: 8
5. County of Well Site: Mitchell
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• This well is to be located 5 miles in a north direction from Iatan, which is the nearest town in the county of the well site.

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Wolfcamp (Wildcat)	5200'	467-1200	40	40	NO	NA	0	1	
Strawn (Wildcat)	7800'	467-1200	40	40	NO	NA	0	1	
Ellenburger (Wildcat)	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
• Lease/Unit 1000' FNL & 2500' FEL
• Survey Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
• Lease/Unit
• Survey/Section

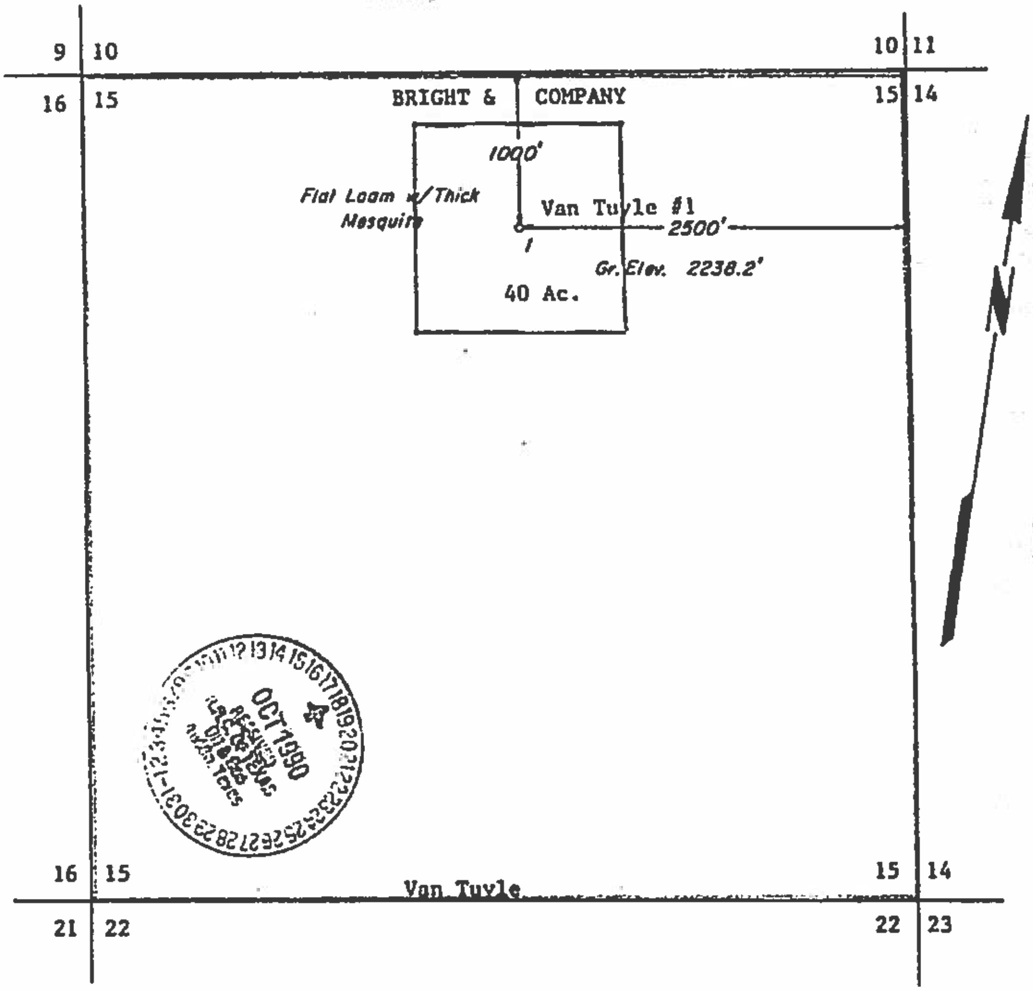
23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]
24. Is item 17 less than item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]
25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X]
If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.
26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? Yes [X] No [ ]
If not, and if the well requires a Rule 37 or 38 exception, see instructions for Rule 37.

Remarks

I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison — Signature
Tracy D. Tenison, Engineer — Name and title of operator's representative
Date: 9/26/90 (mo. day yr.)
Tel.: 915-697-2214 (Area Code Number)

• RRC Use Only •



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DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

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JERRY A. DUNN	TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1" = 1000'	Drawn by: NEG
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

WATER BOARD LETTER DATED 10-1990 1 2

Plugging Record Depth 350

13(A) Exception Dated N/A

13 3/8 - 361

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. 42-335-33555 (If available)

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

Field	Value
1. RRC District	8
4. RRC Lease or Id. Number	
2. FIELD NAME (as per RRC Records)	Wildcat
3. Lease Name	Van Tuyle
5. Well Number	1
6. OPERATOR	Bright & Company
6a. Original Form W-1 Filed in Name of:	
10. County	Mitchell
7. ADDRESS	2911 Turtle Creek Blvd #700 Dallas, TX 75219
6b. Any Subsequent W-1's Filed in Name of:	
11. Date Drilling Permit Issued	10/18/90
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located	1000 Feet From north Line and 2500 Feet From east Line of the Van Tuyle Lease
12. Permit Number	379724
9a. SECTION, BLOCK, AND SURVEY	Sec 15, Blk 29, T1N, T&P RR Co
9b. Distance and Direction From Nearest Town in this County	8.7 miles NW of Westbrook
13. Date Drilling Commenced	11/26/90
16. Type Well (Oil, Gas, Dry)	Dry
Total Depth	8360'
17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s (GAS ID or OIL LEASE # / Oil-O Gas-G / WELL #)	
14. Date Drilling Completed	12/18/90
18. If Gas, Amt. of Cond. on Hand at time of Plugging	
15. Date Well Plugged	12-17-90

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	12-17	12-17	12-17	12-17	12-17			
20. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8			
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15			
*22. Sacks of Cement Used (each plug)	50	50	160	50	10			
*23. Slurry Volume Pumped (cu. ft.)	59	59	189	59	11.8			
*24. Calculated Top of Plug (ft.)	8076	2526	1792	325	Surf.			
25. Measured Top of Plug (if tagged) (ft.)			1790					
*26. Slurry Wt. #/Gal.	15.6	15.6	15.6	15.6	15.6			
*27. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.			

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
13-3/8	48	361	361	17-1/2
8-5/8	32	2274	2274	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well ☐ Yes ☒ No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
2274	8360		

APR 15 1991

Return to Central Records

RECEIVED RAILROAD COMMISSION OF TEXAS JAN 14 1991 MIDLAND, TEXAS

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

D L Hamill

Signature of Cementer or Authorized Representative

Halliburton Services, Big Spring, TX

Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

W J Morris W. J. Morris — REPRESENTATIVE OF COMPANY
Agent — TITLE
1/11/91 — DATE
Phone 214 550-0889 — A/C NUMBER

Did not Witness

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

RECEIVED RRC OF TEXAS MAR 05 1991

OIL & GAS MIDLAND, TEXAS

138

335-33555

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission [X] Yes [ ] No	32. How was Mud Applied? Drilling Rig	33. Mud Weight 9.1 LBS/GAL
34. Total Depth 8360 Depth of Deepest Fresh Water 210	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No 36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Halliburton, P. O. Box 380, Snyder, Texas 79549

Date RRC District Office notified of plugging 12/15/90

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Ben Van Tuyle, 432 Hilldale Dr, Ann Arbor, MI 48105

39. Was Notice Given Before Plugging to Each of the Above?

Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ____________ Date ________

Type Logs:

[ ] Driller's [X] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging ____________ bbls*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ____________

REMARKS ____________

000 57 9713

Operator: Fill in other items.

Form W-15
Cementing Report
Rev. 4/1/83

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1. Operator's Name (As shown on Form P-5, Organization Report)	2. RRC Operator No.	3. RRC District No.	4. County of Well Site
Bright & Co.	093125	8	Mitchell

5. Field Name (Wildcat or exactly as shown on RRC records)	6. API No.	7. Drilling Permit No.
Wildcat	42- 335-33555	379724

8. Lease Name	9. Rule 37 Case No.	10. Oil Lease/Gas ID No.	11. Well No.
Van Tuyle			1

CASING CEMENTING DATA:	SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING: Single String	PRODUCTION CASING: Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS: Tool	MULTI-STAGE CEMENTING PROCESS: Shoe
12. Cementing Date	[illegible]	[illegible]				
13. •Drilled hole size	17-1/2	11				
•Est. % wash or hole enlargement						
14. Size of casing (in. O.D.)	13-3/8	8-5/8				
15. Top of liner (ft.)						
16. Setting depth (ft.)	361	2274				
17. Number of centralizers used	3	3				
18. Hrs. waiting on cement before drill out	12	12				
1st Slurry — 19. API cement used: No. of sacks	390	300				
1st Slurry — Class	Premium Plus	Hall.Light Prem Plus				
1st Slurry — Additives	2% Calcium Chloride	2% CaCl2				
2nd Slurry — No. of sacks						
2nd Slurry — Class						
2nd Slurry — Additives						
3rd Slurry — No. of sacks						
3rd Slurry — Class						
3rd Slurry — Additives						
1st — 20. Slurry pumped: Volume (cu. ft.)	514.8	591				
1st — Height (ft.)	Surface	2268				
2nd — Volume (cu. ft.)						
2nd — Height (ft.)						
3rd — Volume (cu. ft.)						
3rd — Height (ft.)						
Total — Volume (cu. ft.)	514.8	591				
Total — Height (ft.)	Surface	2268				
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?	Yes	No				

22. Remarks

RECEIVED
R.R.C. OF TEXAS
JAN 14 1991
O.G.
MIDLAND, TEXAS

RECEIVED
R.R.C. OF TEXAS
MAR 05 1991
OIL & GAS DIV
MIDLAND TEXAS

OVER

[illegible] TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
[illegible] date								
24. Size of hole or pipe plugged (in.)								
25. Depth to bottom of tubing or drill pipe (ft.)								
[illegible] cement used (each plug)								
[illegible] pumped (cu. ft.)								
[illegible] top of plug (ft.)								
29. Measured top of plug, if tagged (ft.)								
[illegible]								
[illegible]								

CEMENTER'S CERTIFICATE: [illegible] under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this [illegible] and the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my [illegible] and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. [illegible]

[illegible], Jr. — Cementer — Halliburton
[illegible] cementer's representative — Cementing Company — Signature

Box 300 — Snyder, Texas 79549 — 915-573-3526 — 11-26-90
Address — City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data.

W. J. Morris — Agent
Typed or printed name of operator's representative — Title — Signature

2911 Turtle Creek Blvd, #700, Dallas, TX 75219 — 214-559-0889 — 1/11/91
Address — City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For offshore operations, see the requirements of Rule 13 (c).

A. What to file. An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, Form W-2 or G-1, as required by Statewide or special field rules;
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, in addition to Form W-3, to show any casing cemented in the hole.

B. Where to file. The appropriate Commission District Office for the county in which the well is located.

C. Surface casing. An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. Centralizers. Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. Exceptions and alternative casing programs. The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. An operator must obtain approval of any exception before beginning casing and cementing operations.

F. Intermediate and production casing. For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. Plugging and abandoning. Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

R.R.C. Midland

Please Refer
to File No.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2A

8

APPLICATION TO PLUG AND WELL RECORD
FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Name of Company or Operator: The Texas Company Address: Box 1720, Fort Worth, Texas

County: Howard Survey: T&P RRCo. Blk. 29 T-1-N Sec. 4

Name of Lease: A. L. Wasson No. of Acres: 1760 Well No. 1 Elev. 2300 (DF)

Located: Approx. 21 Miles NE Direction from Big Spring, Texas (Nearest P. O. or Town)

Name of Field in which well is located: Wildcat

Form 1, "Notice of Intention to Drill," was filed in name of: The Texas Company

Drilling Commenced: 12-28, 19 52, Drilling Completed: 3-28, 19 52

Has this well ever produced oil? No or Gas? No

Character of Well (Oil, Gas or Dry): Dry Total Depth: 8670'

Date you wish to Plug: 3-27-, 19 52

Name of Party Plugging Well: Livermore Drilling Address: 610 Lubbock Nat'l Bank Lubbock, Texas

Correspondence regarding this well should be sent to: Name: The Texas Company

Address: Box 1720, Fort Worth, Texas

CASING RECORD

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
13 3/8"	196		None		196		Texas Pattern
9 5/8"	2115		100		2015		Halliburton F & S

IF CASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS

Initial Production of Gas: Volume (MCF) None 24 hrs. Pressure None

Initial Production of Oil: Barrels None

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

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MIDLAND, TEXAS
APR 10 1952
Railroad Commission of Texas
OIL & GAS DIVISION

NOTE: If no log available, so state and give all information that can be obtained as to total depth, casing record, formation, water sands, and as near as possible date well was drilled.

General Remarks: This well drilled to a total depth of 8670' without encountering oil or gas. We therefore desire to abandon selvage and plug well in the following manner: (Cut 9 5/8" casing at 100' and pull same) (Over)

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Caliche	0	100	At depth 206' cemented 13 3/8"
Red Beds	100	206	casing at 206' with 250 sacks.
Shale & Anhy	206	945	Cement circulated.
Anhy	945	1254	
Anhy & Shale	1254	1499	At depth 2125' cemented 9 5/8" casing
Anhy & Salt	1499	1750	at 2125' with 600 sacks.
Anhy & Shale	1750	1837	
Anhy	1837	1955	
Anhy & Lime	1955	2125	
Lime	2125	2290	
Lime & Shale	2290	2322	
Lime	2322	3116	
Lime & Shale	3116	3612	
Lime & Chert	3612	3820	
Lime & Sand	3820	3979	
Lime & Chert	3979	4155	
Lime & Sand	4155	4538	
Lime & Chert	4538	4900	
Lime & Sand	4900	5114	
Lime & Chert	5114	5232	
Lime & Shale	5232	6203	
Shale	6203	7953	
Lime & Chert	7953	8670	
Total Depth		8670	

All Measurements from Rotory Table or 12' above ground.

Remarks Cont'd

Using Heavy mud between plugs, spot the following cement plugs, 95 sacks 8670'-8373'; 15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7655'; 15 sacks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sacks 4680'-4630'; 15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1070'; 40 sacks. 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing.

Drill-Stem Tests

DST # 1: Pkr. failed

DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 2250' salt water cut with drlg. mud.

DST # 3: 5100-5210, Tool open 1 1/2 hrs. Recovered 300' drlg. mud.

DST # 4: 5440-5485, Tool open 1 hr. Recovered 75' slightly gas cut drlg. mud.

DST # 5: 5902-6000, Tool open 1 hr. Recovered 100' drlg. mud. [illegible]

DST # 6: 780[illegible]-7870, Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120' [illegible] gas cut drlg. mud.

DST # 7: 783[illegible] [illegible] hrs., Recovered 5' drlg. mud & 180' slightly [illegible] mud.

Method of shutting off water: Cased off   Is water completely shut off? Yes

Amount of water with oil: None   per cent: None

I, T. P. [illegible] being first duly sworn [illegible] that I have knowledge of the facts and matter herein [illegible] and that the same are true and correct.

[signature]

Representative of Company.

Subscribed and sworn to before me this 7 day of April, 1952

[signature] W. E. BRUZEK

Notary Public

Midland County, Texas.

RECEIVED

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.

DST # 10: 8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

Please Refer to
File No.........................

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 4
Plugging Record

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

8

Company The Texas Company Address Box 1720, Ft. Worth, Texas

Sec. No. 4 Block No. 29 T-I-N Survey T & P RRCO County Howard

Well No. 1 Name of Lease A. L. Wasson No. of Acres 1760

Name of Field in which well is located Wildcat Date well was plugged 3-27- 19 52

Form 1 (Notice of Intention to Drill) Was Filed in Name of The Texas Company

Character of Well at the time of completion: Oil - bbls.; (Initial Production) Gas - Cu. ft.; (Initial Production) Dry Yes

Amount well producing when plugged: Oil None bbls.; Gas None Cu. ft.; Water None bbls.

Has this well ever produced oil or gas? No

Total Depth 8670 feet. Top of each producing sand - feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Thru drill pipe

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depths placed. Also amount of cement and rock. Was well shot? No
Spotted the following plugs: 95 sx 8670-8373, 15 sx 8213-8163, 15 sx 7860-7810, 15 sx 7705-7655, 15 sx 5600-5550, 15 sx 5430-5380, 15 sx [redacted] 50-25-4975, 15 sx 4680-4630, 15 sx 2810-2760, 15 sx 2093-2043, Cut off 9 5/8" casing @ 100' and pulled, spot 40 sx 1125-1070, 40 sx 1025-975, 40 sx 875-825, 30 sx in top of casing.

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: All 13 3/8" casing left in hole & 2015' 9 5/8" casing left in hole. All strata protected by casing left in hole or cassed of with cement.

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:
All adjacent property leased by The Texas Company

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, T. P. Drew, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name T P Drew Dist. Supt.

Subscribed and sworn to before me this 15 day of May, 19 52

[signature]

Notary Public Midland County, Texas

Correspondence regarding this well should be addressed to:

Name The Texas Company Address Box 1720, Ft. Worth, Texas

0 0 0 2 2 0 7 7 7

FORM W-1 (6/78)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

[ ] Directional Well [ ] Amended or Corrected Permit

RRC Permit Number, if previously assigned: 084247

API Well No. 42
Instruction (7(d)(b)) on back side.

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

Check one: [ ] DRILL [ ] DEEPEN (Below Casing) [ ] DEEPEN (Within Casing) [ ] PLUG BACK [X] OTHER (Specify) re-entry

If Amended Application, explain fully in Remarks or Attach Separate Page.

1. Operator: McCann Corporation 538853
2. Address (Including City and Zip Code): P. O. Box 448, Big Spring, TX 79720
3. Is Form P-5 (Organization Report) in Exact Operator Name Filed? YES [X] NO [ ] (Instruction (2) on back side.)
4. Lease Name and RRC Lease or ID No. (If Assigned): Stewart
5. Location (Sec., Blk., Survey): Sec. 4, Blk. 29, T-1-N, T & P RR Co.
6. This well is to be located 4 miles Southeast Direction from Vincent, TX Nearest Post Office or Town.
7. RRC District: 8
8. County: Howard
9. Well Number: 1
10. Number of Acres in Lease: 640
11. Distance from Proposed Location to Nearest Property or Lease Line (ft.): 660'
12. Total Depth: 4600'

EACH PROPOSED COMPLETION

REFER TO INSTRUCTIONS ON BACK SIDE. READ CAREFULLY AND FURNISH COMPLETE DATA.

13. FIELD NAME (Exactly as shown on R.R.C. Proration Schedule including Reservoir if applicable.) If Wildcat, so state below.	14. Completion Depth	15. All Prior Rule 37 Exc. Case Numbers for this wellbore. If done, State None.	16. Applicable Field Rules Spacing Pattern. If no Rules, State 467-1200. (ft.)	17. Applicable Field Rules Density Pattern. If no Rules, State 40. (acres)	18. Number of Acres in Drilling Unit for this Well AND DESIGNATE ON PLAT.	19. Is this acreage presently assigned to another well in same field? (Yes or No; if yes explain in remarks.)	20. Distance and Direction from proposed location to nearest drilling completed or applied for well in same res. on same lease (ft.)	21. Is this a 1. Regular or 2. Rule 37 Exc. Location? Check the appropriate box.	22. Oil, Gas, or other Type Well (Specify)	23. Number of Wells or Permitted locations on this Lease in same Reservoir for which this Permit is Requested? OIL	GAS
00018 001											
Wildcat	4210'	None	467-1200	40	40	No	None	Regular 1 [X] Rule 37 2 [ ]	Oil	0	0
								Regular 1 [ ] Rule 37 2 [ ]			
								Regular 1 [ ] Rule 37 2 [ ]			
								Regular 1 [ ] Rule 37 2 [ ]			

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24. PERPENDICULAR LOCATION FROM TWO DESIGNATED:
A. Lease Lines: 660' FWL & 1980' FNL
B. Survey Lines: 660' FWL & 1980' FNL

25. (a) Is this wellbore subject to SWR 36? Yes [X] No [ ]
(b) If subject to SWR 36, has Form H-9 been filed? Yes [X] No [ ]
(If no, attach explanation.)

NOTICE
NO ALLOWABLE WILL BE ASSIGNED to any well which does not have sufficient surface casing to protect all fresh water sands. Where Commission rules do not specify surface casing requirements, it will be necessary to contact Texas Water Development Board, Austin, Texas, to ascertain the depth to which fresh water sands must be protected.

CERTIFICATE
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

REMARKS: Original Operator: The Texas Company
Original Lease Name: A.L. Wasson, Well #1.
Plugged and Abandoned: 3-27-52

Signature: Ellen W. Bitt[illegible]
Title: Administrative Assistant
Date: June 12, 1980
Telephone: Area Code 915 267-7[illegible]

READ INSTRUCTIONS ON BACK SIDE AND FURNISH COMPLETE DATA.

0 0022 0775

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. (If available) 42-227-00000

RRC District: 08

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or ID Number

2. FIELD NAME (as per RRC Records): Wildcat	3. Lease Name: Stewart	5. Well Number: 1
6. OPERATOR: McCann Corporation	6a. Original Form W-1 Filed in Name of: McCann Corporation	10. County: Howard
7. ADDRESS: P. O. Box 448, Big Spring, TX	6b. Any Subsequent W-1's Filed in Name of:	11. Date Drilling Permit Issued: 6-17-80
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located	660 Feet From West Line and 1980 Feet From North Line of the Stewart Lease	12. Permit Number: 084247
9a. SECTION, BLOCK, AND SURVEY: Sec. 4, Blk. 29, T-1-N, T&P RR Co.	9b. Distance and Direction From Nearest Town in this County: 4 miles SE of Vincent	13. Date Drilling Commenced: 10-10-80
16. Type Well (Oil, Gas, Dry): DRY; Total Depth: 1100	17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s — GAS ID or OIL LEASE # / Oil-O Gas-G / WELL #	14. Date Drilling Completed: 10-12-
18. If Gas, Amt. of Cond. on Hand at time of Plugging		15. Date Well Plugged: 10-12-

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	10-12-80	10-13	10-13					
20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8					
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1100	250	Top Out					
*22. Sacks of Cement Used (each plug)	50	100	10					
*23. Slurry Volume Pumped (cu. ft.)	66	133	13					
*24. Calculated Top of Plug (ft.)	990	70	Surf.					
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	1.33	1.33	1.33					
*27. Type Cement	C	C	C					

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
8 5/8	24#	200	200	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well? [ ] Yes [X] No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

Signature of Cementer or Authorized Representative

Dowell Division of Dow Chemical Co.
Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Tom McCann — REPRESENTATIVE OF COMPANY | President — TITLE | April 9, 1981 — DATE | Phone 915 (A/C) 267-7488 (NUMBER)

Did Not Witness
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

RECEIVED
R.R.C. OF TEXAS
APR 20 1981
O.G.
MIDLAND, TEXAS

DR-80

31. Was Well Filled with Mud-Laden Fluid, according to the regulations of the Commission? [X] Yes [ ] No

32. How was Mud Applied? Circulated

33. Mud Weight 8.6 LBS/GAL

34. Total Depth 1100

Depth of Deepest Fresh Water 150

Other Fresh Water Zones by T.D.W.R.

TOP	BOTTOM

35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No

36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well

Dowell Division of Dow Chemical Co. - Colorado City, TX

Date RRC District Office notified of plugging 10-1-85

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Danny Stewart - P. O. Box 26, Sterling City, Tx. 76951

39. Was Notice Given Before Plugging to Each of the Above?

Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______ Date ______

Type Logs: [ ] Driller's [ ] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Was FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging None bbls.*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ______

REMARKS ______

APR 2 0 1986

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form W-15
(Rev. [illegible])

CEMENTING REPORT

*1. Field Name (as per RRC Records or Wildcat) Wildcat	*2. RRC District 08
*3. Operator Mc Cann Corporation	*4. County Howard
*5. Lease Name(s) and RRC Lease Number(s) or I. D. Number(s) Stewart	*6. Well Number 1
*7. Location (Section, Block, and Survey) Sec. 4, Blk. 29, T-1-N, T&P RR Co. Survey	

CASING CEMENTING DATA:	SURFACE CASING	INTERMEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
8. Cementing Date						
*9. (a) Size of Drill Bit (inches)						
(b) Estimated % Wash or Hole Enlargement Used in Calculations.						
*10. Size of Casing (inches O.D.)						
*11. Top of Liner (if liner used) (ft.)						
*12. Setting Depth of Casing (ft.)						
13. Type API Class Cement & Amount of Additives Used: (a) In First (Lead) or Only Slurry (if additional space is needed, use "REMARKS" on reverse side.)						
(b) In Second Slurry						
(c) In Third Slurry						
14. Sacks of Cement Used: (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Sacks of Cement Used						
15. Slurry Volume per Sack of Cement (cu.ft./sack): (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
16. Volume of Slurry Pumped: (cu.ft.) (Item 14 x Item 15) (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Slurry Volume Pumped (cu.ft.)						
17. Calculated Annular Height of Cement Slurry behind Pipe (ft.)						
18. Was cement circulated to ground surface (or bottom of cellar) outside casing? (Yes or No)						

CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6
19. Cementing Date	10-12-80	10-13-80	10-13			
*20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8			
*21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1000	250	Top Out			
22. Sacks of Cement Used (each plug)	50	100	10			
23. Slurry Volume Pumped (cu. ft.)	66	133	13			
24. Calculated Top of Plug (ft.)	990	70	Surf.			
*25. Measured Top of Plug (if tagged) (ft.)						

RECEIVED
R.R.C. OF TEXAS
APR 20 1981
MIDLAND, TEXAS

(CEMENTING COMPANY AND OPERATOR MUST COMPLY WITH THE INSTRUCTIONS ON REVERSE SIDE HEREOF.)

– OVER –

* Designated items to be completed by Operator. Items not so designated shall be completed by Cementing Company.

Remarks:

*27. Remarks:

CEMENTING COMPANY

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

P. N. Shackelford
Signature of Cementer or Authorized Representative

P. N. Shackelford, Sr.District Clerk
Name of Person and Title (type or print)

Dowell Division of Dow Chemical Co.
Cementing Company

Route 3, Box 178
Street Address or P.O. Box

Colorado City, Tx 79512
City, State — Zip Code

Telephone 915 728-5291
Area Code

10-14-80
Date

***OPERATOR**

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data and information presented herein.

Tom McCann
*Signature of Operator or Authorized Representative

Tom McCann - President
*Name of Person and Title (type or print)

McCann Corporation
*Operator

P. O. Box 448
*Street Address or P.O. Box

Big Spring, Texas — 79720
*City, State — Zip Code

*Telephone 915 267-7488
Area Code

4-6-81
*Date

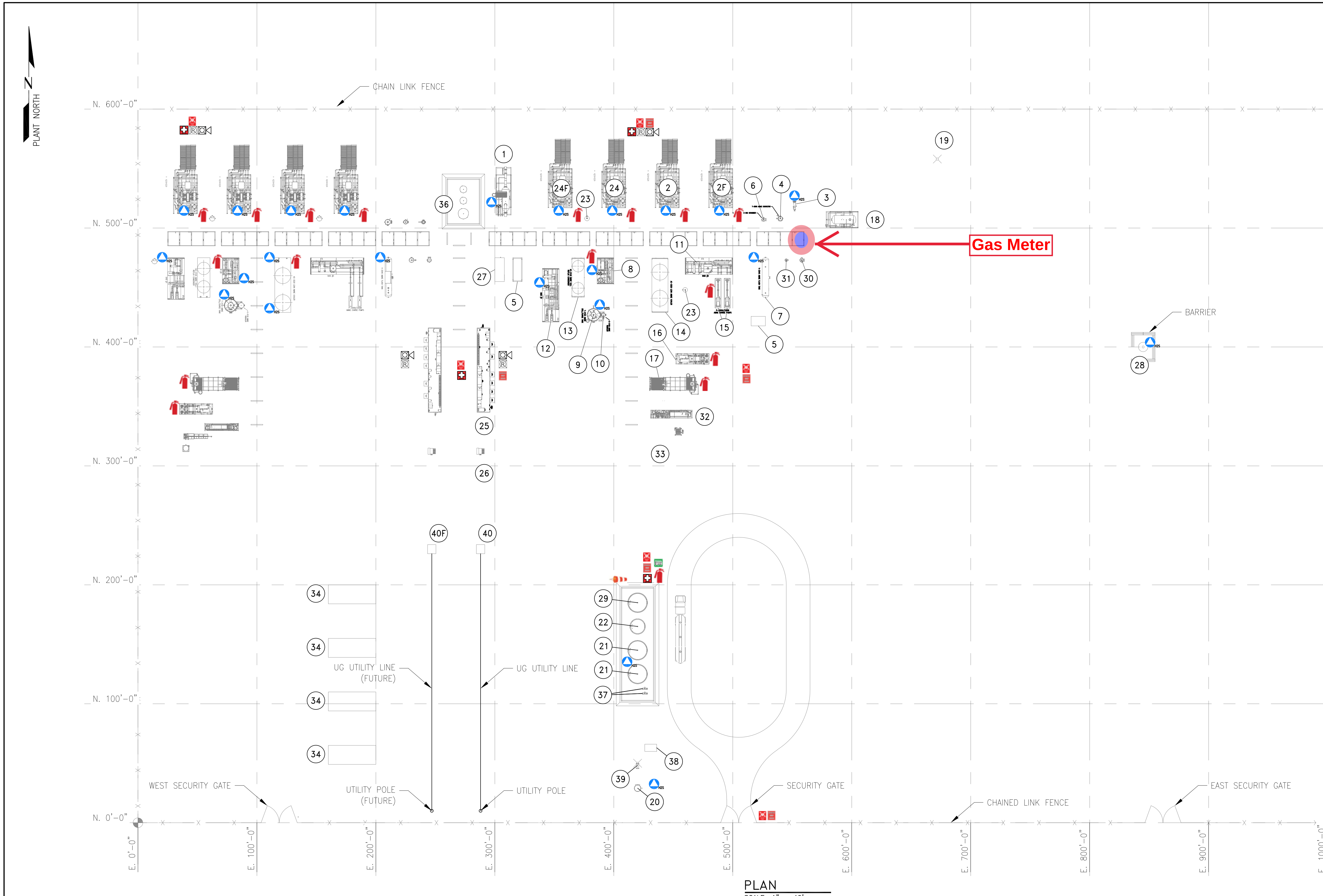
INSTRUCTIONS

1. A. This form shall be filed by the operator in the RRC District Office with:
   (1) Each copy of an initial Form G-1 or W-2 if a cementing report is required by Statewide or Special Rules, or if exception is needed to cementing requirements in Statewide or Special Rules;
   (2) Each copy of Form W-3;
   (3) Each copy of Form W-4 if a multiple parallel casing completion.
   B. At least an original and one copy of this form shall be filed for each cementing company used on a well.
   C. The cementing of different casing strings on a well by one cementing company may be consolidated on one form (to be filed in duplicate)
2. Cementing Company and Operator shall comply with the applicable portions of Statewide Rules 8, 13, and 14. For offshore operations, Cementing Company and Operator shall comply with Statewide Rule 13(E).
3. If setting FULL AMOUNT OF SURFACE CASING
   A. Depth to protect fresh water determined by:
   (1) Field Rule
   (2) Texas Water Development Board, if no Field Rule
   B. Set surface casing below depth to be protected and cement from casing shoe to ground surface.
4. IF SETTING ANYTHING OTHER THAN THE FULL AMOUNT OF SURFACE CASING, PERMISSION SHALL BE OBTAINED FROM THE RAILROAD COMMISSION.
5. If setting NO SURFACE CASING (See Item 4 above.):
   A. If no multi-stage tool is used, the next deeper casing string shall be cemented from the casing shoe to the surface.
   B. If using the multi-stage tool on the next deeper string, cement from the depth that protects fresh water sands to the surface.
6. If setting SHORT SURFACE CASING (See Item 4 above.):
   A. Cement short surface casing from the shoe to the surface.
   B. Whether the multi-stage tool is or is not used on the next deeper casing string, cement from the depth that protects fresh water sands to
   (1) the surface, or
   (2) a point midway between shoe of surface string and the surface. Compliance will be considered if a temperature survey shows that the top of the cement is at least one-third of the distance from the shoe of the surface string to the surface.
7. Setting PRODUCTION STRING of Casing: (Statewide Rules, Special Rules may vary.)
   A. Cement to a point at least 600 feet above the casing shoe.
   B. When 3,000 feet or more of pipe is set for the production or protecting string, a minimum of 30 feet of cement shall be left inside the pipe
8. PLUGGING and ABANDONING:
   A. Cement plugs shall be placed in the well bore as required by Rules and Regulations of the Commission plus any additional plugs as may be specified by the RRC District Director.
   B. The minimum amount of cement normally used in each plug shall be a slurry volume equal to the amount necessary to fill the calculated volume of 100 feet of the hole in which the plug is placed.
   C. A 10 foot cement plug is required to be placed in the top of the well.

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H_2S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



ITEM	DESCRIPTION
1	SLUG CATCHER
2	INLET COMPRESSOR W/ COOLER
2F	INLET COMPRESSOR (FUTURE) W/ COOLER
3	COMPRESSOR DISCHARGE COALESCER
4	AMINE CONTACTOR
5	FUEL GAS SKID
6	TREATER GAS SCRUBBER
7	AMINE FLASH TANK
8	AMINE REGEN SKID
9	AMINE REGENERATOR/REFLUX ACCUMULATOR
10	AMINE REGENERATOR REBOILER
11	AMINE SURGE TANK
12	AMINE BOOSTER/REFLUX PUMP SKID
13	AMINE REGENERATOR REFLUX CONDENSER
14	LEAN AMINE COOLER
15	AMINE CHARGE PUMPS
16	HOT OIL PUMP SKID
17	HOT OIL HEATER
18	FLARE K.O. DRUM
19	FLARE
20	COMBUSTOR
21	SLOP STORAGE TANKS
22	AMINE MAKE UP STORAGE TANK
23	SUMP TANKS
24	ACID GAS COMPRESSOR W/ COOLER
24F	ACID GAS COMPRESSOR W/ COOLER (FUTURE)
25	PDC BUILDING
26	LV TRANSFORMER
27	INSTRUMENT AIR PACKAGE
28	ACID GAS INJECTION WELL
29	DI WATER TANK
30	GLYCOL CONTACTOR
31	GLYCOL SEPARATOR
32	TEG REGEN
33	BTEX
34	GAS GENERATOR SET
35	AMINE SUMP TANK
36	NEW LUBE OIL TANKS
37	CONDENSATE TRANSFER PUMPS
38	VAPOR RECOVERY UNIT
39	TANK COMBUSTOR K.O. DRUM
40	MV TRANSFORMER
40F	MV TRANSFORMER (FUTURE)

LEGEND

- FIRE EXTINGUISHER = 9 ea.
- HYDROGEN SULFIDE DETECTOR = 10 ea.
- AUDIBLE ALARM SOUNDER = 4 ea.
- STROBE LIGHT (RED) – FIRE = 4 ea.
- PLANT EMERGENCY SHUTDOWN = 6 ea.
- FIRST AID & SCBA KIT = 3 ea.
- EYE WASH STATION = 3 ea.
- WIND SOCK = 1 ea.
- MUSTER POINT = 3 ea.

NOTES:

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
C	08/16/22	ISSUED FOR INFORMATION	HJP	CN	–
B	07/12/22	ISSUED FOR INFORMATION	RDC	CN	–
A	06/13/22	ISSUED FOR INFORMATION	RDC	RAF	–

F&C ENGINEERS
TX REG. NO. 8419

BAYSWATER

CLIENT : BAYSWATER EXPLORATION & PRODUCTION

PROJECT : SOUR GAS TREATING FACILITY

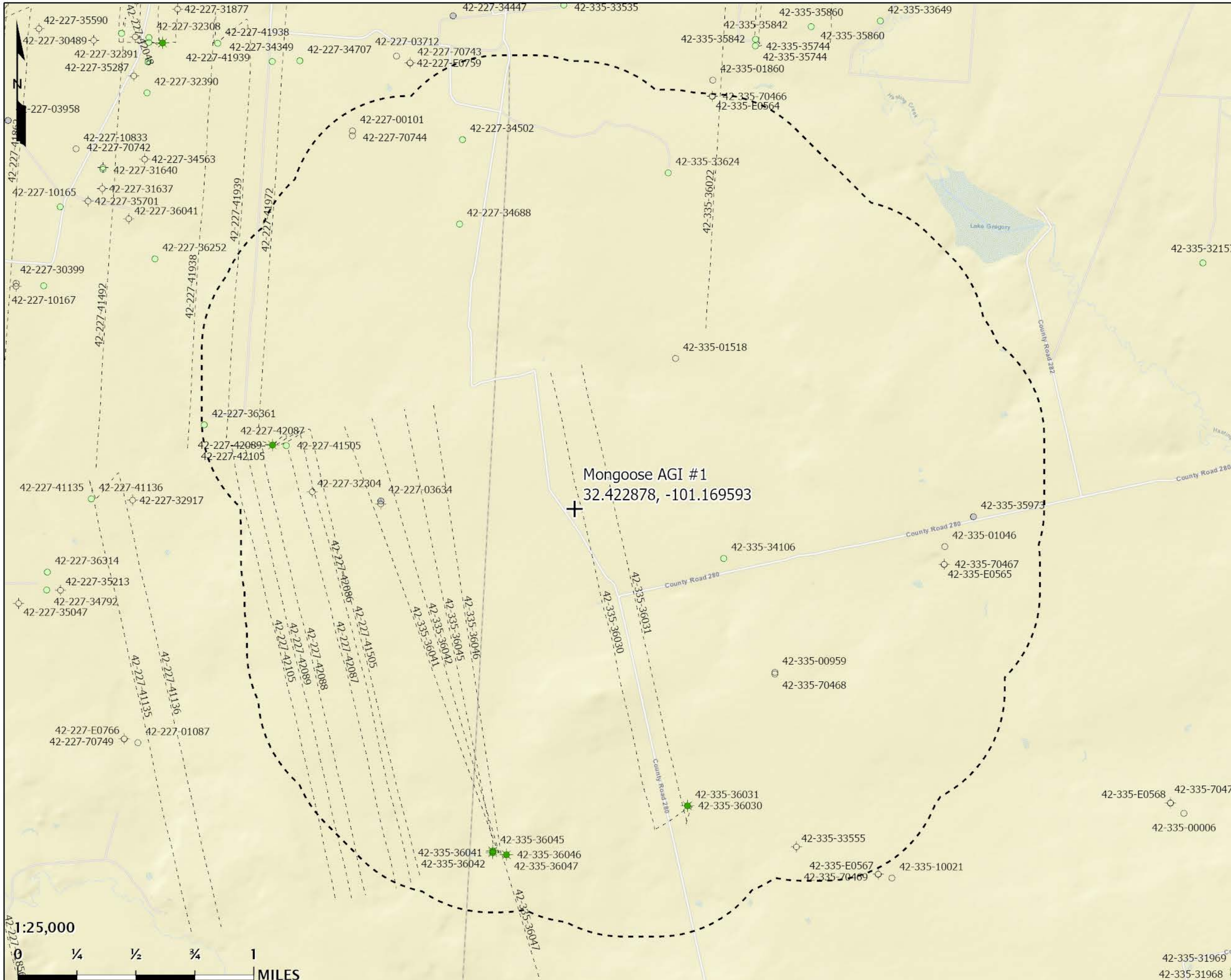
TITLE : INSTRUMENTATION FACILITY SAFETY LOCATION PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.	SHEET NO.	
RDC	GA	AS NOTED	06/09/22	BAY220316	IN-PLN-0790	1 OF 1	C

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST



C-1

Mongoose AGI No. 1

All Oil & Gas Wells

Bayswater Operating, LLC

Mitchell County, TX

Drawn by: SJL	Date: 10/19/2023	Approved by: SLP

PCS: NAD 1927 State Plane TX - N. Central FIPS 4202 (US Ft.)

LONQUIST SEQUESTRATION LLC

+ Mongoose AGI No. 1

Half Mile Buffer (from Plume @ Stabilization, Maximum Monitoring Area)

All Offset Well Directionals

All Offset Well SHLs

- <Null>
- CBM
- CONFIDENTIAL
- DISPOSAL
- DRY HOLE
- GAS
- INJECTION
- OIL
- OIL & GAS
- OTHER
- SERVICE
- STORAGE
- UNKNOWN
- WATER
- <all other values>

Mongoose AGI No. 1

Area of Review: Oil & Gas Wells List										
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022
4222741505	KAMIKAZE 5-8-17-20	3W	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023

LONQUIST SEQUESTRATION LLC

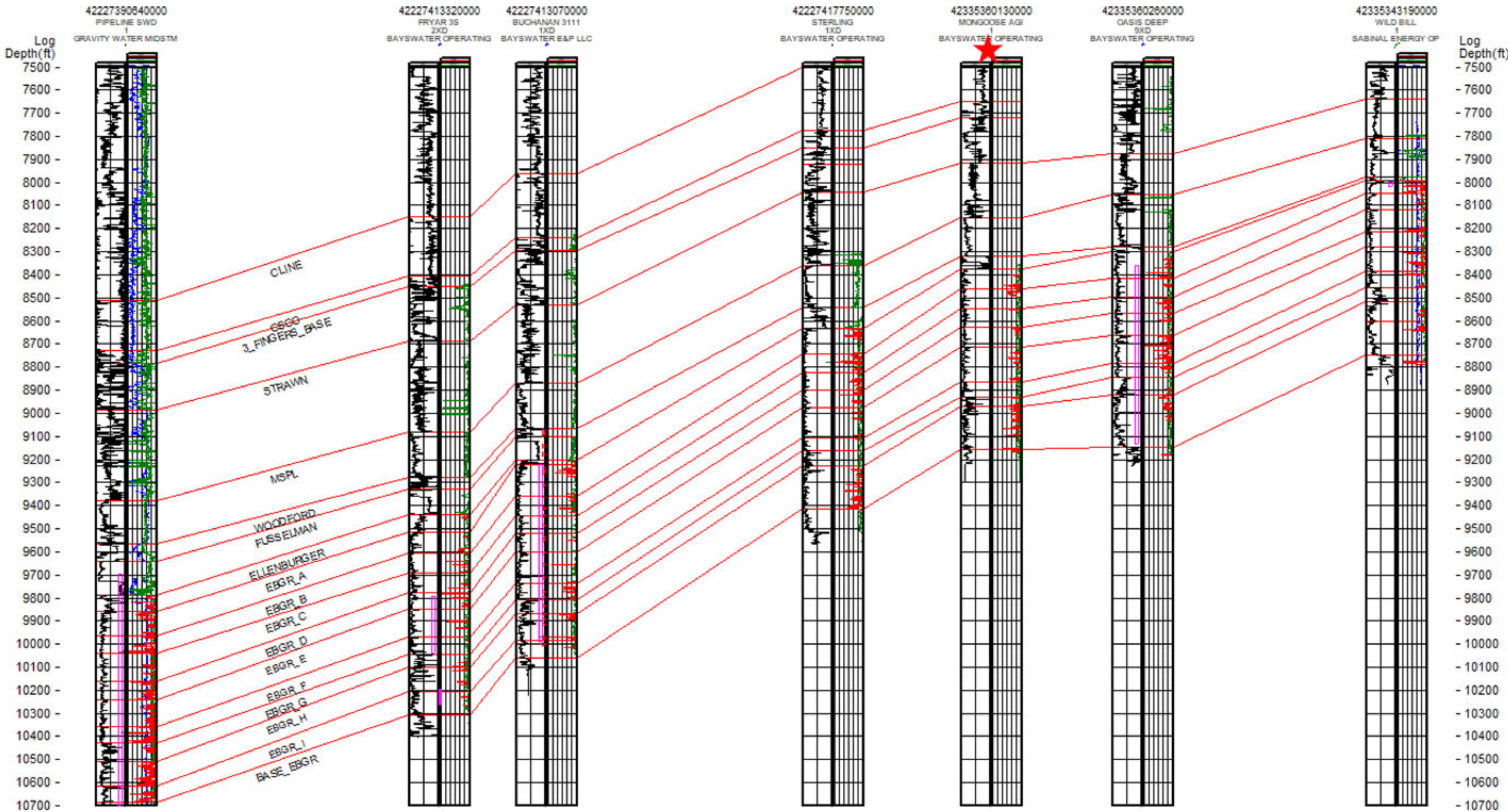
Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.

APPENDIX D – SECTION 2 CROSS SECTIONS

D-1



42227390640000
PIPELINE SWD
1
GRAVITY WATER MIDSTM
42227413320000
FRYAR 3S
2XD
BAYSWATER OPERATING
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BUCHANAN 3111
1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
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OASIS DEEP
9XD
BAYSWATER OPERATING
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SABINAL ENERGY OP
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7700
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STRAWN
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
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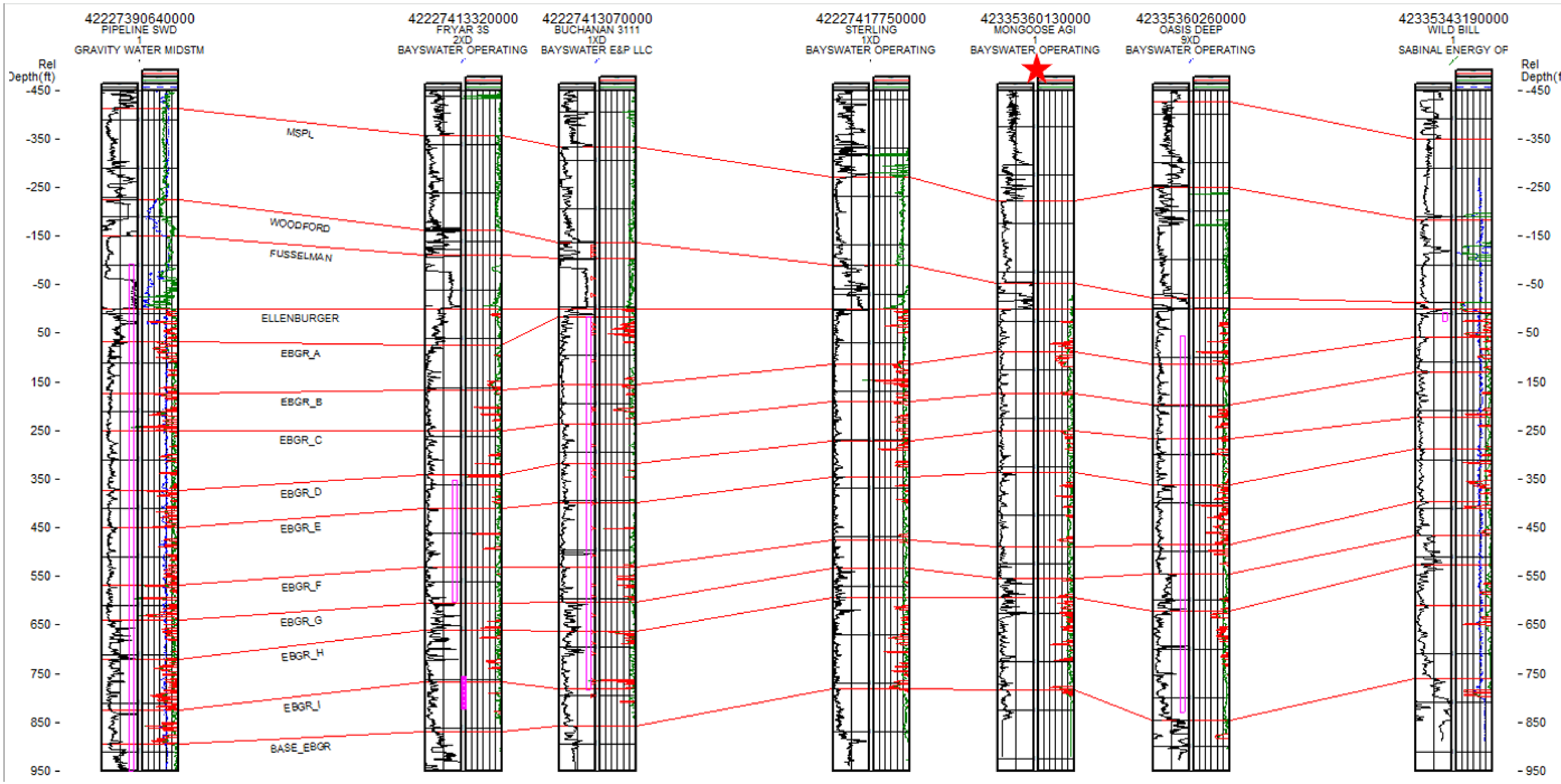
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR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GRAVITY WATER MIDSTM
42227413320000
FRYAR 3S
2XD
BAYSWATER OPERATING
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1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Rel Depth(ft)
-450
-350
-250
-150
-50
50
150
250
350
450
550
650
750
850
950
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR

Request for Additional Information: Mongoose Amine Treating Facility
August 12, 2024

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	2.4	42	"Large scale versions of Figures 28 and 29 are provided in Appendix C." According to the Appendices submitted with the MRV plan, Appendix D contains the structural and stratigraphic cross sections. Note that these figures are identified as Figures 27 and 28 in the Appendices. Please review the MRV plan to ensure that all references to external documents within the text are correct.	Section 2.4 and the Appendix D have been updated accordingly.
2.	4.2	71	"The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset APs is unlikely." The term "APs" is not defined anywhere in the MRV plan. Please ensure that all acronyms are defined during the first use within the MRV plan.	Section 4.2 has been updated with the term "artificial penetrations".
3.	4	67	"The lateral continuity of the UCZ is recognized as a very competent seal." This statement appears in Table 12. Please specify how the UCZ being a competent seal relates to the likelihood of leakage for each of these pathways or update the descriptions accordingly.	Table 12 has been updated to explain how the confining interval provides a competent seal relative to the leakage pathways.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	7.5	85	"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." Per 40 CFR 98.443(f)(2), this variable should be, "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**." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Equation 7.5 has been updated to include ", for which a calculation procedure is provided in subpart W of this part"

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC*
Denver, CO

By

Lonquist Sequestration, LLC
Austin, TX

Version 3.0
May 2024

INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.

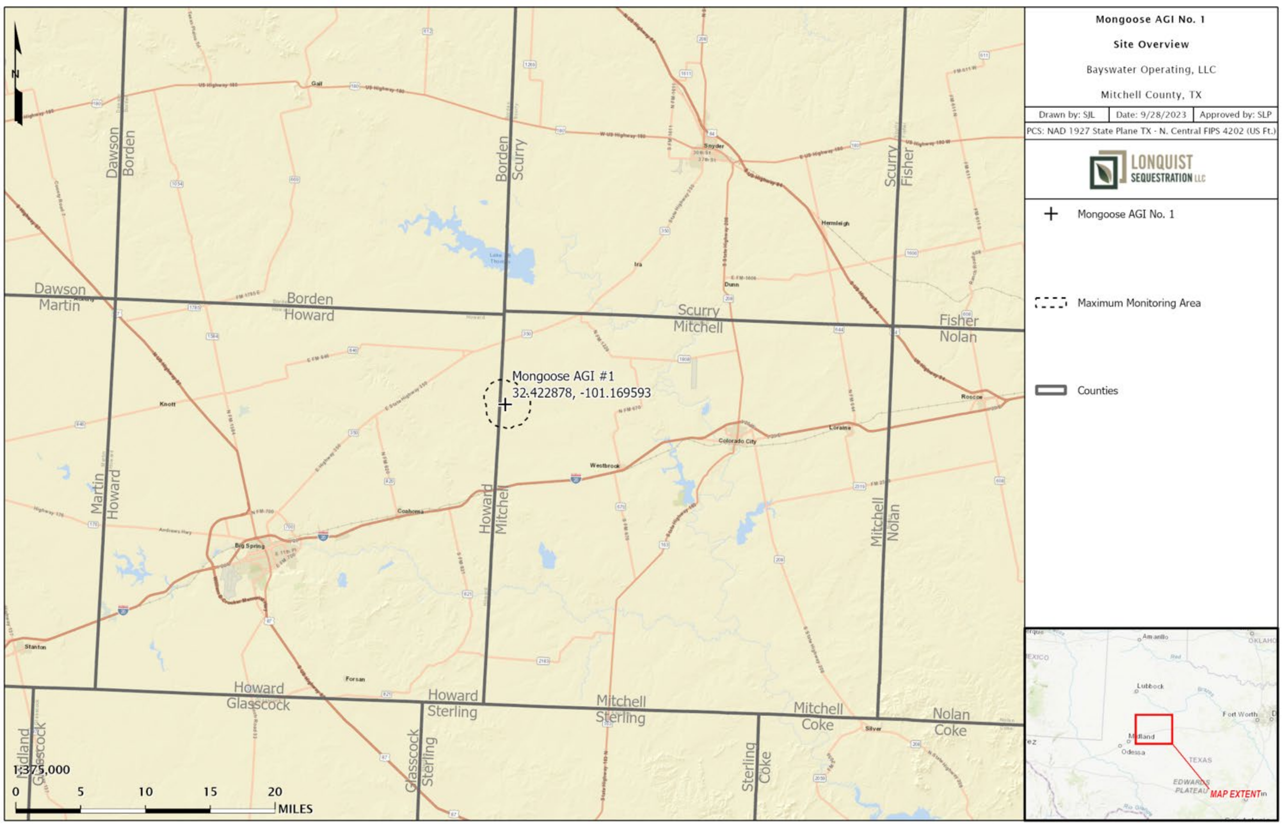

Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO_2 gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
pH	Scale of Acidity
PISC	Post Injection Site Care
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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Appendices

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 Reporter Number

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
    - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility
1625 County Road 280
Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641
Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).

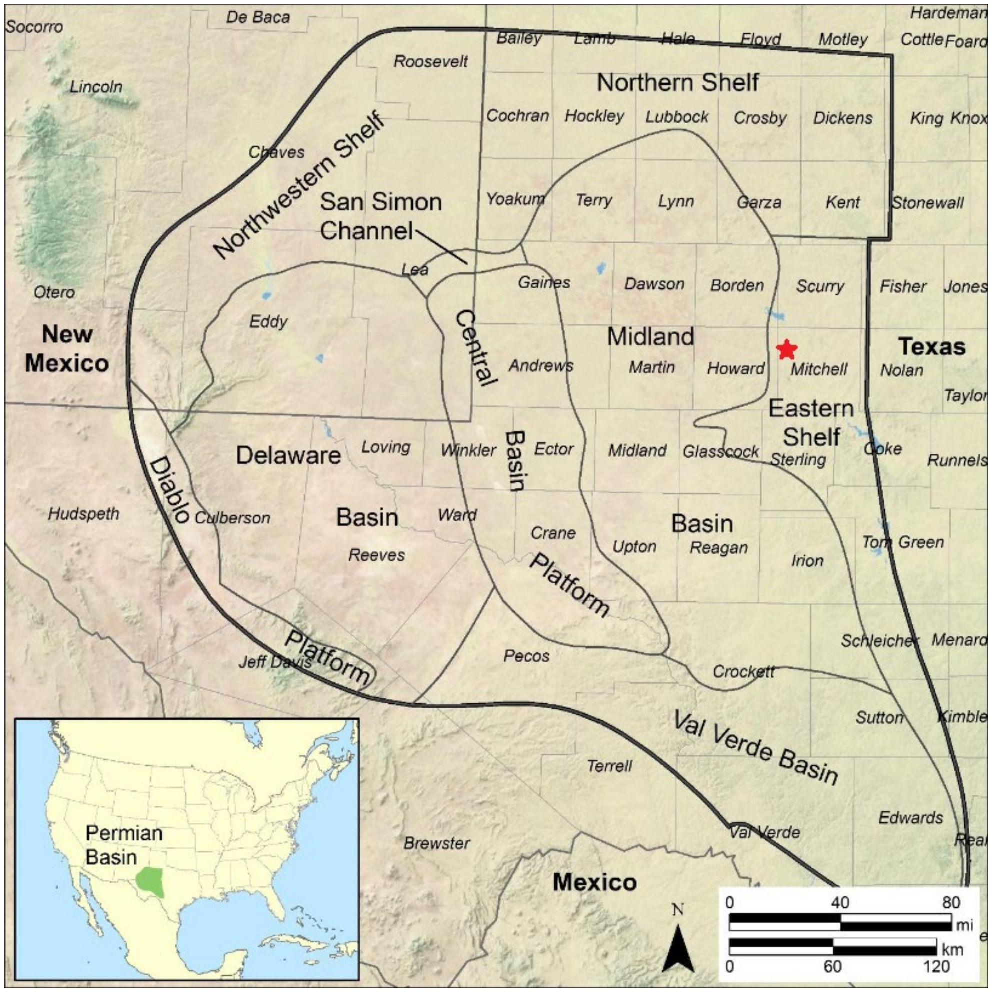


Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).

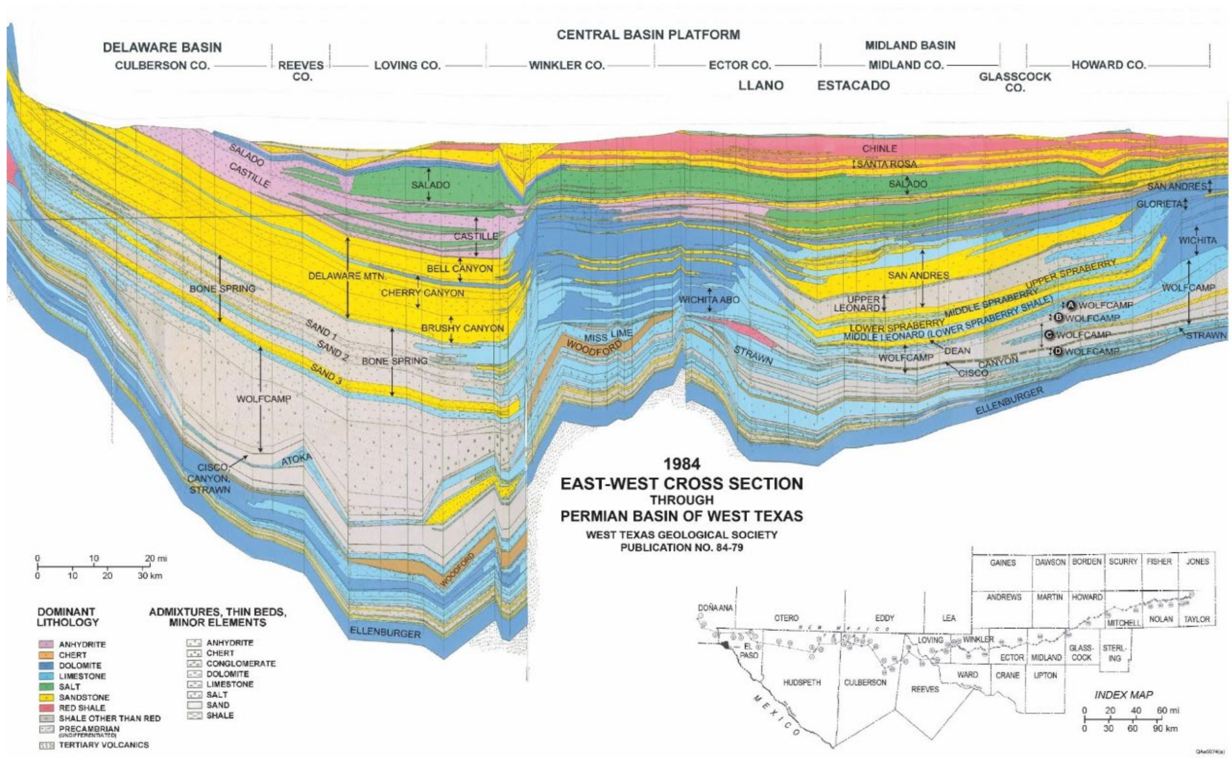


Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).

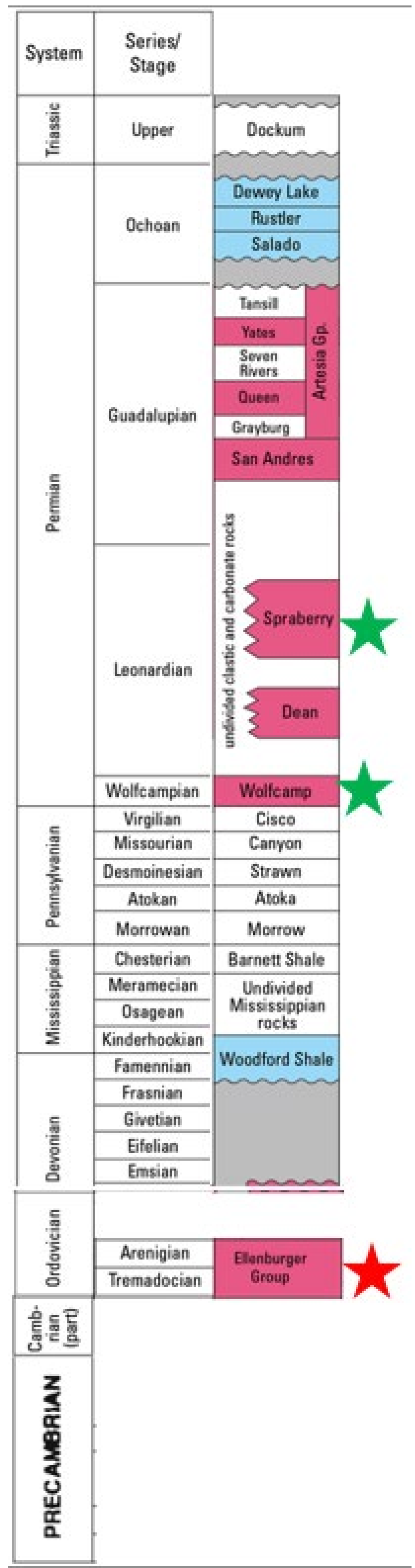


Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf

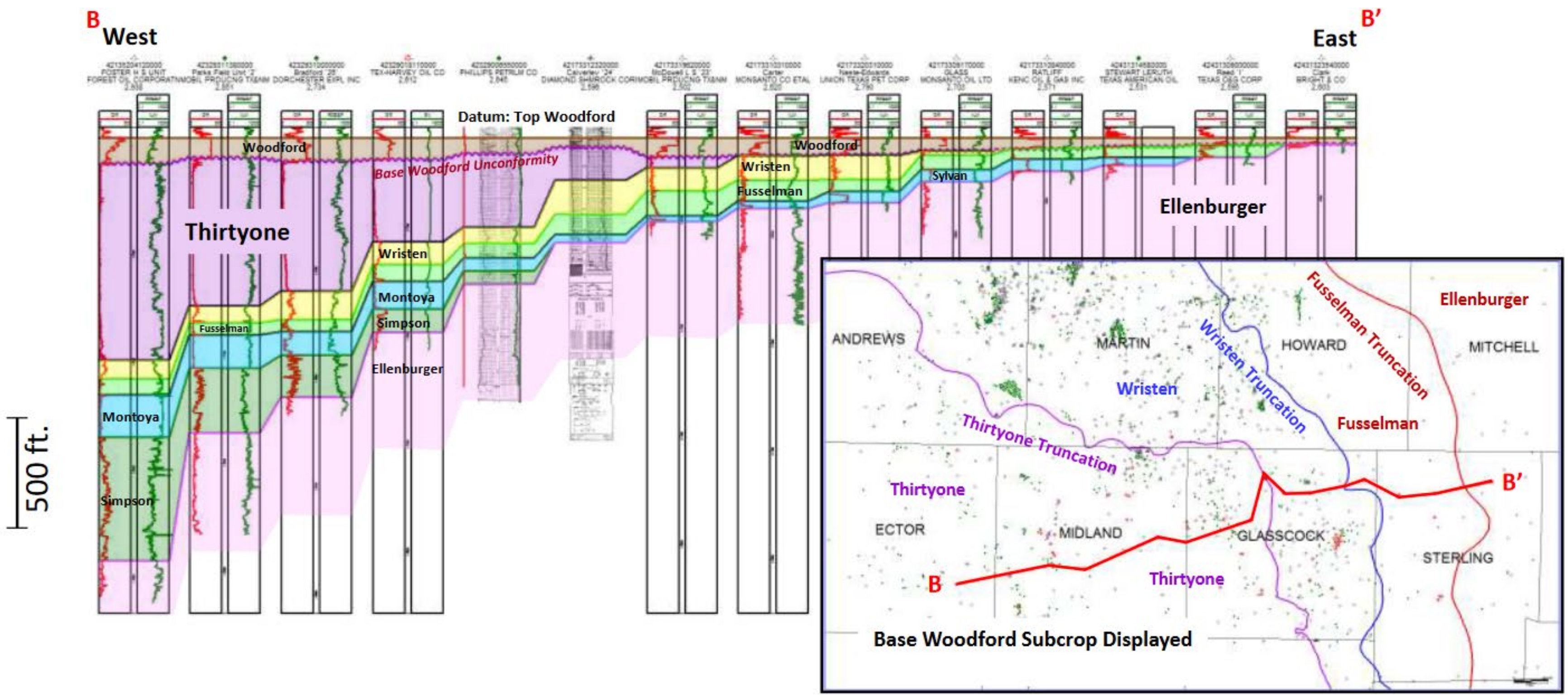


Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).

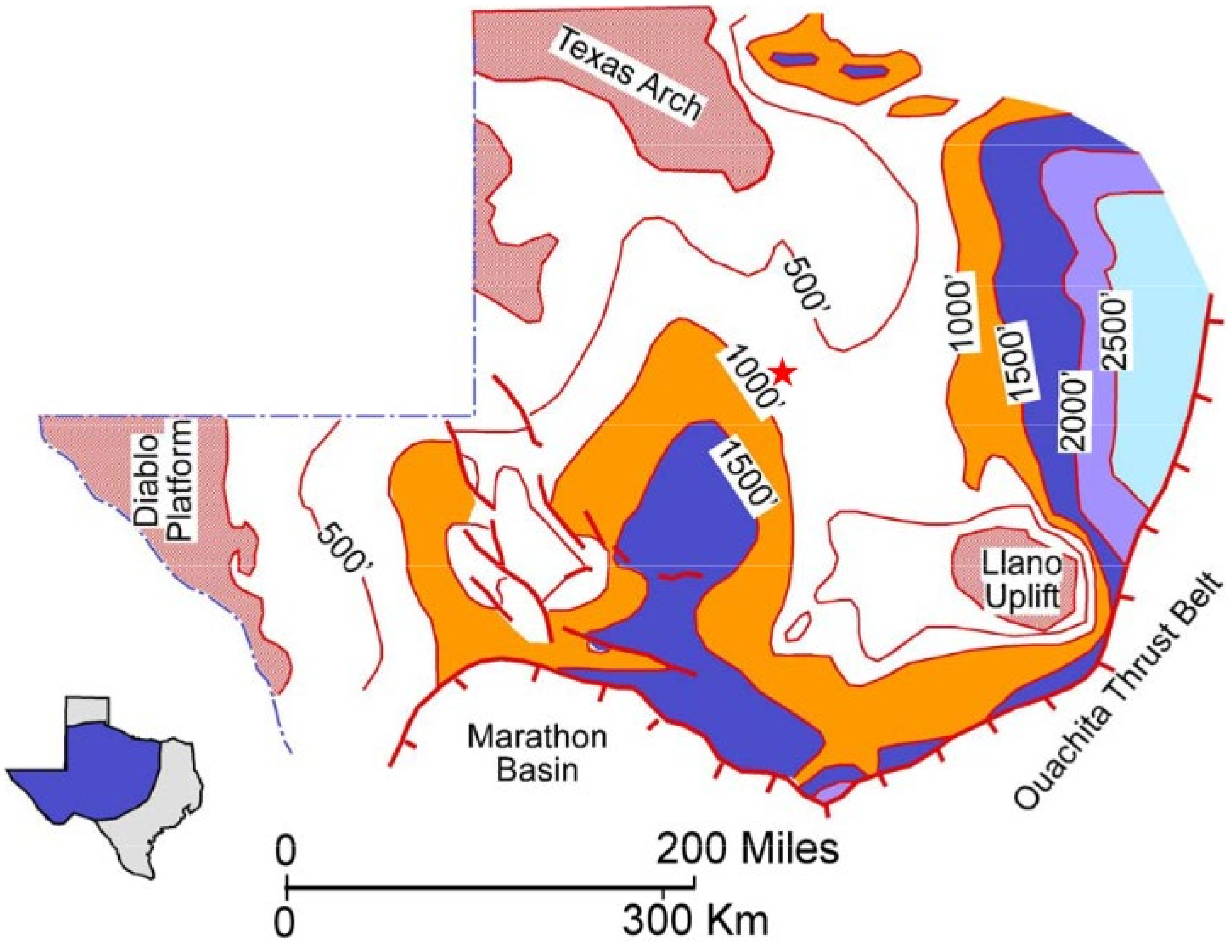


Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)

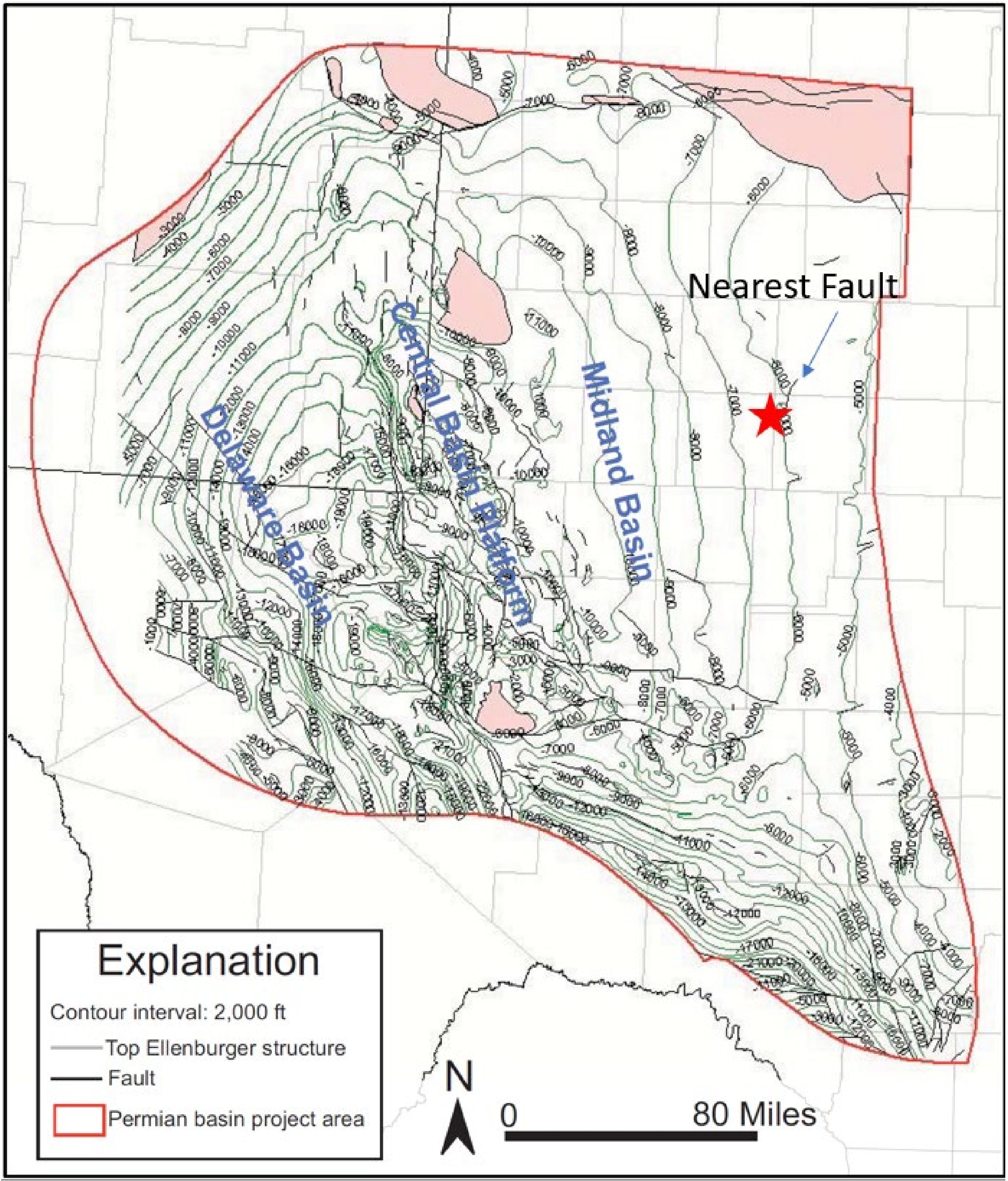


Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).

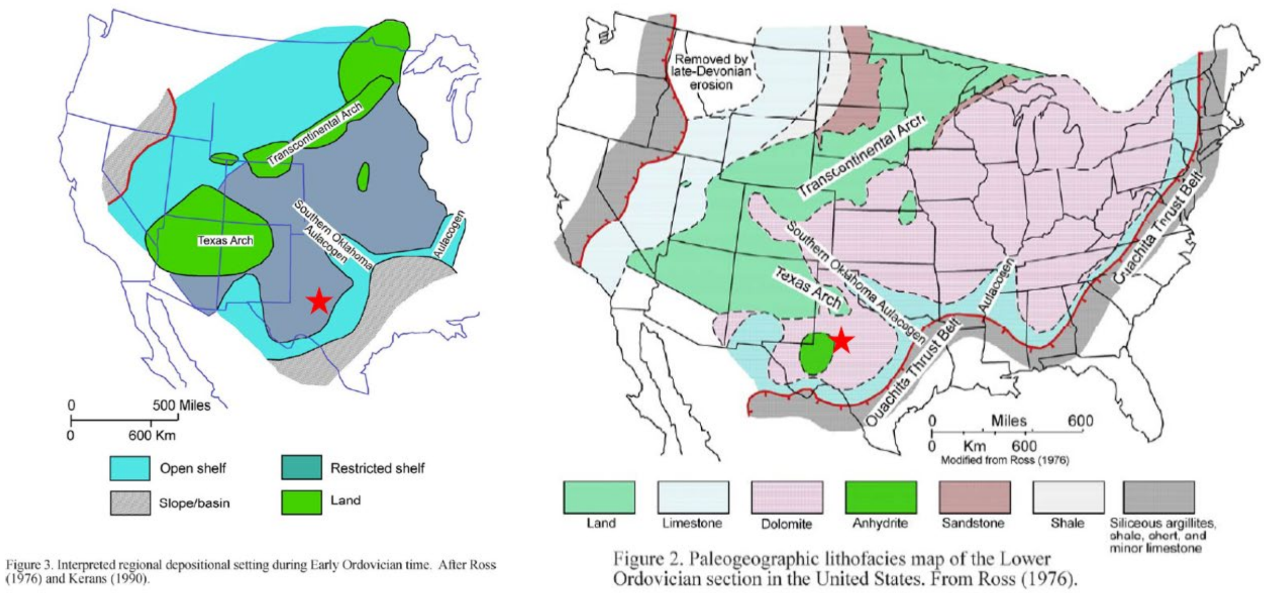


Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).

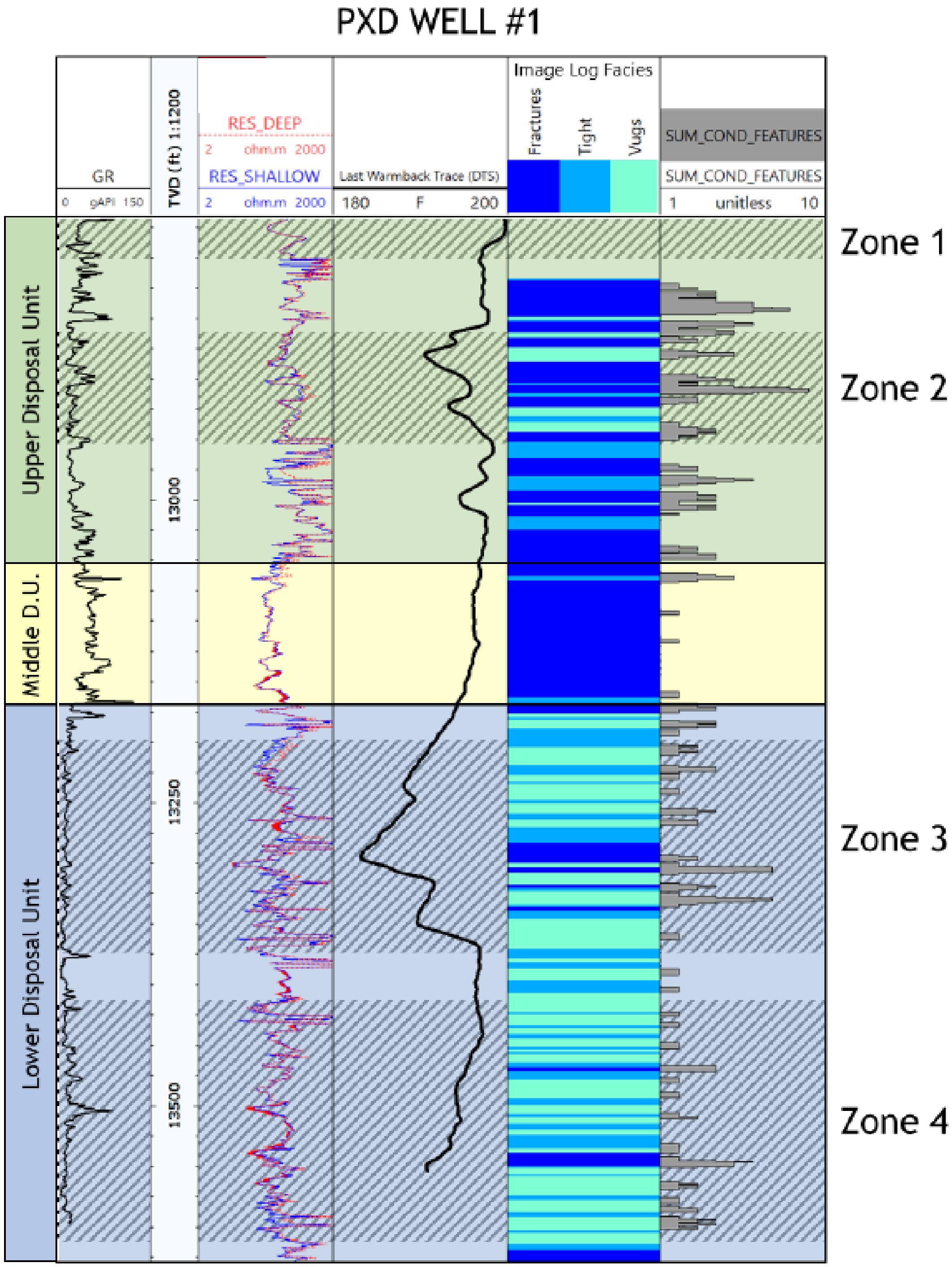


Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, & Coringrato, 2019)

2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.

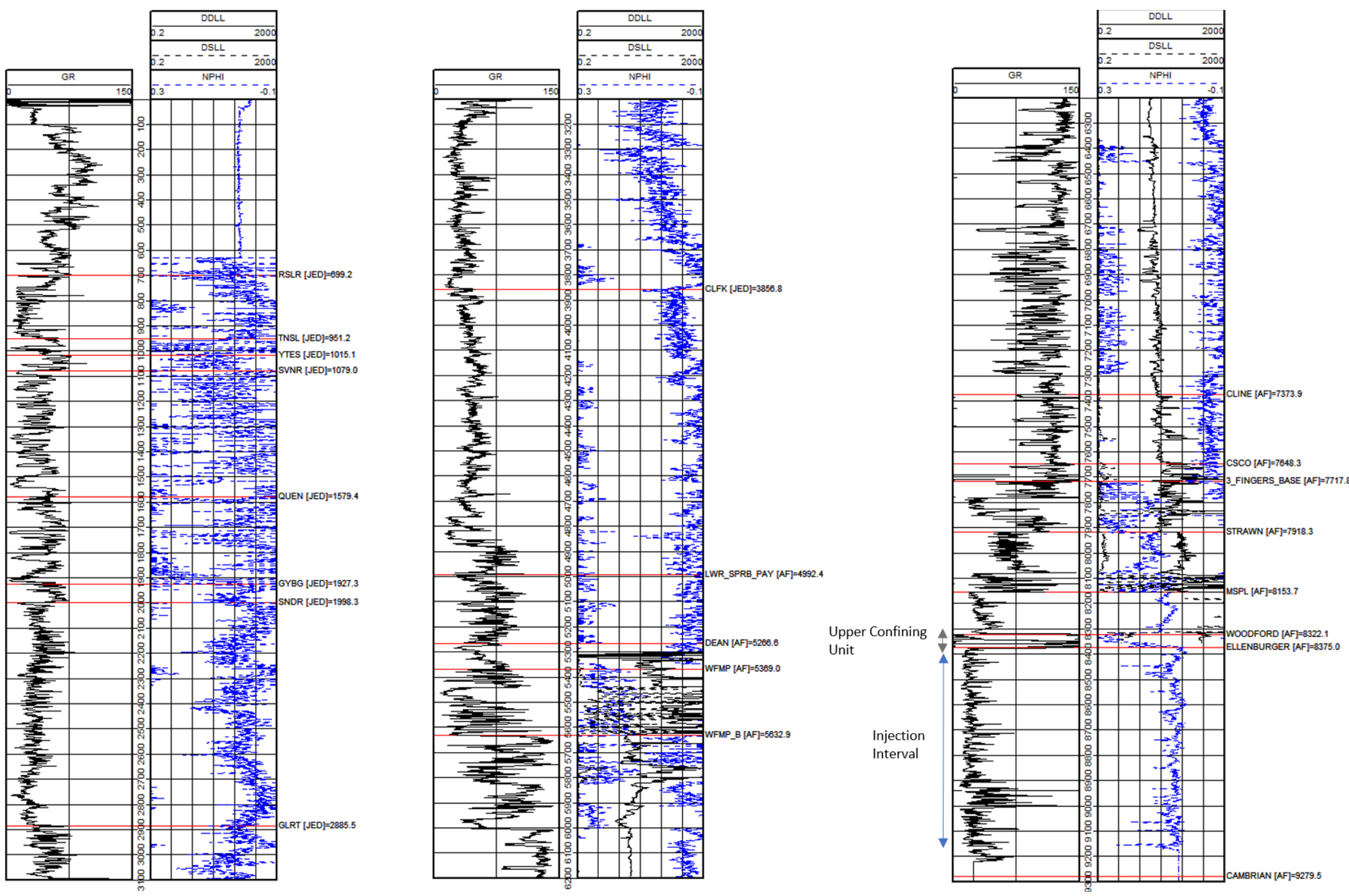


Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown previously in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO_2 Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.

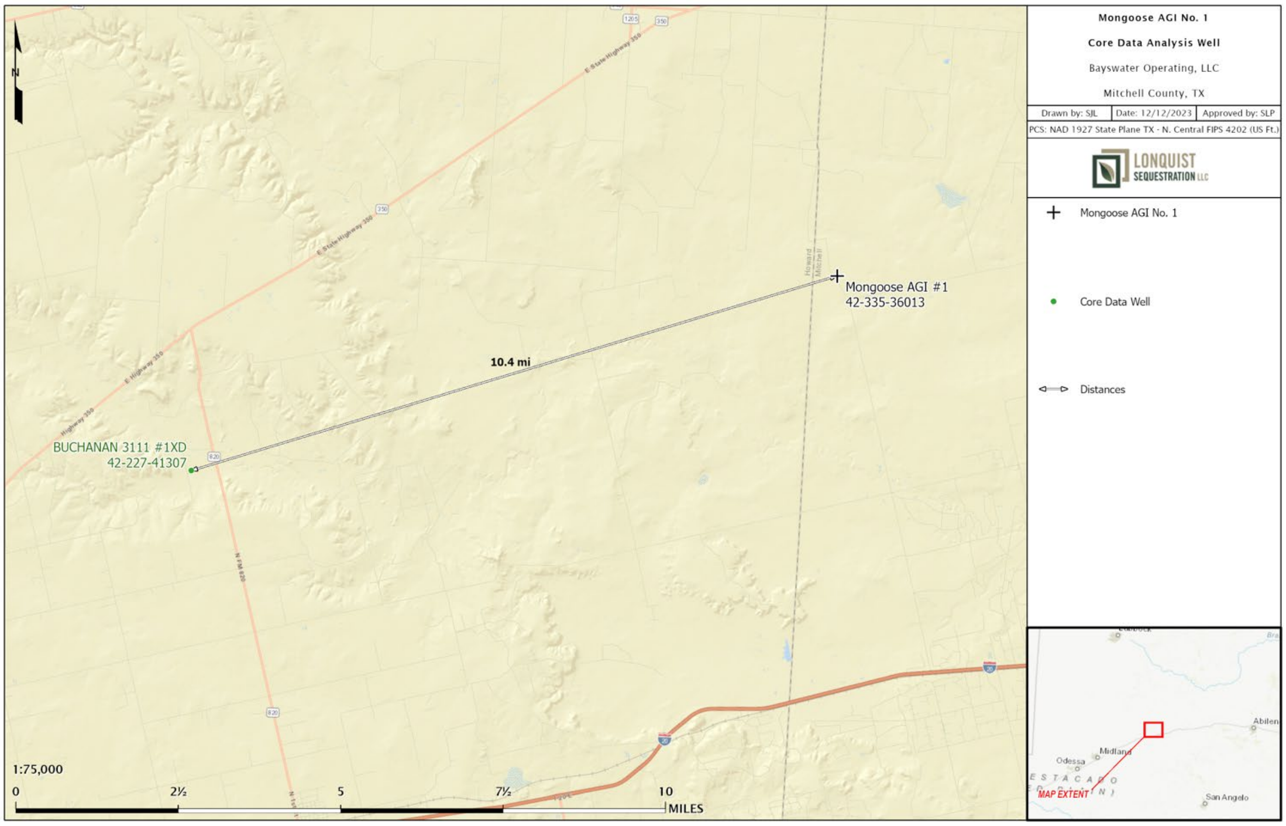


Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data

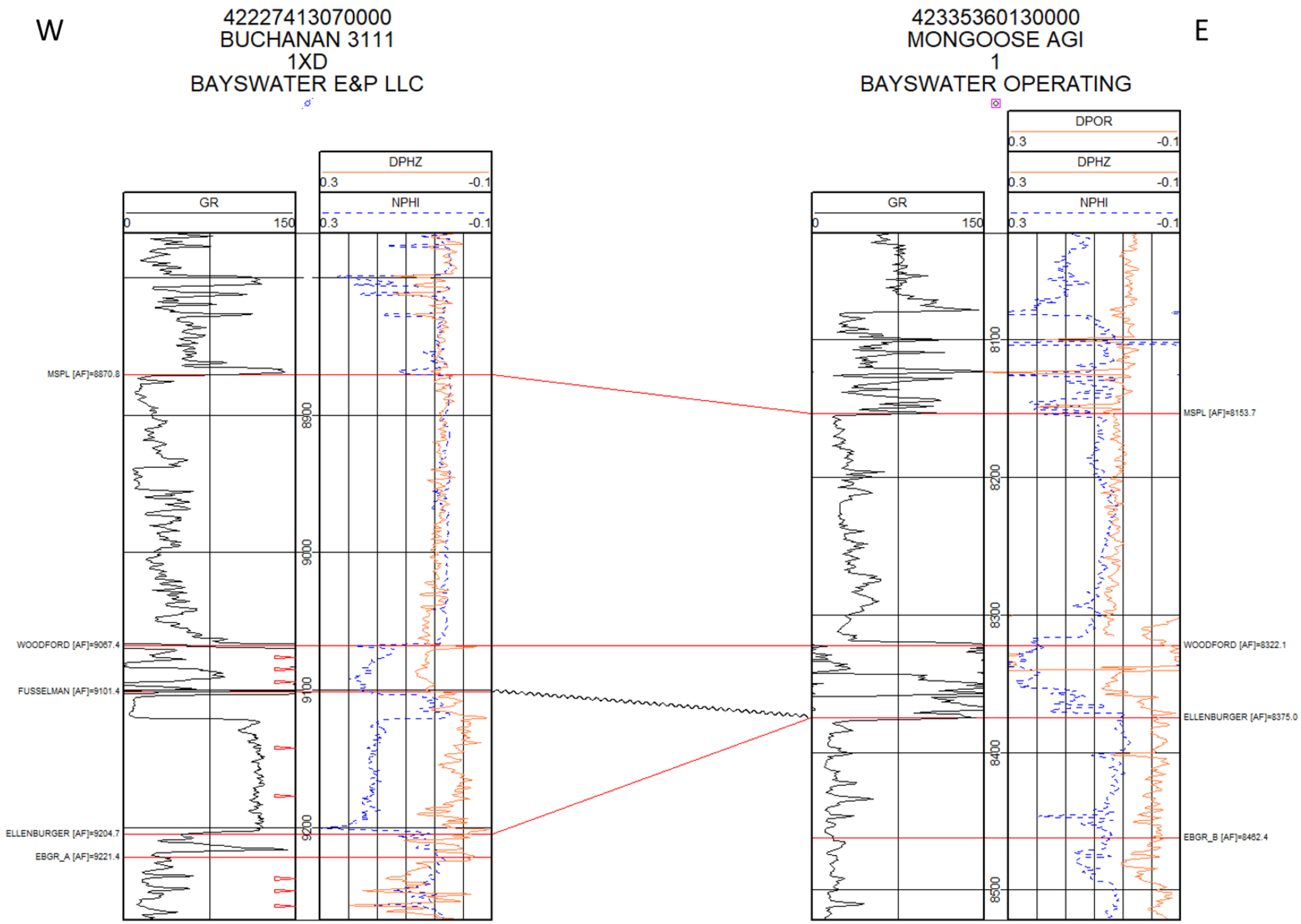


Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.

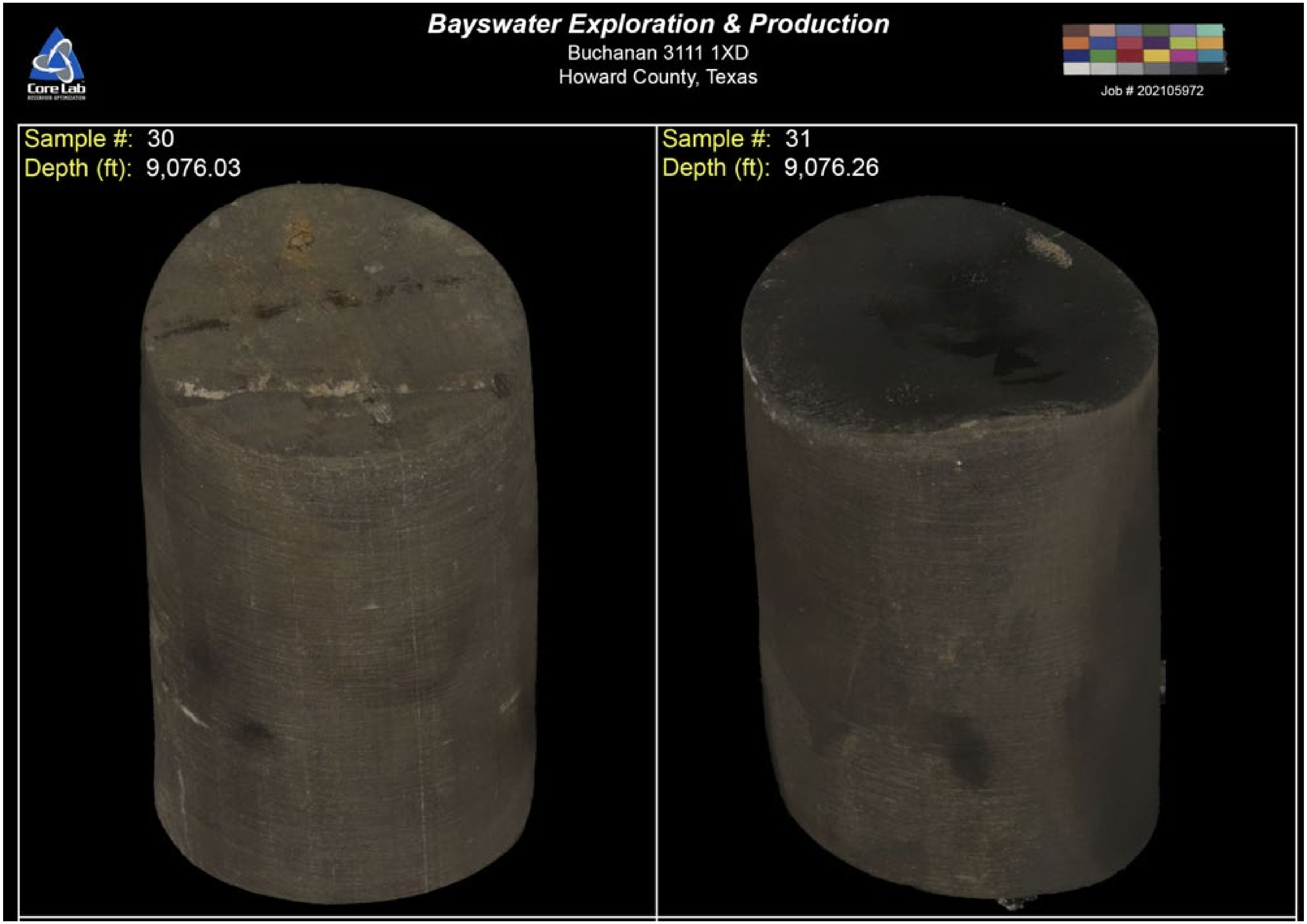


Figure 13 – Core Photo of Samples Within the Woodford Formation

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: February 04, 2022
Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

		As received				Dry & Dean Stark Extracted Conditions (2)				
Sample	**Depth** (ft)	**Bulk Density** (g/cc)	**Matrix Permeability (1)** (mD)	**Gas-filled Porosity** (%)	**Gas Saturation** (%)	**Grain Density** (g/cc)	**Matrix Permeability (5)** (mD)	**Porosity** (%)	**Oil Saturation (3)** (%)	**Water Saturation (4)** (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.
(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.
(3) Oil volume computed assuming an oil density of 0.844 g/cc
(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc
(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS
Net Confining Stress: 2960 psi   Temperature: 68°F
Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas   File: HOU-2105972

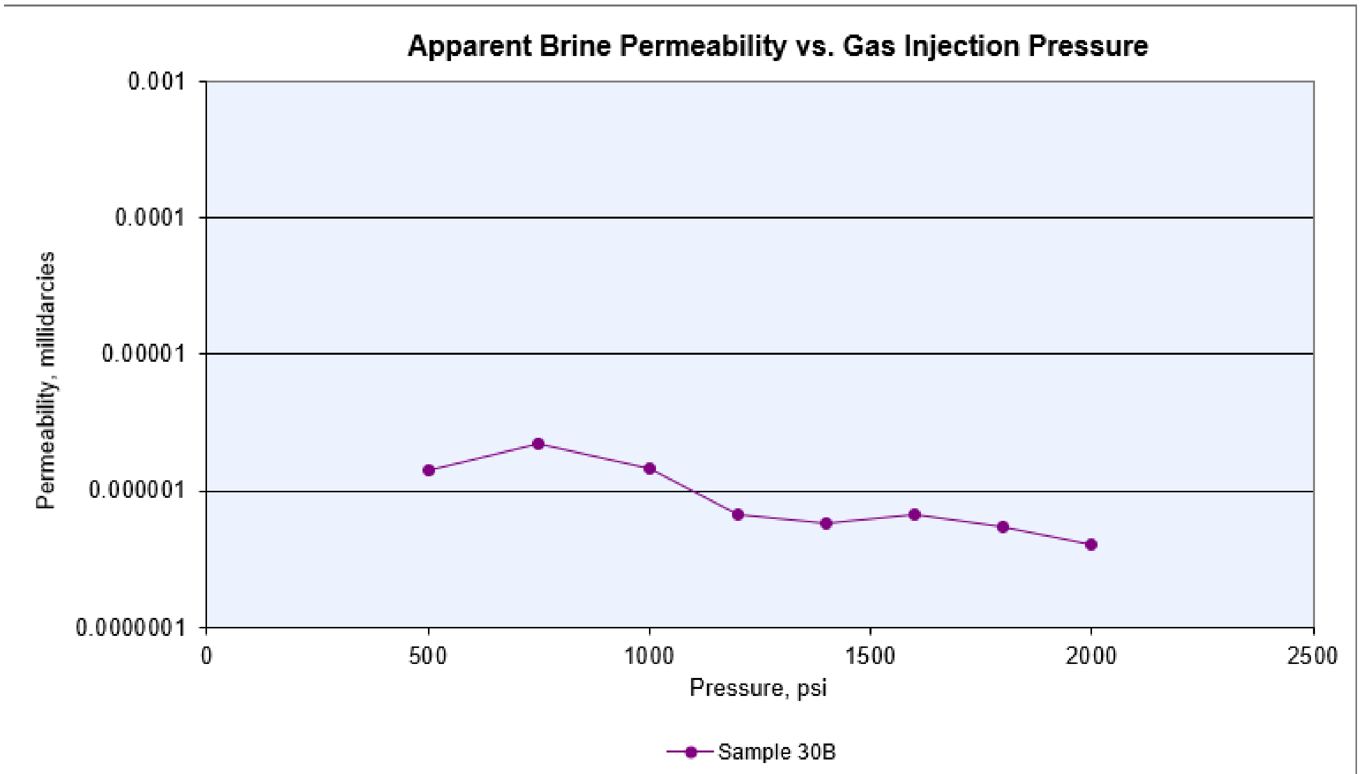


Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F
Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample 30B	
Gas Injection Pressure, psi	Permeability to Brine*, mD
500	1.44E-06
750	2.20E-06
1000	1.46E-06
1200	6.73E-07
1400	5.77E-07
1600	6.72E-07
1800	5.39E-07
2000	4.03E-07

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi   Temperature: 68°F
Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample Number	Depth, feet	Length, cm	Diameter, cm	Final Permeability to Brine*, millidarcies	Threshold Entry Pressure, psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and non-applicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A two-function porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

If Effective Porosity (Φeff) < 6.5%: $K(mD) = 7E{-}08e^{3.3028*\Phi \mathrm{eff}}$

If Effective Porosity (Φeff) > 6.5%: $K(mD) = 277.39\ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: March 31, 2022
Analyst(s): MP

CMS-300 ROTARY SIDEWALL ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability: Klinkenberg (md)	Permeability: Kair (md)	b(air) psi	Beta ft(-1)	Alpha (microns)	Saturation: Oil (% Pore Volume)	Saturation: Water (% Pore Volume)	Grain Density (g/cm3)	Footnote
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

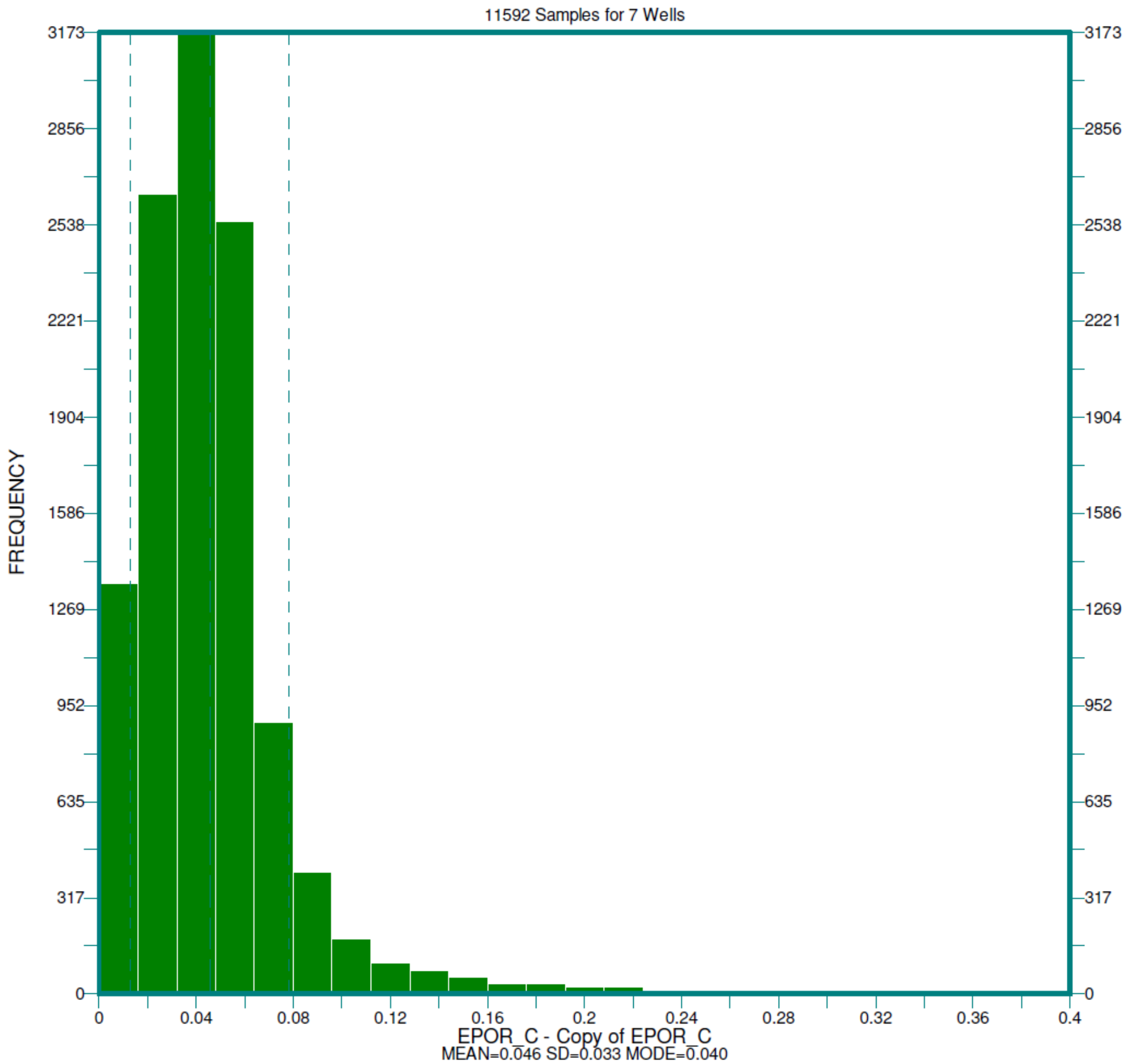


Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

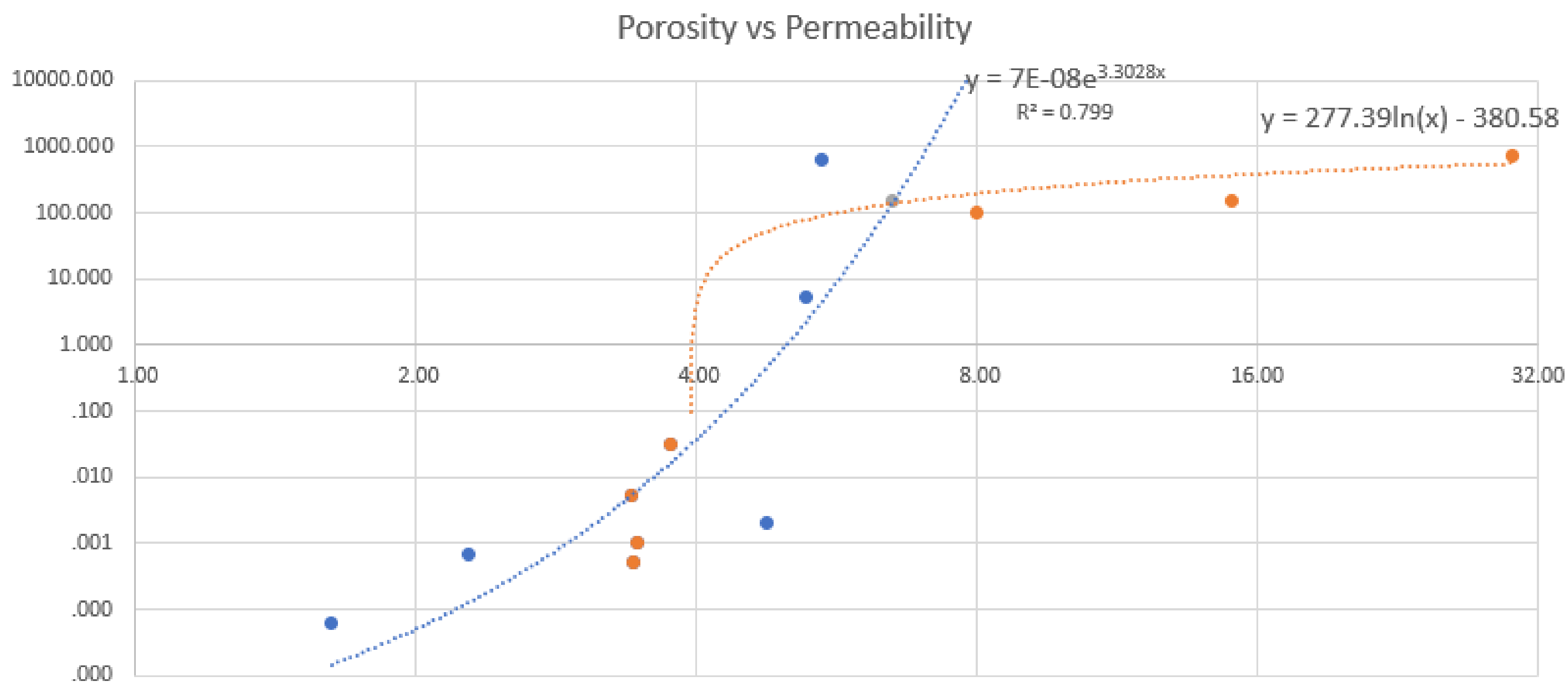


Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data

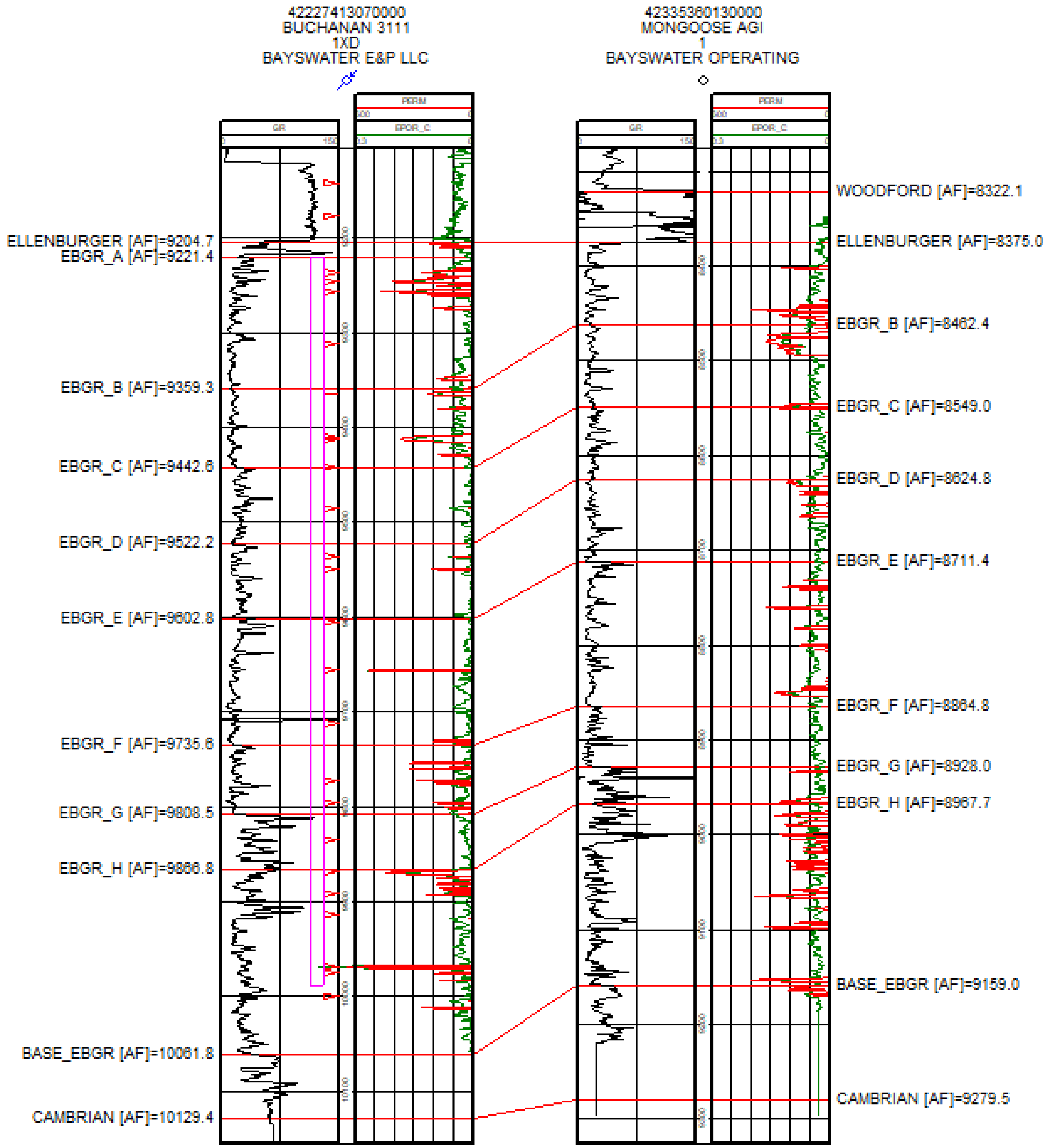


Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.

Figure 23 – Core photo of Ellenburger sample displaying vug features.

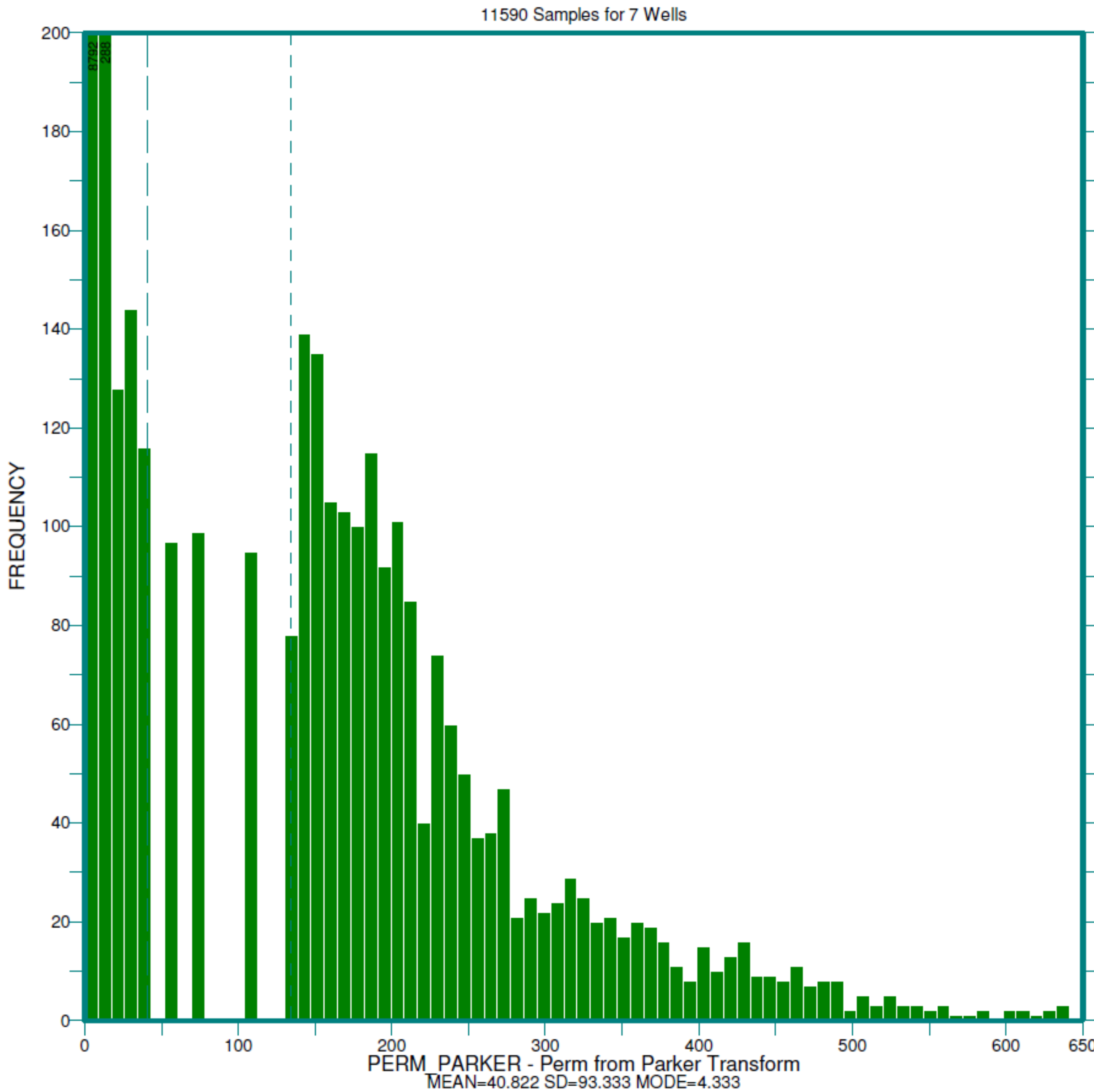


Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oil-field brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.

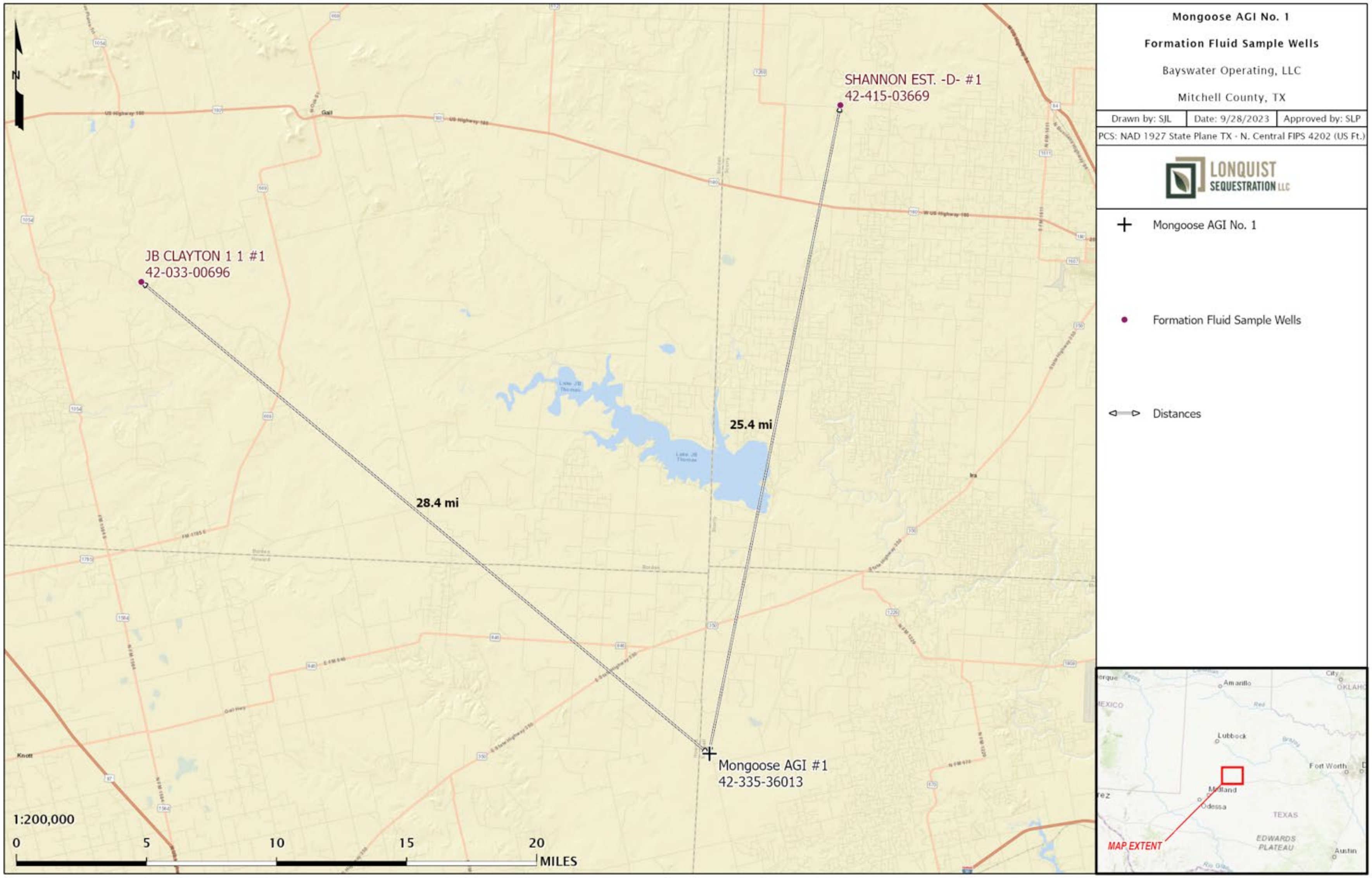


Figure 25 – Offset wells used for formation fluid characterization.

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
pH	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian". Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.

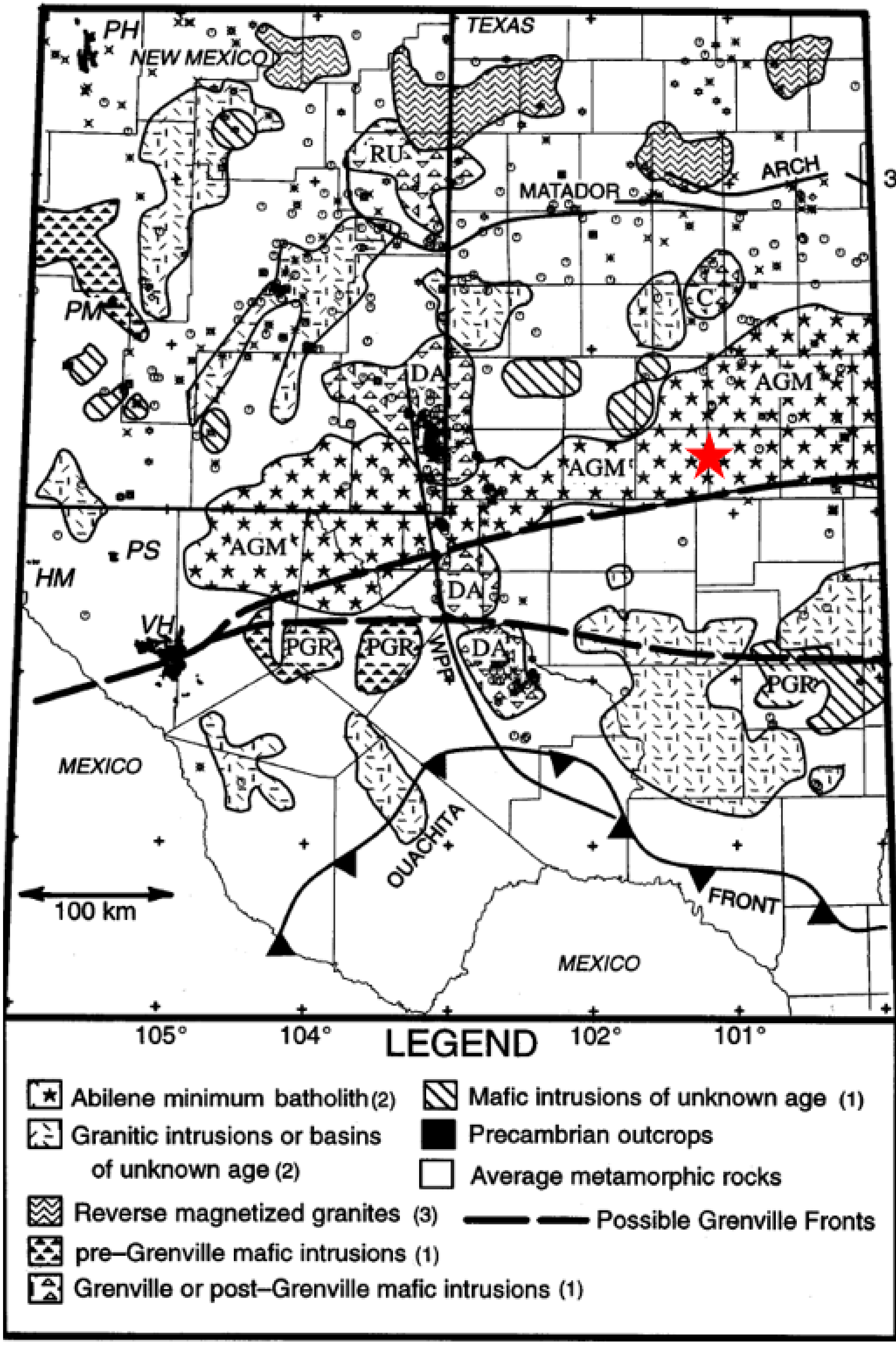


Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Table 4 – Calculated Vertical Stresses

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$\nu = \frac{\frac{1}{2}\left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

ν = Poisson's Ratio
v_p = Compressional Velocity
v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1-0.261}(1.029 - 0.465) + 0.465 = 0.664\, psi/ft$$

$$FG\ with\ SF = 0.689\ \times 90\% = \mathbf{0.598}\, \boldsymbol{psi/ft}$$

Table 5 – Fracture Gradient Calculation Inputs and Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 <u>Local Structure</u>

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix C*.

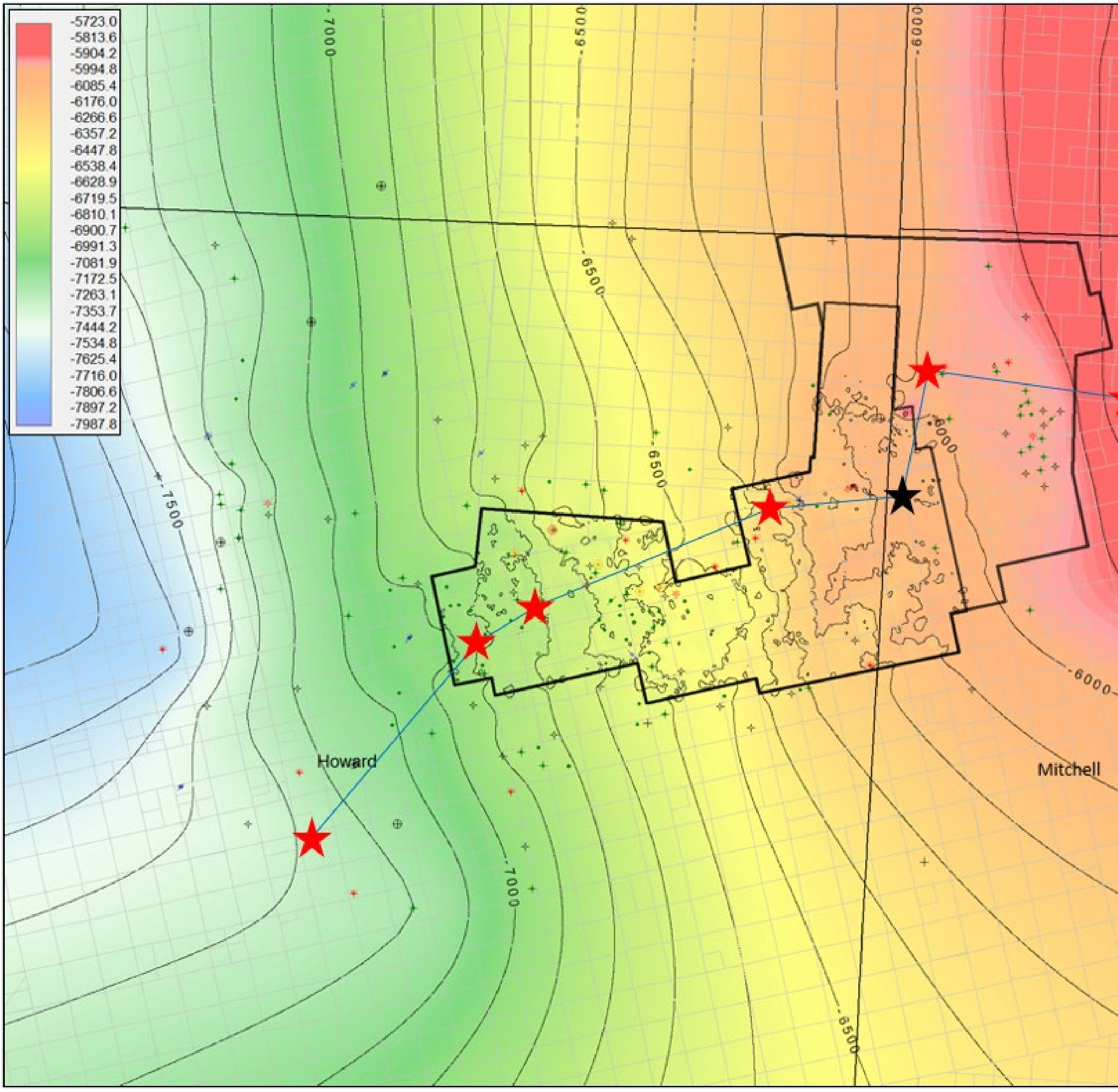


Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.

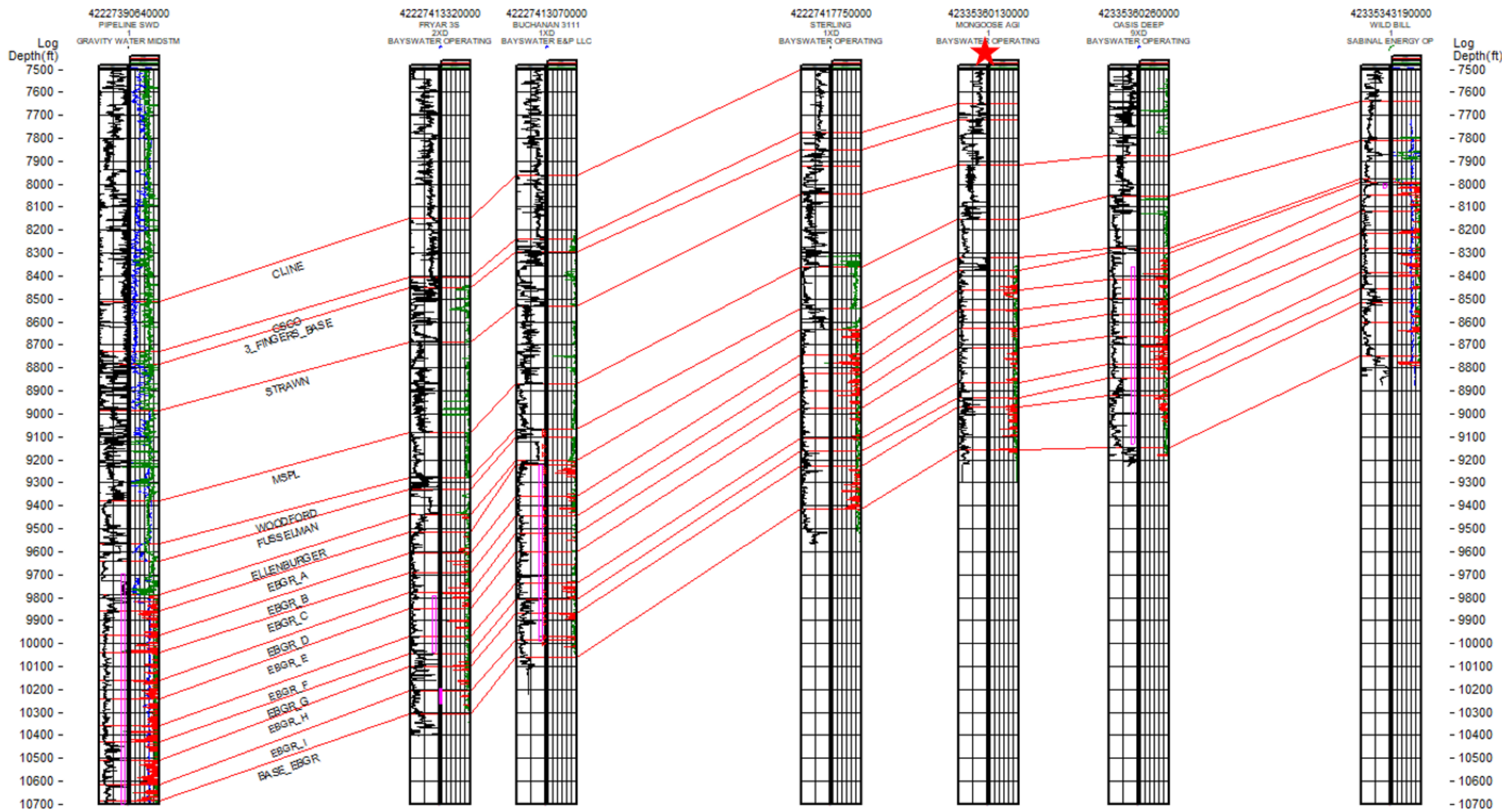


Figure 28 – Structural cross section depicting the Ellenburger.

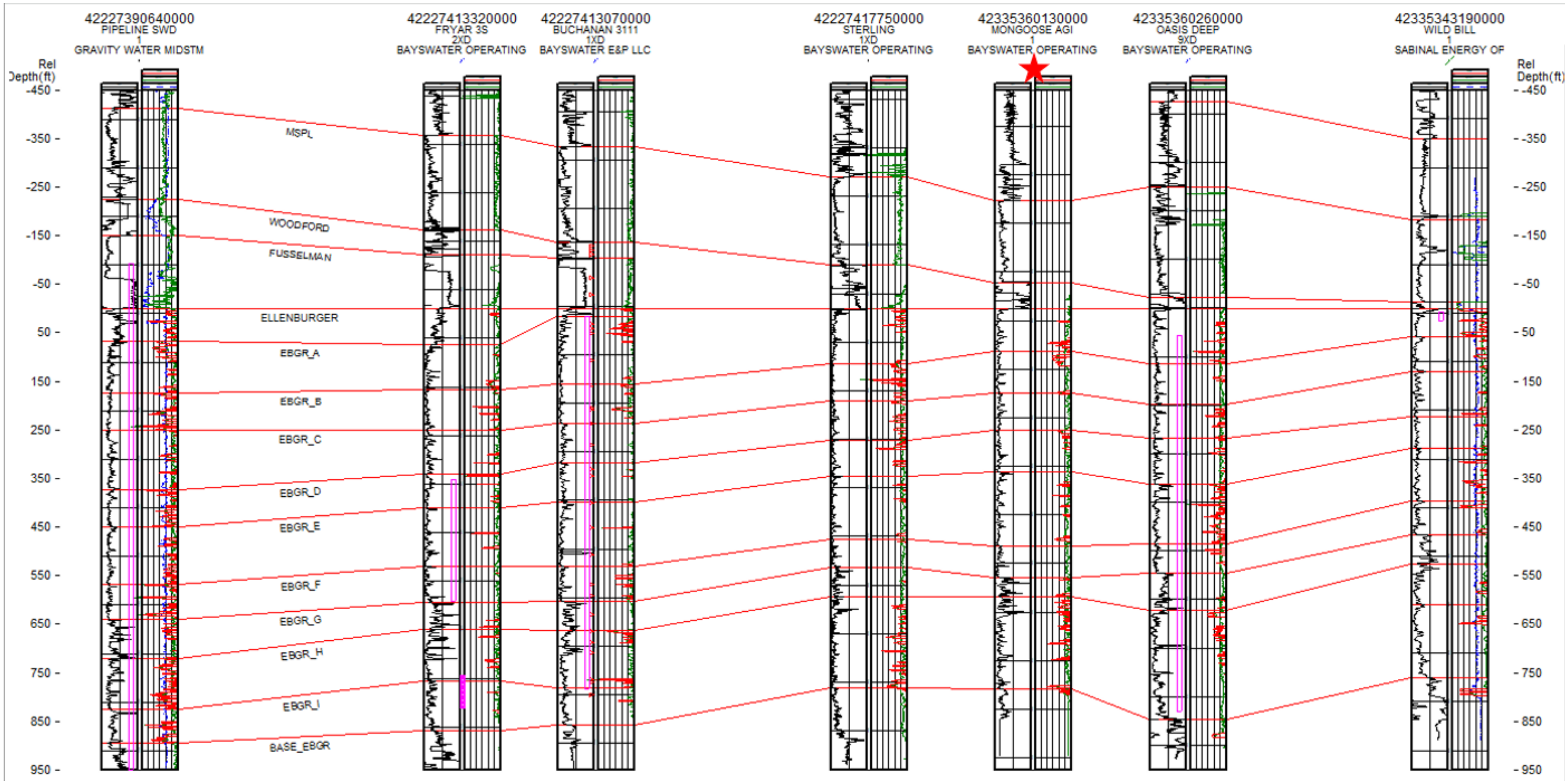


Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colorado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
Cretaceous	Comanche	Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous limestone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potable but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
Triassic		Dockum	Chinle	0-640	Predominantly red to maroon and purplish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sandstone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
			Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaceous and carbonaceous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capacity of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to highly mineralized water to livestock and domestic wells.

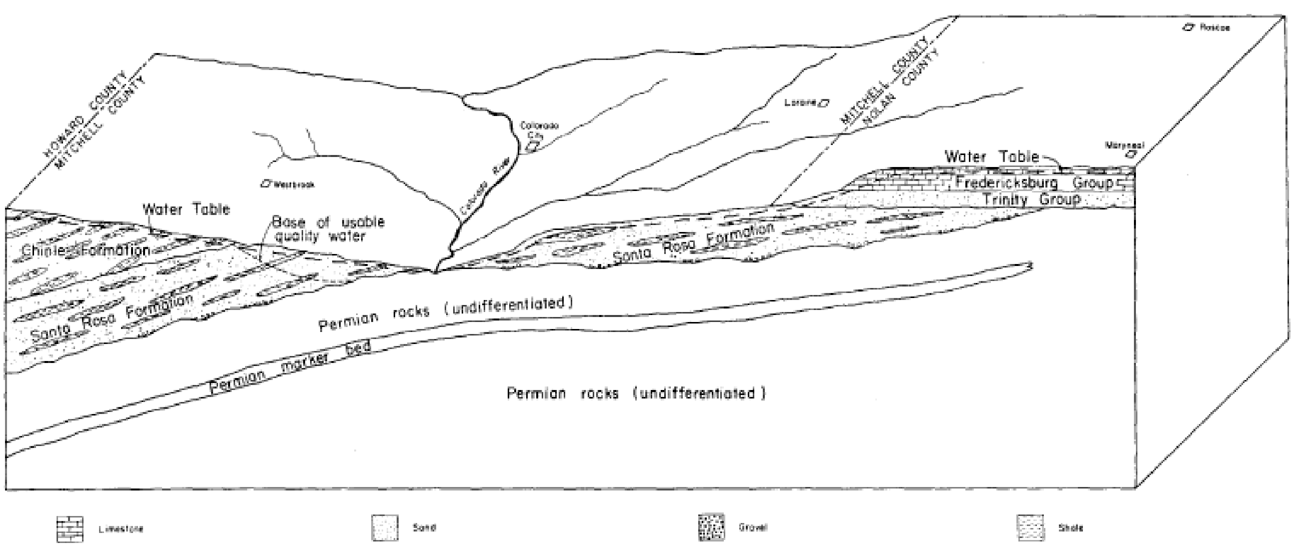


Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.

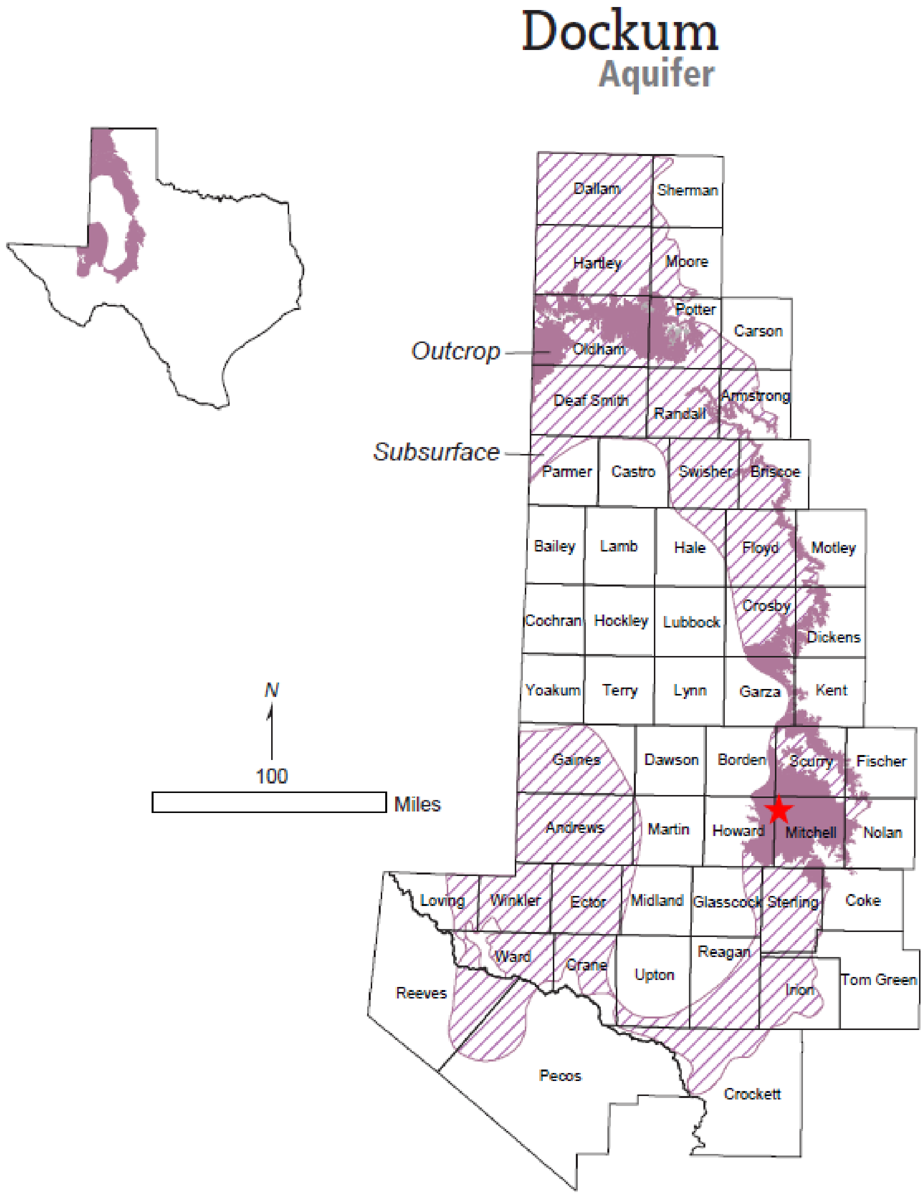


Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).

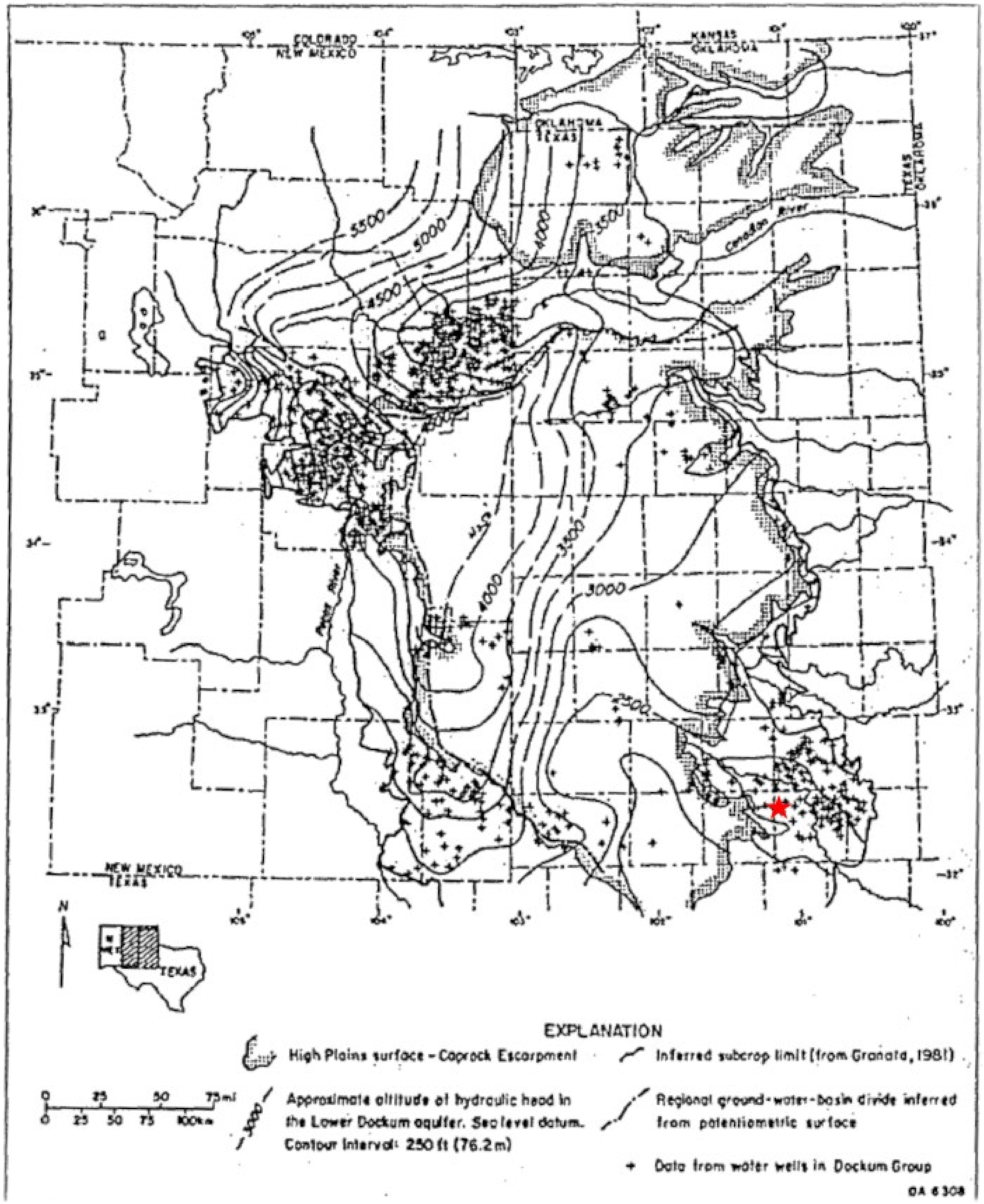


Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).

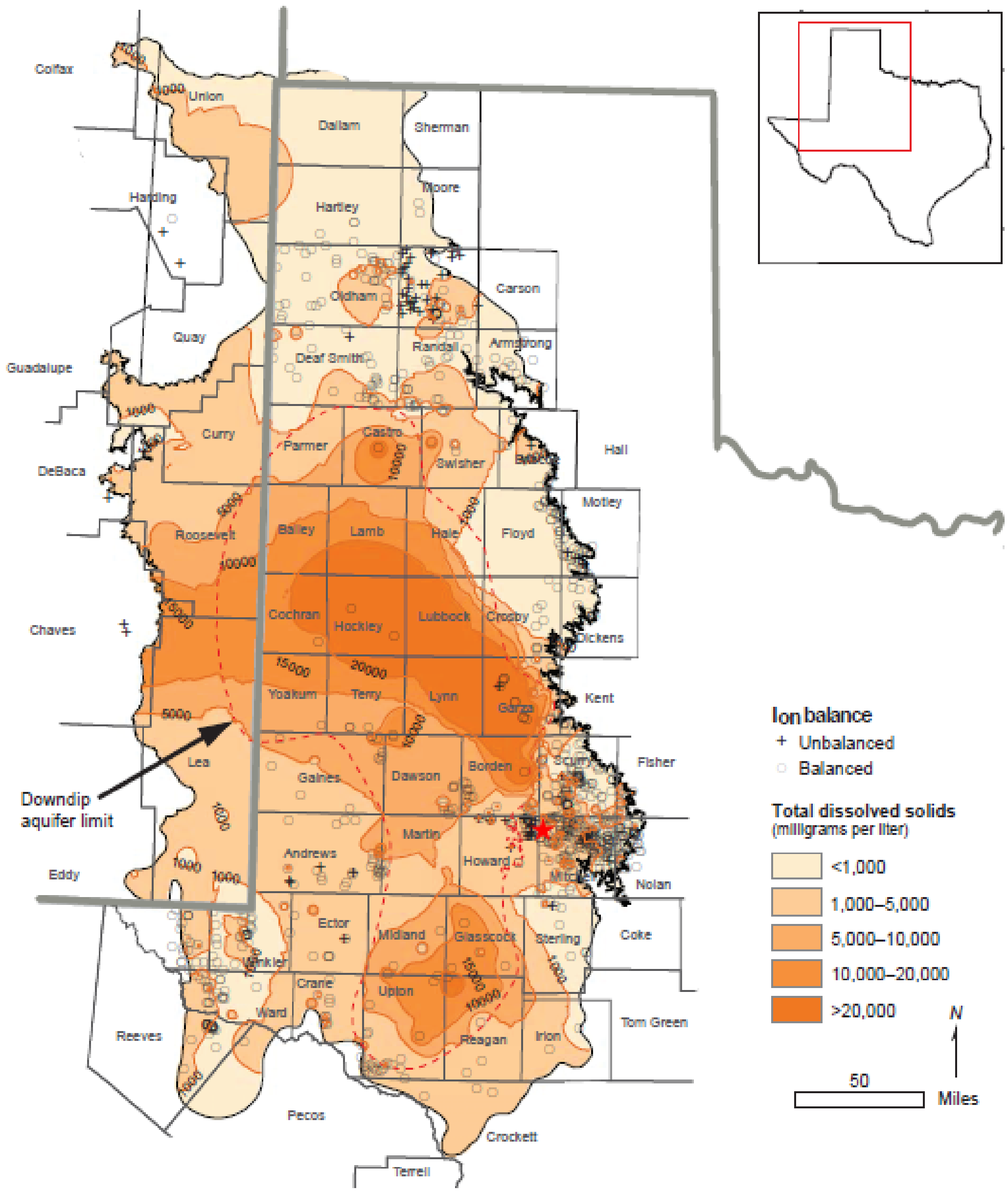


Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 Description of the Injection Process

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO_2, which equates to 155.3 MT/yr of CO_2 each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

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

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite-acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S and CO_2 based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H_2S and 41.2% CO_2. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H_2S and 41.2% CO_2.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H_2S)	58.8	58.8
Carbon Dioxide (CO_2)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.

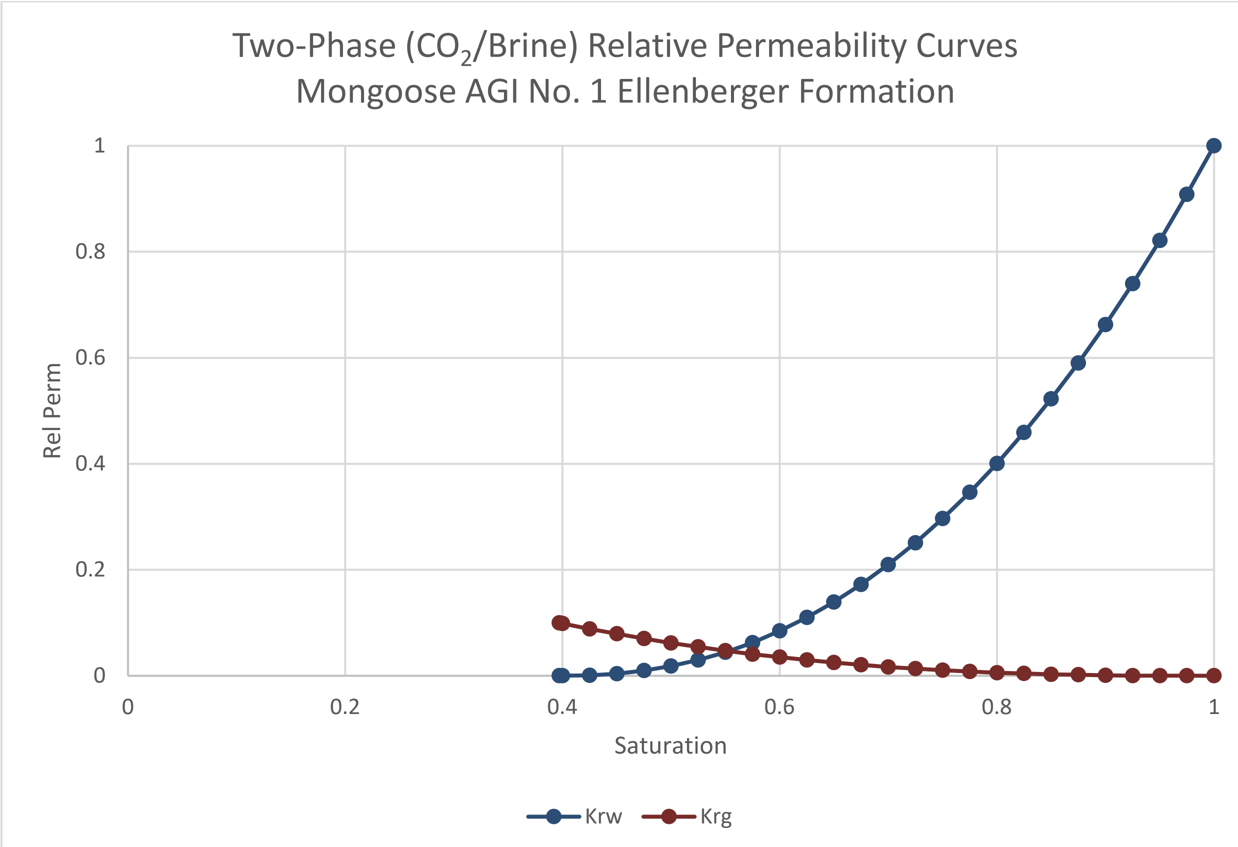


Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (north-south), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Table 9 – GEM Model Layer Package Properties

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

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

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

Table 10 – Offset SWD Wells Included in GEM Model

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.

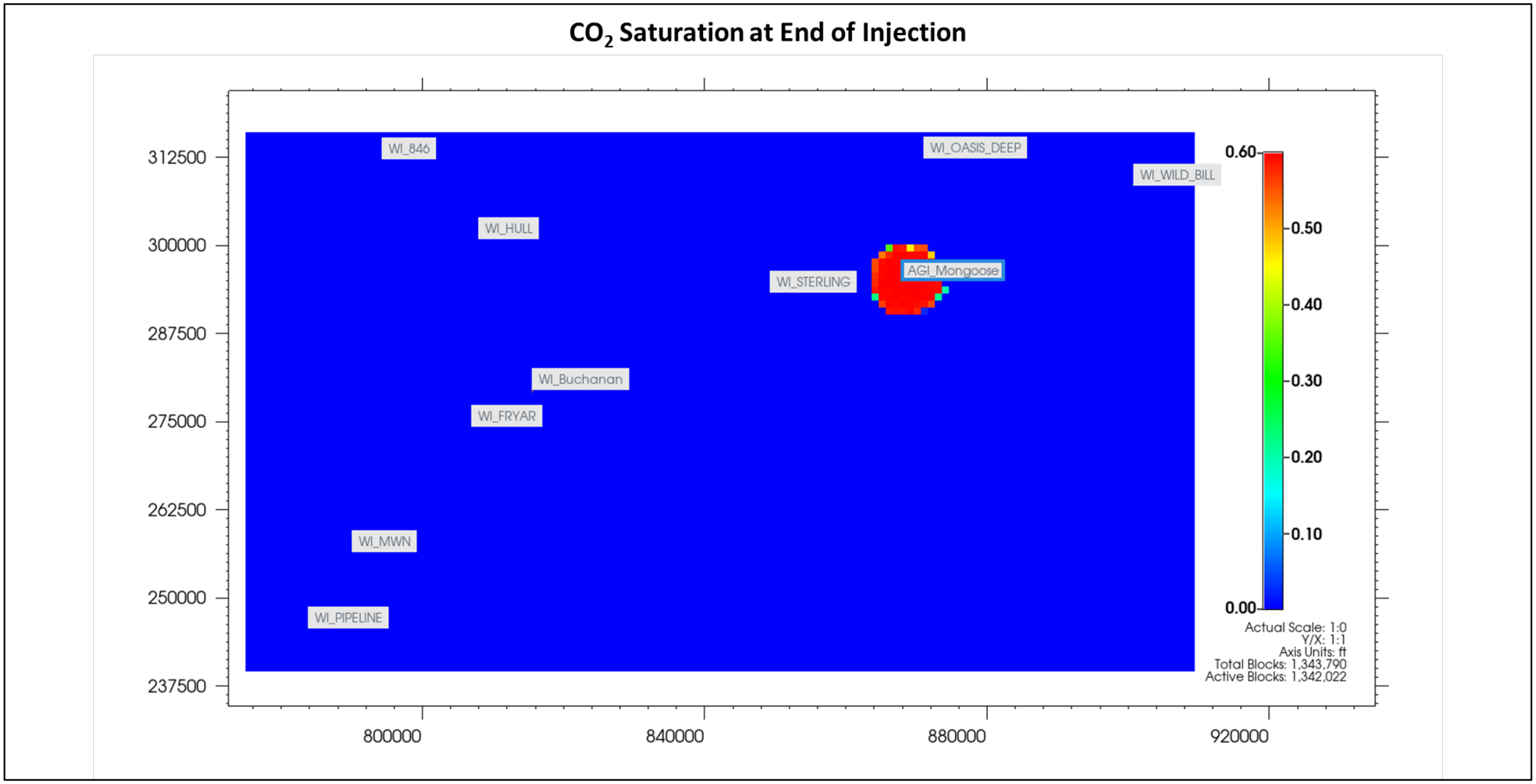


Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)

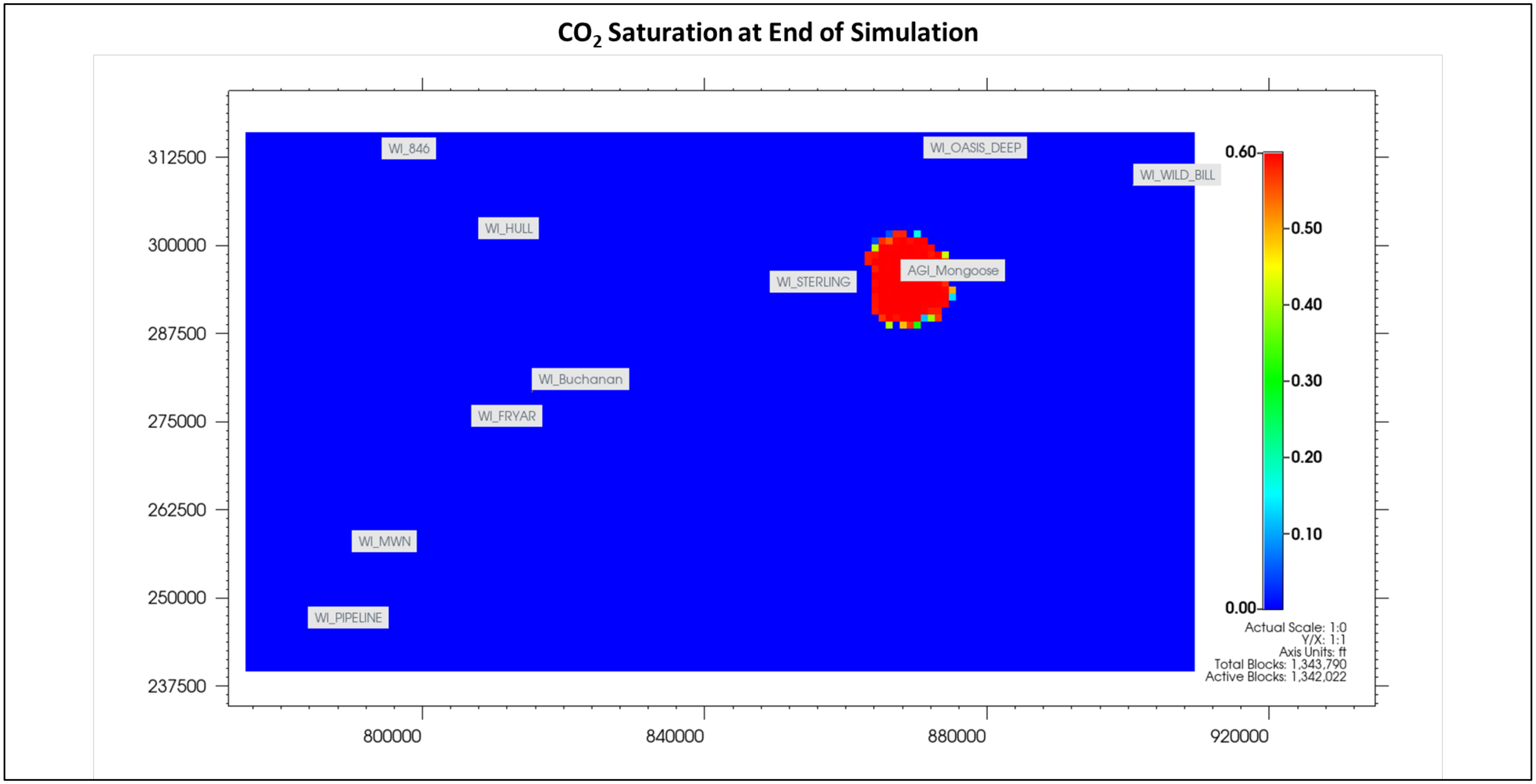


Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

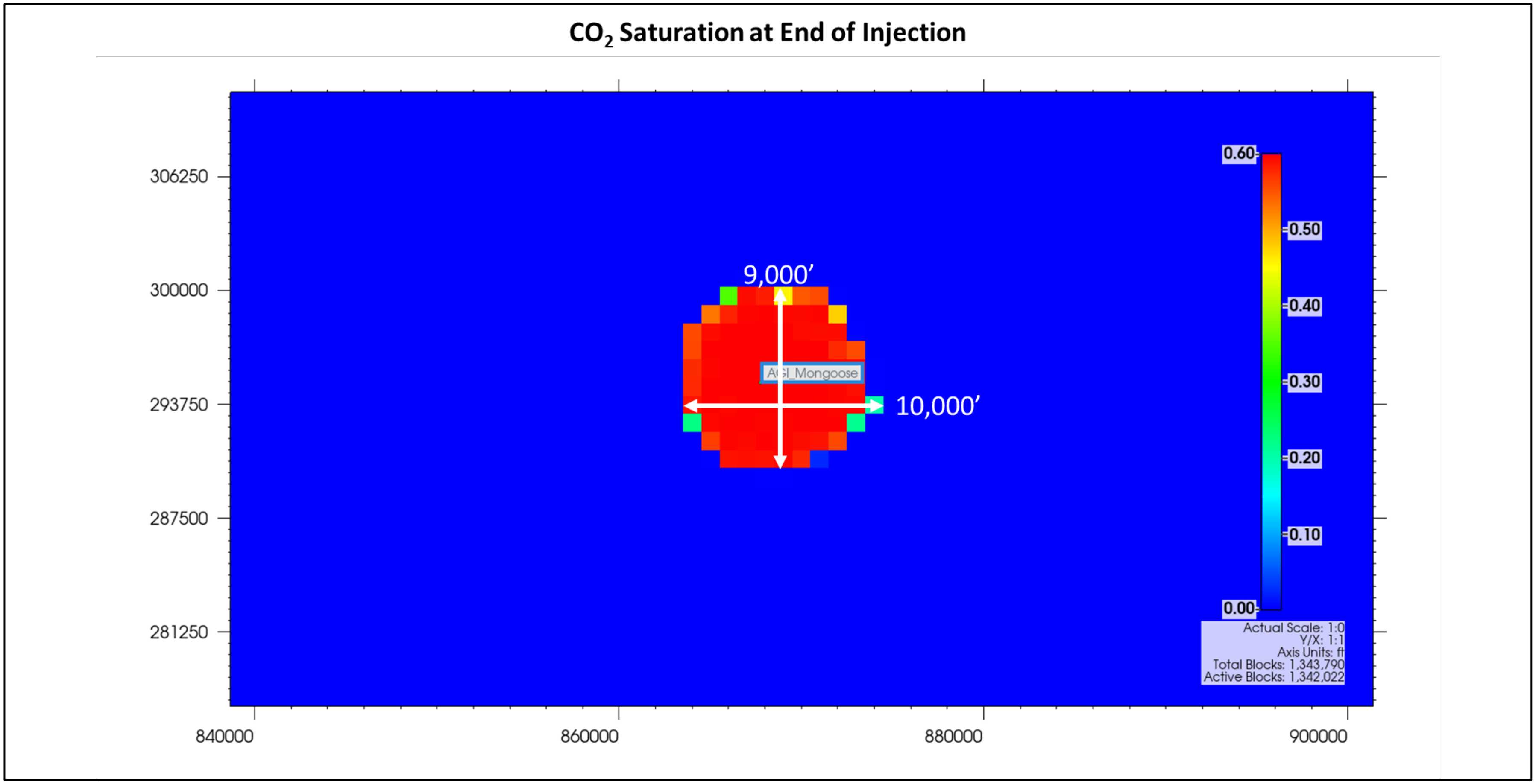


Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)

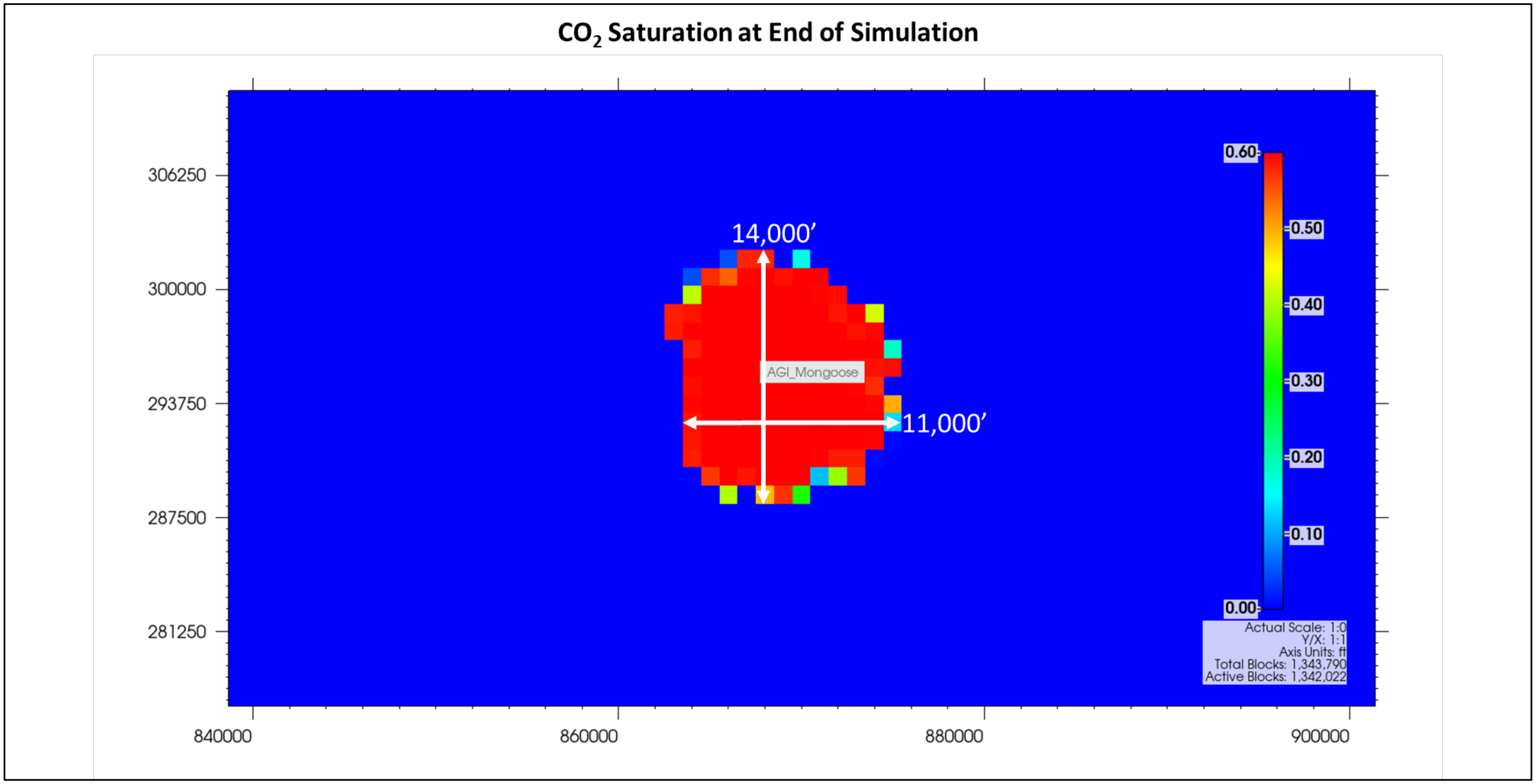


Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.

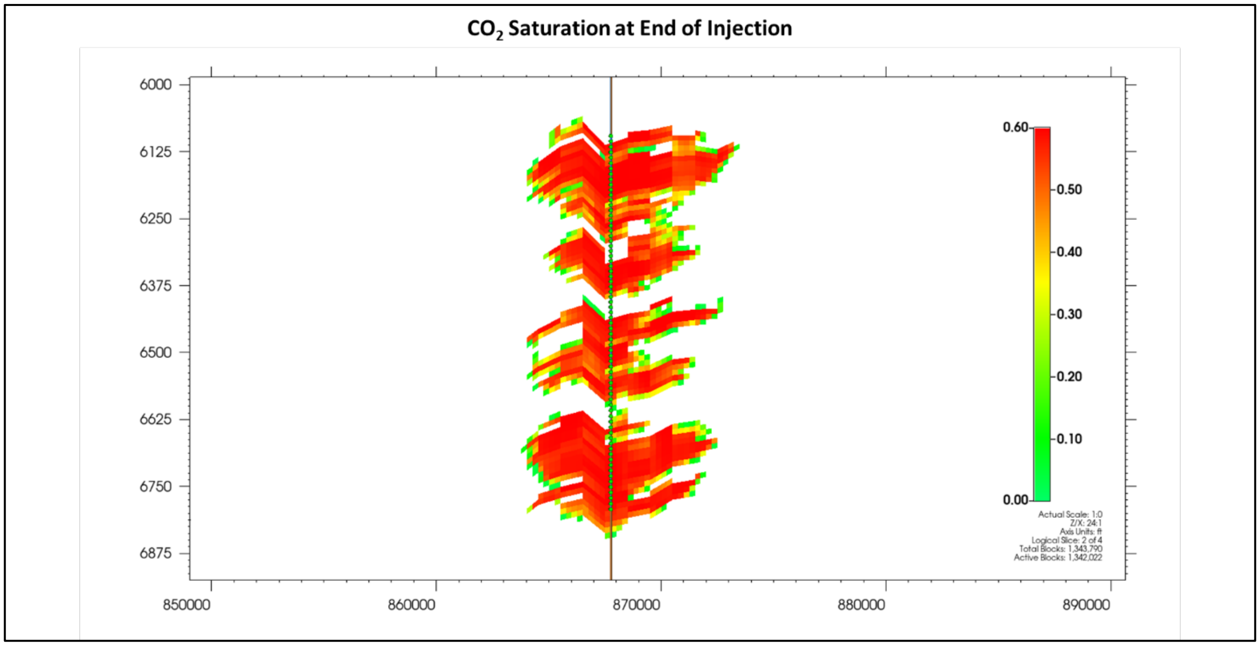


Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

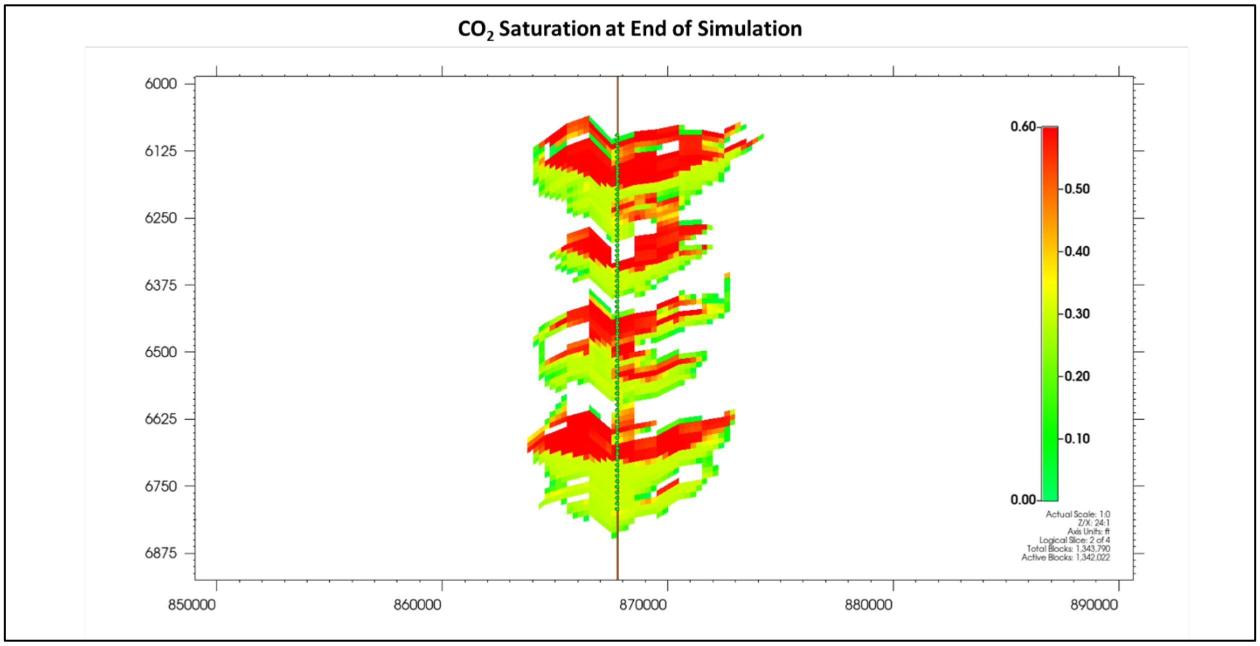


Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.

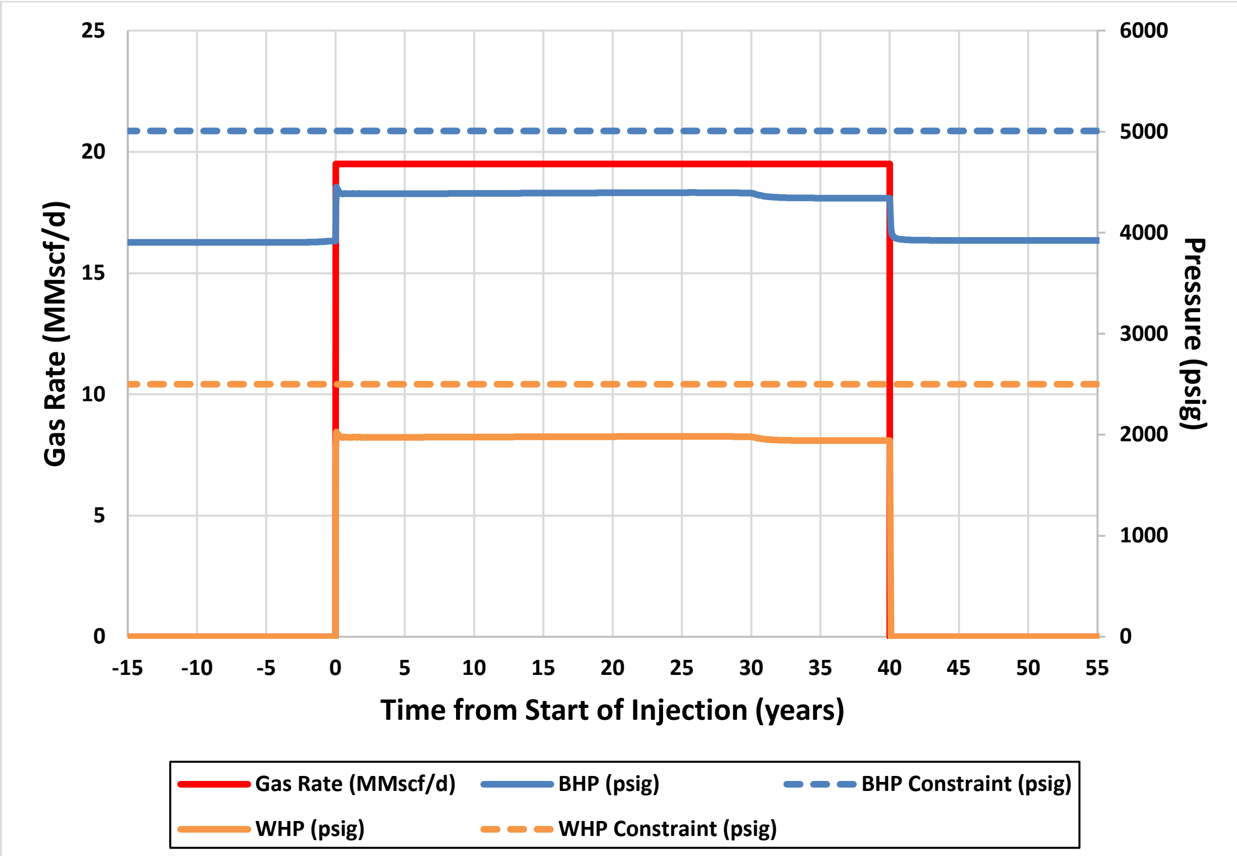


Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H_2S and 41.2% CO_2, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.

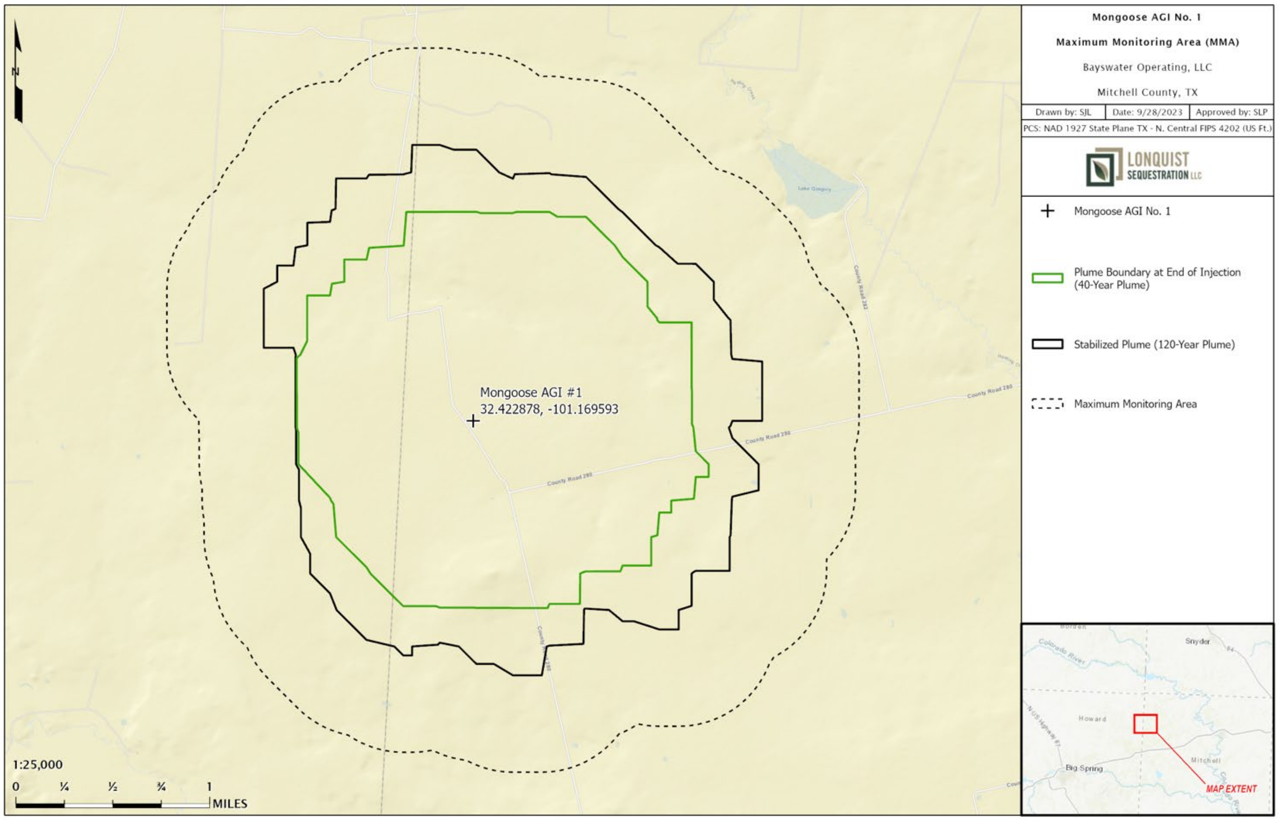


Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.

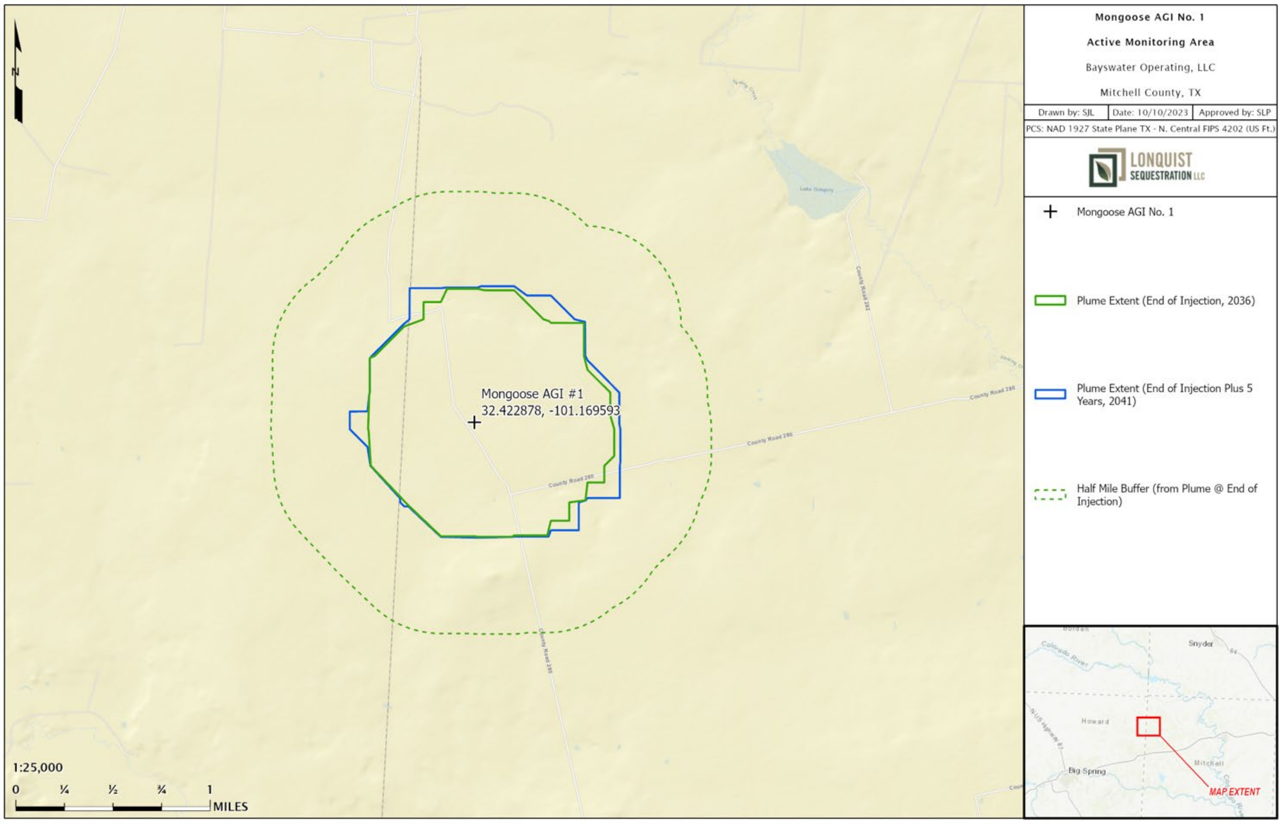


Figure 43 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

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

Table 12 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. The lateral continuity of the UCZ[1] is recognized as a very competent seal.	Low. Any vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care[2] period.
Faults and fractures	Possible. The lateral continuity of UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.

1 - UCZ is defined as the Upper Confining Zone.

2 - Post Injection Site Care is the period of time from the end of injection throught plume stabilization and site closure.

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

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H_2S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H_2S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year, per 40 CFR **§98.444(b)**.

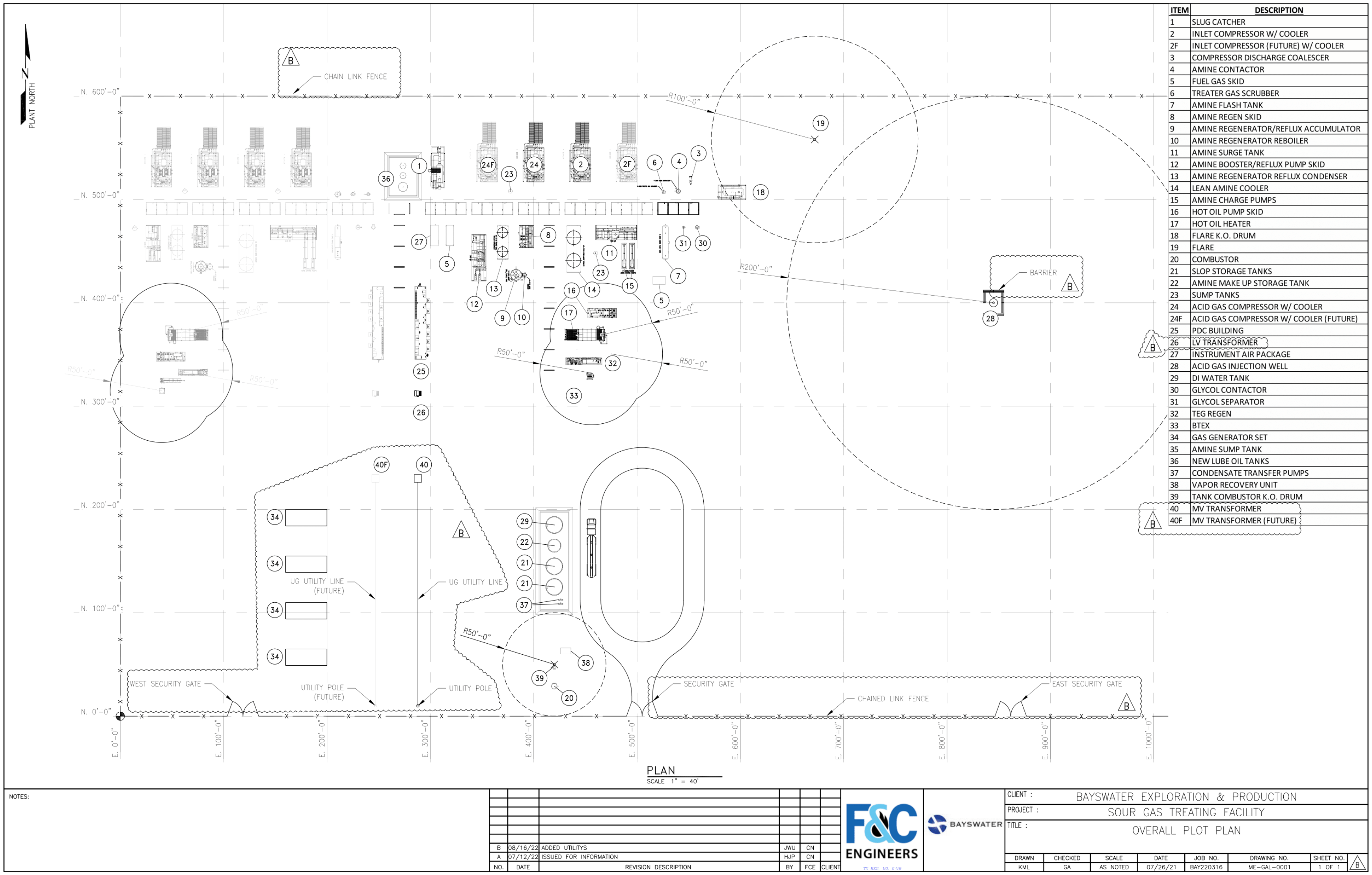
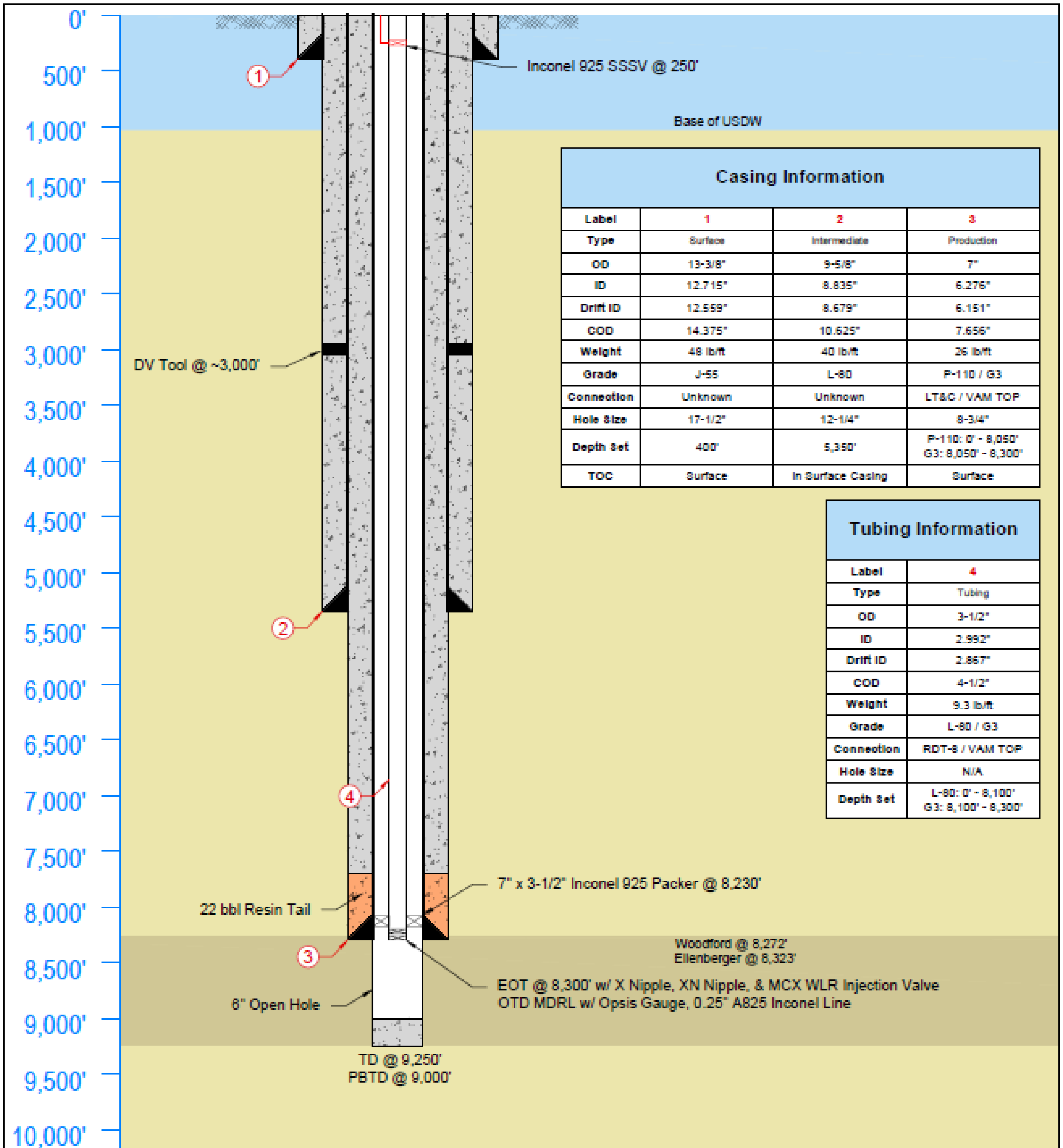


Figure 44 – Site Plan



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
ID	12.715"	8.835"	6.276"
Drift ID	12.559"	8.679"	6.151"
COD	14.375"	10.625"	7.656"
Weight	48 lb/ft	40 lb/ft	26 lb/ft
Grade	J-55	L-80	P-110 / G3
Connection	Unknown	Unknown	LT&C / VAM TOP
Hole Size	17-1/2"	12-1/4"	8-3/4"
Depth Set	400'	5,350'	P-110: 0' - 8,050' G3: 8,050' - 8,300'
TOC	Surface	In Surface Casing	Surface

Tubing Information

Label	4
Type	Tubing
OD	3-1/2"
ID	2.992"
Drift ID	2.867"
COD	4-1/2"
Weight	9.3 lb/ft
Grade	L-80 / G3
Connection	RDT-8 / VAM TOP
Hole Size	N/A
Depth Set	L-80: 0' - 8,100' G3: 8,100' - 8,300'

LONQUIST FIELD SERVICE	Bayswater Operating Company LLC	Mongoose AGI #1	
	Country: USA	State/Province: TX	County/Parish: Mitchell
	API No: 42-335-36013	Field: Sprayberry Trend	Well Type/Status: Acid Gas Injection
Texas License F-9147	RRC District No:	Project No: LS188	Date: 09/07/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved:
	Rev No: 1	Notes:	

Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO_2 will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in Section 2.2.2. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset APs is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.

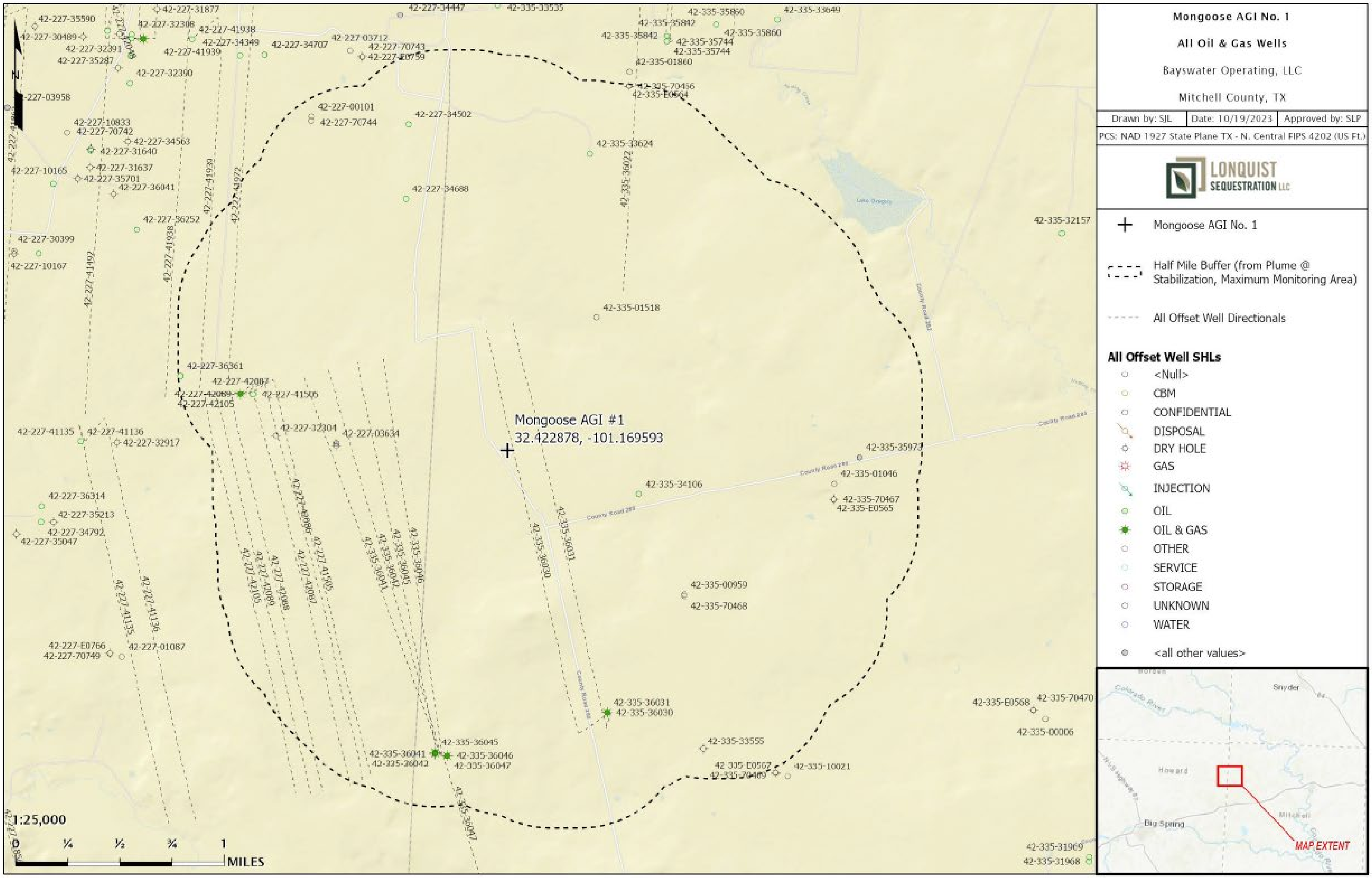


Figure 46 – All Oil and Gas Wells Within the MMA

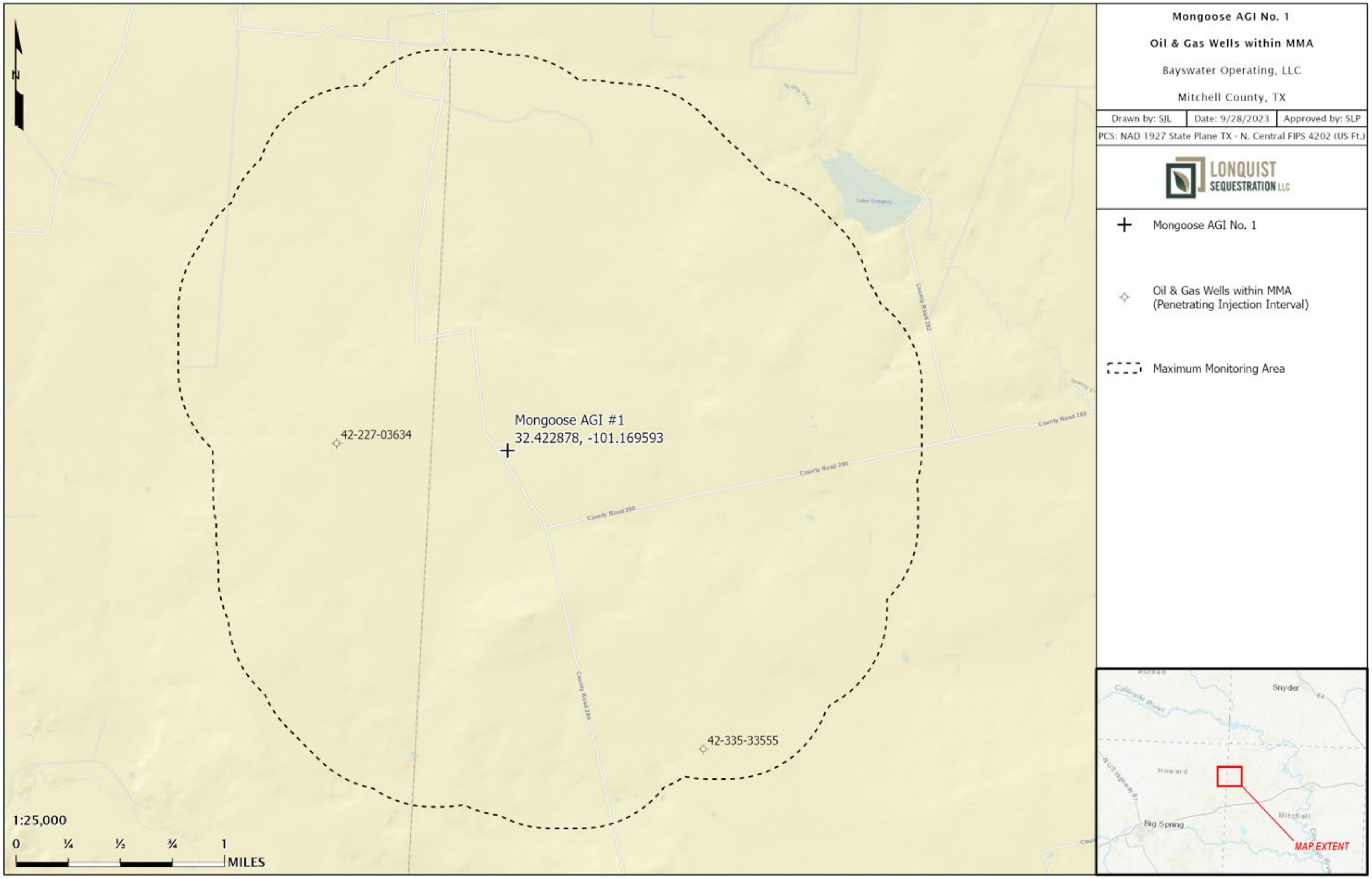


Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Mongoose drilling permit, provided in *Appendix A*, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a quarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued (also provided in the permit in *Appendix A*).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 <u>Leakage Through Faults and Fractures</u>

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

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

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

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

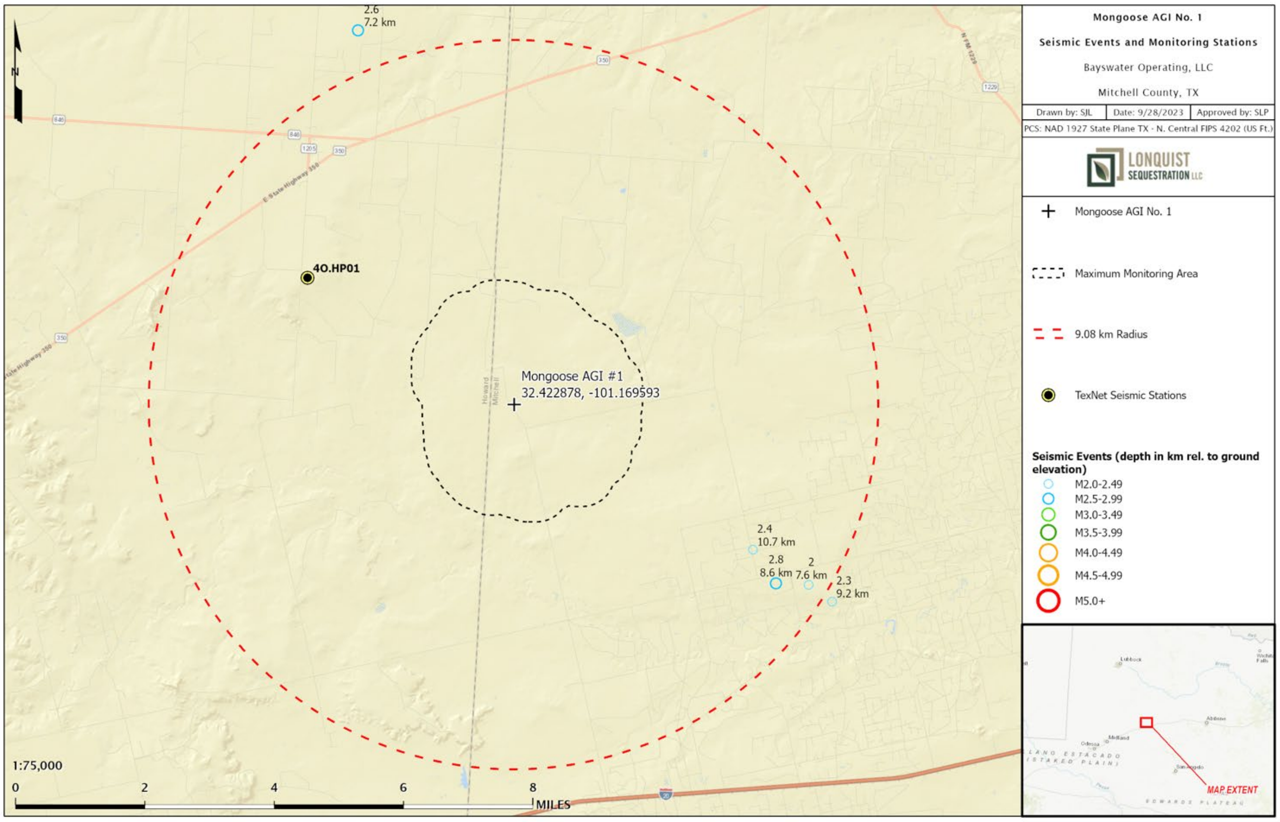


Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Table 13 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Visual inspections
	SCADA continuous monitoring of the AGI facility
Leakage through existing wells	SCADA continuous monitoring of the AGI well
	Monitor CO_2 levels in Above Zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage from natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established during the commissioning of the Plant. Ambient H_2S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H_2S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

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

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2, migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 Groundwater Quality Monitoring

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 Leakage Through Faults, Fractures, or Confining Seals

Bayswater continuously monitors the operations of the Mongoose well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO_2 content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO_2 content would be an early indicator of a potential issue. Should the CO_2 migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

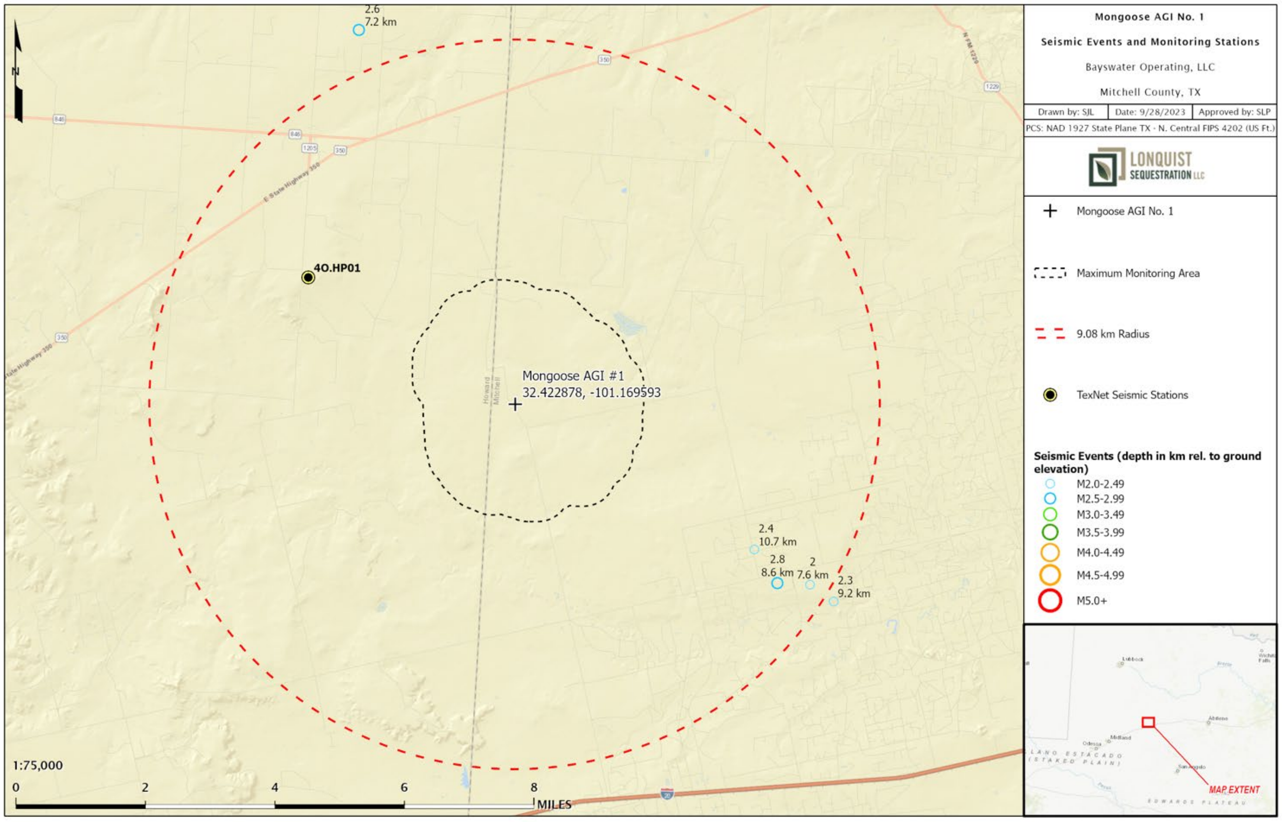


Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

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

6.2 CO_2/H_2S Detection

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H_2S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

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

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

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

7.4 Mass of CO_2 Emitted by Surface Leakage

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

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

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

Where:

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

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

X = Leakage pathway

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

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

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead

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

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Bayswater plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

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

CO_2 Emissions from Leaks and Vented Emissions

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

Measurement Devices

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

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

9.2 Missing Data

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

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

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

9.3 <u>MRV Plan Revisions</u>

If any changes outlined in 40 CFR **§98.448(d)** occur, Bayswater will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

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

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

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Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC*
Denver, CO

By

Lonquist Sequestration, LLC
Austin, TX

Version 2.0
October 2023

INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.

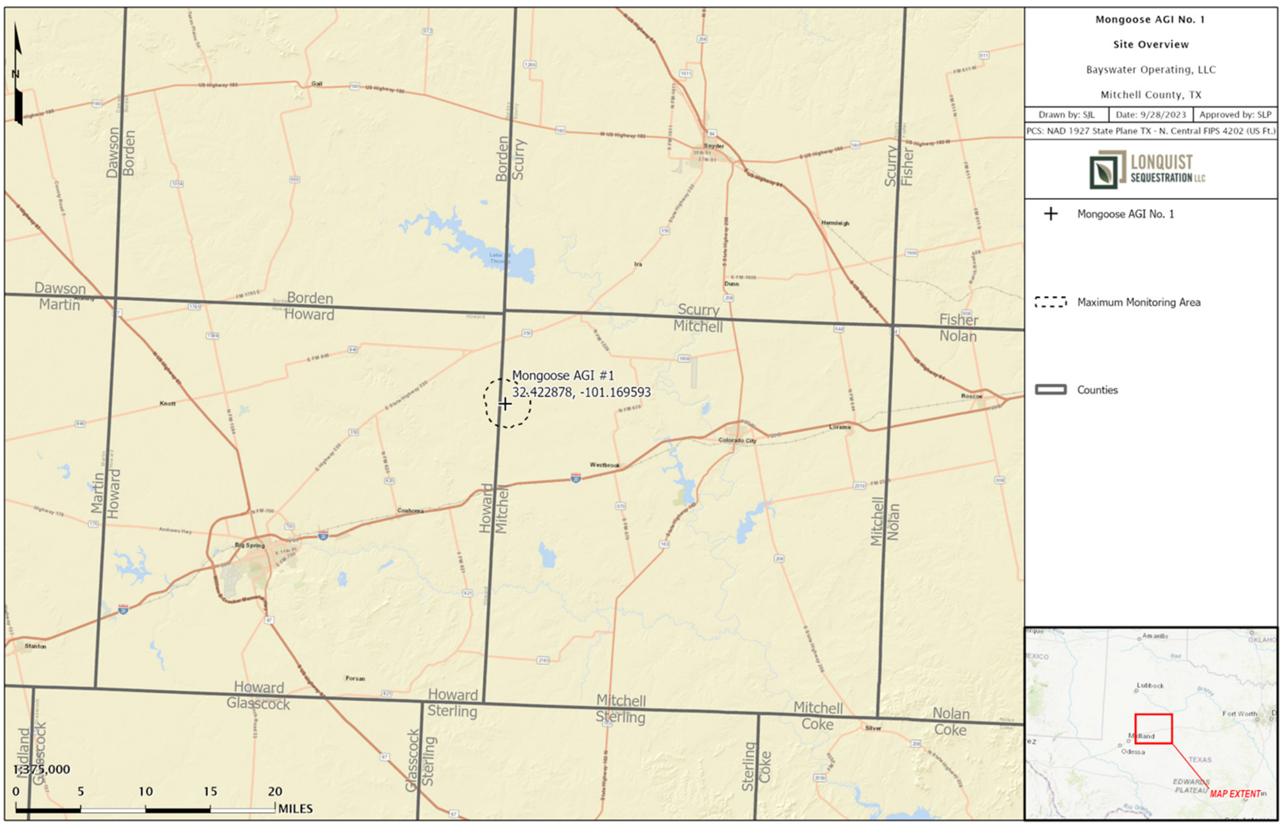

Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO_2 gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
pH	Scale of Acidity
PISC	Post Injection Site Care
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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Appendices

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 Reporter Number

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
  - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility
1625 County Road 280
Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641
Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).

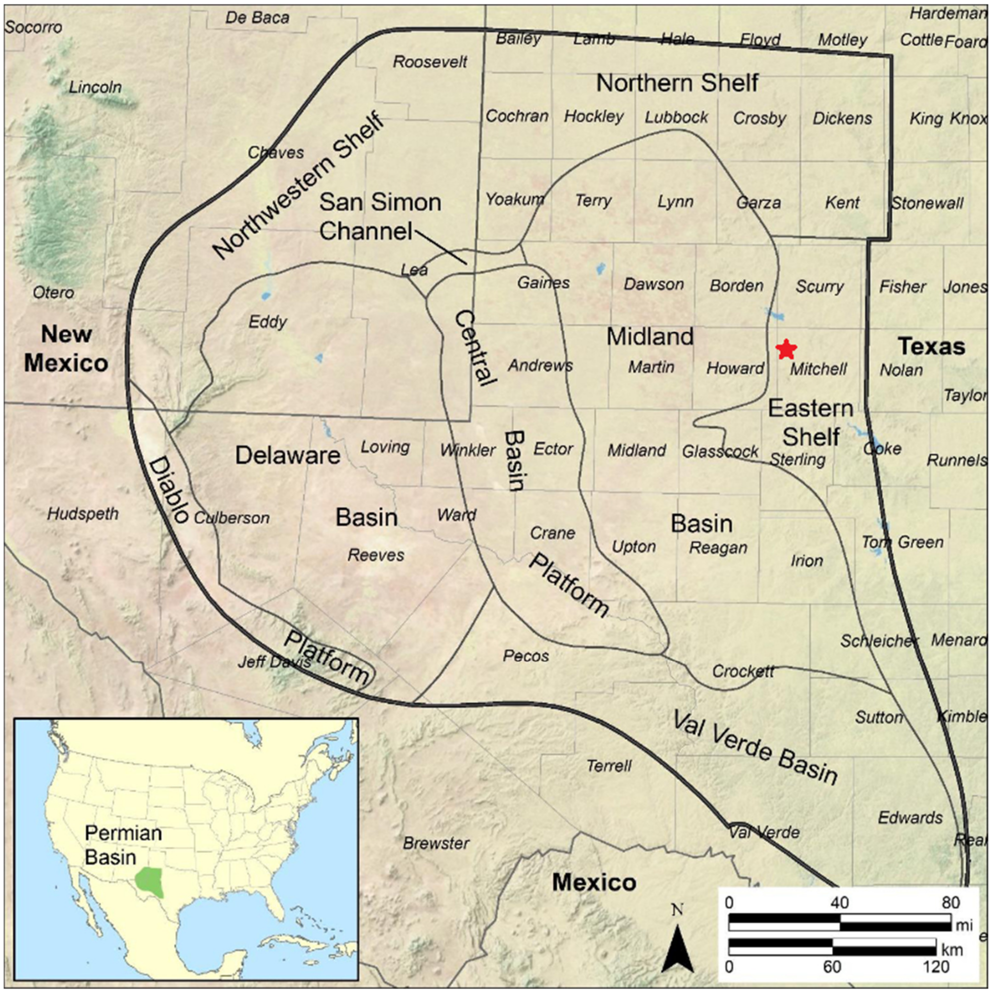


Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).

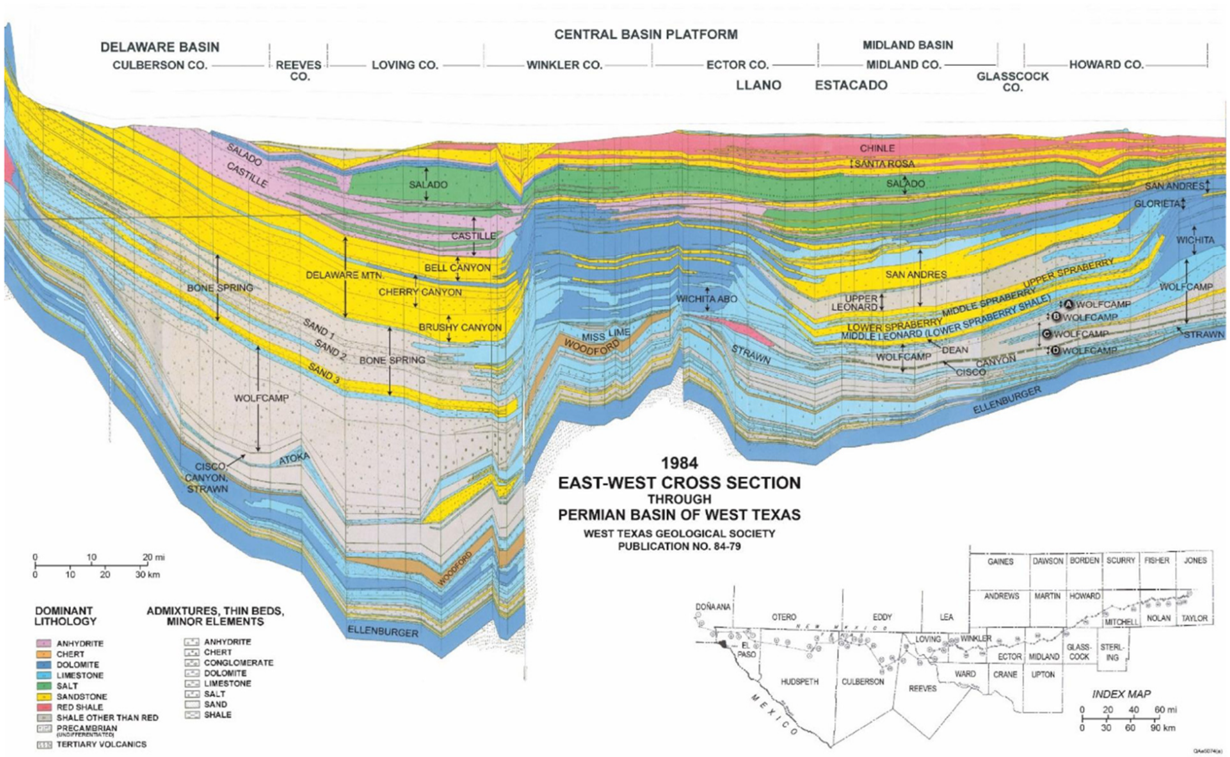


Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are “ooid grainstone; ooid-peloid packstone-grainstone”

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).

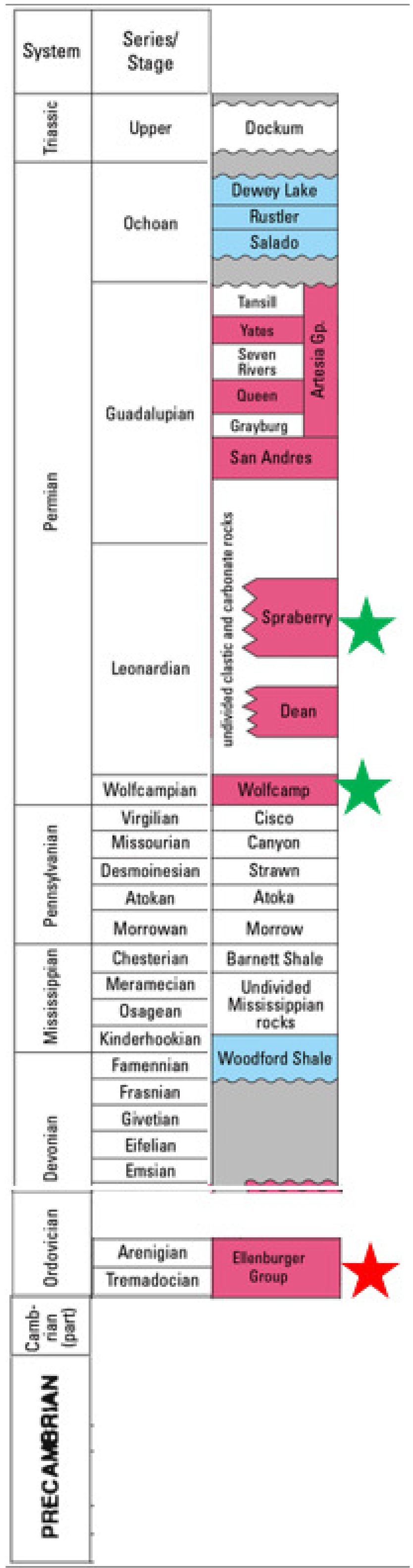


Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf

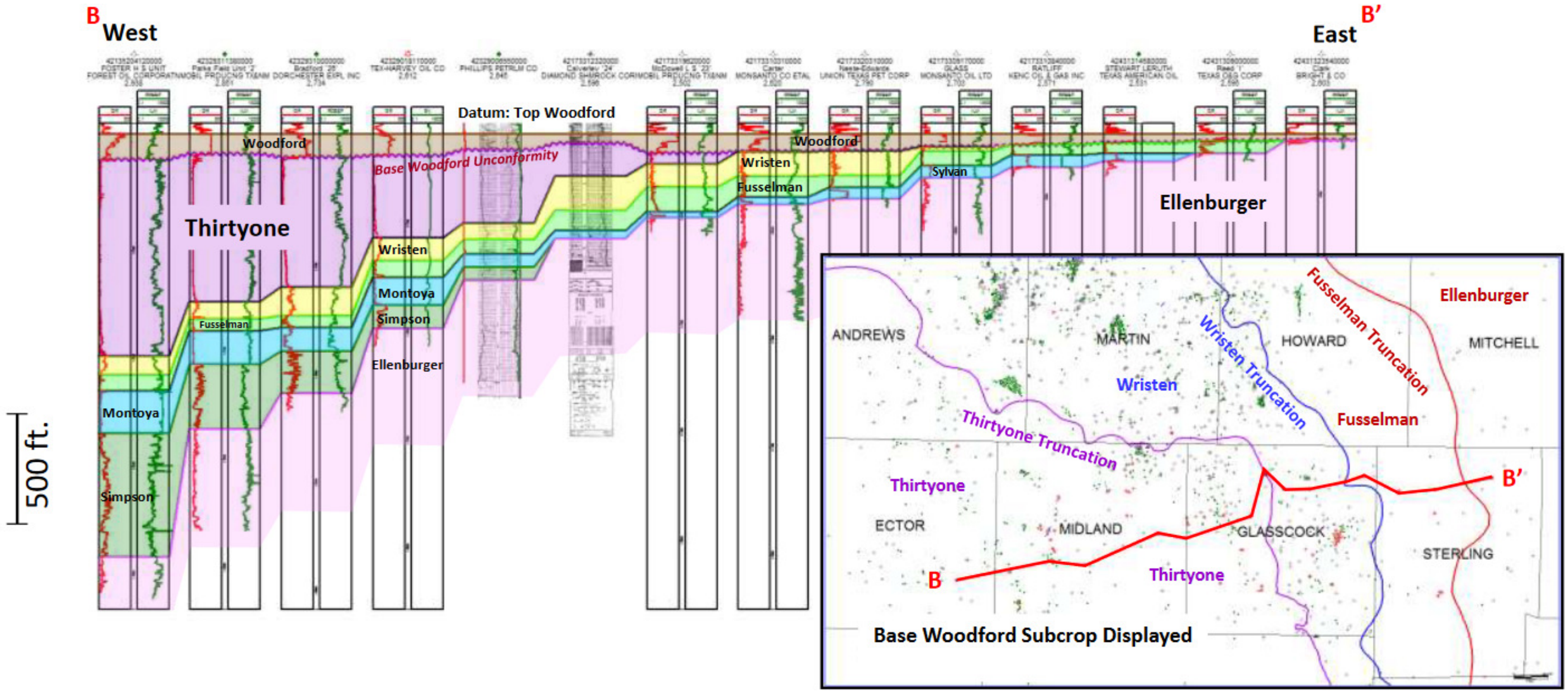


Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).

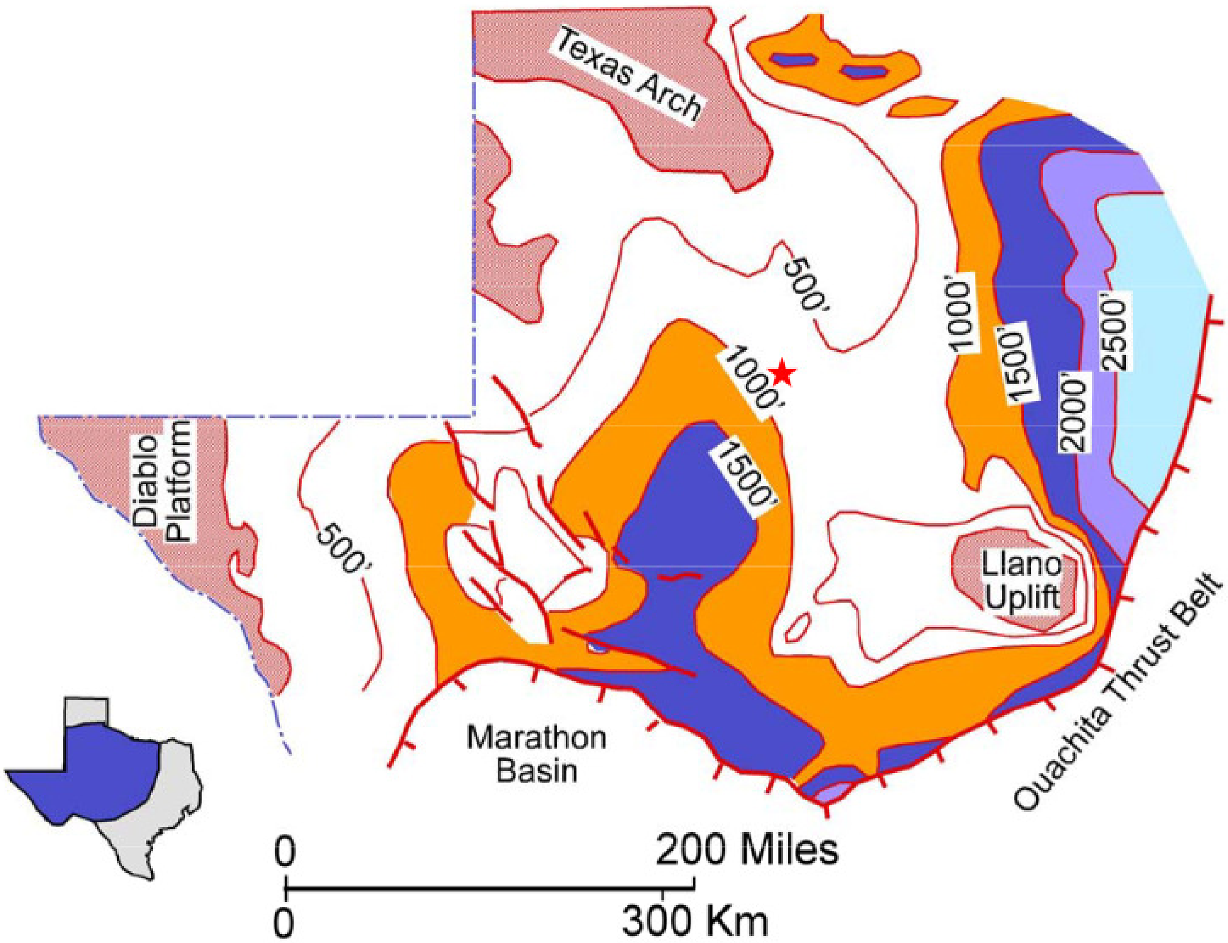


Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)

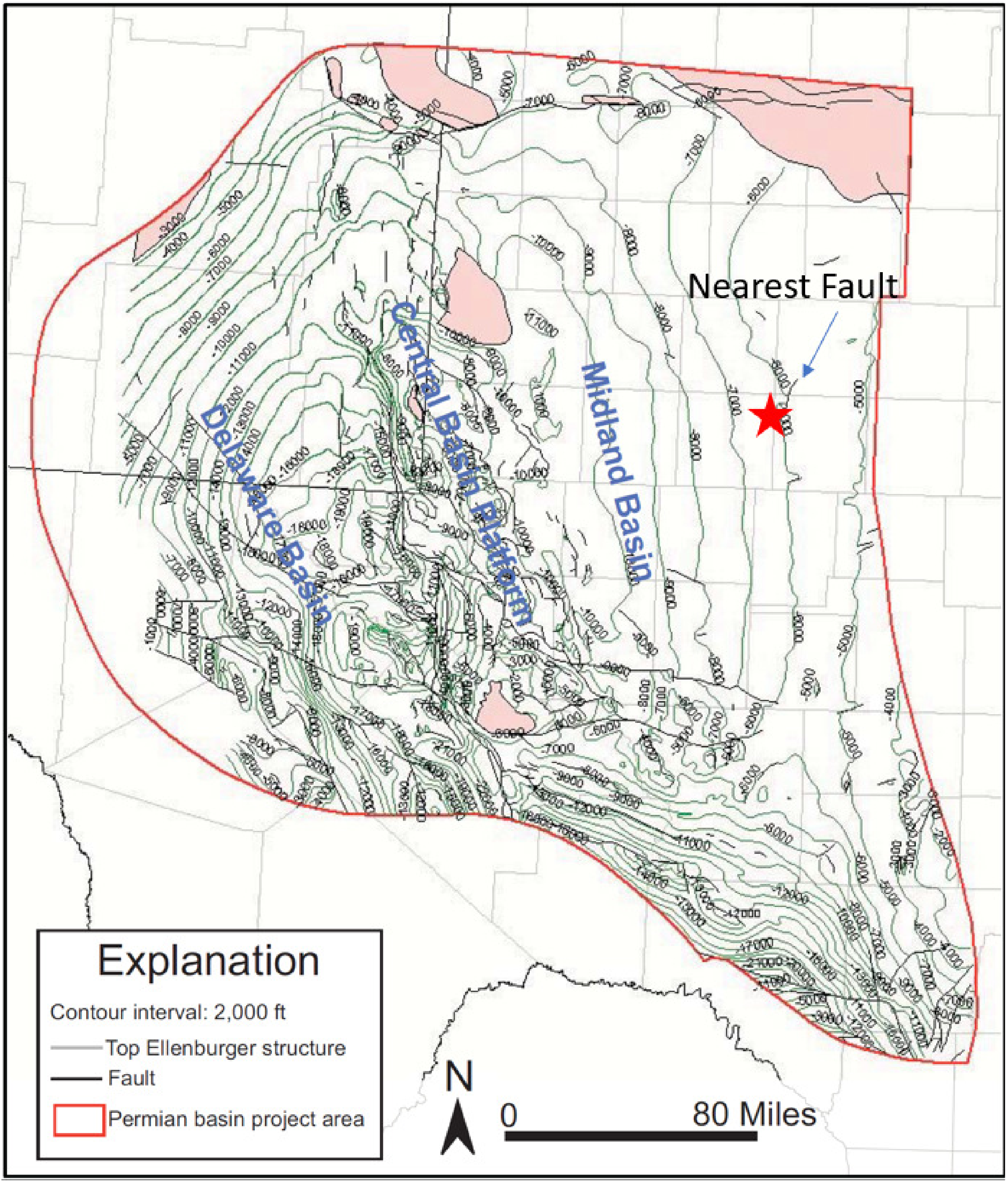


Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant “karsting” and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).

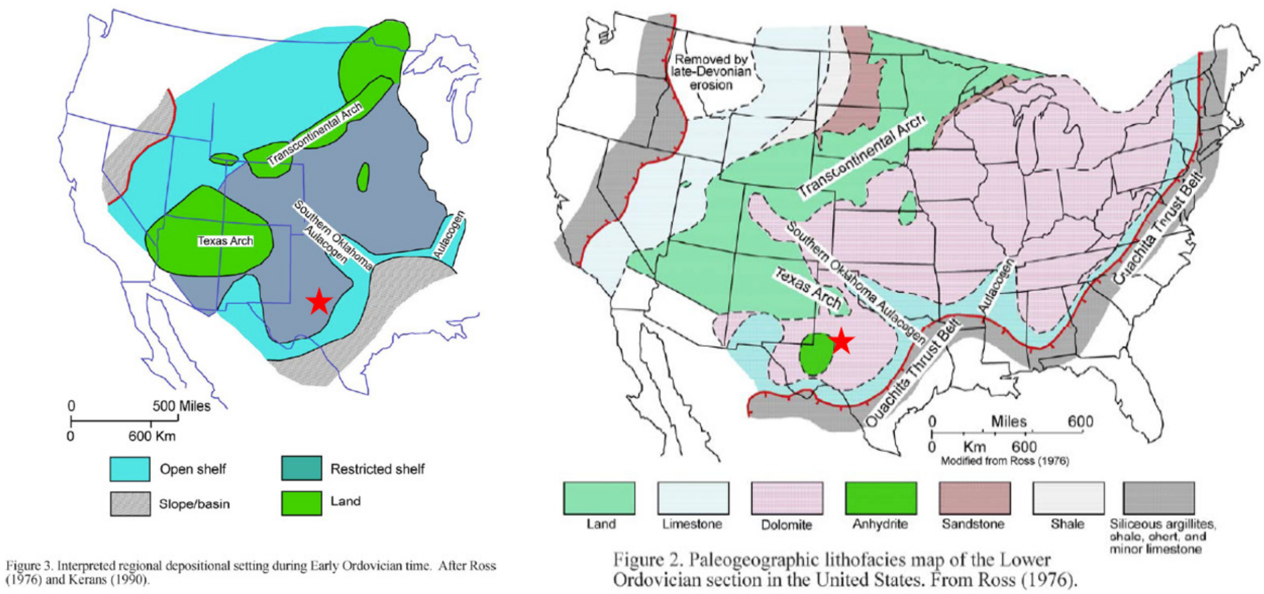


Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).

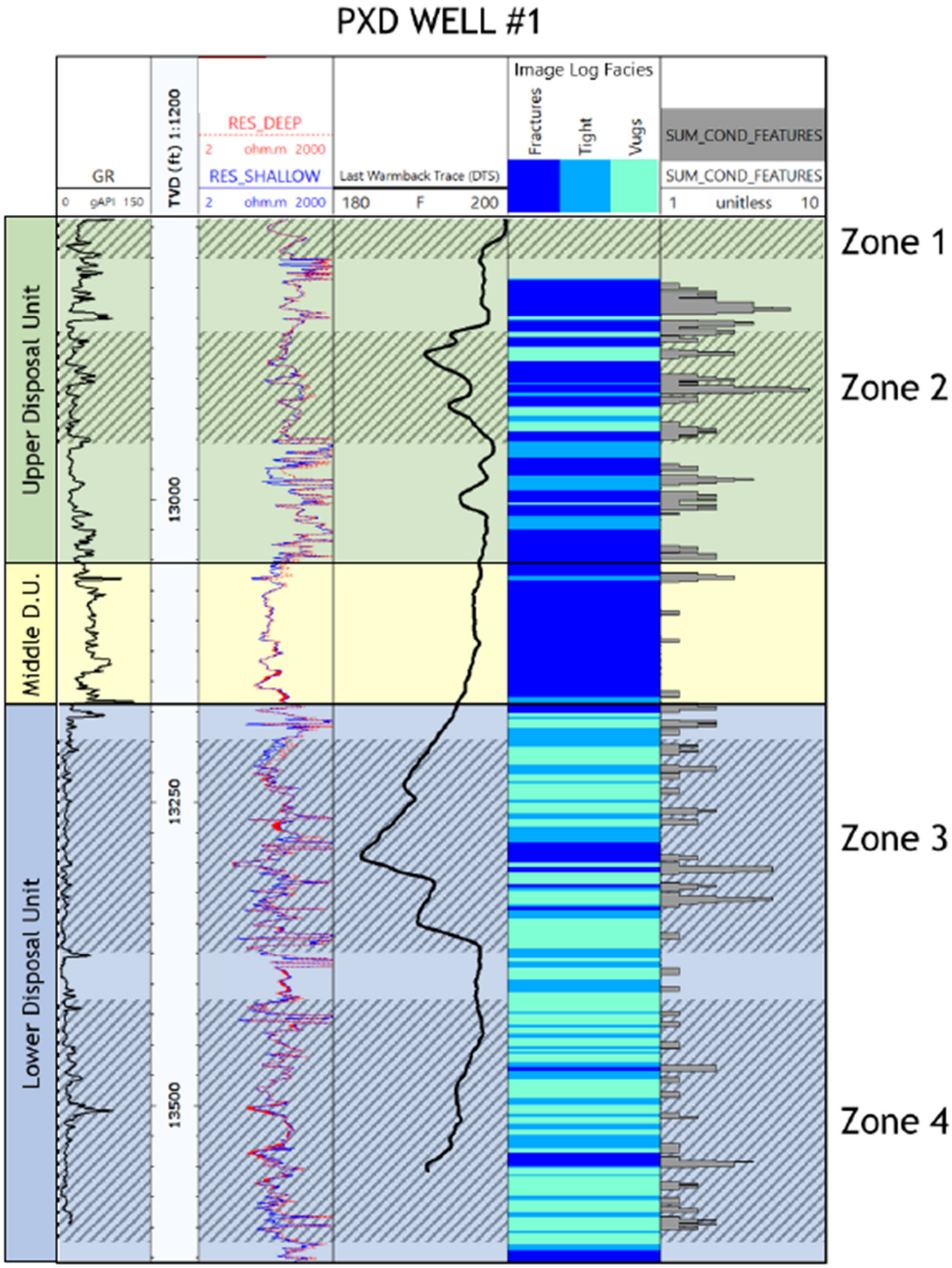


Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, & Coringrato, 2019)

2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.

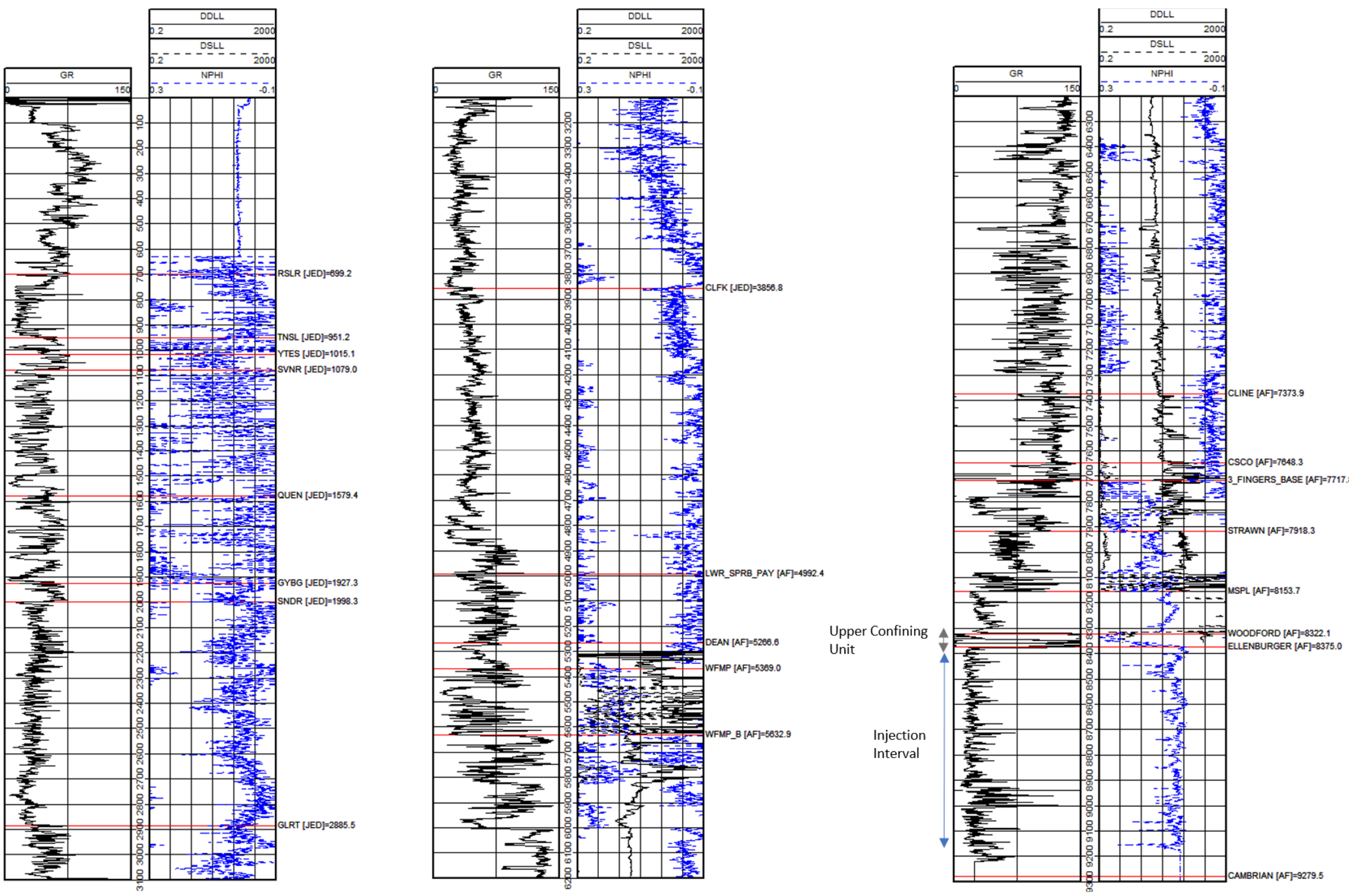


Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown previously in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO_2 Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.

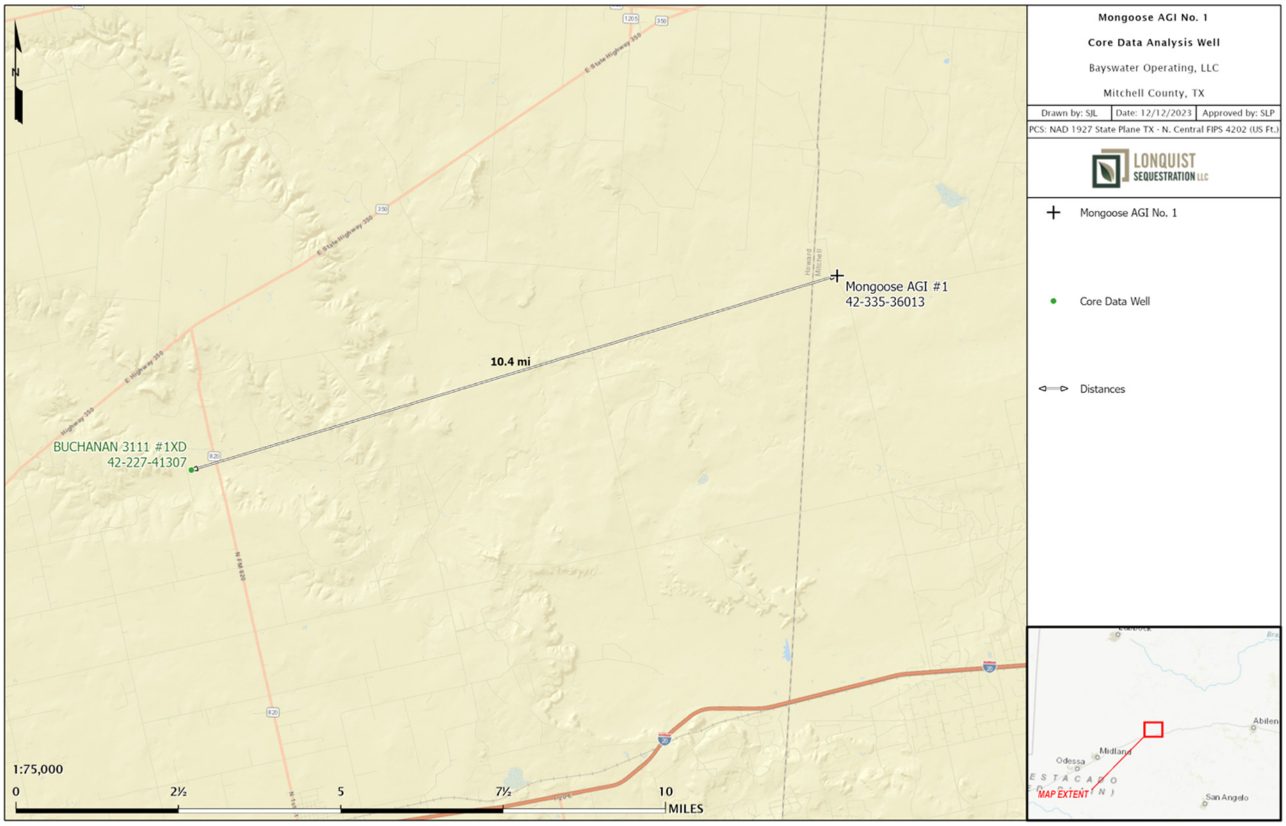


Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data

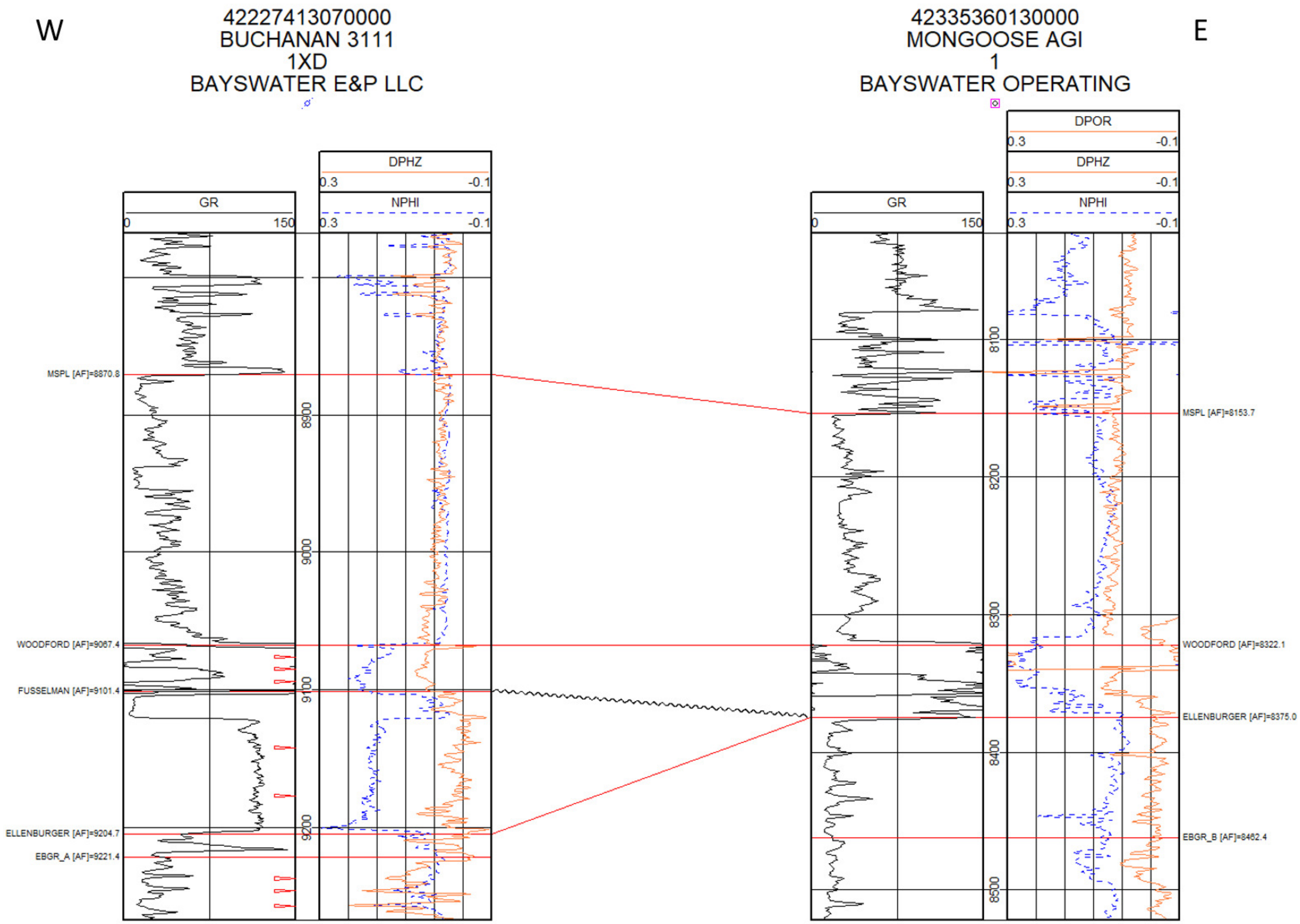


Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.

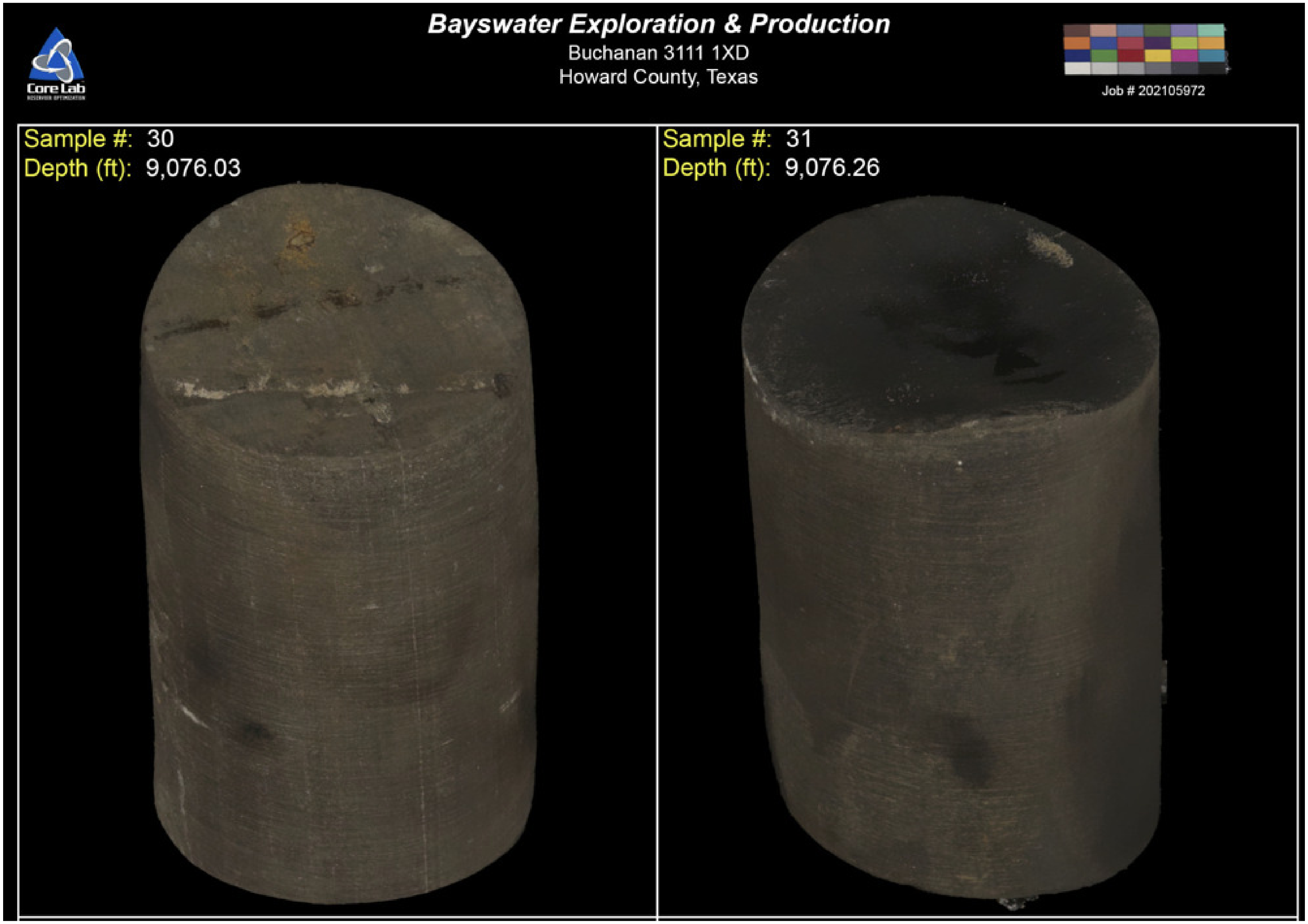


Figure 13 – Core Photo of Samples Within the Woodford Formation

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: February 04, 2022
Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

		As received				Dry & Dean Stark Extracted Conditions [2]				
Sample	**Depth** (ft)	**Bulk Density** (g/cc)	**Matrix Permeability** [1] (mD)	**Gas-filled Porosity** (%)	**Gas Saturation** (%)	**Grain Density** (g/cc)	**Matrix Permeability** [5] (mD)	**Porosity** (%)	**Oil Saturation** [3] (%)	**Water Saturation** [4] (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.
(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.
(3) Oil volume computed assuming an oil density of 0.844 g/cc
(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc
(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS
Net Confining Stress: 2960 psi Temperature: 68°F
Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

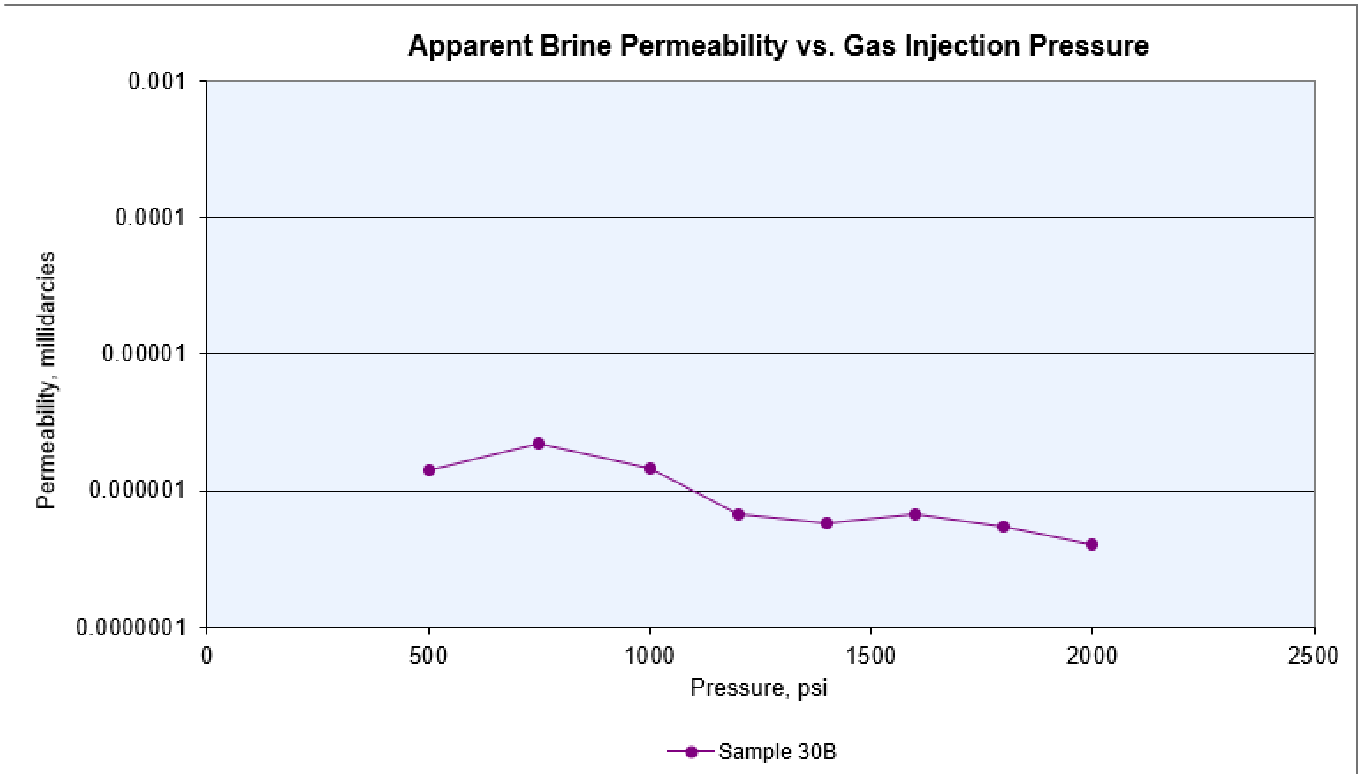


Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi   Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample 30B	
Gas Injection Pressure, psi	Permeability to Brine*, mD
500	1.44E-06
750	2.20E-06
1000	1.46E-06
1200	6.73E-07
1400	5.77E-07
1600	6.72E-07
1800	5.39E-07
2000	4.03E-07

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi   Temperature: 68°F
Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample Number	Depth, feet	Length, cm	Diameter, cm	Final Permeability to Brine*, millidarcies	Threshold Entry Pressure, psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and non-applicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A two-function porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

If Effective Porosity (Φeff) < 6.5%: $K(mD) = 7E{-}08e^{3.3028*\Phi \mathrm{eff}}$

If Effective Porosity (Φeff) > 6.5%: $K(mD) = 277.39\ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: March 31, 2022
Analyst(s): MP

CMS-300 ROTARY SIDEWALL ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Klinkenberg (md)	Permeability Kair (md)	b(air) psi	Beta ft(-1)	Alpha (microns)	Saturation Oil (% Pore Volume)	Saturation Water (% Pore Volume)	Grain Density (g/cm3)	Footnote
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

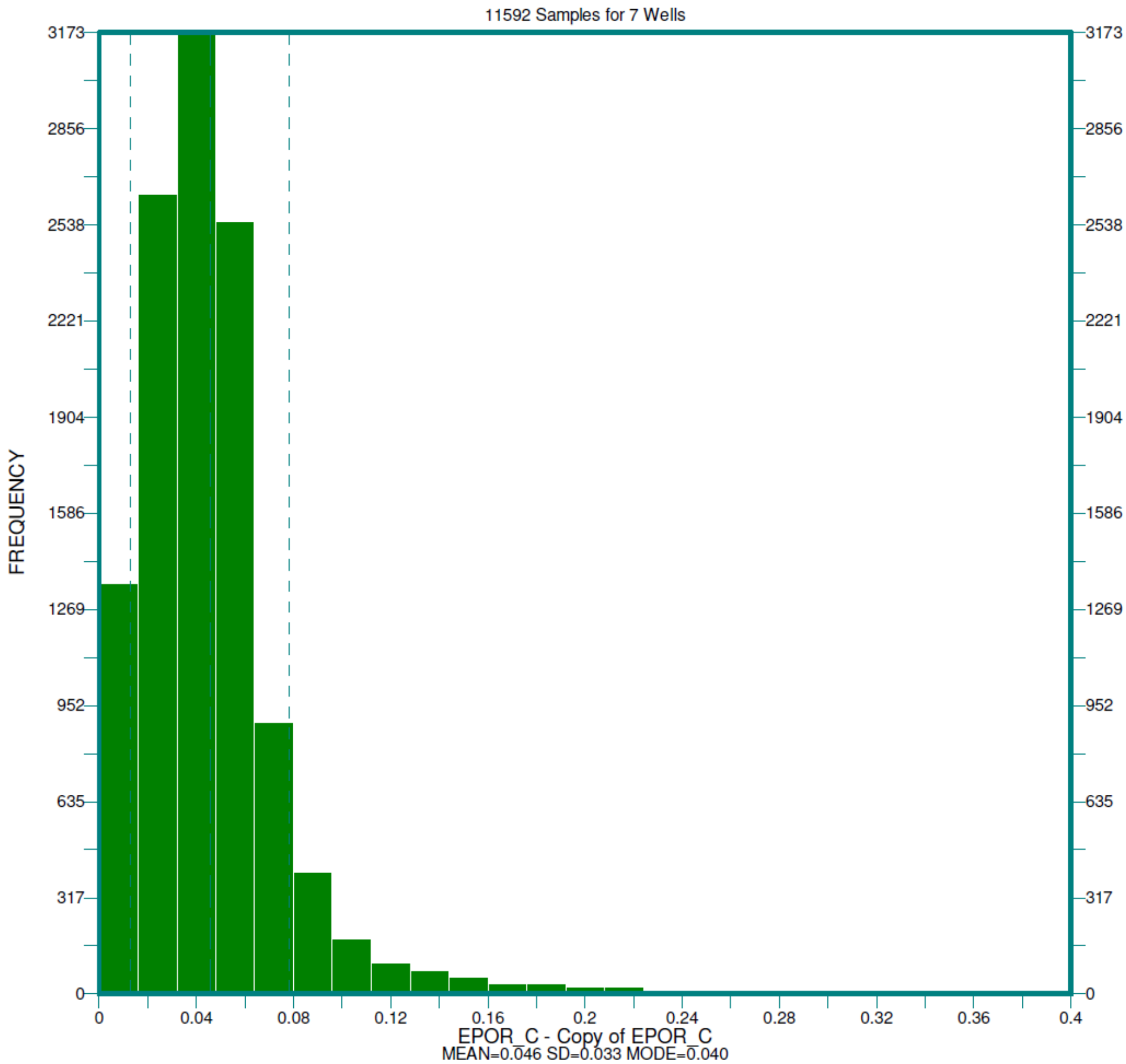


Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

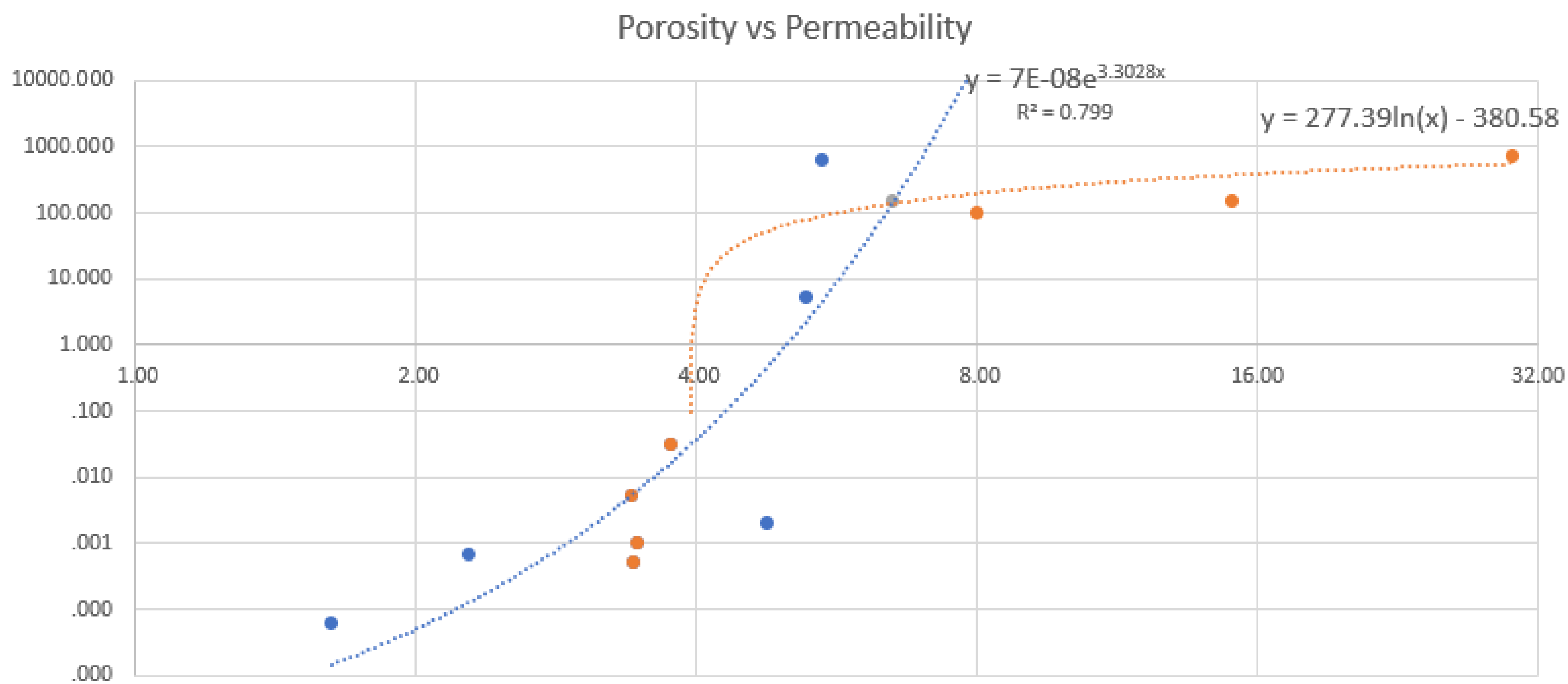


Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data

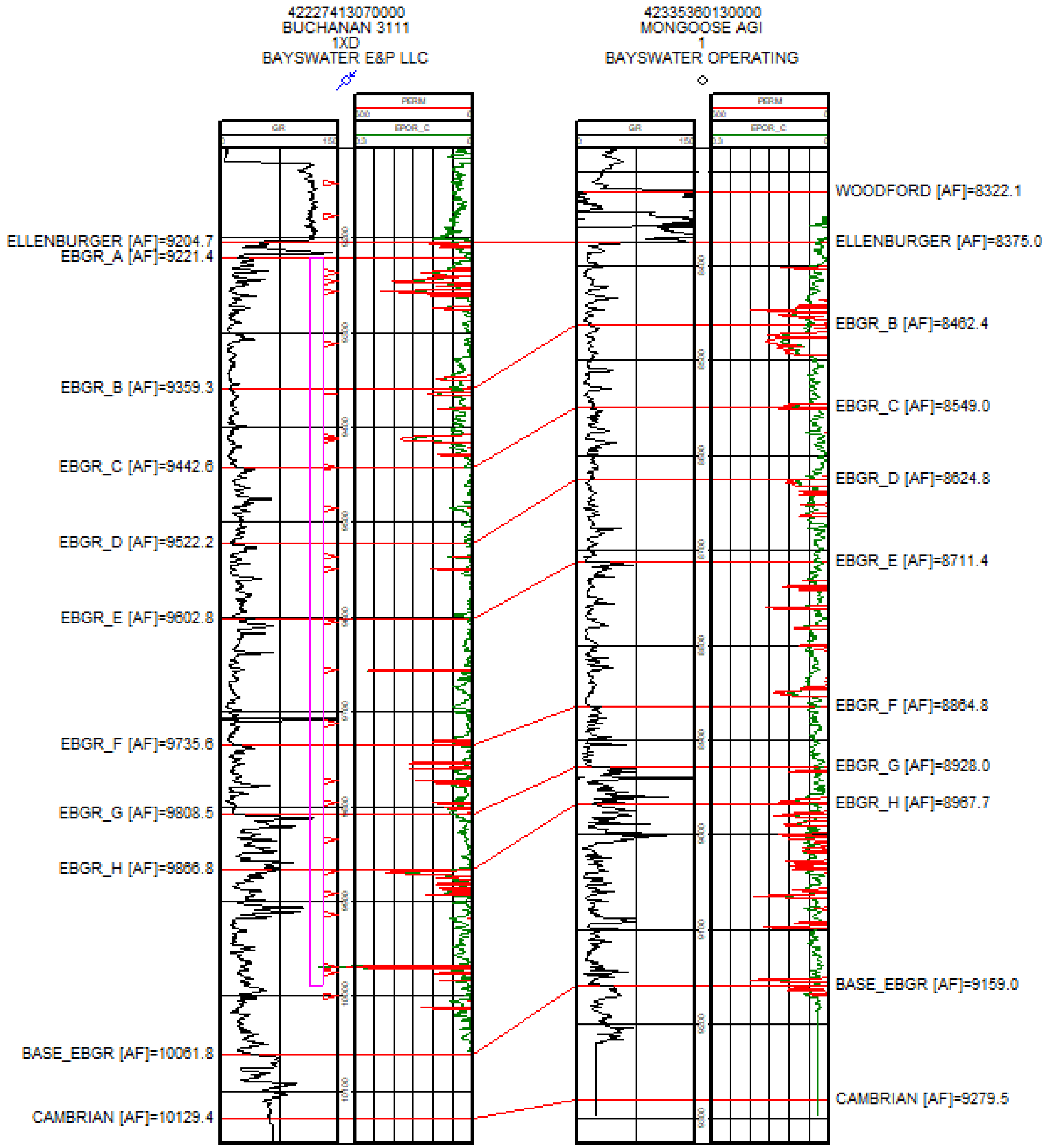


Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.

Figure 23 – Core photo of Ellenburger sample displaying vug features.

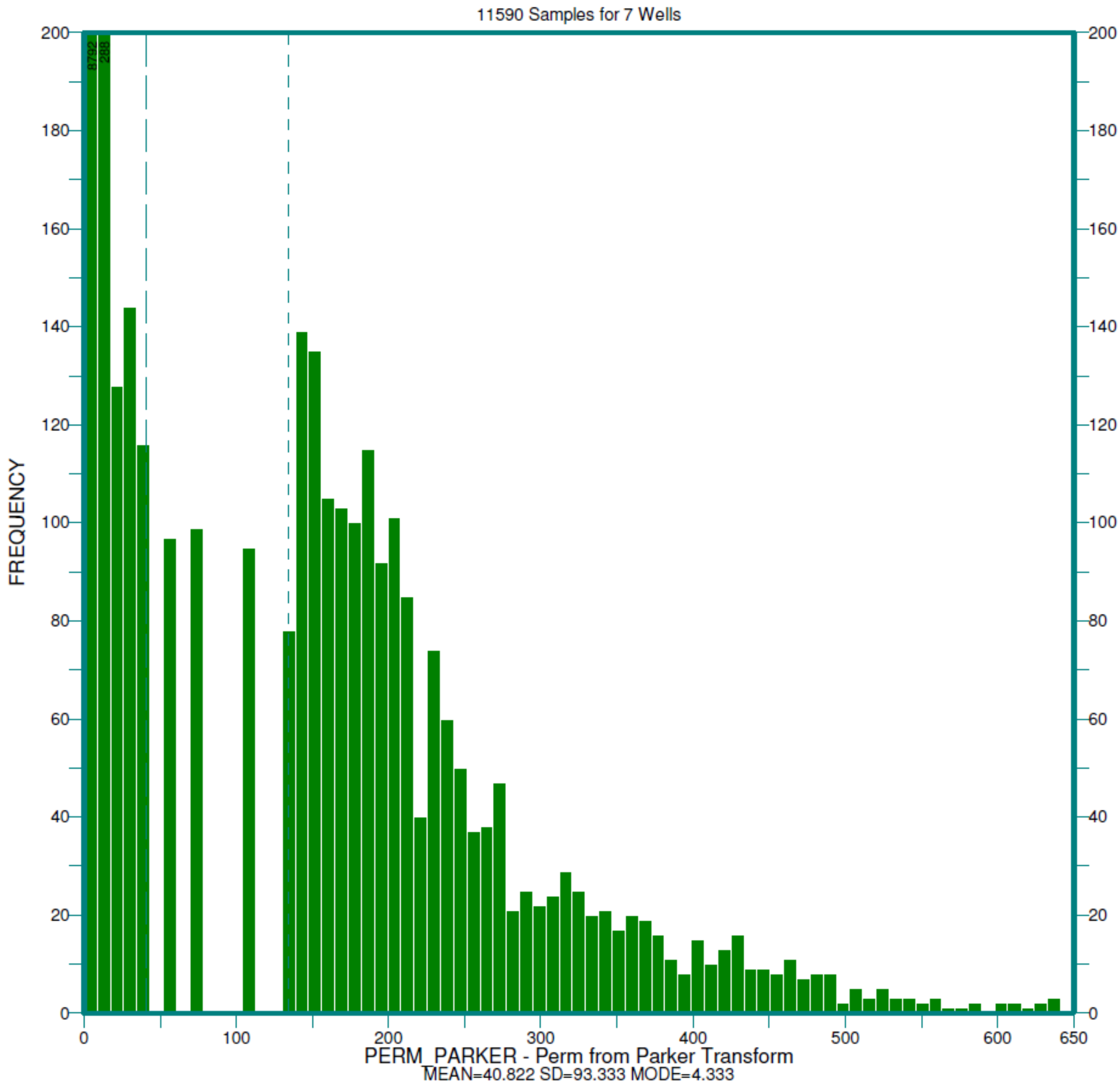


Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oil-field brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.

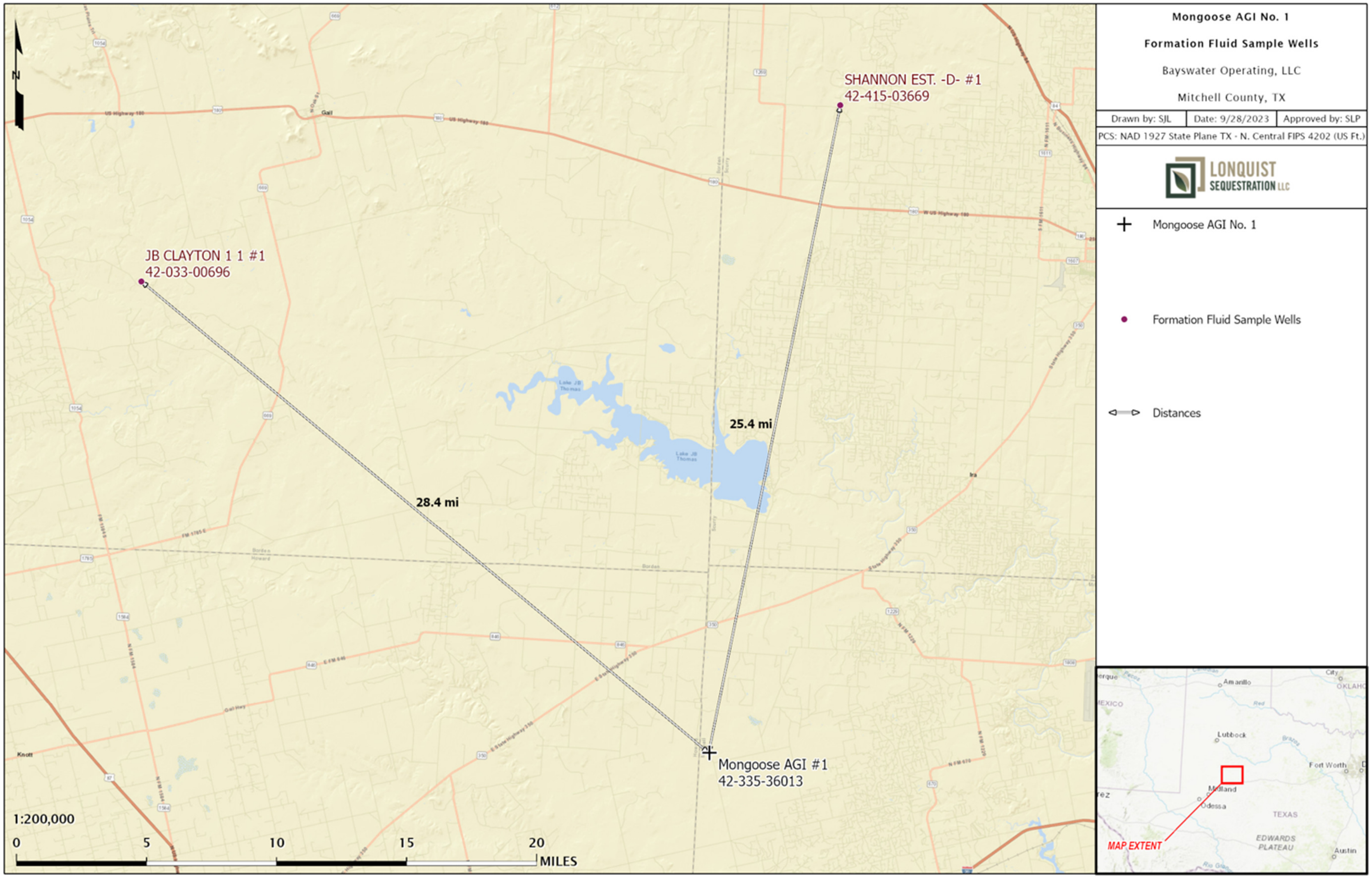


Figure 25 – Offset wells used for formation fluid characterization.

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
pH	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian". Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.

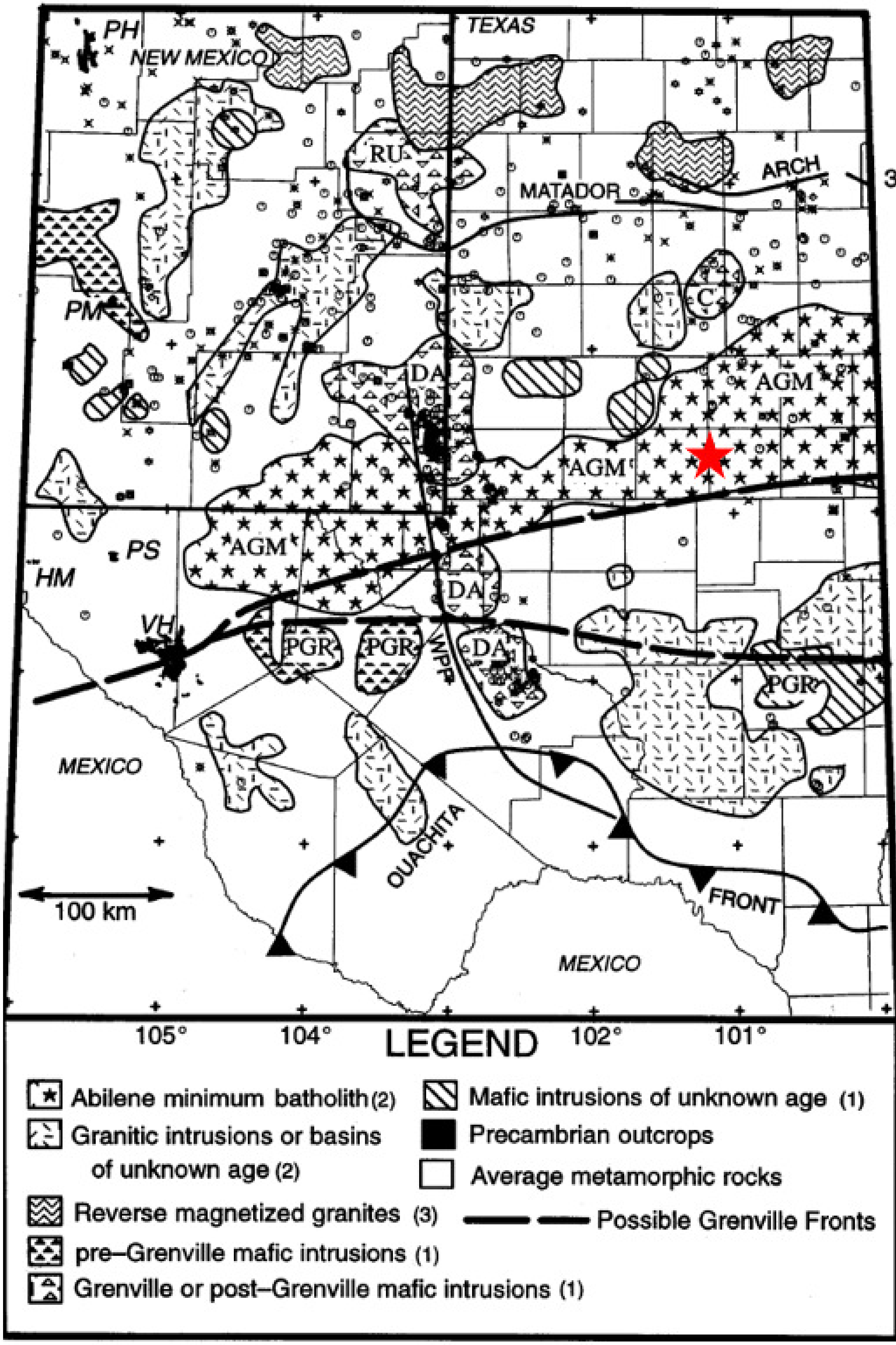


Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_V) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Table 4 – Calculated Vertical Stresses

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$\nu = \frac{\frac{1}{2}\left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

ν = Poisson's Ratio
v_p = Compressional Velocity
v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1-0.261}(1.029 - 0.465) + 0.465 = 0.664\, psi/ft$$

$$FG\ with\ SF = 0.689\ \times 90\% = \mathbf{0.598\, psi/ft}$$

Table 5 – Fracture Gradient Calculation Inputs and Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix C*.

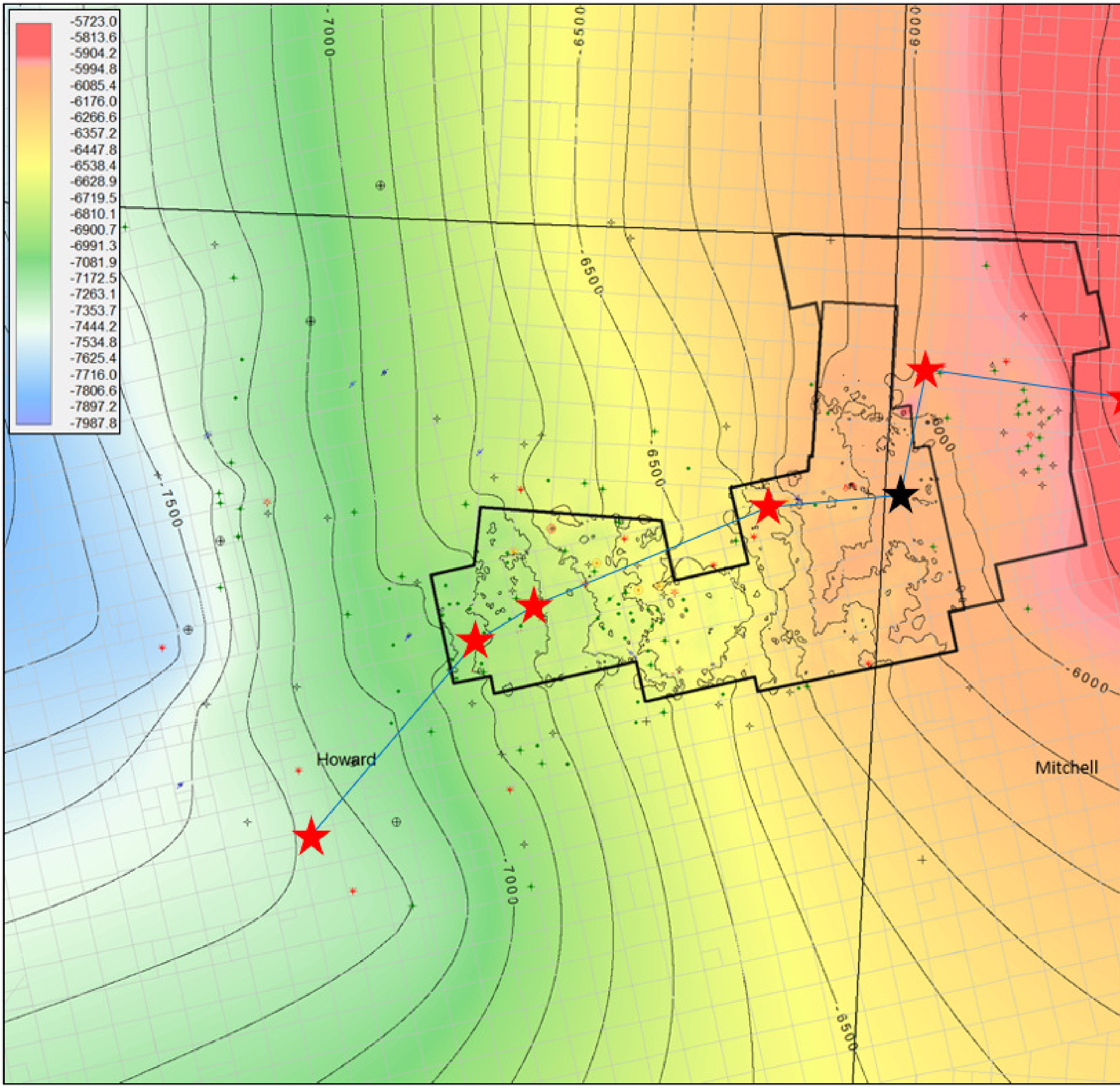


Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.

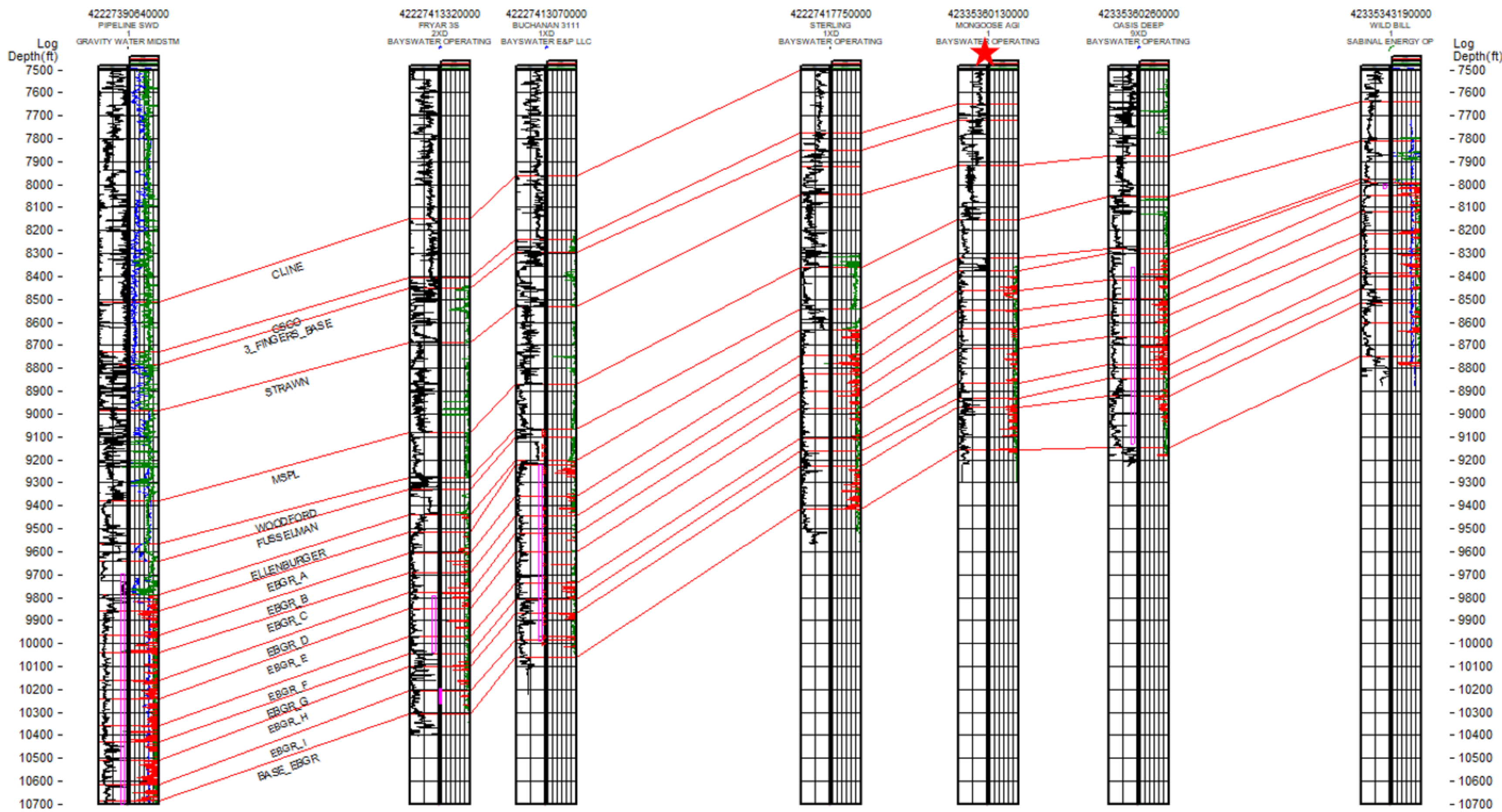


Figure 28 – Structural cross section depicting the Ellenburger.

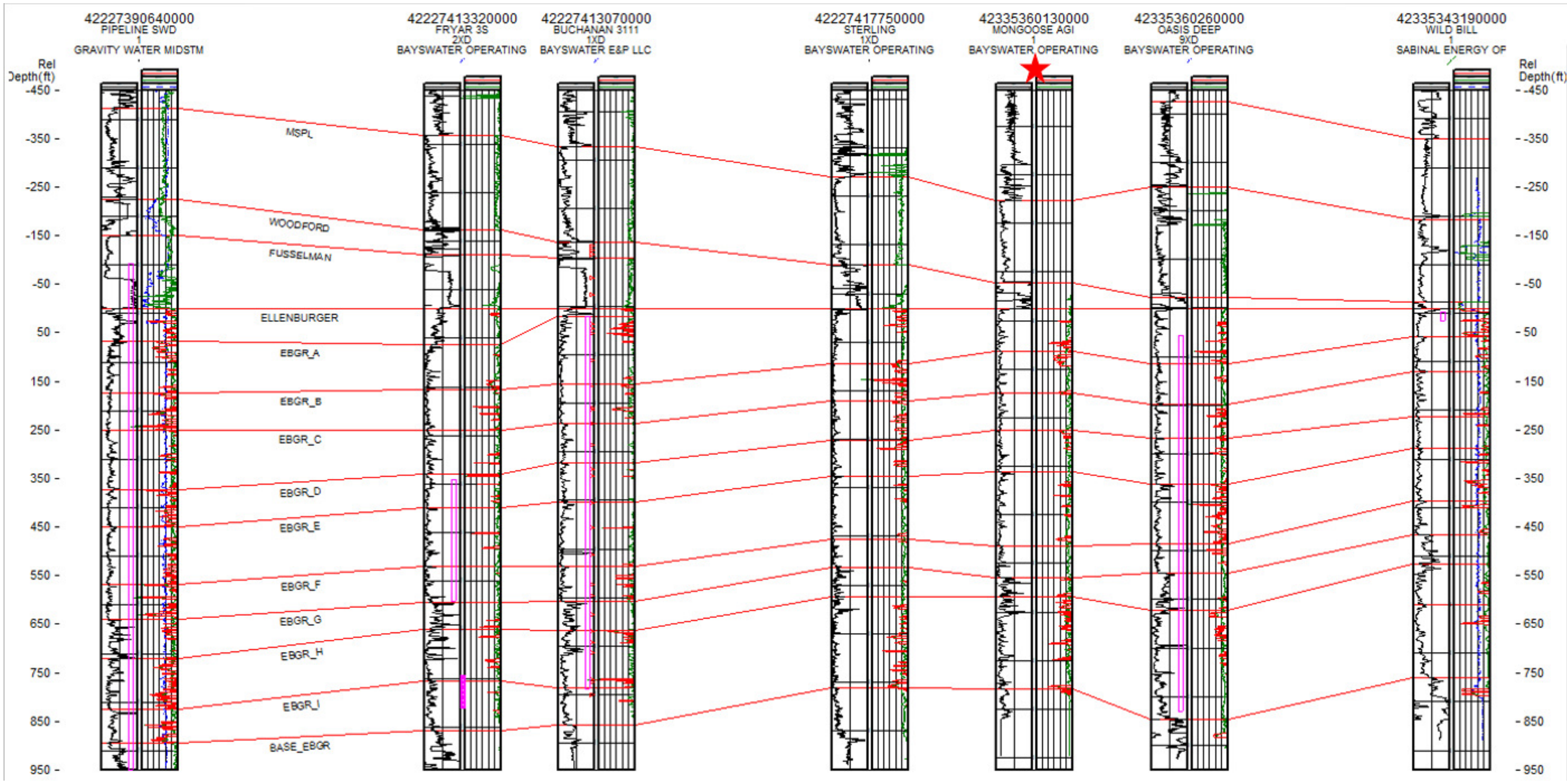


Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colorado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
Cretaceous	Comanche	Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous limestone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potable but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
Triassic		Dockum	Chinle	0-640	Predominantly red to maroon and purplish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sandstone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
			Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaceous and carbonaceous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capacity of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to highly mineralized water to livestock and domestic wells.

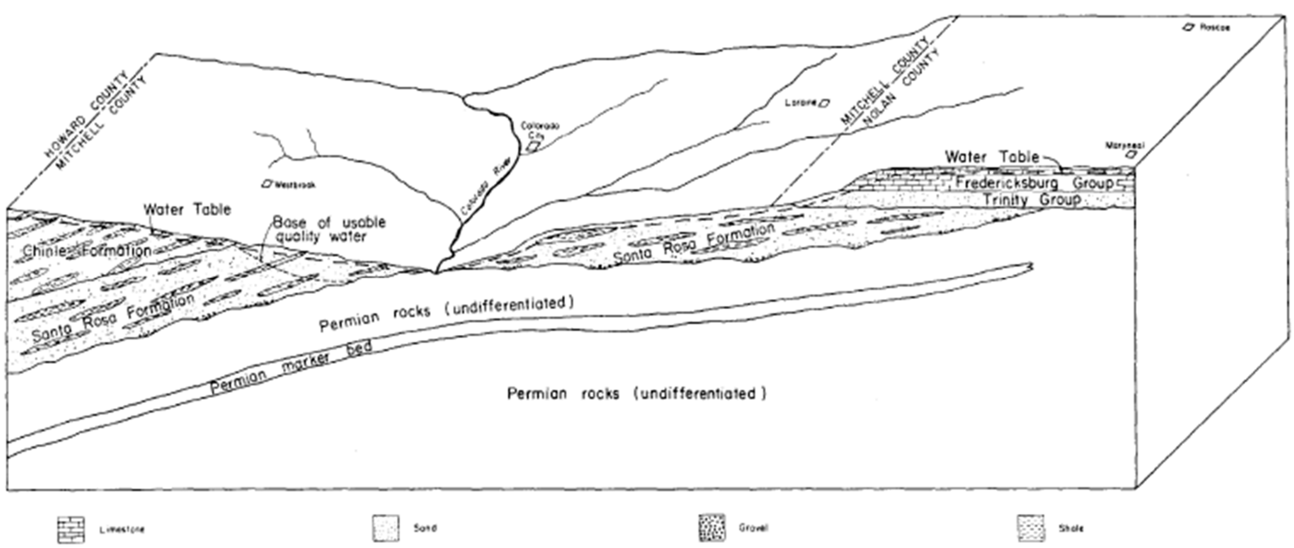


Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.

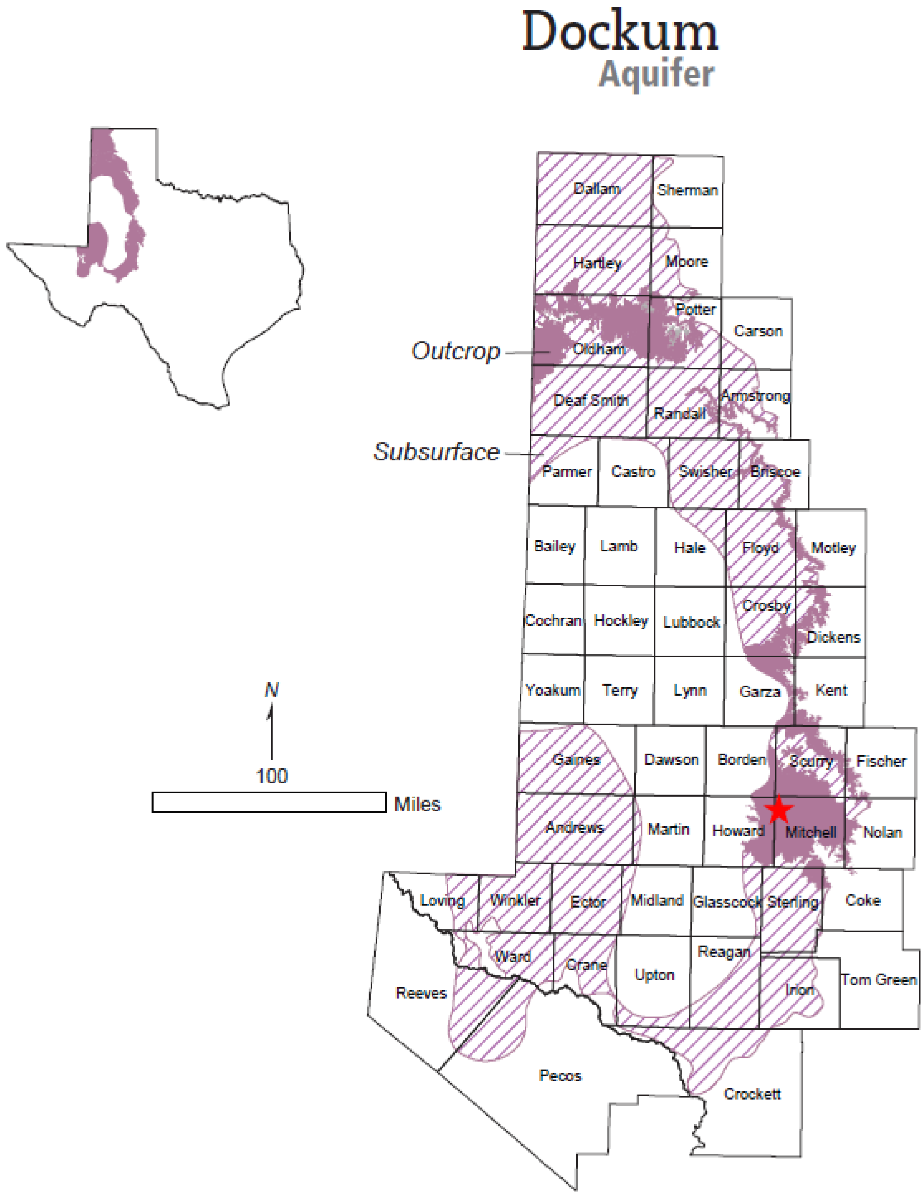


Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).

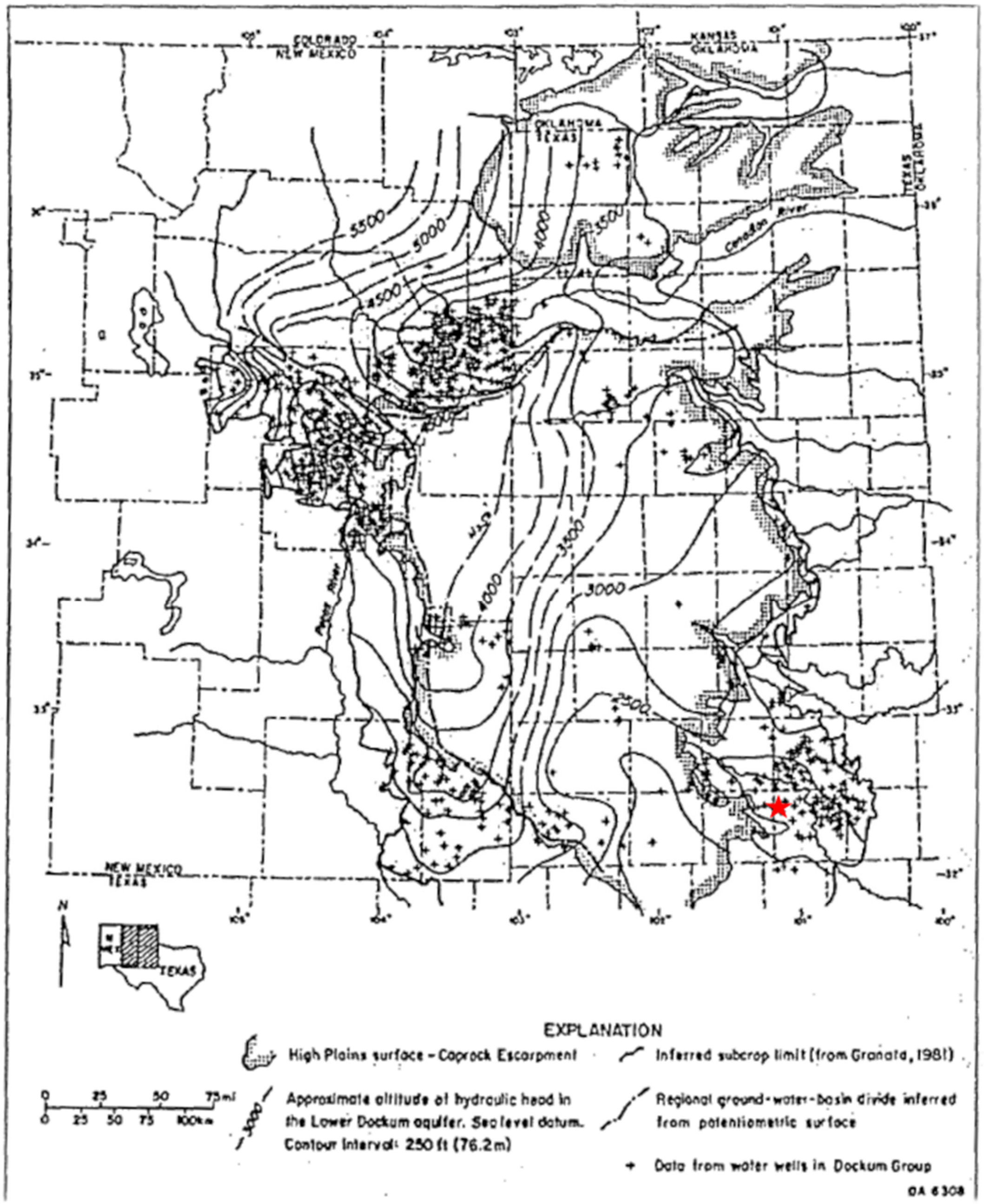


Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).

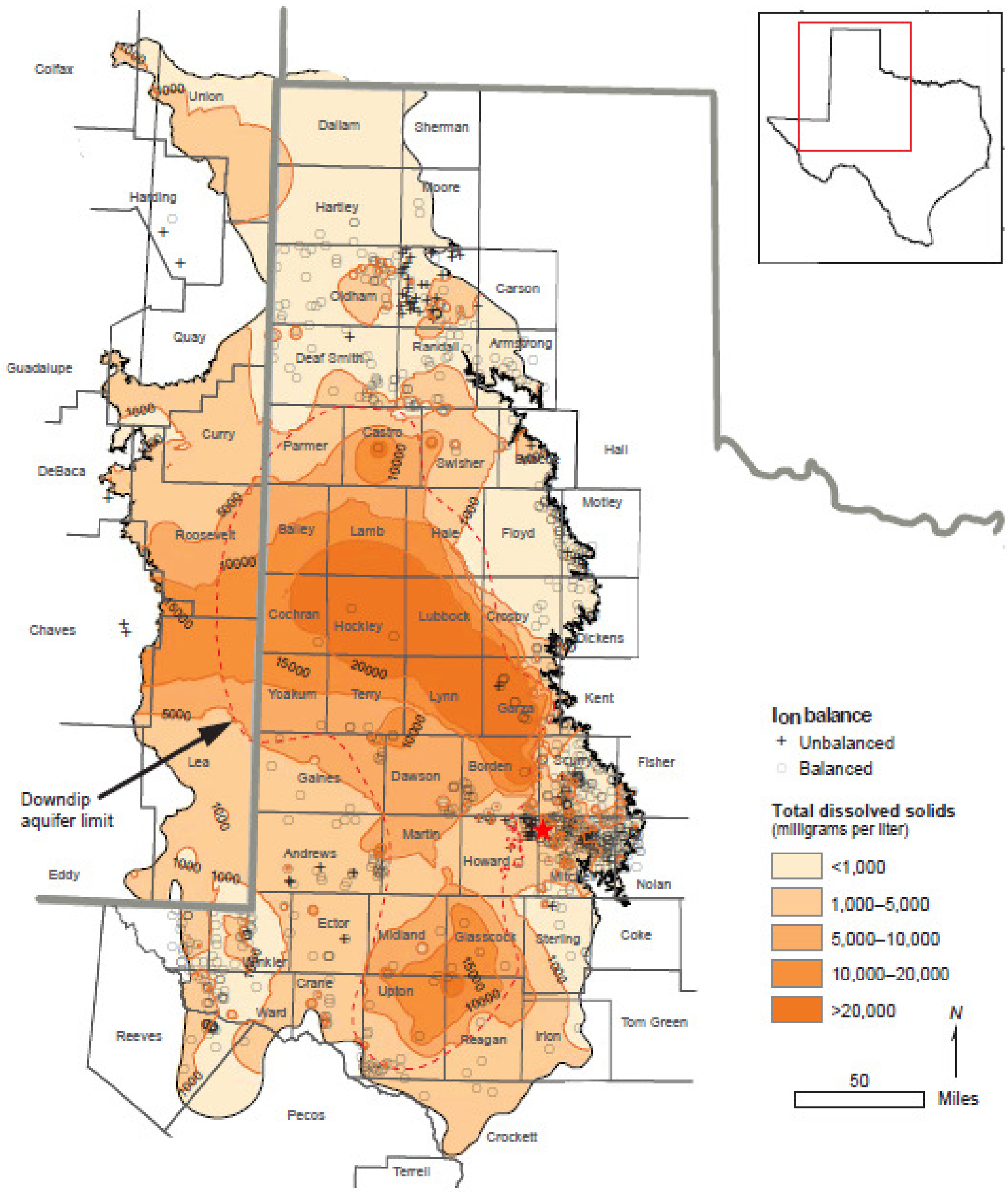


Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 Description of the Injection Process

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO_2, which equates to 155.3 MT/yr of CO_2 each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

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

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite-acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S and CO_2 based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H_2S and 41.2% CO_2. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H_2S and 41.2% CO_2.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H_2S)	58.8	58.8
Carbon Dioxide (CO_2)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.

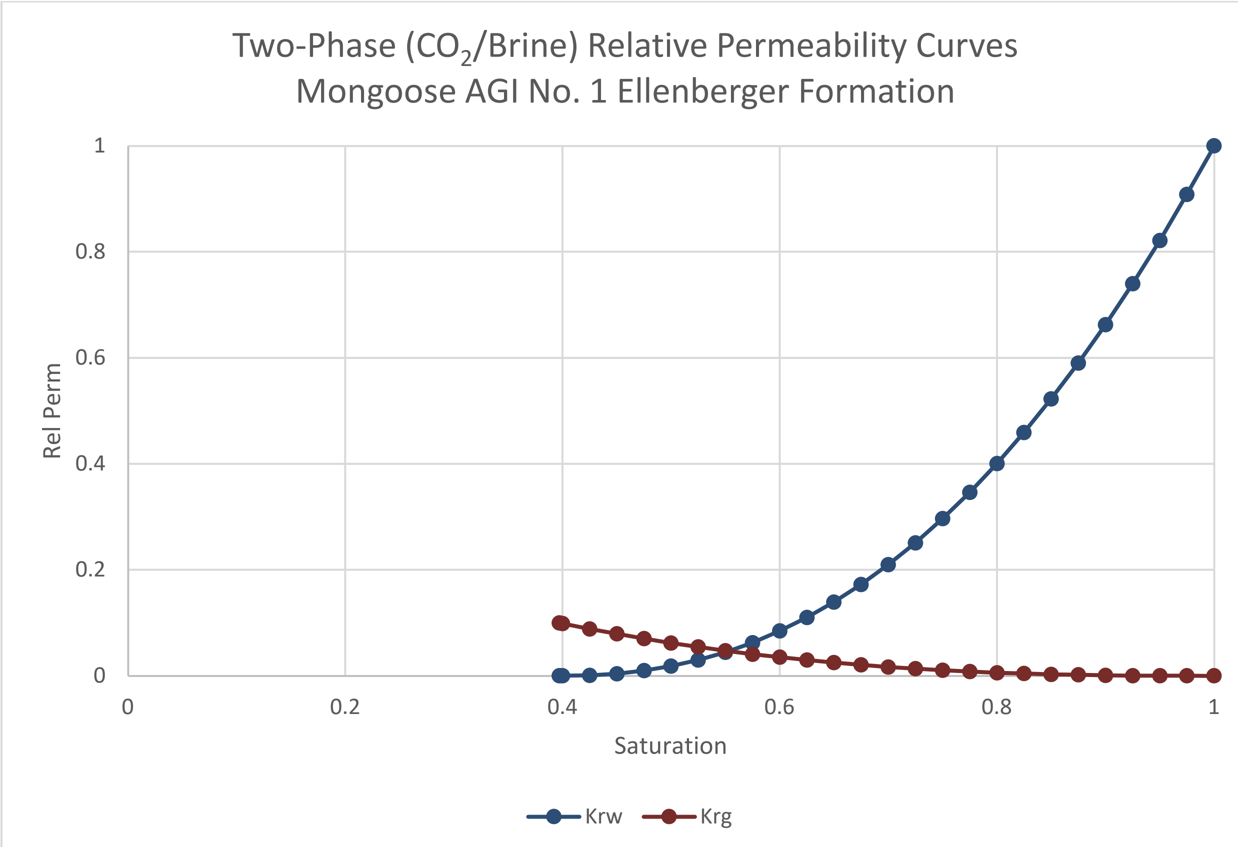


Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (north-south), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Table 9 – GEM Model Layer Package Properties

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

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

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

Table 10 – Offset SWD Wells Included in GEM Model

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.

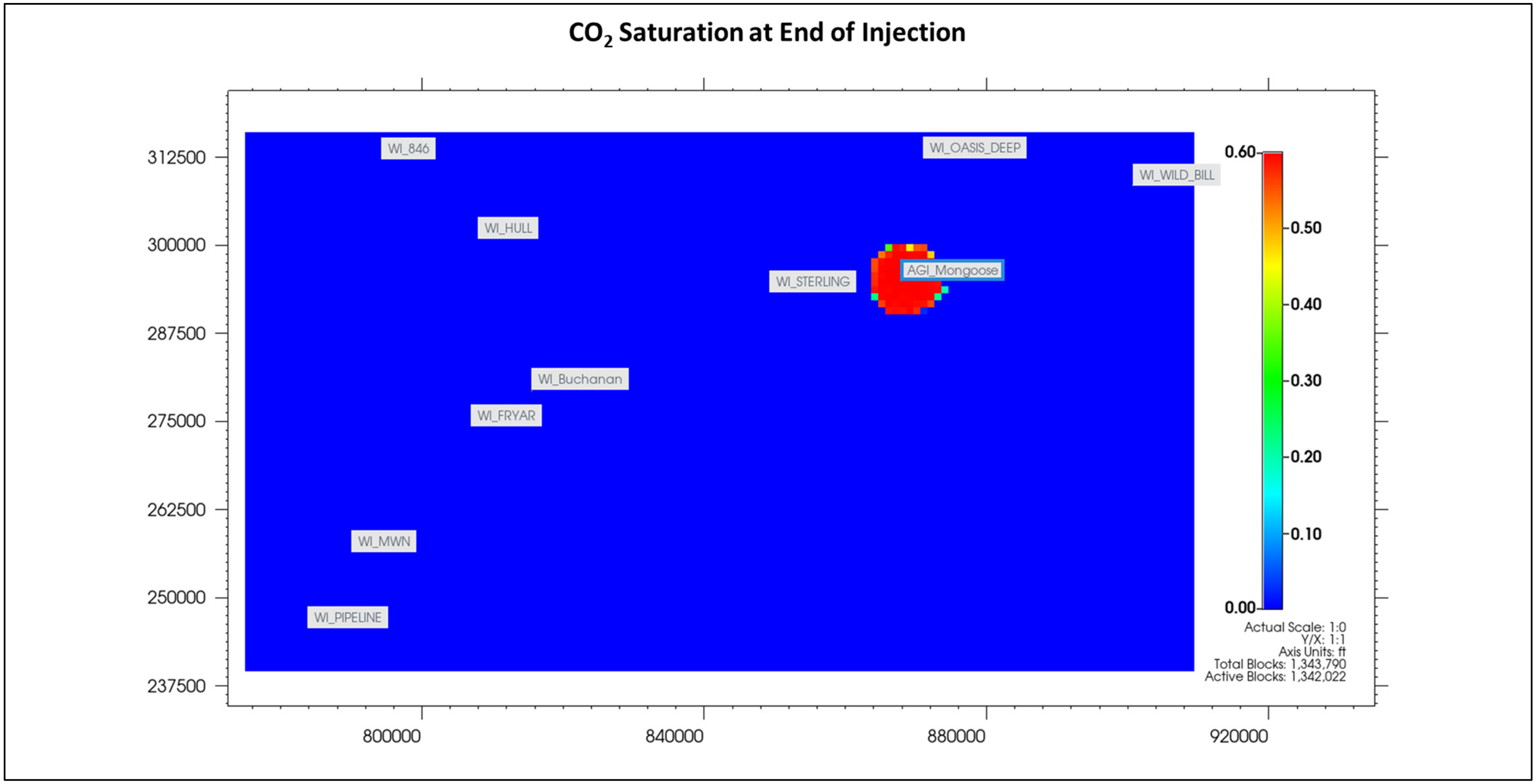


Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)

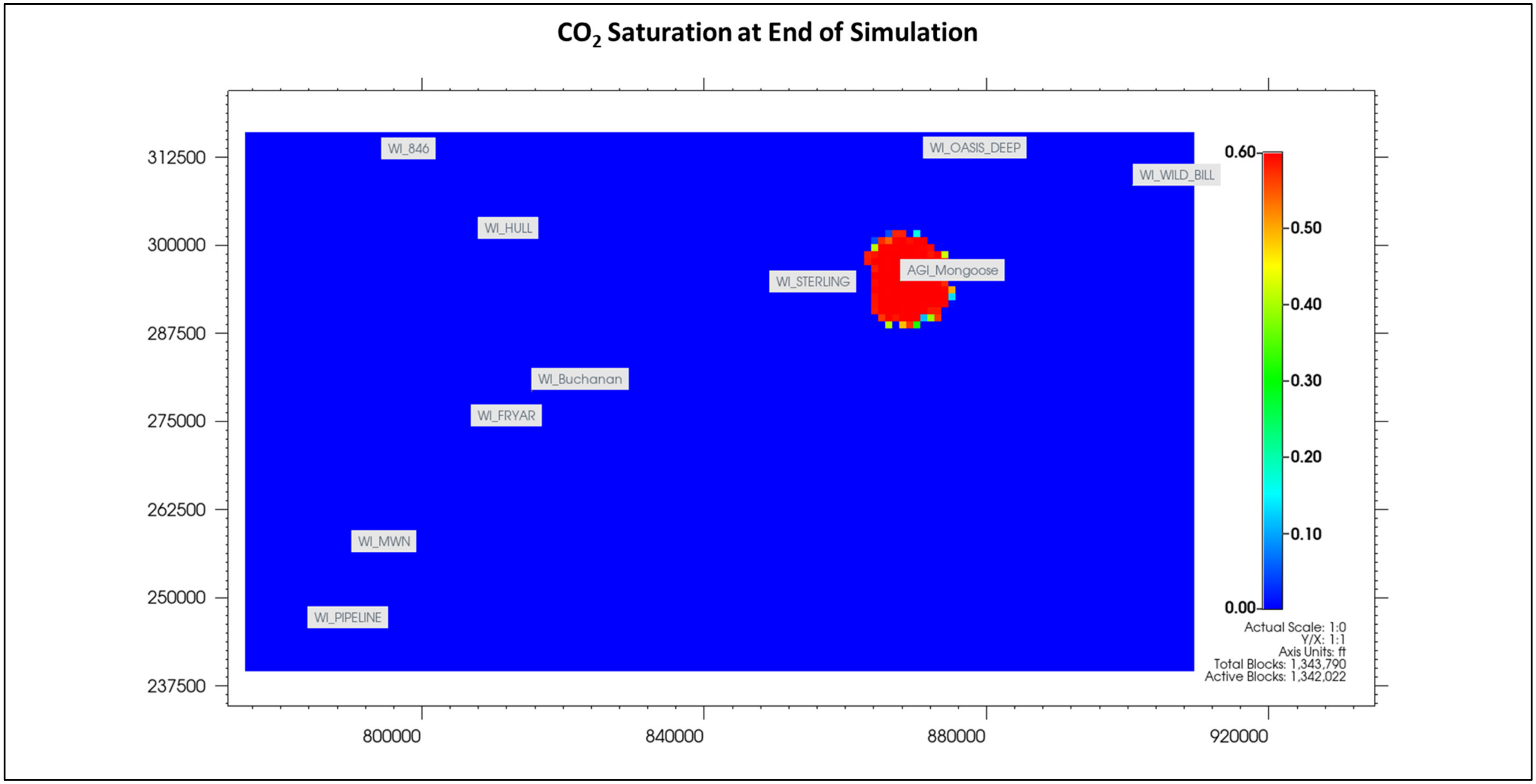


Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

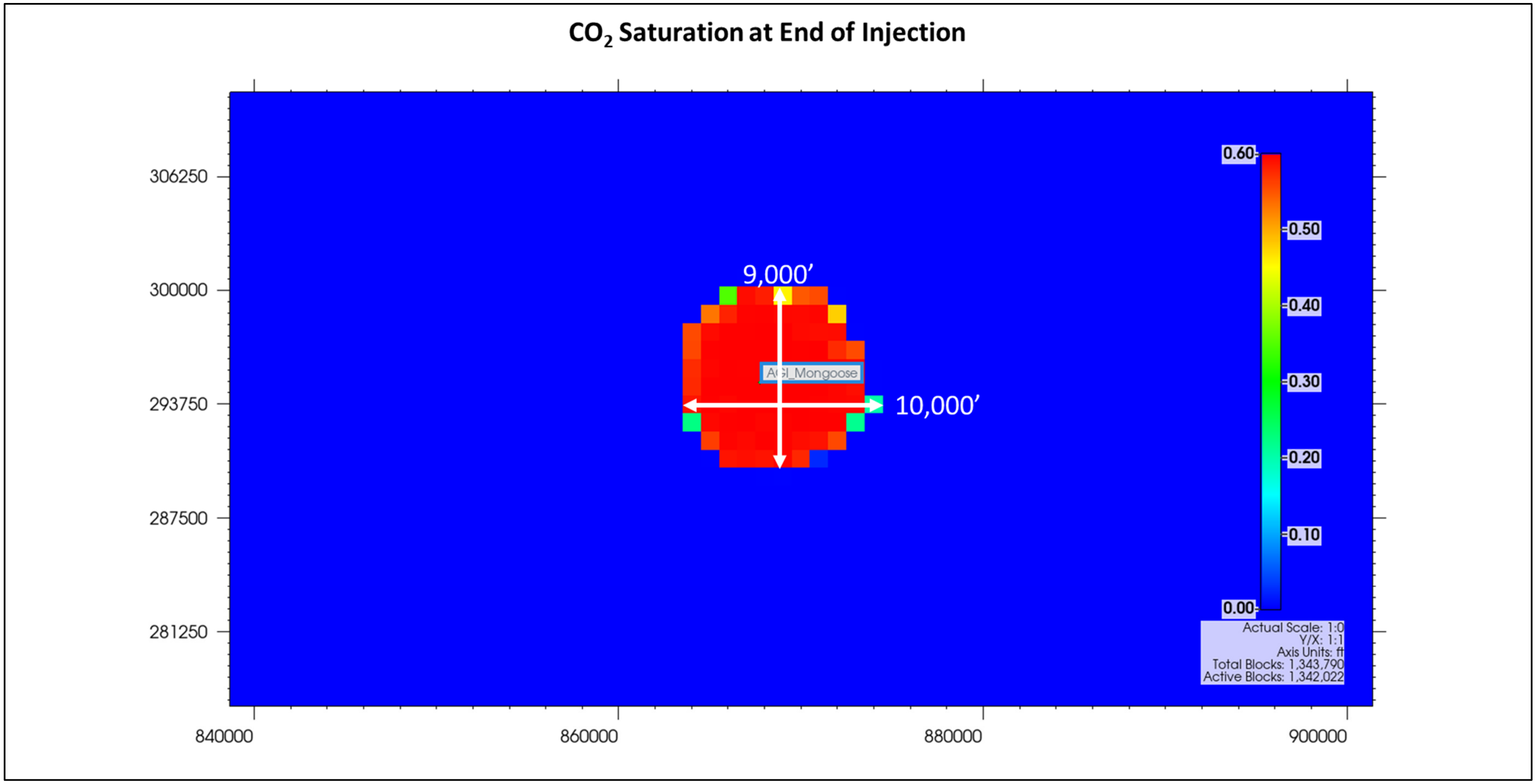


Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)

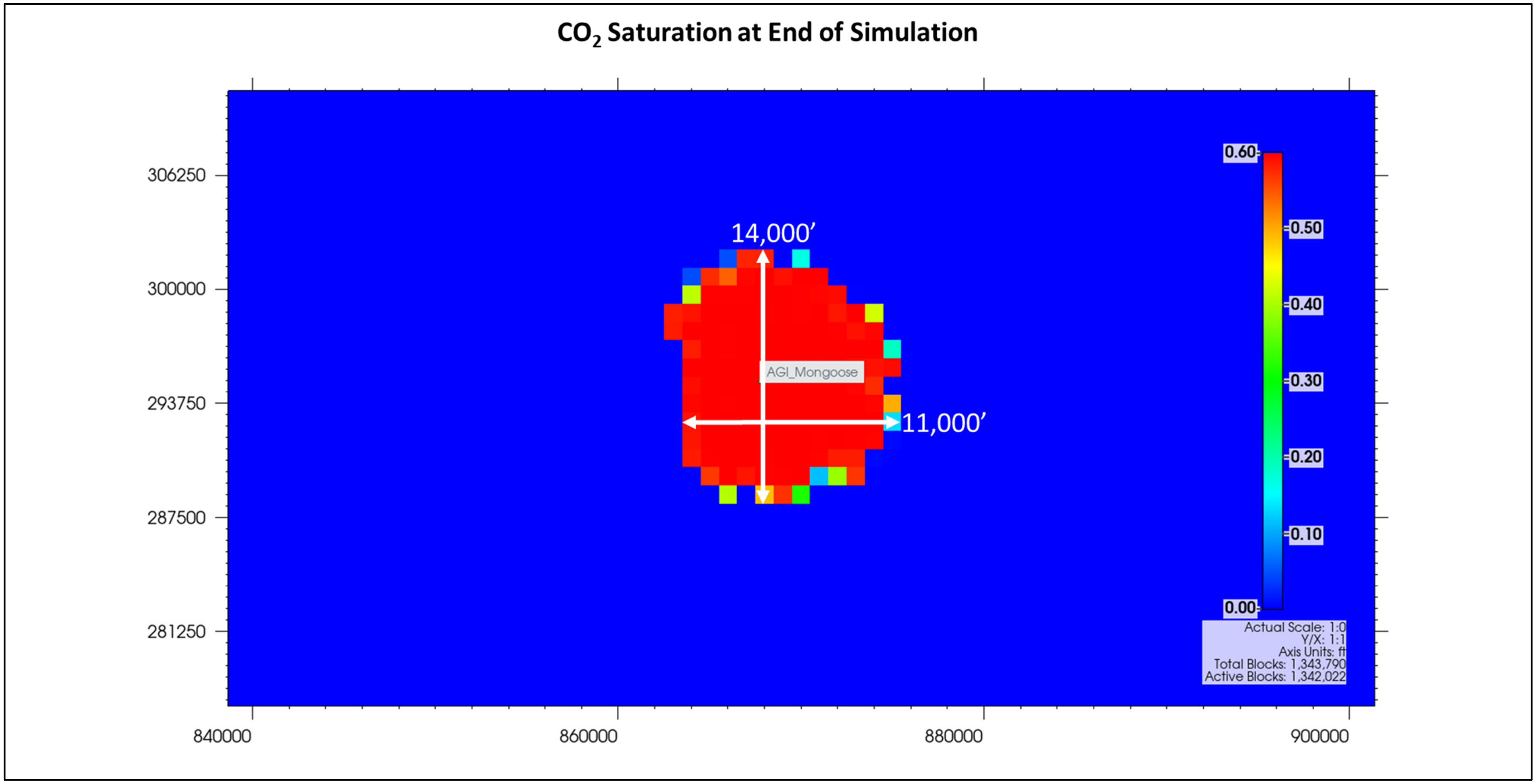


Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.

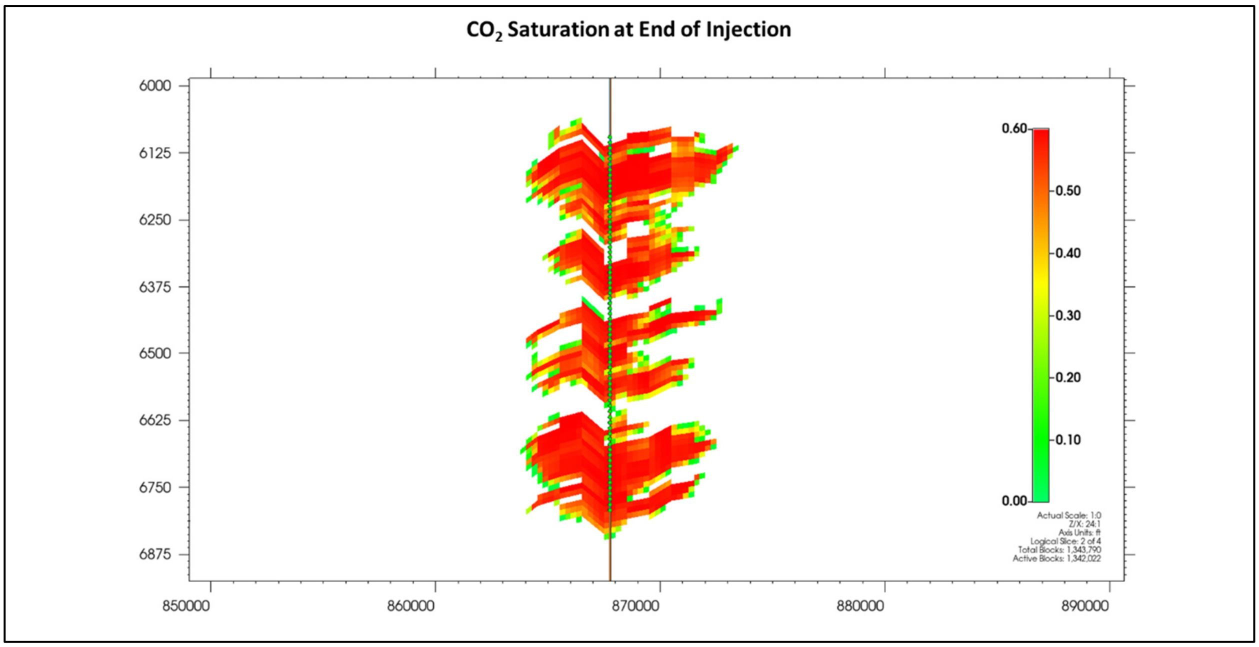


Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

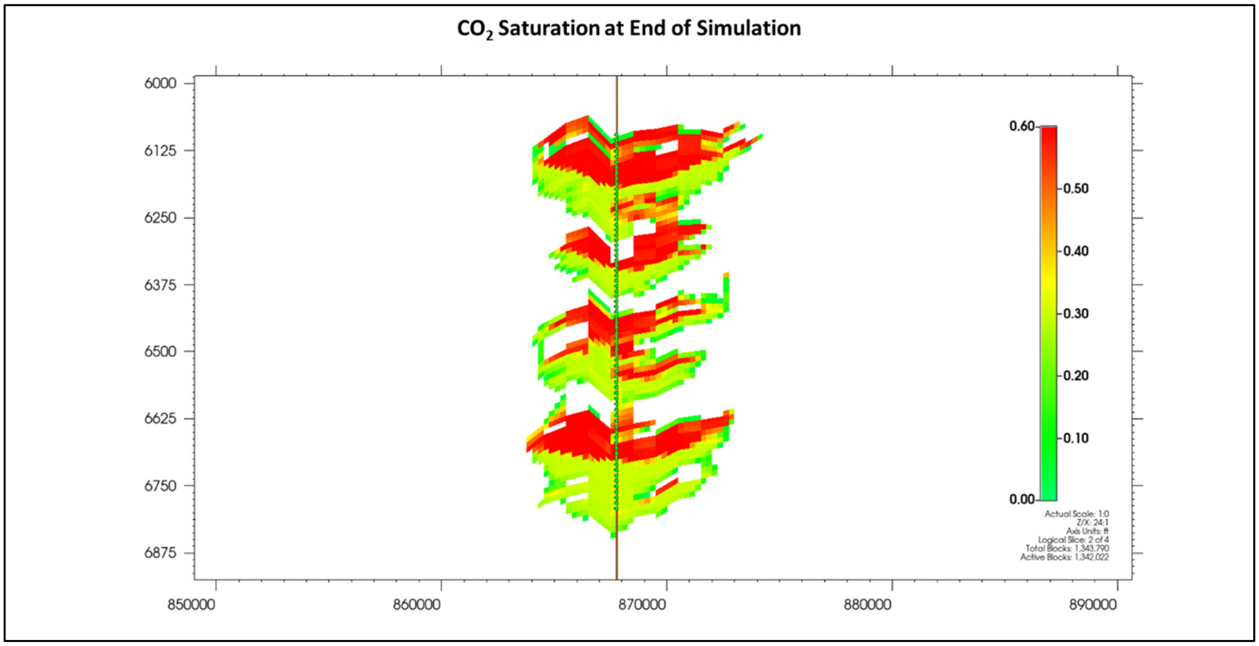


Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.

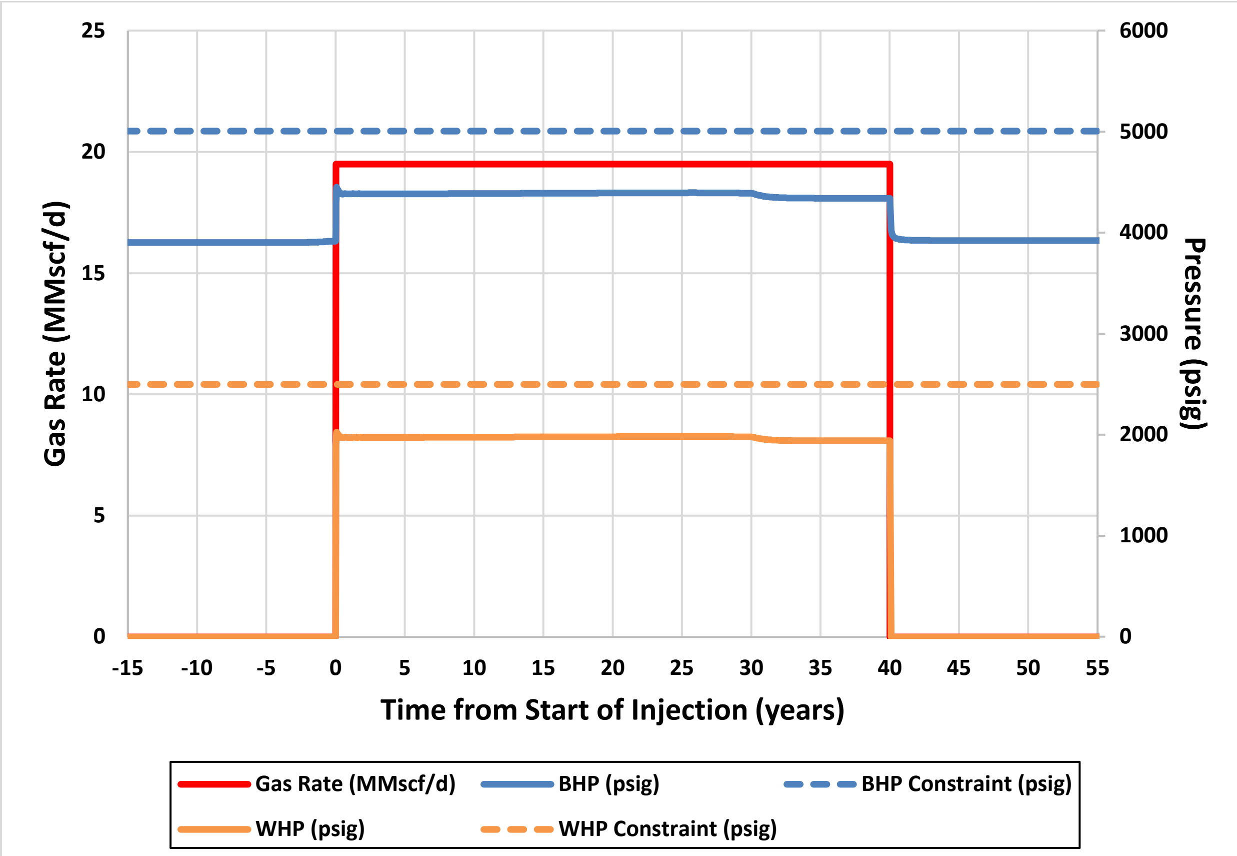


Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H_2S and 41.2% CO_2, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.

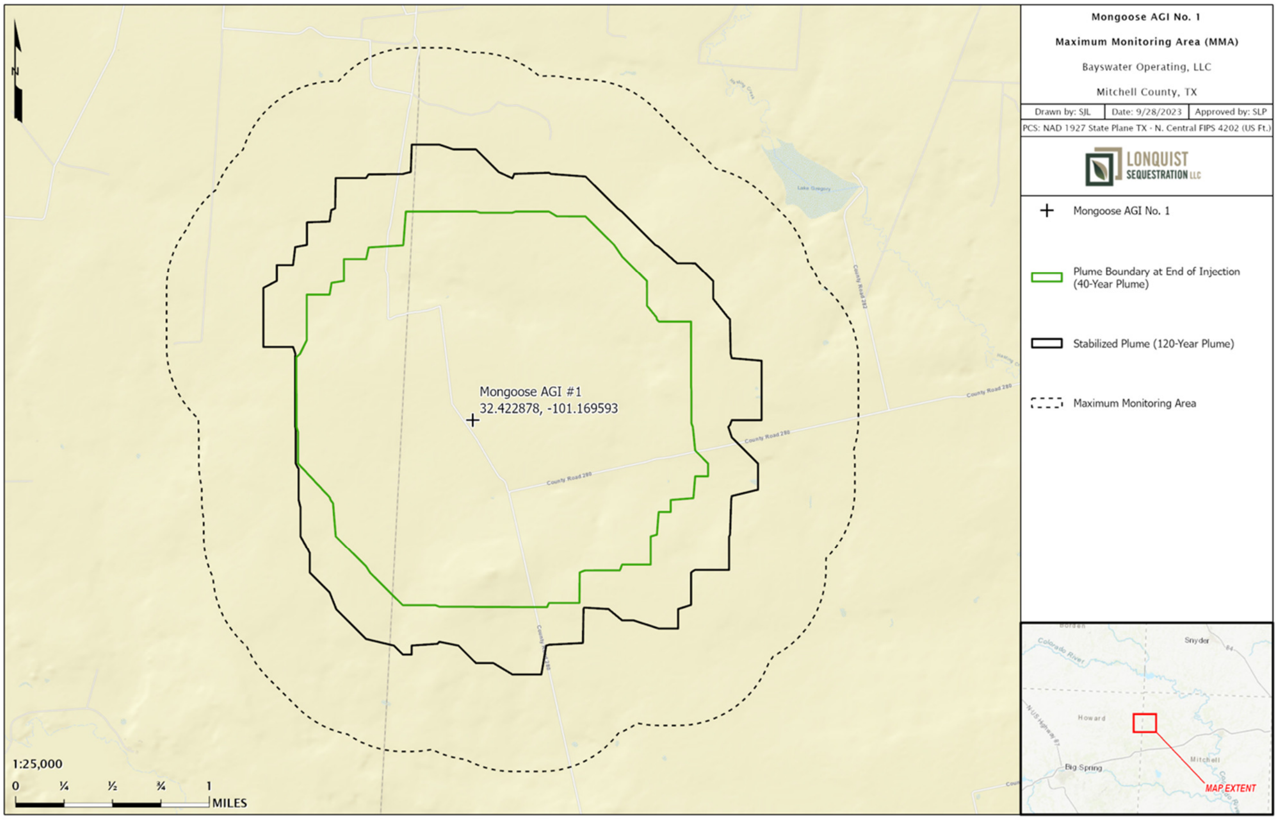


Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.

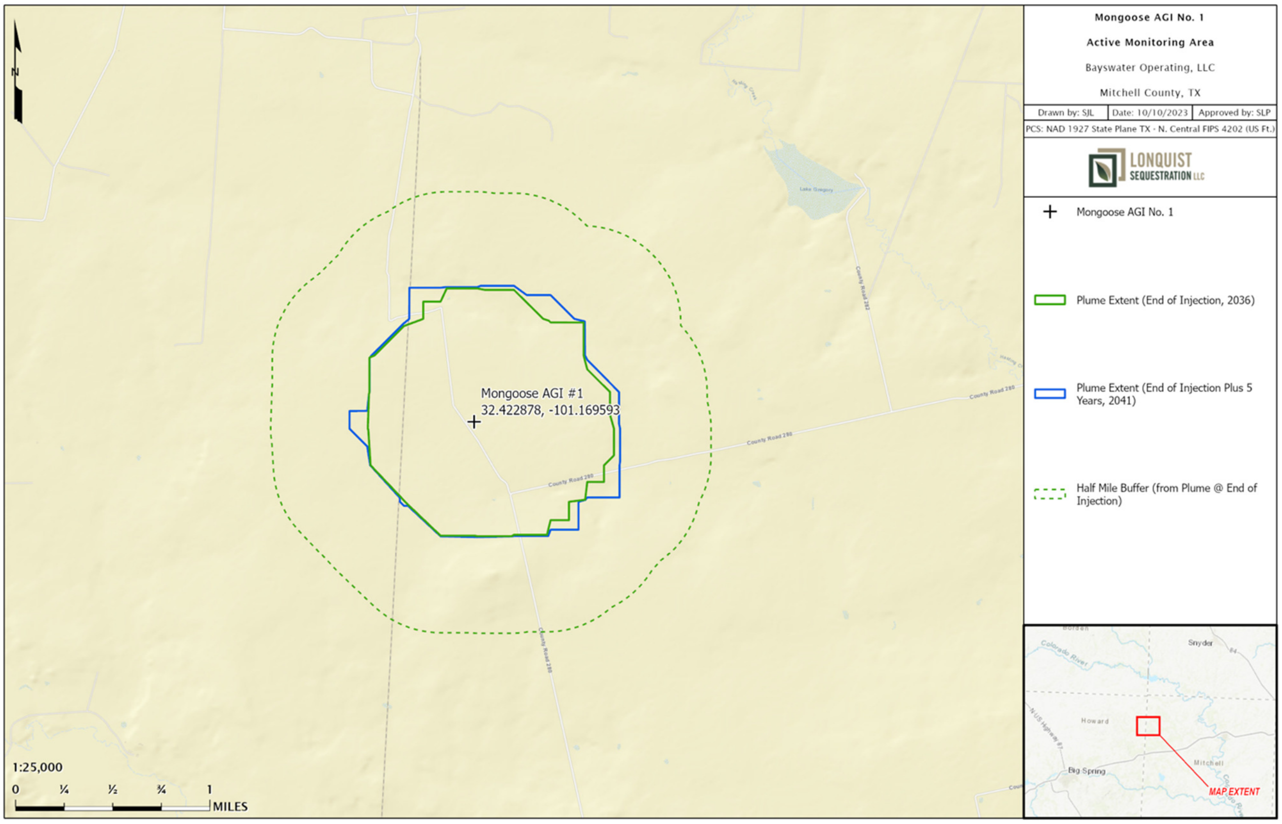


Figure 43 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

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

Table 12 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. The lateral continuity of the UCZ[1] is recognized as a very competent seal.	Low. Any vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care[2] period.
Faults and fractures	Possible. The lateral continuity of UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.

1 - UCZ is defined as the Upper Confining Zone.

2 - Post Injection Site Care is the period of time from the end of injection throught plume stabilization and site closure.

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

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H_2S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H_2S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year, per 40 CFR **§98.444(b)**.

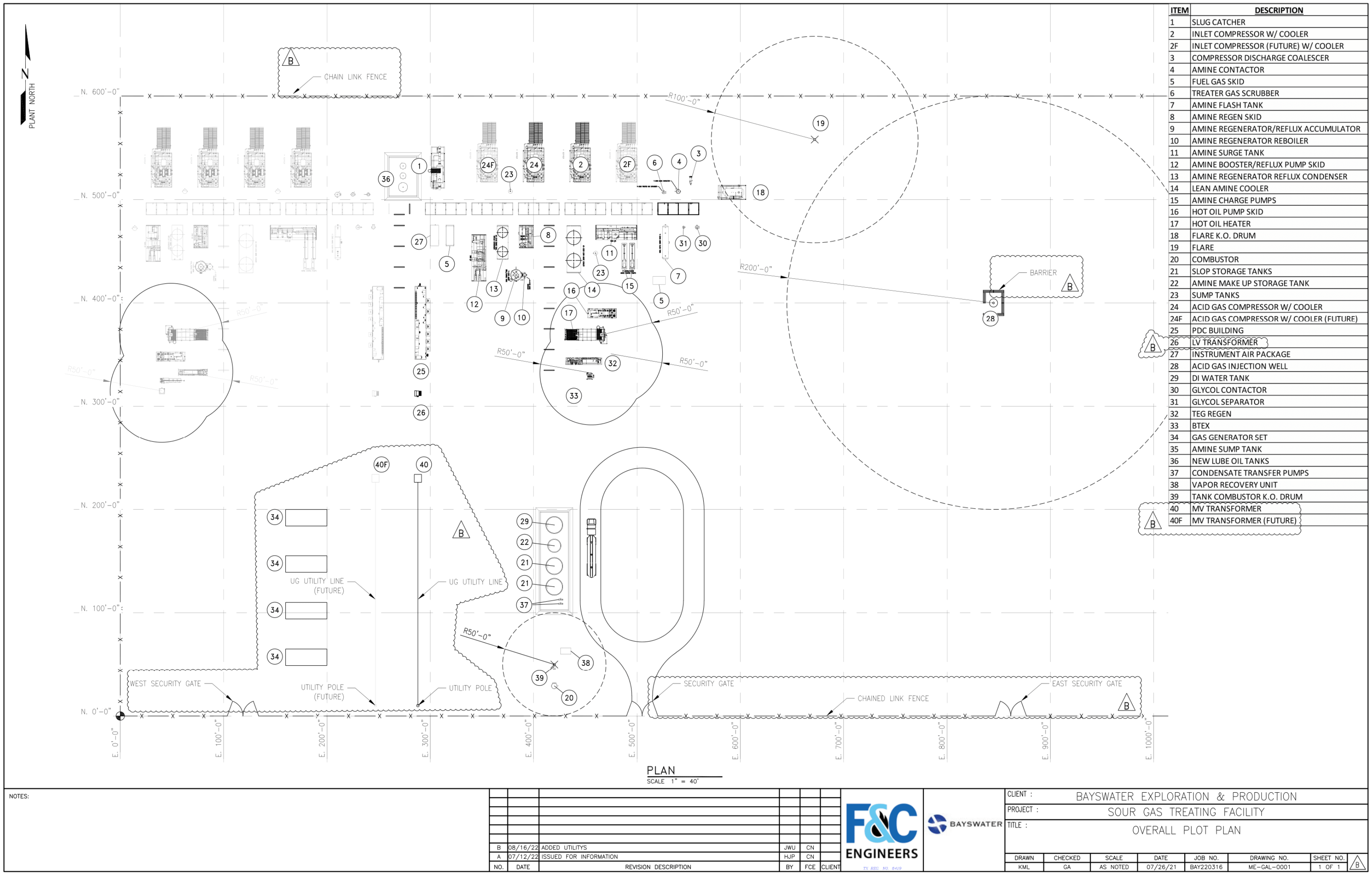
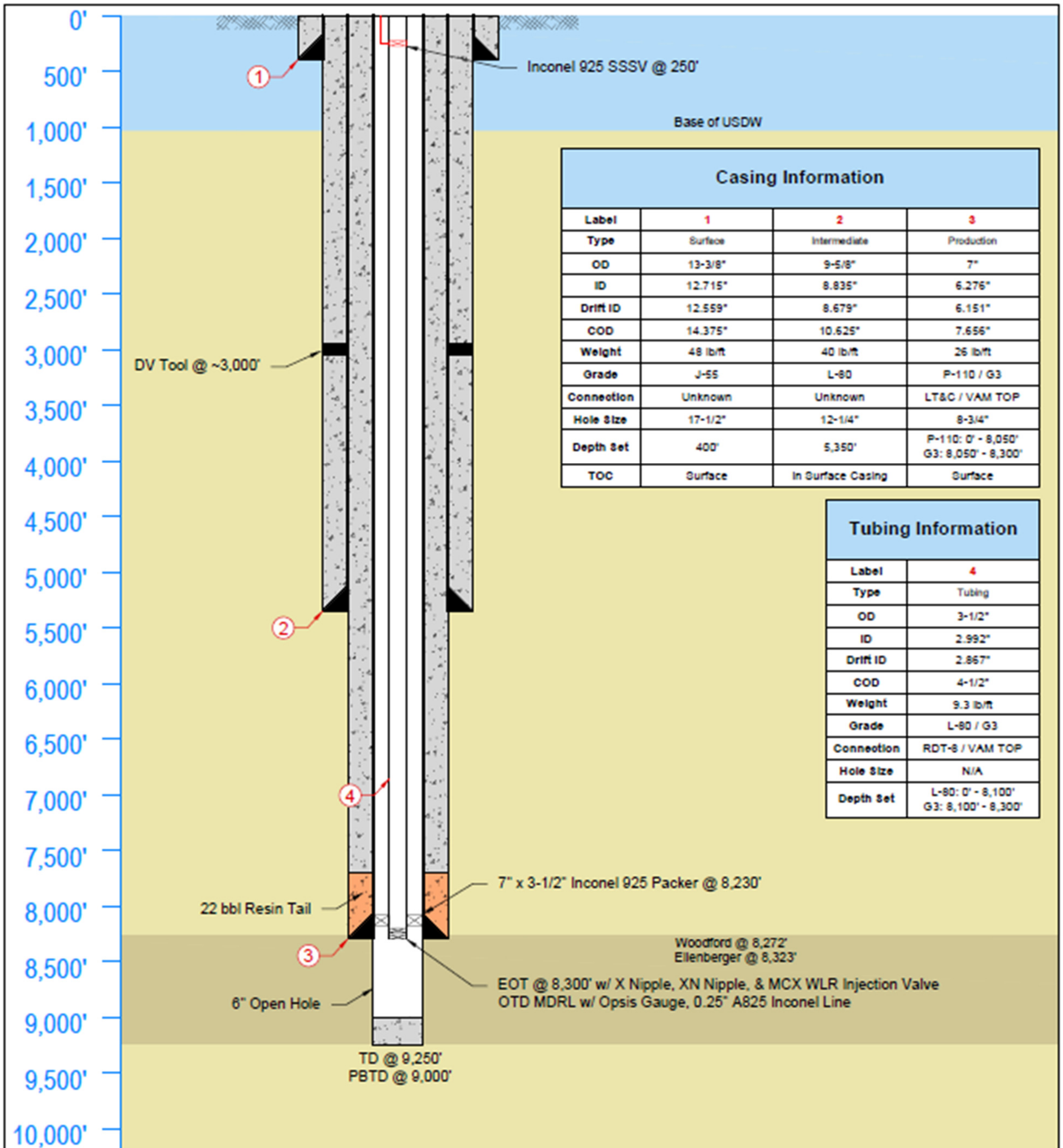


Figure 44 – Site Plan



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
ID	12.715"	8.835"	6.276"
Drift ID	12.559"	8.679"	6.151"
COD	14.375"	10.625"	7.656"
Weight	48 lb/ft	40 lb/ft	26 lb/ft
Grade	J-55	L-80	P-110 / G3
Connection	Unknown	Unknown	LT&C / VAM TOP
Hole Size	17-1/2"	12-1/4"	8-3/4"
Depth Set	400'	5,350'	P-110: 0' - 8,050' G3: 8,050' - 8,300'
TOC	Surface	In Surface Casing	Surface

Tubing Information

Label	4
Type	Tubing
OD	3-1/2"
ID	2.992"
Drift ID	2.867"
COD	4-1/2"
Weight	9.3 lb/ft
Grade	L-80 / G3
Connection	RDT-8 / VAM TOP
Hole Size	N/A
Depth Set	L-80: 0' - 8,100' G3: 8,100' - 8,300'

LONQUIST FIELD SERVICE	Bayswater Operating Company LLC	Mongoose AGI #1	
	Country: USA	State/Province: TX	County/Parish: Mitchell
	API No: 42-335-36013	Field: Sprayberry Trend	Well Type/Status: Acid Gas Injection
Texas License F-9147	RRC District No:	Project No: LS188	Date: 09/07/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved:
	Rev No: 1	Notes:	

Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO_2 will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in Section 2.2.2. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset APs is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.

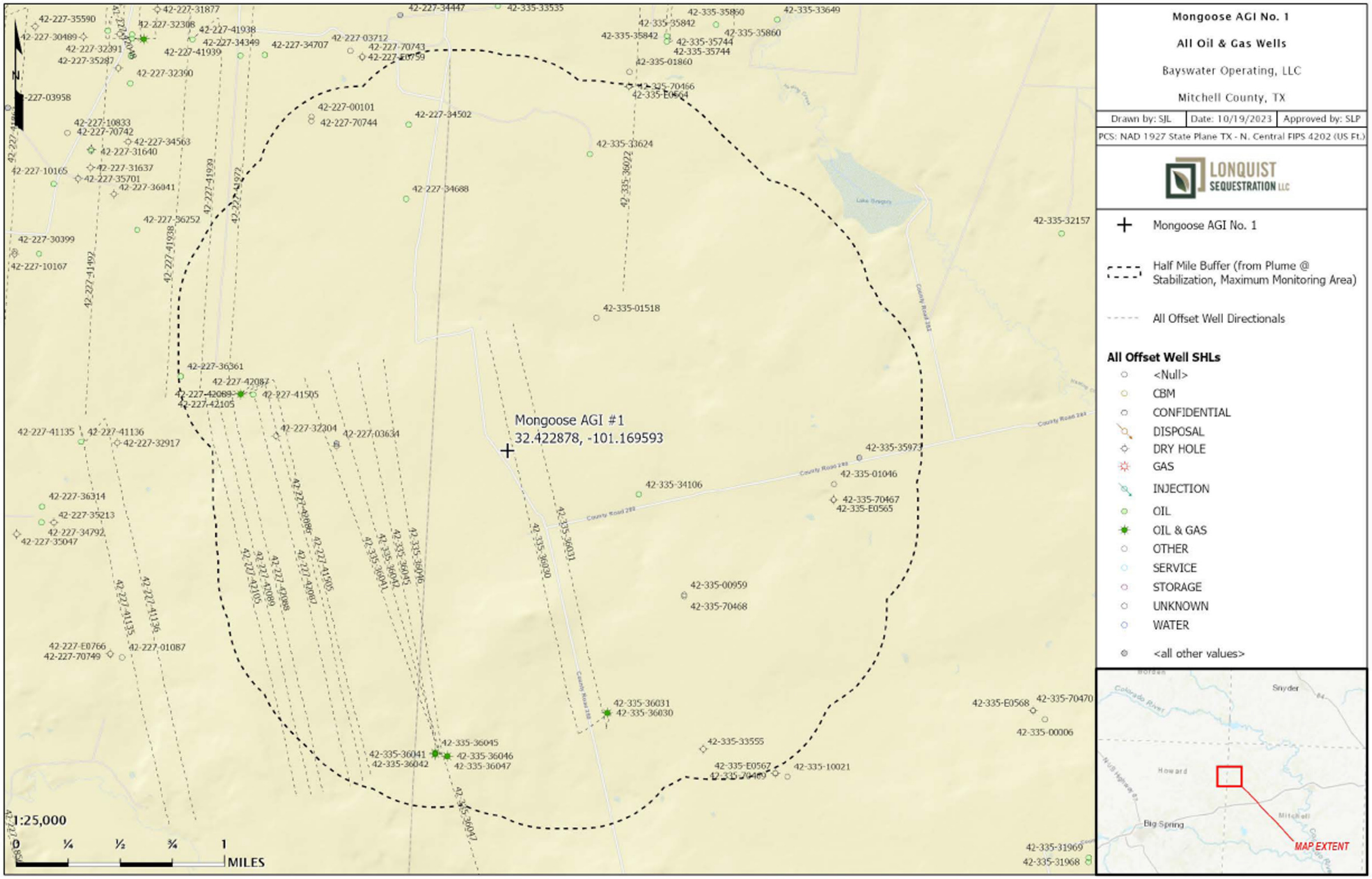


Figure 46 – All Oil and Gas Wells Within the MMA

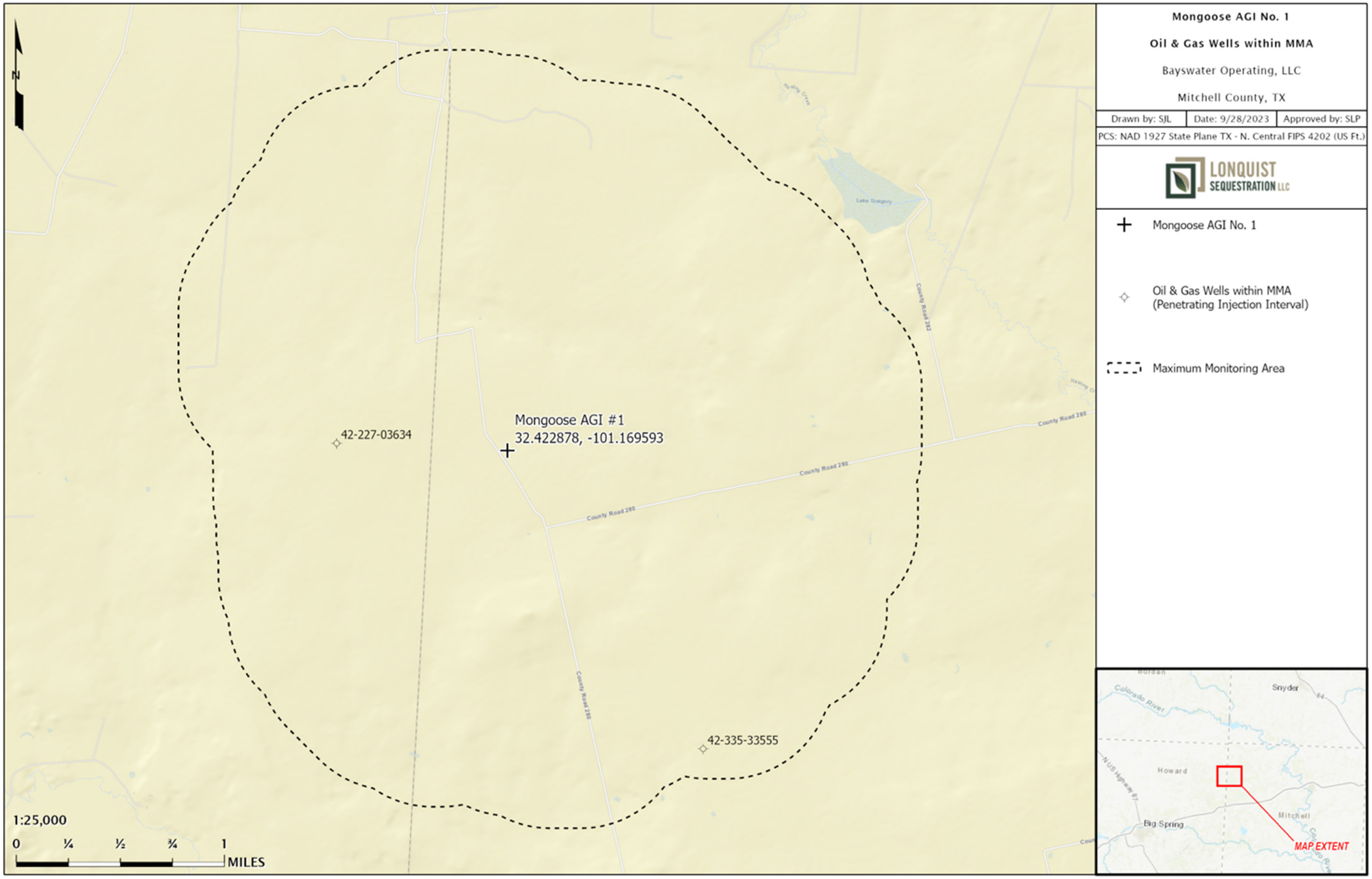


Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Mongoose drilling permit, provided in *Appendix A*, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a quarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued (also provided in the permit in *Appendix A*).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

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

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

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

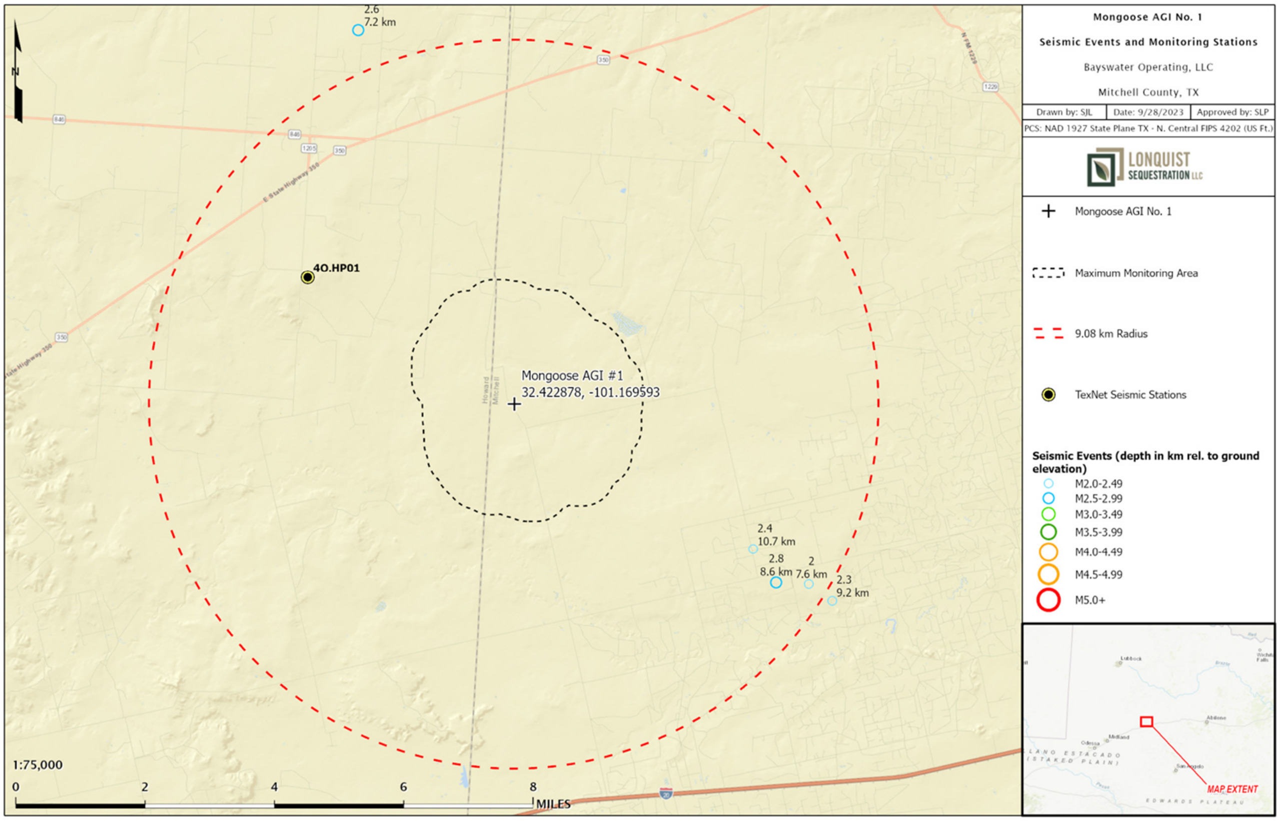


Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Table 13 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Visual inspections
	SCADA continuous monitoring of the AGI facility
Leakage through existing wells	SCADA continuous monitoring of the AGI well
	Monitor CO_2 levels in Above Zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage from natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established during the commissioning of the Plant. Ambient H_2S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H_2S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

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

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2, migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 Groundwater Quality Monitoring

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 Leakage Through Faults, Fractures, or Confining Seals

Bayswater continuously monitors the operations of the Mongoose well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO_2 content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO_2 content would be an early indicator of a potential issue. Should the CO_2 migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

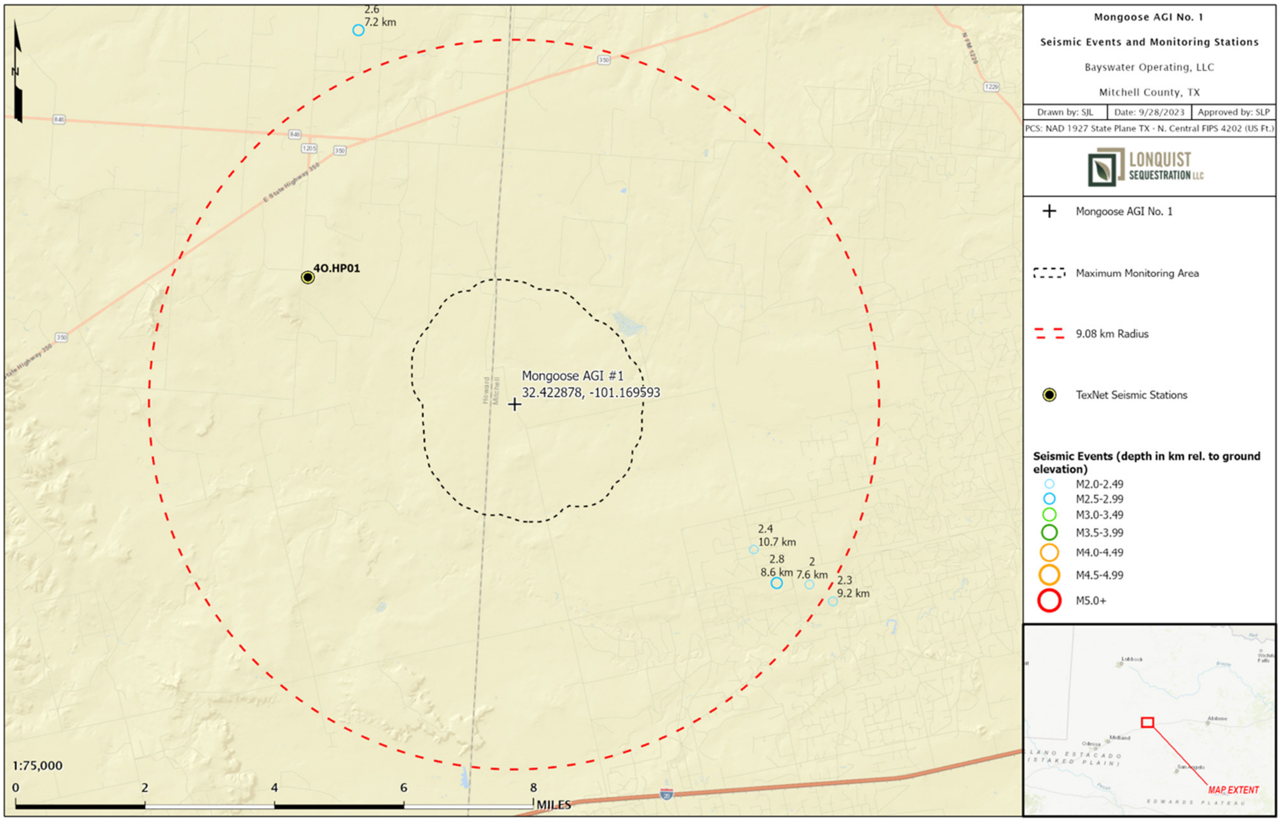


Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

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

6.2 CO_2/H_2S Detection

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H_2S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

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

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

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

7.4 Mass of CO_2 Emitted by Surface Leakage

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

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

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

Where:

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

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

X = Leakage pathway

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

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

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead

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

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Bayswater plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

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

CO_2 Emissions from Leaks and Vented Emissions

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

Measurement Devices

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

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

9.2 Missing Data

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

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

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

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Bayswater will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

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

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

SECTION 11 - REFERENCES

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APPENDICES

APPENDICES

APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN
WAYNE CHRISTIAN, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
DEPUTY EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS, P.E.
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17174

BAYSWATER OPERATING COMPANY LLC
730 17TH STREET
SUITE 500
DENVER CO 80202

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE
SPRABERRY (TREND AREA) FIELD
MITCHELL COUNTY
DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33536013	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.** **3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;

Note: This document will only be distributed electronically.

c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON March 10, 2023.

FOR Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	04 March 2022	**GAU Number:**	336979

Attention:	BAYSWATER OPERATING 730 17TH STREET SUITE 500 DENVER, CO 80202	**API Number:**	33536013
		County:	MITCHELL
		Lease Name:	Mongoose AGI
		Lease Number:	
Operator No.:	058827	**Well Number:**	1
		Total Vertical	9250
		Latitude:	32.422884
		Longitude:	-101.169661
		Datum:	NAD27

Purpose: Injection into Non-producing Zone (W-14)

Location: Survey-T&P RR CO; Abstract-1545; Block-29; Township-1N; Section-4

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 350 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 475 feet at the site of the referenced well.

This recommendation is applicable to all wells within a radius of 200 feet of this location.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 03/02/2022. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary. If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER	DATE PERMIT ISSUED OR AMENDED	DISTRICT
876754	Feb 10, 2022	* 08
API NUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03, 2022	COUNTY MITCHELL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 40

OPERATOR 058827

BAYSWATER OPERATING COMPANY LLC
730 17TH STREET SUITE 500
DENVER, CO 80202-0000

NOTICE
This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored.
District Office Telephone No:
(432) 684-5581

LEASE NAME: MONGOOSE AGI	WELL NUMBER: 1
LOCATION: 10.4 miles NW direction from WESTBROOK	TOTAL DEPTH: 10000

Section, Block and/or Survey
SECTION 4 BLOCK 29 T1N ABSTRACT 1545
SURVEY T&P RR CO/MORRISON, W

DISTANCE TO SURVEY LINES: 551 ft. EAST 2164 ft. SOUTH	DISTANCE TO NEAREST LEASE LINE: ft.
DISTANCE TO LEASE LINES: 400 ft. EAST 650 ft. SOUTH	DISTANCE TO NEAREST WELL ON LEASE: See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL # / NEAREST WE	DIST
SPRABERRY (TREND AREA) / MONGOOSE AGI	40.00 / 0	10,000	1	08

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Submitted
Date: 09/11/2023
Tracking No.: 298516

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator BAYSWATER OPERATING COMPANY LLC **Operator** 058827
Operator 730 17TH STREET SUITE 500 DENVER, CO 80202-

WELL INFORMATION

API 42-335-36013
County: MITCHELL
Well No.: 1
RRC District 08
Lease MONGOOSE AGI
Field SPRABERRY (TREND AREA)
RRC Lease
Field No.: 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRISON, W, Abstract: 1545

Latitude 32.423000
Longitud -101.170059
This well is 10.4 **miles in a** NW
direction from WESTBROOK,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC
Completion or Recompletion 04/28/2023

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	02/10/2022	876754
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal		17174
Other:		

COMPLETION INFORMATION

Spud 10/12/2022
Date of first production after rig 04/28/2023
Date plug back, deepening, drilling operation 10/12/2022
Date plug back, deepening, recompletion, drilling operation 04/28/2023
Number of producing wells on this lease this field (reservoir) including this 1
Distance to nearest well in lease & reservoir
Total number of acres in 40.00
Elevation 2252 GL
Total depth TVD 9289
Total depth MD
Plug back depth TVD 9036
Plug back depth MD
Was directional survey made other inclination (Form W- Yes
Rotation time within surface casing 41.0
Is Cementing Affidavit (Form W-15) Yes
Recompletion or No
Multiple No
Type(s) of electric or other log(s) Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease of lease on which this well is
Off Lease : No
400.0 **Feet from the** East **Line and**
650.0 **Feet from the** South **Line of the**
MONGOOSE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

	Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type
PACKET: N/A				

W2:	N/A				

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination		**Depth**	350.0	**Date**	03/04/2022
SWR 13 Exception		**Depth**			

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		**Production**	
Number of hours	24	**Choke**	
Was swab used during this	No	**Oil produced prior to**	

PRODUCTION DURING TEST PERIOD:

Oil		**Gas**	
Gas - Oil	0	**Flowing Tubing**	
Water			

CALCULATED 24-HOUR RATE

Oil		**Gas**	
Oil Gravity - API - 60.:		**Casing**	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	569			C	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		C	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			C	610	1175.0	3001	Calculation
4	Conventional Production	7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL 925

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	Yes	L 8343	9036.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1	Other	OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H	9036	9289

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

OPERATOR'S CERTIFICATION

Printed	James Clark	**Title:**	Consulting Petroleum Engineer
Telephone	(512) 415-4191	**Date**	09/11/2023

A-5

000057 0708

▶ Return each W-1 with plat and $100.00 fee. Make check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas Oil and Gas Division, Drilling Permits P. O. Drawer 12967, Capitol Station Austin, Texas 78711
▶ File a copy of W-1 and plat in RRC District Office.

~~Cal 13~~

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1
Rev. 9/1/83
483-080

020
VMC

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ▶ API No. 42-335-33555 ▶ Permit No. 379724 ▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report)	3. RRC Operator No.	4. RRC District No.	5. County of Well Site
Bright & Company 10-18-90	093125	8	Mitchell

2. Address (including city and zip code)
3200 West Cuthbert, Suite 2-C
Midland, Texas 79701

6. Lease Name (32 spaces maximum)	7. RRC Lease/ID No.	8. Well No.	9. Total Depth
Van Tuyle	--	1	8500'

10. Location
• Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1-N~~ Abstract No. A-584
• This well is to be located 5 miles in a north direction from Iatan which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.
12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

Granted 10/29/90

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
~~Wolfcamp (Wildcat)~~	~~5200'~~	~~467-1200~~	~~40~~	~~40~~	~~NO~~	~~NA~~	~~0~~	~~1~~	
~~Strawn (Wildcat)~~ Tracy per	7800'	~~467-1200~~	40	40	NO	NA	0	1	
~~Ellenburger~~ (Wildcat) 18001	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
• Lease/Unit 1000' FNL & 2500' FEL
• Survey/Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
• Lease/Unit
• Survey/Section

Code C 0-8500

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]
24. Is Item 17 less than Item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]
25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X]
If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.
26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? If not, and if the well requires a Rule 37 or 38 exception, see instructions for Rule 37. Yes [X] No [ ]

Remarks
W/C per Cindy 10/26/90

I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison
Signature

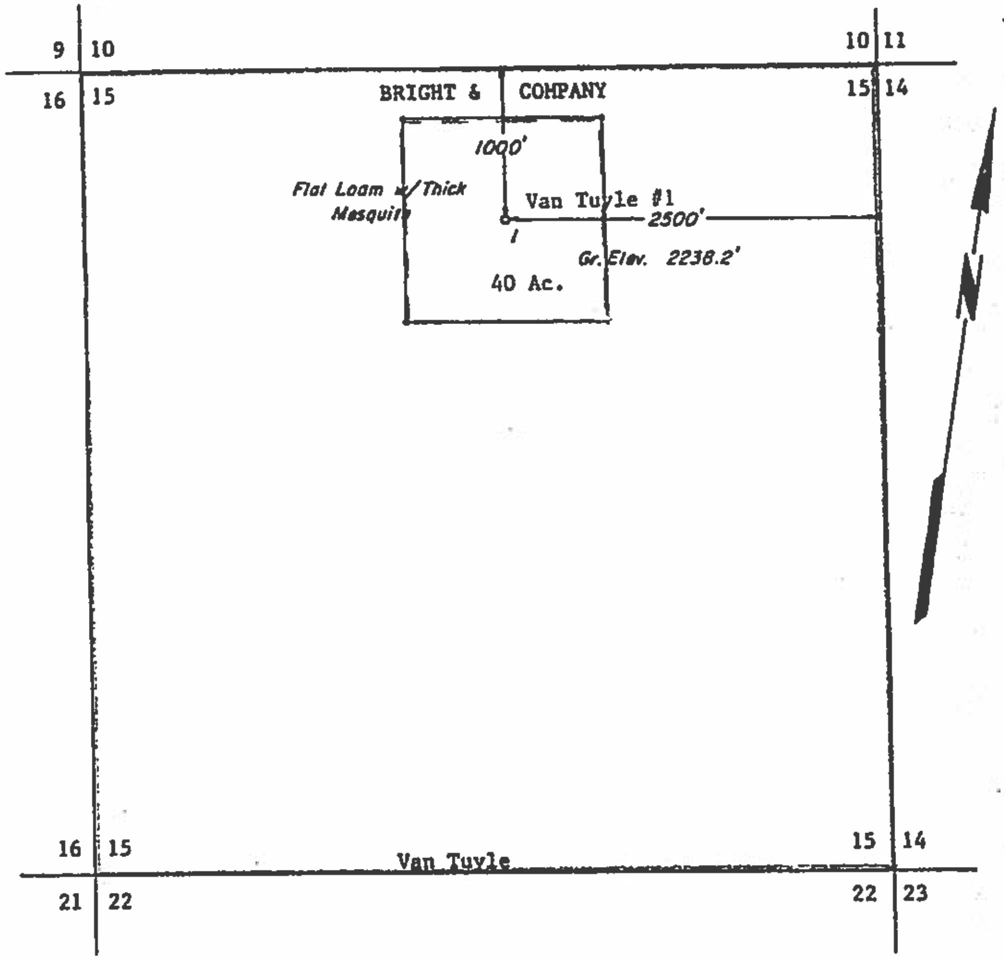
Tracy D. Tenison, Engineer
Name and title of operator's representative

9/26/90
Date: mo. day yr.

915-697-2214
Tel: Area Code Number

▶ RRC Use Only ◀
203091 OCT 1890
379724

335-33555



OCT 1990

THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON TEXAS P.L.S. NO. 1883
GARY G. EIDSON TEXAS P.L.S. NO. 4735
JERRY A. DUNN TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1" = 1000'	Drawn by: NED
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

▶ Return each W-1 with plat and $100.00 fee. Make a check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas, Oil and Gas Division, Drilling Permits, P. O. Drawer 12967, Capitol Station, Austin, Texas 78711

▶ File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1
Rev. 9/1/83
483-080

020

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ▶ API No. 42- ▶ Permit No. ▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): Bright & Company
3. RRC Operator No.: 093125
4. RRC District No.: 8
5. County of Well Site: Mitchell
2. Address (including city and zip code): 3200 West Cuthbert, Suite 2-C, Midland, Texas 79701
6. Lease Name (32 spaces maximum): Van Tuyle
7. RRC Lease/ID No.: --
8. Well No.: 1
9. Total Depth: 8500'
10. Location
- Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1 N~~ Abstract No. A-584
- This well is to be located 5 miles in a north direction from Iatan which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.
12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well (Specify)	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
Wolfcamp (Wildcat)	5200'	467-1200	40	40	NO	NA	0	1	
Strawn (Wildcat)	7800'	467-1200	40	40	NO	NA	0	1	
Ellenburger (Wildcat)	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
- Lease/Unit 1000' FNL & 2500' FEL
- Survey Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
- Lease/Unit
- Survey/Section

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]
24. Is item 17 less than item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]
25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.
26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? If not, and if the well requires a Rule 37 or 38 exception, see instructions for Rule 37. Yes [X] No [ ]

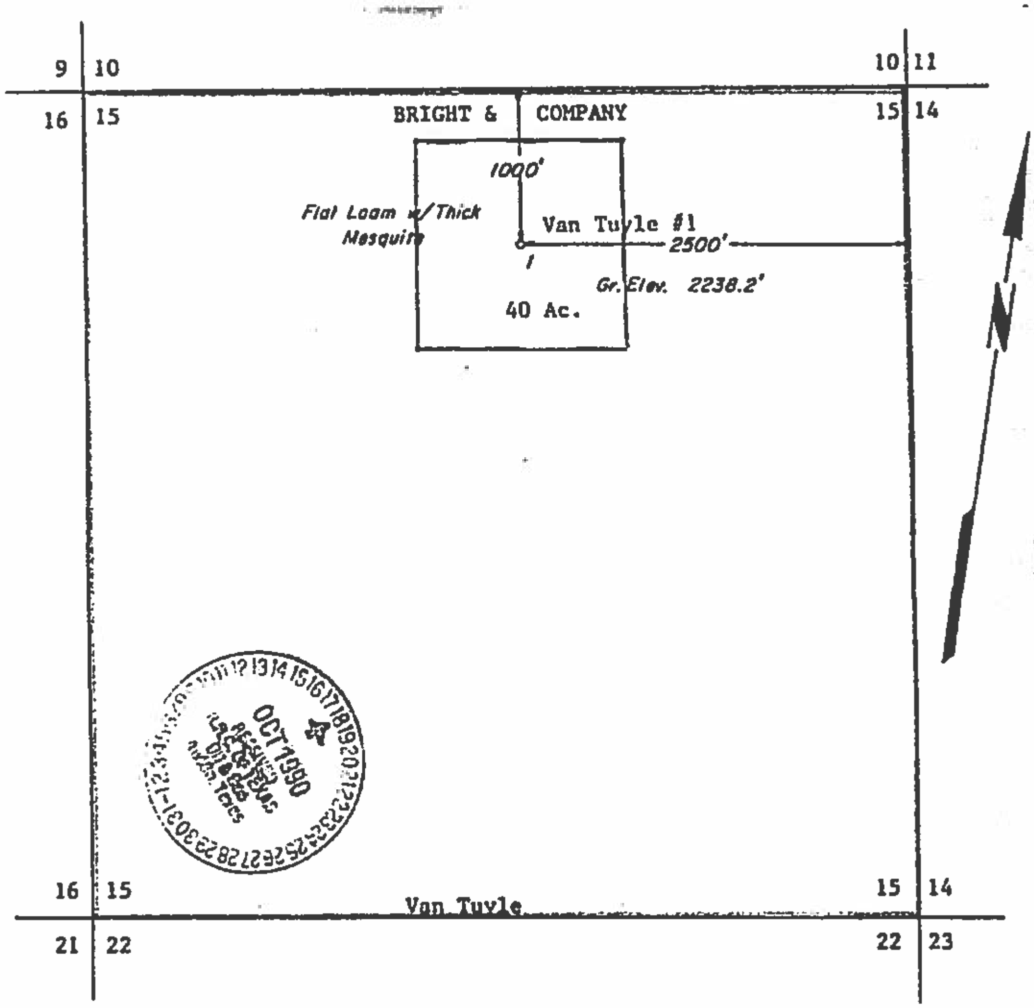
Remarks

I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison — Signature
Tracy D. Tenison, Engineer — Name and title of operator's representative
Date: 9/26/90 (mo. day yr.)
Tel.: 915-697-2214 (Area Code Number)

• RRC Use Only •

0 9 0 5 7 0 7 1 0



THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON	TEXAS P.L.S. NO. 1883
GARY G. EIDSON	TEXAS P.L.S. NO. 4735
JERRY A. DUNN	TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1"= 1000'	Drawn by: NEG
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

WATER BOARD LETTER DATED 10-1990 1 2

Plugging Record Depth 350

13(A) Exception Dated N/A

13 3/8 - 361

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. 42-335-33555 (If available)

1. RRC District: 8

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or Id. Number:

2. FIELD NAME (as per RRC Records): Wildcat

3. Lease Name: Van Tuyle

5. Well Number: 1

6. OPERATOR: Bright & Company

6a. Original Form W-1 Filed in Name of:

10. County: Mitchell

7. ADDRESS: 2911 Turtle Creek Blvd #700, Dallas, TX 75219

6b. Any Subsequent W-1's Filed in Name of:

11. Date Drilling Permit Issued: 10/18/90

8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 1000 Feet From north Line and 2500 Feet From east Line of the Van Tuyle Lease

12. Permit Number: 379724

9a. SECTION, BLOCK, AND SURVEY: Sec 15, Blk 29, T1N, T&P RR Co

9b. Distance and Direction From Nearest Town in this County: 8.7 miles NW of Westbrook

13. Date Drilling Commenced: 11/26/90

16. Type Well (Oil, Gas, Dry): Dry

Total Depth: 8360'

17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s

GAS ID or OIL LEASE #	Oil-O Gas-G	WELL #

14. Date Drilling Completed: 12/18/90

18. If Gas, Amt. of Cond. on Hand at time of Plugging:

15. Date Well Plugged: 12-17-90

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	12-17	12-17	12-17	12-17	12-17			
20. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8			
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15			
*22. Sacks of Cement Used (each plug)	50	50	160	50	10			
*23. Slurry Volume Pumped (cu. ft.)	59	59	189	59	11.8			
*24. Calculated Top of Plug (ft.)	8076	2526	1792	325	Surf.			
25. Measured Top of Plug (if tagged) (ft.)			1790					
*26. Slurry Wt. #/Gal.	15.6	15.6	15.6	15.6	15.6			
*27. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.			

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
13-3/8	48	361	361	17-1/2
8-5/8	32	2274	2274	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well: Yes [ ] No [X]

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
2274	8360		

Return to Central Records

APR 15 1991

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

D L Hamill

Signature of Cementer or Authorized Representative

Halliburton Services, Big Spring, TX

Name of Cementing Company

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

W J Morris — W. J. Morris — REPRESENTATIVE OF COMPANY

Agent — TITLE

1/11/91 — DATE

Phone 214 550-0889 — A/C NUMBER

Did not Witness

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

RECEIVED
RRC OF TEXAS
MAR 05 1991
OIL & GAS
MIDLAND, TEXAS

/38

335-33555

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission	[X] Yes [ ] No	32. How was Mud Applied? Drilling Rig	33. Mud Weight 9.1 LBS/GAL

34. Total Depth	Other Fresh Water Zones by T.D.W.R. TOP	BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules?
8360			[X] Yes [ ] No
Depth of Deepest Fresh Water			36. If NO, Explain
210			

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Halliburton, P. O. Box 380, Snyder, Texas 79549

Date RRC District Office notified of plugging 12/15/90

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Ben Van Tuyle, 432 Hilldale Dr, Ann Arbor, MI 48105

39. Was Notice Given Before Plugging to Each of the Above?

Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______ Date ______

Type Logs:

[ ] Driller's [X] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging ______ bbls*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ______

REMARKS ______

000 57 0713

[illegible]
Operator: Fill in other items.

Form W-15
Cementing Report
Rev. 4/1/83
[illegible]

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1. Operator's Name (As shown on Form P-5, Organization Report)	2. RRC Operator No.	3. RRC District No.	4. County of Well Site
Bright & Co.	093125	8	Mitchell
5. Field Name (Wildcat or exactly as shown on RRC records)	**6. API No.**	**7. Drilling Permit No.**	
Wildcat	42- 335-33555	379724	
8. Lease Name	**9. Rule 37 Case No.**	**10. Oil Lease/Gas ID No.**	**11. Well No.**
Van Tuyle			1

CASING CEMENTING DATA:	SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING: Single String	PRODUCTION CASING: Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS: Tool	MULTI-STAGE CEMENTING PROCESS: Shoe
12. Cementing Date	[illegible]	[illegible]				
13. •Drilled hole size	17-1/2	11				
•Est. % wash or hole enlargement						
14. Size of casing (in. O.D.)	13-3/8	8-5/8				
15. Top of liner (ft.)						
16. Setting depth (ft.)	361	2274				
17. Number of centralizers used	3	3				
18. Hrs. waiting on cement before drill out	12	12				
1st Slurry — 19. API cement used: No. of sacks	390	300				
1st Slurry — Class	Premium Plus	Hall.Light Prem Plus				
1st Slurry — Additives	2% Calcium Chloride	2% CaCl2				
2nd Slurry — No. of sacks						
2nd Slurry — Class						
2nd Slurry — Additives						
3rd Slurry — No. of sacks						
3rd Slurry — Class						
3rd Slurry — Additives						
1st — 20. Slurry pumped: Volume (cu. ft.)	514.8	591				
1st — Height (ft.)	Surface	2268				
2nd — Volume (cu. ft.)						
2nd — Height (ft.)						
3rd — Volume (cu. ft.)						
3rd — Height (ft.)						
Total — Volume (cu. ft.)	514.8	591				
Total — Height (ft.)	Surface	2268				
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?	Yes	No				

22. Remarks

RECEIVED
R.R.C. OF TEXAS
JAN 14 1991
O.G.
MIDLAND, TEXAS

RECEIVED
R.R.C. OF TEXAS
MAR 05 1991
OIL & GAS DIV
MIDLAND TEXAS

OVER ▶

[illegible] TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
[illegible] date								
[illegible] Size of hole or pipe plugged (in.)								
[illegible] Depth to bottom of tubing or drill pipe (ft.)								
[illegible] cement used (each plug)								
[illegible] pumped (cu. ft.)								
[illegible] top of plug (ft.)								
[illegible] Measured top of plug, if tagged (ft.)								
[illegible]								
[illegible]								

[illegible] CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this [illegible] and that the [illegible] of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my [illegible] and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This [illegible]

[illegible], Jr. Cementer — Halliburton — [signature]

[illegible] Cementing Company — Signature

[illegible] 300 — Snyder, Texas 79549 — 915-573-3526 — 11-26-90

City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data.

W. J. Morris — Agent — [signature]

Typed or printed name of operator's representative — Title — Signature

2911 Turtle Creek Blvd, #700, Dallas, TX 75219 — 214-559-0889 — 1/11/91

Address — City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For offshore operations, see the requirements of Rule 13 (c).

A. What to file. An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, Form W-2 or G-1, as required by Statewide or special field rules;
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, in addition to Form W-3, to show any casing cemented in the hole.

B. Where to file. The appropriate Commission District Office for the county in which the well is located.

C. Surface casing. An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. Centralizers. Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. Exceptions and alternative casing programs. The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. An operator must obtain approval of any exception before beginning casing and cementing operations.

F. Intermediate and production casing. For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. Plugging and abandoning. Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

R.R.C. Midland

Please Refer to File No.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2A

8

APPLICATION TO PLUG AND WELL RECORD
FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Name of Company or Operator The Texas Company Address Box 1720, Fort Worth, Texas

County Howard Survey T&P RRCo. Blk 29 T-1-N Sec. 4

Name of Lease A. L. Wasson No. of Acres 1760 Well No. 1 Elev. 2300 (DF)

Located Approx. 21 Miles NE Direction from Big Spring, Texas (Nearest P. O. or Town)

Name of Field in which well is located Wildcat

Form 1, "Notice of Intention to Drill," was filed in name of The Texas Company

Drilling Commenced 12-28, 19 52, Drilling Completed 3-28, 19 52

Has this well ever produced oil? No or Gas? No

Character of Well (Oil, Gas or Dry) Dry Total Depth 8670'

Date you wish to Plug 3-27-, 19 52

Name of Party Plugging Well Livermore Drilling Address 610 Lubbock Nat'l Bank Lubbock, Texas

Correspondence regarding this well should be sent to: Name The Texas Company

Address Box 1720, Fort Worth, Texas

CASING RECORD

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
13 3/8"	196		None		196		Texas Pattern
9 5/8"	2115		100		2015		Halliburton F & S

IF CASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS

Initial Production of Gas: Volume (MCF) None 24 hrs. Pressure None

Initial Production of Oil: Barrels None

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to, to the Deputy Supervisor of district in which well is located. All necessary forms will be furnished by Railroad Commission of Texas

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APR 10 1952
OIL & GAS DIVISION

NOTE: If no log available, so state and give all information that can be obtained as to total depth, casing record, formation, water sands, and as near as possible date well was drilled.

General Remarks: This well drilled to a total depth of 8670' without encountering oil or gas. We therefore desire to abandon salvage and plug well in the following manner: (Cut 9 5/8" casing at 100' and pull same) (Over)

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Caliche	0	100	At depth 206' cemented 13 3/8"
Red Beds	100	206	casing at 206' with 250 sacks.
Shale & Anhy	206	945	Cement circulated.
Anhy	945	1254	
Anhy & Shale	1254	1499	At depth 2125' cemented 9 5/8" casing
Anhy & Salt	1499	1750	at 2125' with 600 sacks.
Anhy & Shale	1750	1837	
Anhy	1837	1955	
Anhy & Lime	1955	2125	
Lime	2125	2290	
Lime & Shale	2290	2322	
Lime	2322	3116	
Lime & Shale	3116	3612	
Lime & Chert	3612	3820	
Lime & Sand	3820	3979	
Lime & Chert	3979	4155	
Lime & Sand	4155	4538	
Lime & Chert	4538	4900	
Lime & Sand	4900	5114	
Lime & Chert	5114	5232	
Lime & Shale	5232	6203	
Shale	6203	7953	
Lime & Chert	7953	8670	
Total Depth		8670	

All Measurements from Rotory Table or 12' above ground.

Remarks Cont'd

Using Heavy mud between plugs, spot the following cement plugs, 95 sacks 8670'-8373'; 15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7655'; 15 sacks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sacks 4680'-4630'; 15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1070'; 40 sacks. 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing.

Drill Stem Tests

DST # 1: Pkr. failed

DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 2250' salt water cut with drlg. mud.

DST # 3: 5100-5210, Tool open 1 1/2 hrs. Recovered 300' drlg. mud.

DST # 4: 5440-5485, Tool open 1 hr. Recovered 75' slightly gas cut drlg. mud.

DST # 5: 5902-6000, Tool open 1 hr. Recovered 100' drlg. mud, [illegible]

DST # 6: 780[illegible]-7870, Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120' [illegible] gas cut drlg. mud.

DST # 7: 783[illegible] [illegible] hrs., Recovered 5' drlg. mud & 180' slightly [illegible] mud.

Method of shutting off water Cased off ..... Is water completely shut off? Yes

Amount of water with oil None ..... per cent None

I, T. P. [illegible] being first duly sworn [illegible] that I have knowledge of the facts and matter herein [illegible] and that the same are true and correct.

[signature]

Representative of Company.

Subscribed and sworn to before me this 7 day of April, 1952

[signature] W. E. BRUZEK

Notary Public

Midland County, Texas.

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A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.

DST # 10: 8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

Please Refer to
File No.........................

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 4
Plugging Record

8

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company The Texas Company Address Box 1720, Ft. Worth, Texas

Sec. No. 4 Block No. 29 T-I-N Survey T & P RRCO County Howard

Well No. 1 Name of Lease A. L. Wasson No. of Acres 1760

Name of Field in which well is located Wildcat Date well was plugged 3-27- 19 52

Form 1 (Notice of Intention to Drill) Was Filed in Name of The Texas Company

Character of Well at the time of completion: Oil - bbls.; (Initial Production) Gas - Cu. ft.; (Initial Production) Dry Yes

Amount well producing when plugged: Oil None bbls.; Gas None Cu. ft.; Water None bbls.

Has this well ever produced oil or gas? No

Total Depth 8670 feet. Top of each producing sand - feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Thru drill pipe

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depths placed. Also amount of cement and rock. Was well shot? No

Spotted the following plugs: 95 sx 8670-8373, 15 sx 8213-8163, 15 sx 7860-7810, 15 sx 7705-7655, 15 sx 5600-5550, 15 sx 5430-5380, 15 sx [redacted] 50-25-4975, 15 sx 4680-4630, 15 sx 2810-2760, 15 sx 2093-2043, Cut off 9 5/8" casing @ 100' and pulled, spot 40 sx 1125-1070, 40 sx 1025-975, 40 sx 875-825, 30 sx in top of casing.

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: All 13 3/8" casing left in hole & 2015' 9 5/8" casing left in hole. All strata protected by casing left in hole or cassed of with cement.

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:
All adjacent property leased by The Texas Company

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, T. P. Drew, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name T. P. Drew Dist. Supt.

Subscribed and sworn to before me this 15 day of May, 19 52

[signature]

Notary Public Midland County, Texas

Correspondence regarding this well should be addressed to:

Name The Texas Company Address Box 1720, Ft. Worth, Texas

0 0 0 0 2 2 .0 7 7 7

FORM W-1 (6/78)

API Well No. 42
Instruction (7(d)(b) on back side.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

☐ Directional Well ☐ Amended or Corrected Permit

RRC Permit Number, if previously assigned. 084247

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

Check one: ☐ DRILL ☐ DEEPEN (Below Casing) ☐ DEEPEN (Within Casing) ☐ PLUG BACK ☒ OTHER (Specify) re-entry

If Amended Application, explain fully in Remarks or Attach Separate Page.

1. Operator: McCann Corporation 538853	4. Lease Name and RRC Lease or ID No. (If Assigned): Stewart
2. Address (Including City and Zip Code): P. O. Box 448, Big Spring, TX 79720	5. Location (Sec., Blk., Survey): Sec. 4, Blk. 29, T-1-N, T & P RR Co.
	6. This well is to be located 4 miles Southeast. Direction from Vincent, TX. Nearest Post Office or Town.
3. Is Form P-5 (Organization Report) in Exact Operator Name Filed? YES ☒ NO ☐ (Instruction (2) on back side.)	

7. RRC District	8
8. County	Howard
9. Well Number	1
10. Number of Acres in Lease	640
11. Distance from Proposed Location to Nearest Property or Lease Line (ft.)	660'
12. Total Depth	4600'

EACH PROPOSED COMPLETION

REFER TO INSTRUCTIONS ON BACK SIDE. READ CAREFULLY AND FURNISH COMPLETE DATA.

13. FIELD NAME (Exactly as shown on R.R.C. Proration Schedule including Reservoir if applicable.) If Wildcat, so state below. 00018 001	14. Completion Depth	15. All Prior Rule 37 Exc. Case Numbers for this wellbore. If done, State None.	16. Applicable Field Rules Spacing Pattern. If no Rules, State 467-1200. (ft.)	17. Applicable Field Rules Density Pattern. If no Rules, State 40. (acres)	18. Number of Acres in Drilling Unit for this Well AND DESIGNATE ON PLAT.	19. Is this acreage presently assigned to another well in same field? (Yes or No. If yes explain in remarks.)	20. Distance and Direction from proposed location to nearest drilling completed or applied for well in same res. on same lease (ft.)	21. Is this a 1. Regular or 2. Rule 37 Exc. Location? Check the appropriate box.	22. Oil, Gas, or other Type Well (Specify)	23. Number of Wells or Permitted locations on this Lease in same Reservoir for which this Permit is Requested? OIL	GAS
Wildcat	4210'	None	467/1200	40	40	No	None	Regular 1 ☒ Rule 37 2 ☐	Oil	0	0
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			

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24. PERPENDICULAR LOCATION FROM TWO DESIGNATED:
A. Lease Lines 660' FWL & 1980' FNL
B. Survey Lines 660' FWL & 1980' FNL

25. (a) Is this wellbore subject to SWR 36? Yes ☒ No ☐
(b) If subject to SWR 36, has Form H-9 been filed? Yes ☒ No ☐
(If no, attach explanation.)

NOTICE
NO ALLOWABLE WILL BE ASSIGNED to any well which does not have sufficient surface casing to protect all fresh water sands. Where Commission rules do not specify surface casing requirements, it will be necessary to contact Texas Water Development Board, Austin, Texas, to ascertain the depth to which fresh water sands must be protected.

CERTIFICATE
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

REMARKS: Original Operator: The Texas Company
Original Lease Name: A.L. Wasson, Well #1.
Plugged and Abandoned: 3-27-52

Elsie W. Britton
Signature
Administrative Assistant
Title
June 12, 1980
Date
Telephone: Area Code 915 267-7451

READ INSTRUCTIONS ON BACK SIDE AND FURNISH COMPLETE DATA.

0 0022 0775

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. (If available) 42-227-00000 | RRC District: 08

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or ID Number:

2. FIELD NAME (as per RRC Records): Wildcat	3. Lease Name: Stewart	5. Well Number: 1
6. OPERATOR: McCann Corporation	6a. Original Form W-1 Filed in Name of: McCann Corporation	10. County: Howard
7. ADDRESS: P. O. Box 448, Big Spring, TX	6b. Any Subsequent W-1's Filed in Name of:	11. Date Drilling Permit Issued: 8-17-80
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 660 Feet From West Line and 1980 Feet From North Line of the Stewart Lease		12. Permit Number: 084247
9a. SECTION, BLOCK, AND SURVEY: Sec. 4, Blk. 29, T-1-N, T&P RR Co.	9b. Distance and Direction From Nearest Town in this County: 4 miles SE of Vincent	13. Date Drilling Commenced: 10-10-80
16. Type Well (Oil, Gas, Dry): DRY — Total Depth: 1100	17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s — GAS ID or OIL LEASE # / Oil-O Gas-G / WELL #	14. Date Drilling Completed: 10-12-
18. If Gas, Amt. of Cond. on Hand at time of Plugging:		15. Date Well Plugged: 10-12-

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	10-12-80	10-13	10-13					
20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8					
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1100	250	Top Out					
*22. Sacks of Cement Used (each plug)	50	100	10					
*23. Slurry Volume Pumped (cu. ft.)	66	133	13					
*24. Calculated Top of Plug (ft.)	990	70	Surf.					
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	1.33	1.33	1.33					
*27. Type Cement	C	C	C					

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
8 5/8	24#	200	200	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well? Yes [ ] No [X]

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

Signature of Cementer or Authorized Representative — Dowell Division of Dow Chemical Co. — Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Tom McCann — REPRESENTATIVE OF COMPANY | President — TITLE | April 9, 1981 — DATE | Phone 915 — A/C | 267-7488 — NUMBER

Did Not Witness
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

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O.G.
MIDLAND, TEXAS

DR-80

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Commission? [X] Yes [ ] No	32. How was Mud Applied? Circulated	33. Mud Weight 8.5 LBS/GAL
34. Total Depth 1100	Other Fresh Water Zones by T.D.W.R. TOP BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No
Depth of Deepest Fresh Water 150		36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Dowell Division of Dow Chemical Co. - Colorado City, TX

Date RRC District Office notified of plugging 10-1-85

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Danny Stewart - P. O. Box 26, Sterling City, Tx. 76951

39. Was Notice Given Before Plugging to Each of the Above?
Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______ Date ______

Type Logs: [ ] Driller's [ ] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Was FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging None bbls.*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field

REMARKS

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form W-15
(Rev. 1/1/80)

CEMENTING REPORT

*1. Field Name (as per RRC Records or Wildcat): Wildcat	*2. RRC District: 08
*3. Operator: Mc Cann Corporation	*4. County: Howard
*5. Lease Name(s) and RRC Lease Number(s) or I. D. Number(s): Stewart	*6. Well Number: 1
*7. Location (Section, Block, and Survey): Sec. 4, Blk. 29, T-1-N, T&P RR Co. Survey	

CASING CEMENTING DATA:	SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
8. Cementing Date						
*9. (a) Size of Drill Bit (inches)						
(b) Estimated % Wash or Hole Enlargement Used in Calculations.						
*10. Size of Casing (inches O.D.)						
*11. Top of Liner (if liner used) (ft.)						
*12. Setting Depth of Casing (ft.)						
13. Type API Class Cement & Amount of Additives Used: (a) In First (Lead) or Only Slurry (if additional space is needed, use "REMARKS" on reverse side.)						
(b) In Second Slurry						
(c) In Third Slurry						
14. Sacks of Cement Used: (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Sacks of Cement Used						
15. Slurry Volume per Sack of Cement (cu.ft./sack): (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
16. Volume of Slurry Pumped: (cu.ft.) (Item 14 x Item 15) (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Slurry Volume Pumped (cu.ft.)						
17. Calculated Annular Height of Cement Slurry behind Pipe (ft.)						
18. Was cement circulated to ground surface (or bottom of cellar) outside casing? (Yes or No)						

CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6
19. Cementing Date	10-12-80	10-13-80	10-13			
*20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8			
*21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1000	250	Top Out			
22. Sacks of Cement Used (each plug)	50	100	10			
23. Slurry Volume Pumped (cu. ft.)	66	133	13			
24. Calculated Top of Plug (ft.)	990	70	Surf.			
*25. Measured Top of Plug (if tagged) (ft.)						

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(CEMENTING COMPANY AND OPERATOR MUST COMPLY WITH THE INSTRUCTIONS ON REVERSE SIDE HEREOF.)

– OVER –

* Designated items to be completed by Operator. Items not so designated shall be completed by Cementing Company.

Remarks:

*27. Remarks:

CEMENTING COMPANY

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

P.N. Shackelford
Signature of Cementer or Authorized Representative

P. N. Shackelford, Sr. District Clerk
Name of Person and Title (type or print)

Dowell Division of Dow Chemical Co.
Cementing Company

Route 3, Box 178
Street Address or P.O. Box

Colorado City, Tx 79512
City, State — Zip Code

Telephone 915 728-5291
Area Code

10-14-80
Date

***OPERATOR**

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data and information presented herein.

Tom McCann
*Signature of Operator or Authorized Representative

Tom McCann - President
*Name of Person and Title (type or print)

McCann Corporation
*Operator

P. O. Box 448
*Street Address or P.O. Box

Big Spring, Texas — 79720
*City, State — Zip Code

*Telephone 915 267-7488
Area Code

4-6-81
*Date

INSTRUCTIONS

1. A. This form shall be filed by the operator in the RRC District Office with:
   (1) Each copy of an initial Form G-1 or W-2 if a cementing report is required by Statewide or Special Rules, or if exception is needed to cementing requirements in Statewide or Special Rules;
   (2) Each copy of Form W-3;
   (3) Each copy of Form W-4 if a multiple parallel casing completion.

   B. At least an original and one copy of this form shall be filed for each cementing company used on a well.

   C. The cementing of different casing strings on a well by one cementing company may be consolidated on one form (to be filed in duplicate).

2. Cementing Company and Operator shall comply with the applicable portions of Statewide Rules 8, 13, and 14. For offshore operations, Cementing Company and Operator shall comply with Statewide Rule 13(E).

3. If setting FULL AMOUNT OF SURFACE CASING:
   A. Depth to protect fresh water determined by:
   (1) Field Rule
   (2) Texas Water Development Board, if no Field Rule
   B. Set surface casing below depth to be protected and cement from casing shoe to ground surface.

4. IF SETTING ANYTHING OTHER THAN THE FULL AMOUNT OF SURFACE CASING, PERMISSION SHALL BE OBTAINED FROM THE RAILROAD COMMISSION.

5. If setting NO SURFACE CASING (See Item 4 above.):
   A. If no multi-stage tool is used, the next deeper casing string shall be cemented from the casing shoe to the surface.
   B. If using the multi-stage tool on the next deeper string, cement from the depth that protects fresh water sands to the surface.

6. If setting SHORT SURFACE CASING (See Item 4 above.):
   A. Cement short surface casing from the shoe to the surface.
   B. Whether the multi-stage tool is or is not used on the next deeper casing string, cement from the depth that protects fresh water sands to
   (1) the surface, or
   (2) a point midway between shoe of surface string and the surface. Compliance will be considered if a temperature survey shows that the top of the cement is at least one-third of the distance from the shoe of the surface string to the surface.

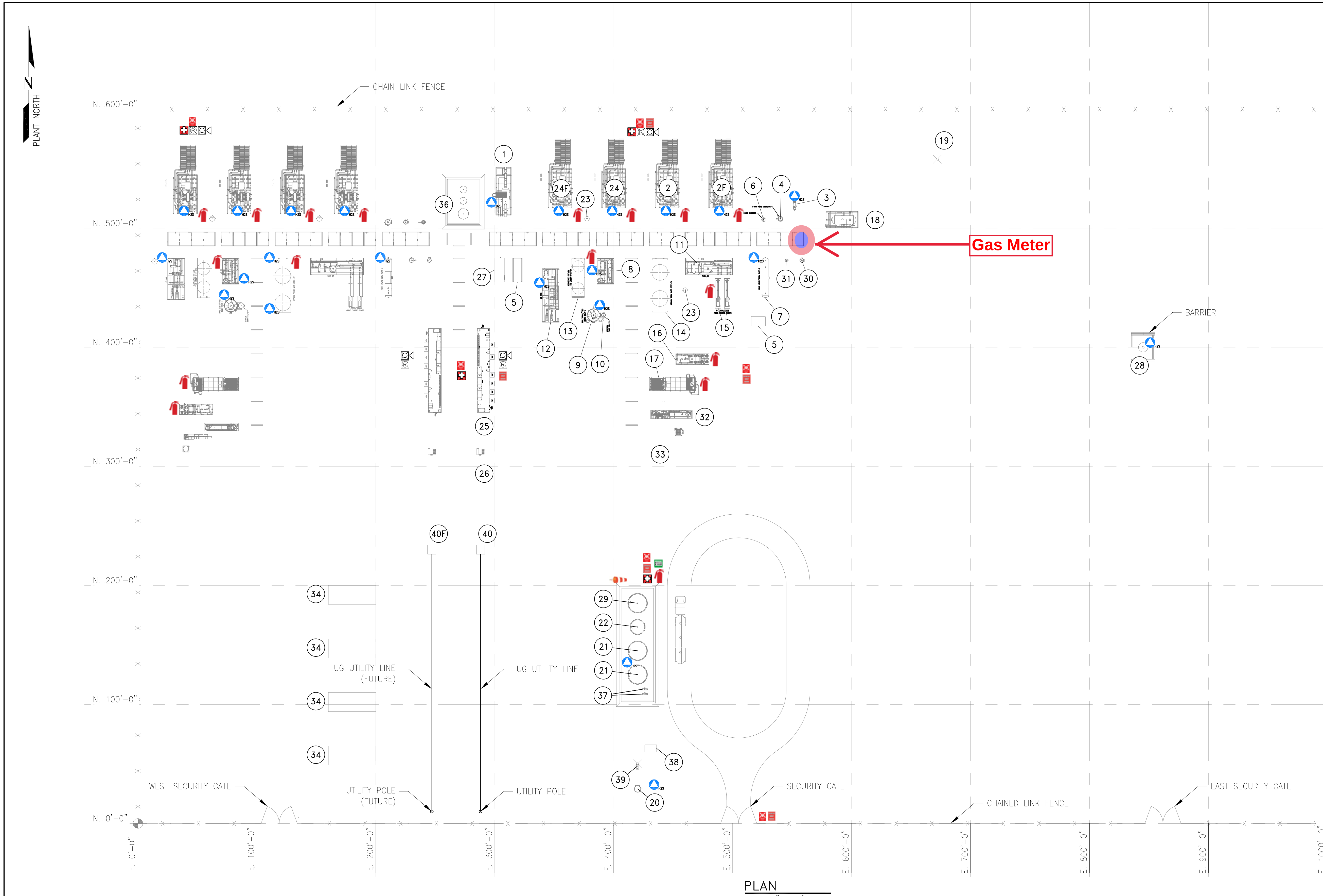
7. Setting PRODUCTION STRING of Casing: (Statewide Rules, Special Rules may vary.)
   A. Cement to a point at least 600 feet above the casing shoe.
   B. When 3,000 feet or more of pipe is set for the production or protecting string, a minimum of 30 feet of cement shall be left inside the pipe.

8. PLUGGING and ABANDONING:
   A. Cement plugs shall be placed in the well bore as required by Rules and Regulations of the Commission plus any additional plugs as may be specified by the RRC District Director.
   B. The minimum amount of cement normally used in each plug shall be a slurry volume equal to the amount necessary to fill the calculated volume of 100 feet of the hole in which the plug is placed.
   C. A 10 foot cement plug is required to be placed in the top of the well.

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H_2S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



ITEM	DESCRIPTION
1	SLUG CATCHER
2	INLET COMPRESSOR W/ COOLER
2F	INLET COMPRESSOR (FUTURE) W/ COOLER
3	COMPRESSOR DISCHARGE COALESCER
4	AMINE CONTACTOR
5	FUEL GAS SKID
6	TREATER GAS SCRUBBER
7	AMINE FLASH TANK
8	AMINE REGEN SKID
9	AMINE REGENERATOR/REFLUX ACCUMULATOR
10	AMINE REGENERATOR REBOILER
11	AMINE SURGE TANK
12	AMINE BOOSTER/REFLUX PUMP SKID
13	AMINE REGENERATOR REFLUX CONDENSER
14	LEAN AMINE COOLER
15	AMINE CHARGE PUMPS
16	HOT OIL PUMP SKID
17	HOT OIL HEATER
18	FLARE K.O. DRUM
19	FLARE
20	COMBUSTOR
21	SLOP STORAGE TANKS
22	AMINE MAKE UP STORAGE TANK
23	SUMP TANKS
24	ACID GAS COMPRESSOR W/ COOLER
24F	ACID GAS COMPRESSOR W/ COOLER (FUTURE)
25	PDC BUILDING
26	LV TRANSFORMER
27	INSTRUMENT AIR PACKAGE
28	ACID GAS INJECTION WELL
29	DI WATER TANK
30	GLYCOL CONTACTOR
31	GLYCOL SEPARATOR
32	TEG REGEN
33	BTEX
34	GAS GENERATOR SET
35	AMINE SUMP TANK
36	NEW LUBE OIL TANKS
37	CONDENSATE TRANSFER PUMPS
38	VAPOR RECOVERY UNIT
39	TANK COMBUSTOR K.O. DRUM
40	MV TRANSFORMER
40F	MV TRANSFORMER (FUTURE)

LEGEND

- FIRE EXTINGUISHER = 9 ea.
- H2S HYDROGEN SULFIDE DETECTOR = 10 ea.
- AUDIBLE ALARM SOUNDER = 4 ea.
- R STROBE LIGHT (RED) – FIRE = 4 ea.
- EMERGENCY SHUT DOWN PLANT EMERGENCY SHUTDOWN = 6 ea.
- FIRST AID & SCBA KIT = 3 ea.
- EYE WASH STATION = 3 ea.
- WIND SOCK = 1 ea.
- MUSTER POINT = 3 ea.

NOTES:

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
C	08/16/22	ISSUED FOR INFORMATION	HJP	CN	–
B	07/12/22	ISSUED FOR INFORMATION	RDC	CN	–
A	06/13/22	ISSUED FOR INFORMATION	RDC	RAF	–

F&C ENGINEERS
TX REG. NO. 8419

BAYSWATER

CLIENT : BAYSWATER EXPLORATION & PRODUCTION

PROJECT : SOUR GAS TREATING FACILITY

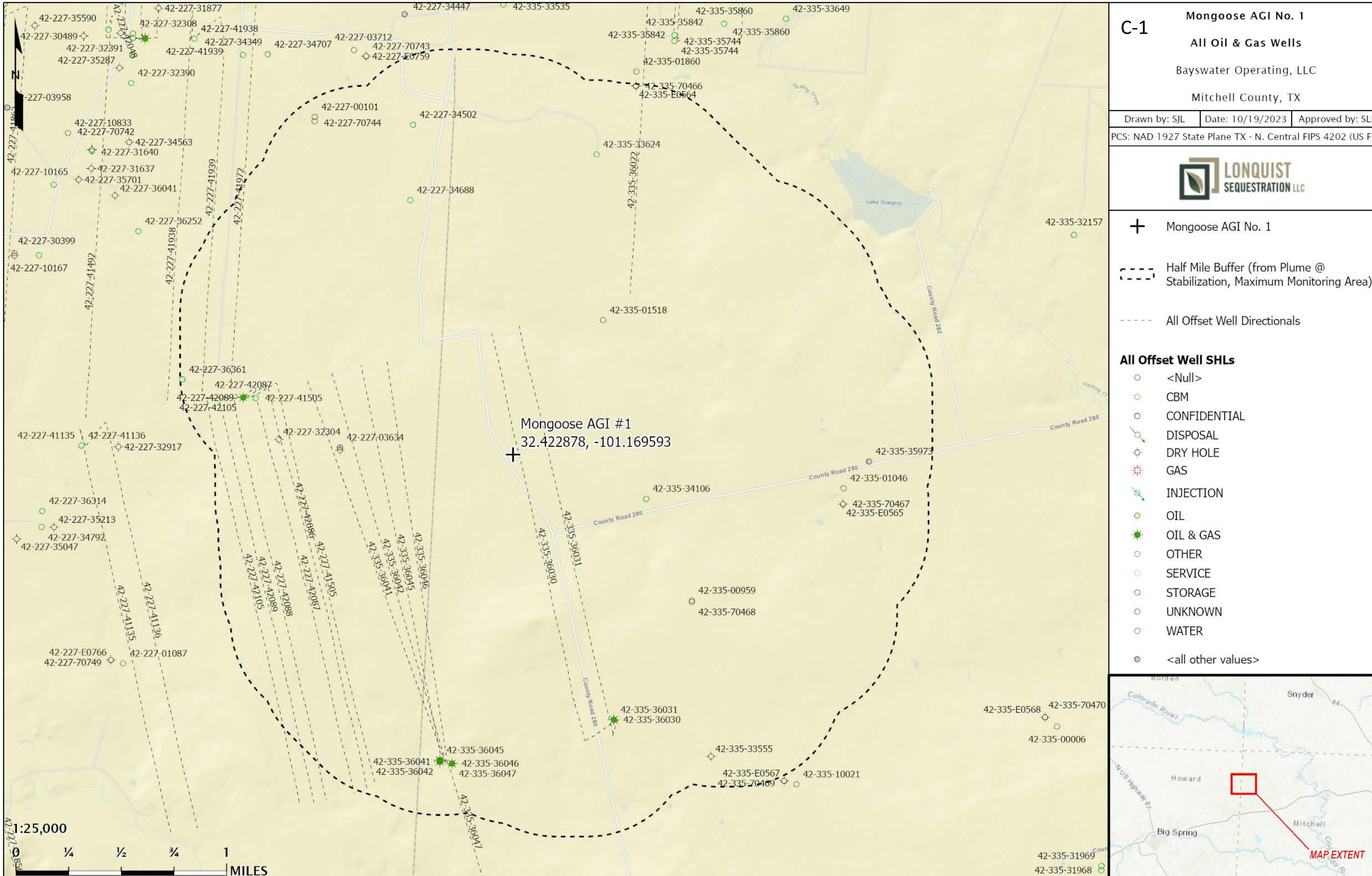
TITLE : INSTRUMENTATION FACILITY SAFETY LOCATION PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.	SHEET NO.	
RDC	GA	AS NOTED	06/09/22	BAY220316	IN-PLN-0790	1 OF 1	C

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST


C-1
Mongoose AGI No. 1
All Oil & Gas Wells
Bayswater Operating, LLC
Mitchell County, TX
Drawn by: SJL
Date: 10/19/2023
Approved by: SLP
PCS: NAD 1927 State Plane TX - N. Central FIPS 4202 (US Ft.)
LONQUIST SEQUESTRATION LLC
Mongoose AGI No. 1
Half Mile Buffer (from Plume @ Stabilization, Maximum Monitoring Area)
All Offset Well Directionals
All Offset Well SHLs
<Null>
CBM
CONFIDENTIAL
DISPOSAL
DRY HOLE
GAS
INJECTION
OIL
OIL & GAS
OTHER
SERVICE
STORAGE
UNKNOWN
WATER
<all other values>
Mongoose AGI #1
32.422878, -101.169593
N
1:25,000
0
¼
½
¾
1
MILES
County Road 280
County Road 282
Lake Gregory
Borden
Snyder
Howard
Mitchell
Big Spring
Colorado River
MAP EXTENT
42-227-35590
42-227-31877
42-227-32308
42-227-41938
42-227-34447
42-335-33535
42-335-35860
42-335-33649
42-335-35842
42-335-35860
42-227-30489
42-227-32391
42-227-34349
42-227-34707
42-227-03712
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42-227-41939
42-227-35287
42-227-E0759
42-335-01860
42-227-32390
42-335-70466
42-335-E0564
42-227-03958
42-227-00101
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42-335-70468
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42-335-33555
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42-335-36047
42-335-E0567
42-335-70469
42-335-10021
42-335-31969
42-335-31968

Mongoose AGI No. 1

Area of Review: Oil & Gas Wells List										
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022
4222741505	KAMIKAZE 5-8-17-20	3W	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023

LONQUIST SEQUESTRATION LLC

Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.

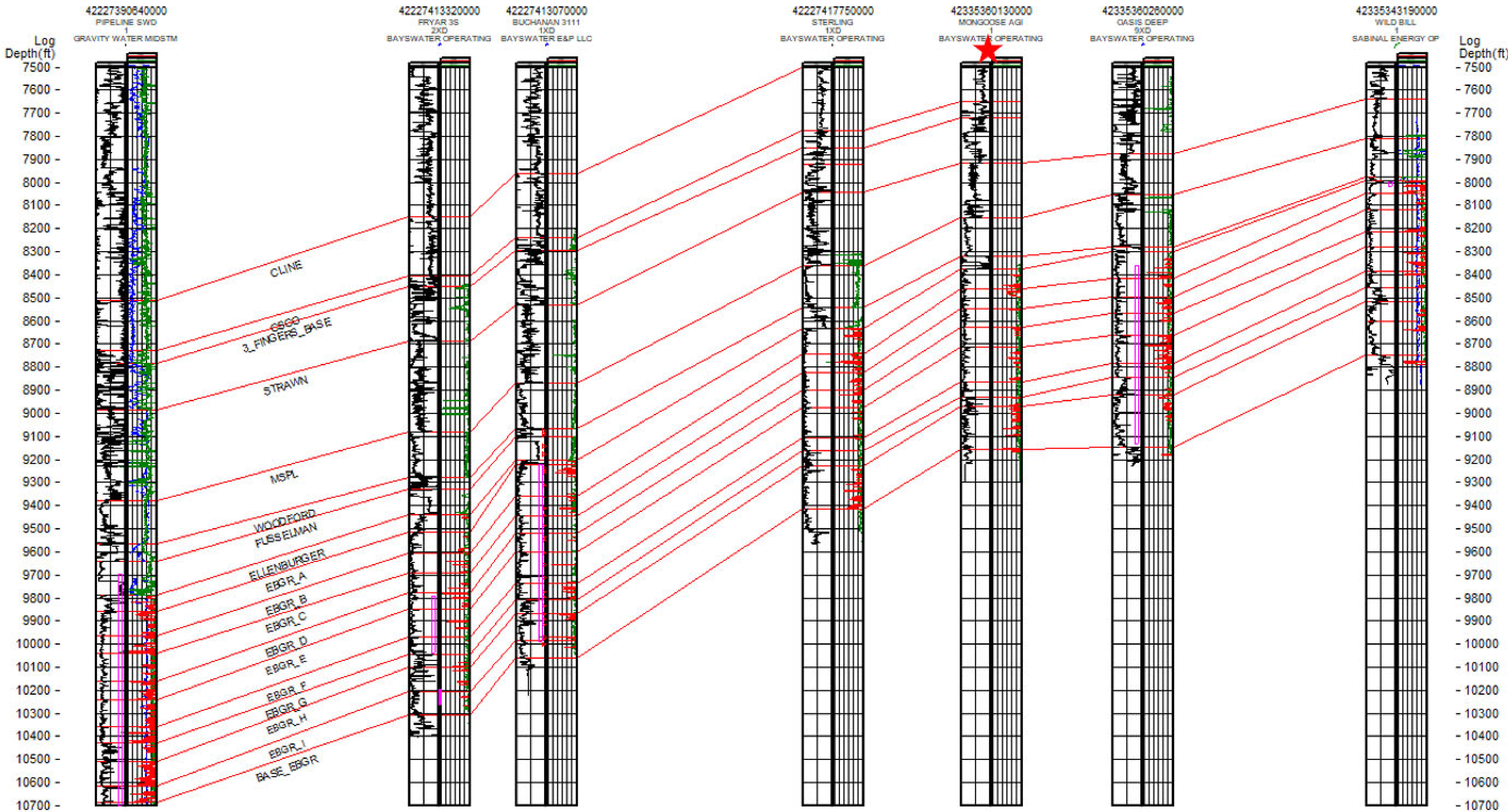
LONQUIST SEQUESTRATION LLC

APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 27 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 28 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER

D-1



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GRAVITY WATER MIDSTM
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FRYAR 3S
2XD
BAYSWATER OPERATING
42227413070000
BUCHANAN 3111
1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Log Depth(ft)
7500
7600
7700
7800
7900
8000
8100
8200
8300
8400
8500
8600
8700
8800
8900
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9600
9700
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9900
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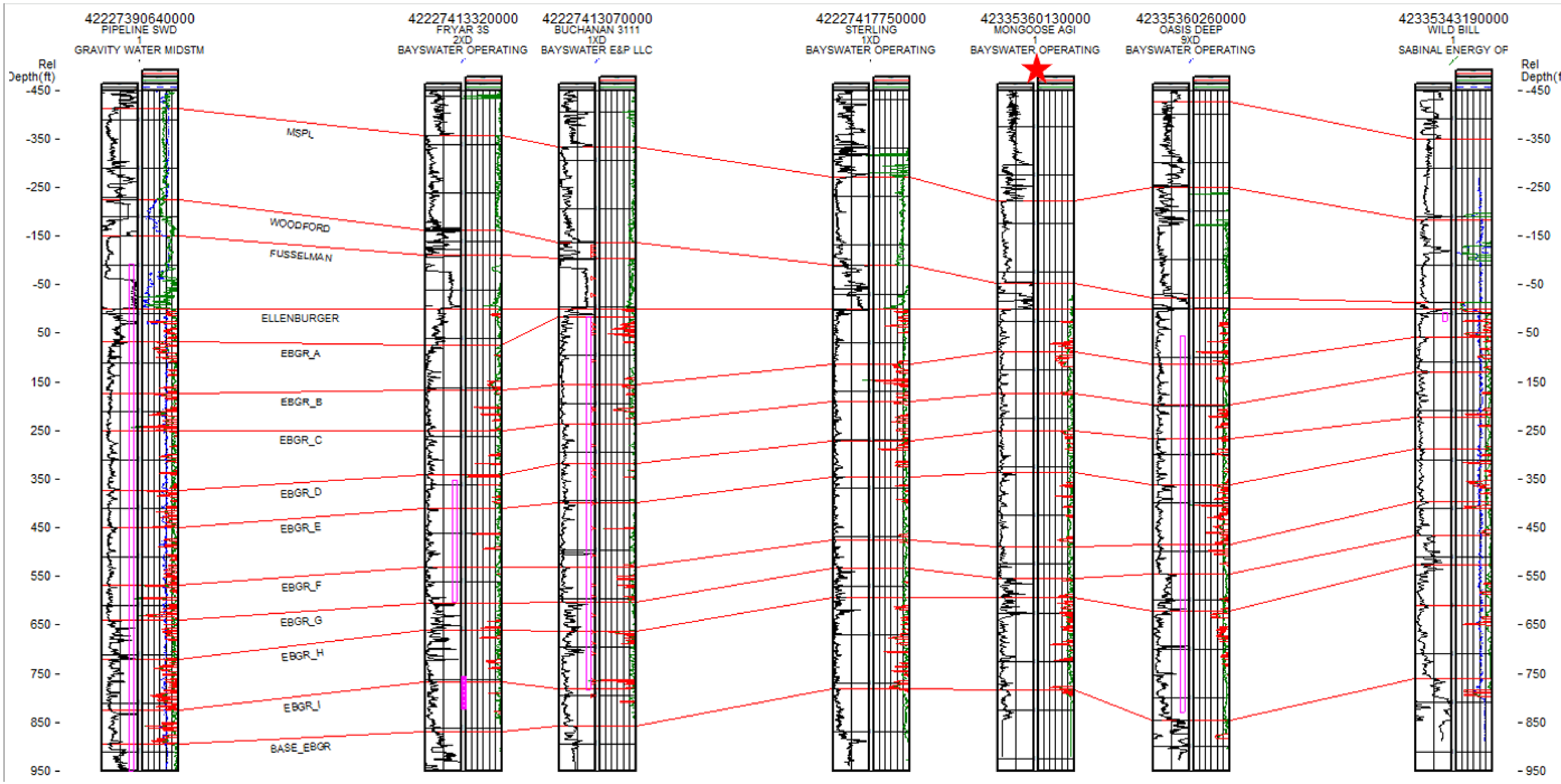
10100
10200
10300
10400
10500
10600
10700
CLINE
CISCO
3_FINGERS_BASE
STRAWN
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR

D-2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GRAVITY WATER MIDSTM
42227413320000
FRYAR 3S
2XD
BAYSWATER OPERATING
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1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Rel Depth(ft)
-450
-350
-250
-150
-50
50
150
250
350
450
550
650
750
850
950
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR

Request for Additional Information: Mongoose Amine Treating Facility
April 23, 2024

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>1.</td><td>2.2</td><td>21</td><td>“Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991).”

The Wristen Group is mentioned in the statement above, but it does not appear in the stratigraphic column or anywhere else in the text. Please clarify its significance as it relates to the MRV plan. Additionally, the Precambrian is time period rather than a formation. Please clarify as necessary.</td><td>The following sentence has been added to clarify how the Wristen Group relates to this location: “As shown previously in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location.”

For Precambrian discussions, the following was added in Section 2.2.4: In the Permian Basin area, Precambrian aged formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the “Precambrian”.</td></tr>
<tr><td>2.</td><td>4.1</td><td>68</td><td>“These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the Mongoose, and gas monitors and the gas meter are called out in the detailed site plan in Appendix B-2.”

Please consider revising the statement above for clarity.</td><td>The sentence was updated for clarity “These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2.”</td></tr>
</table>

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>3.</td><td>4.1</td><td>69</td><td>In the previous RFAI, the following was asked:

“Figure 43 of the MRV plan shows the Bayswater Amine Facility and provides a description of the surface equipment and monitors. We recommend showing the location of all flow meters relevant to subpart RR calculations in this or a similar figure.”

The facility diagram in Appendix B-2 identifies a gas meter. However, please update the figure or associated text to clarify where the flow meter is in relation to other facility components and how it relates to the monitoring requirements in 40 CFR 98.444. E.g., for which subpart RR measurement will this meter be used?</td><td>The following sentence was added to describe how the flow meter relates to the monitoring requirement: “Data from this flow meter will be used in the calculations of the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year, per 40 CFR §98.444(b).”</td></tr>
<tr><td>4.</td><td>4.2</td><td>71</td><td>“A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in Appendix D.”

“The summary of all oil and gas wells in Appendix D also provides the total depth (TD) of all wells within the MMA.”

According to the Appendices submitted with the MRV plan, Appendix D contains the structural and stratigraphic cross sections. Please review the MRV plan to ensure that all references to external documents within the text are correct.</td><td>The appendix references have been updated throughout the document. The label for the gas meter on Appendix B-2 has been updated to read “Gas Flow Meter”.</td></tr>
<tr><td>5.</td><td>5.1</td><td>78</td><td>“The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in Appendix E.”

The statement above references “Appendix E,” but the Appendices submitted with the MRV plan do not contain an Appendix E. Please review the MRV plan to ensure that all references to external documents within the text are correct.</td><td>The appendix references have been updated throughout the document.</td></tr>
</table>

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	7.5	85	"CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well covered by this source category in the reporting year." Per 40 CFR 98.443(f)(2), this variable should be, "CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well **or group of wells** covered by this source category in the reporting year." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	The definitions of variables for the equations in Sections 7.2 and 7.5 have been updated to reflect the precise language used in 40 CFR 98.443.

BAYSWATER

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC*
Denver, CO

By

Lonquist Sequestration, LLC
Austin, TX

Version 2.0
October 2023

LONQUIST SEQUESTRATION LLC

INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.

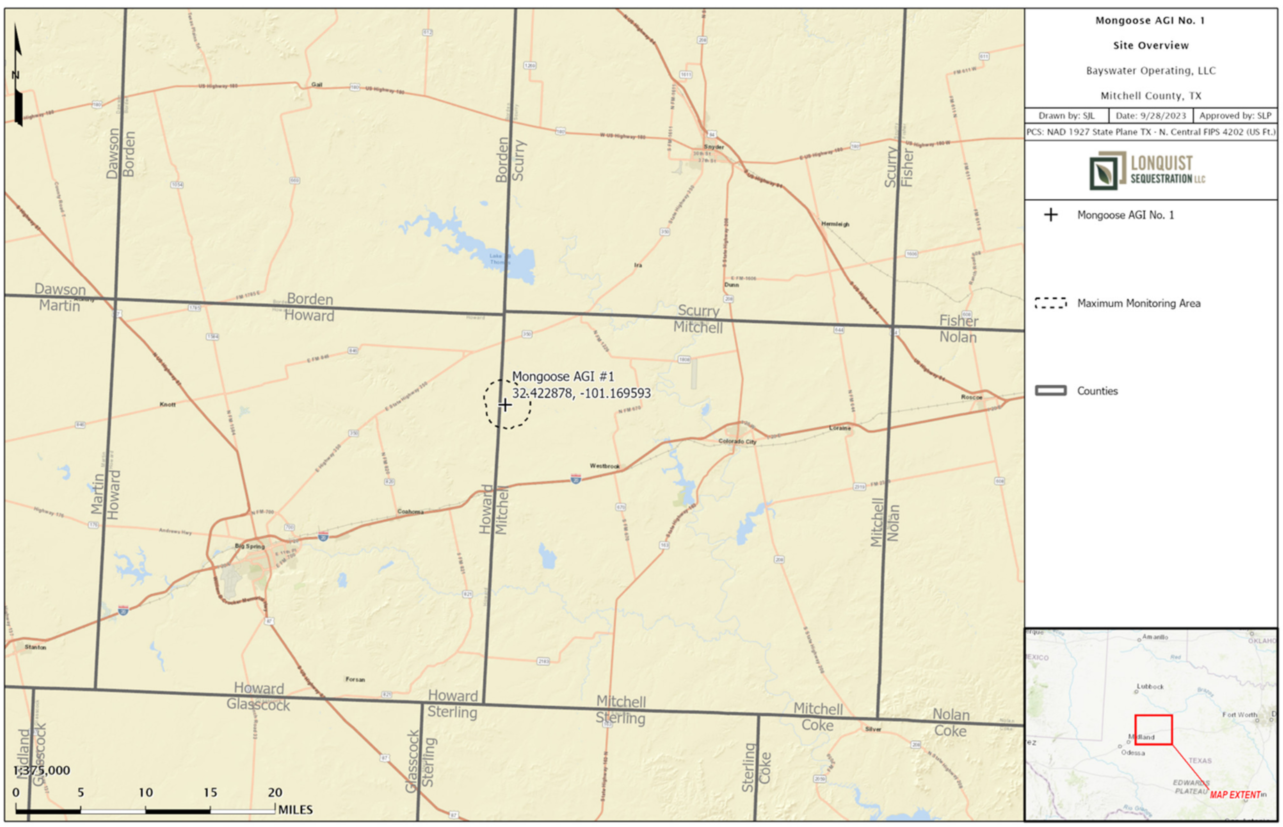


Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO_2 gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
pH	Scale of Acidity
PISC	Post Injection Site Care
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

Figures

Tables

Appendices

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 Reporter Number

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
    - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility
1625 County Road 280
Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641
Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extended across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).

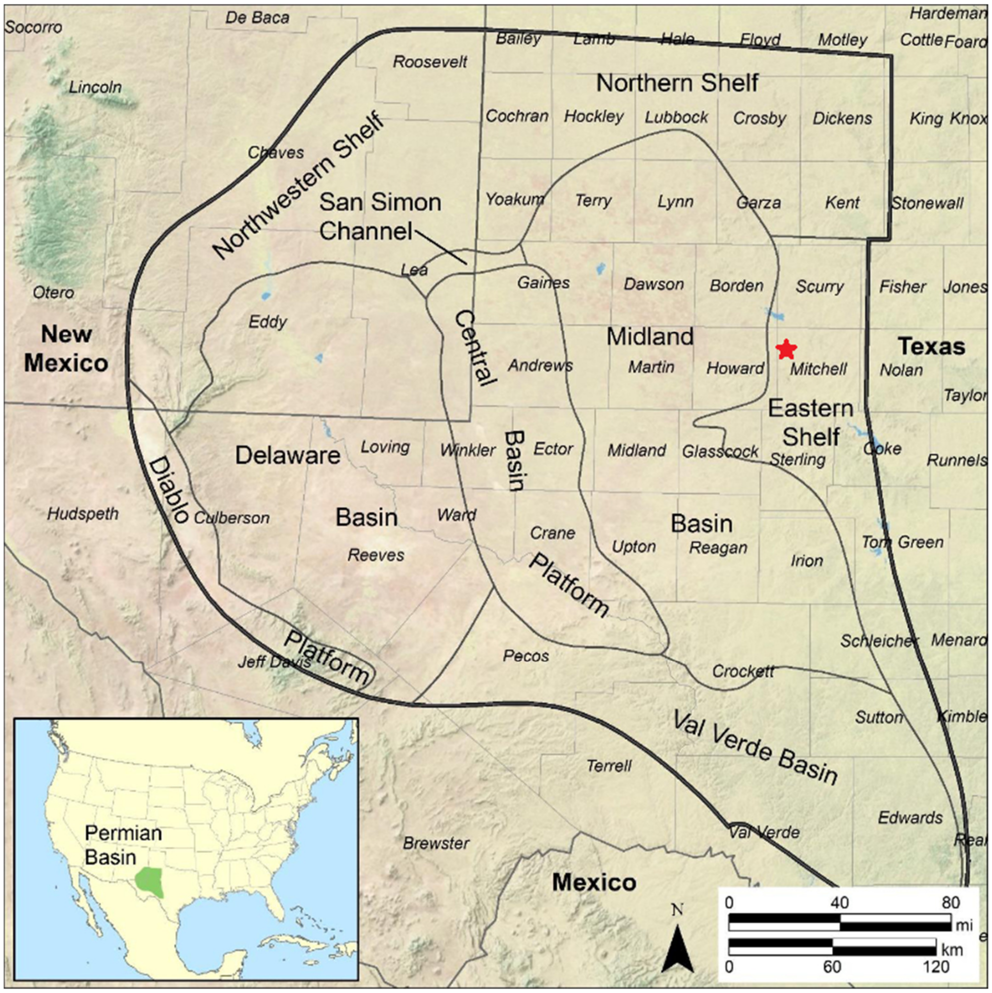


Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).

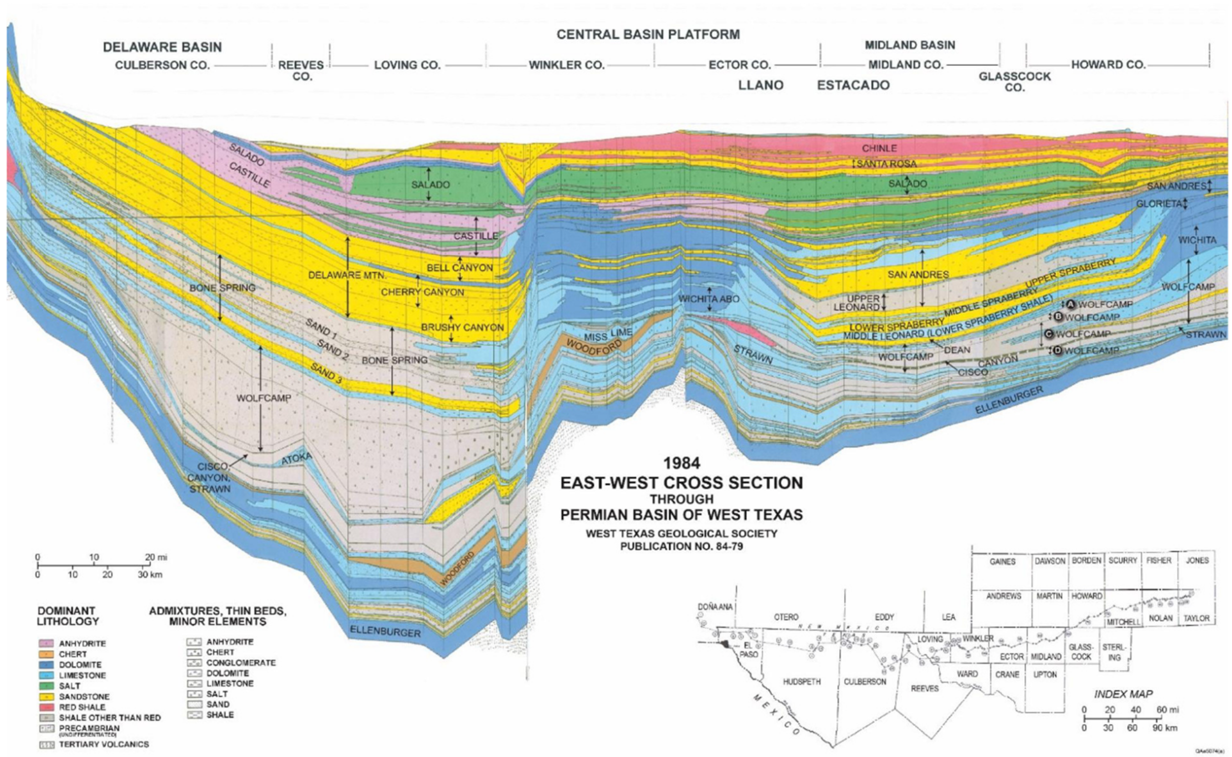


Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).

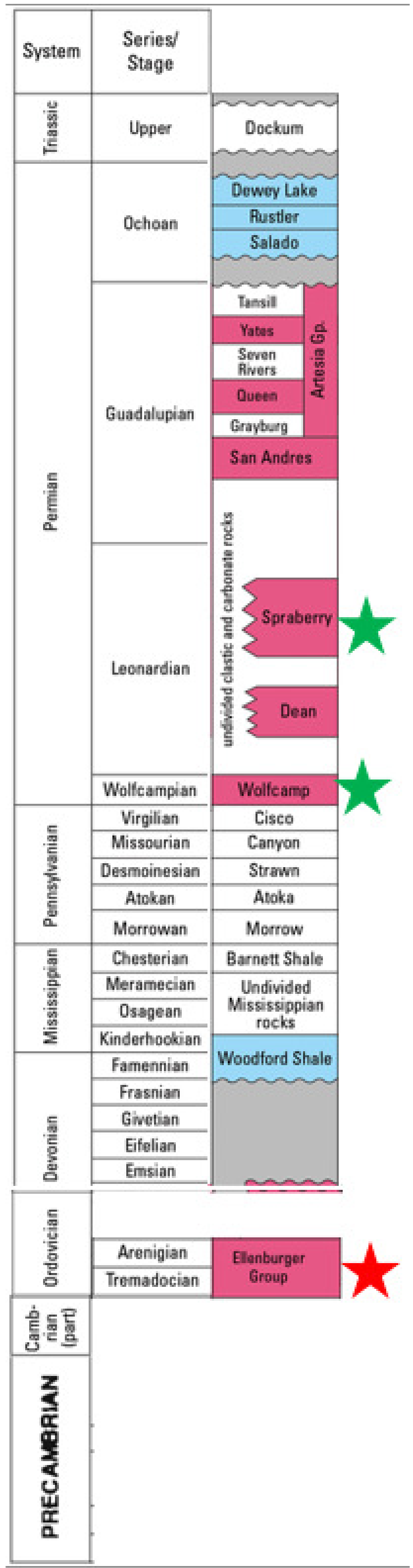


Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf

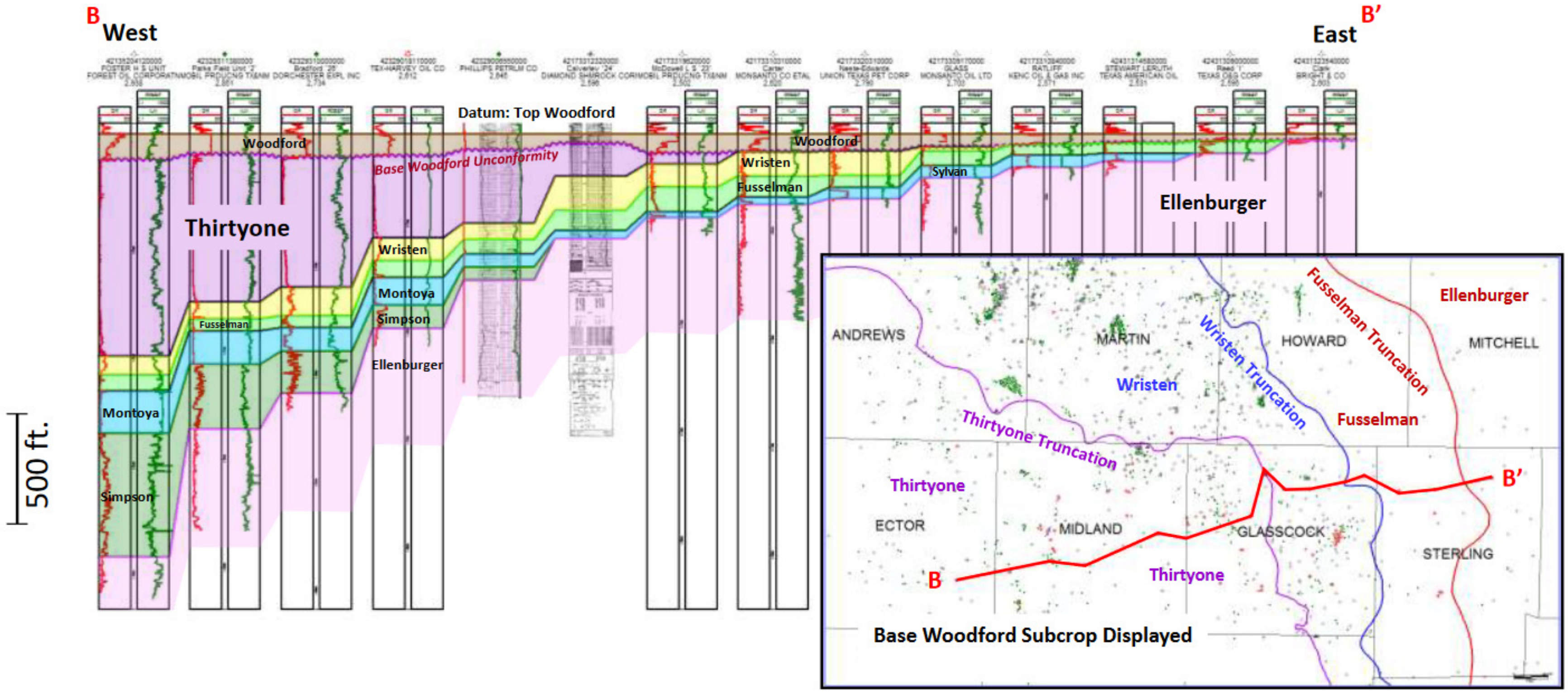


Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).

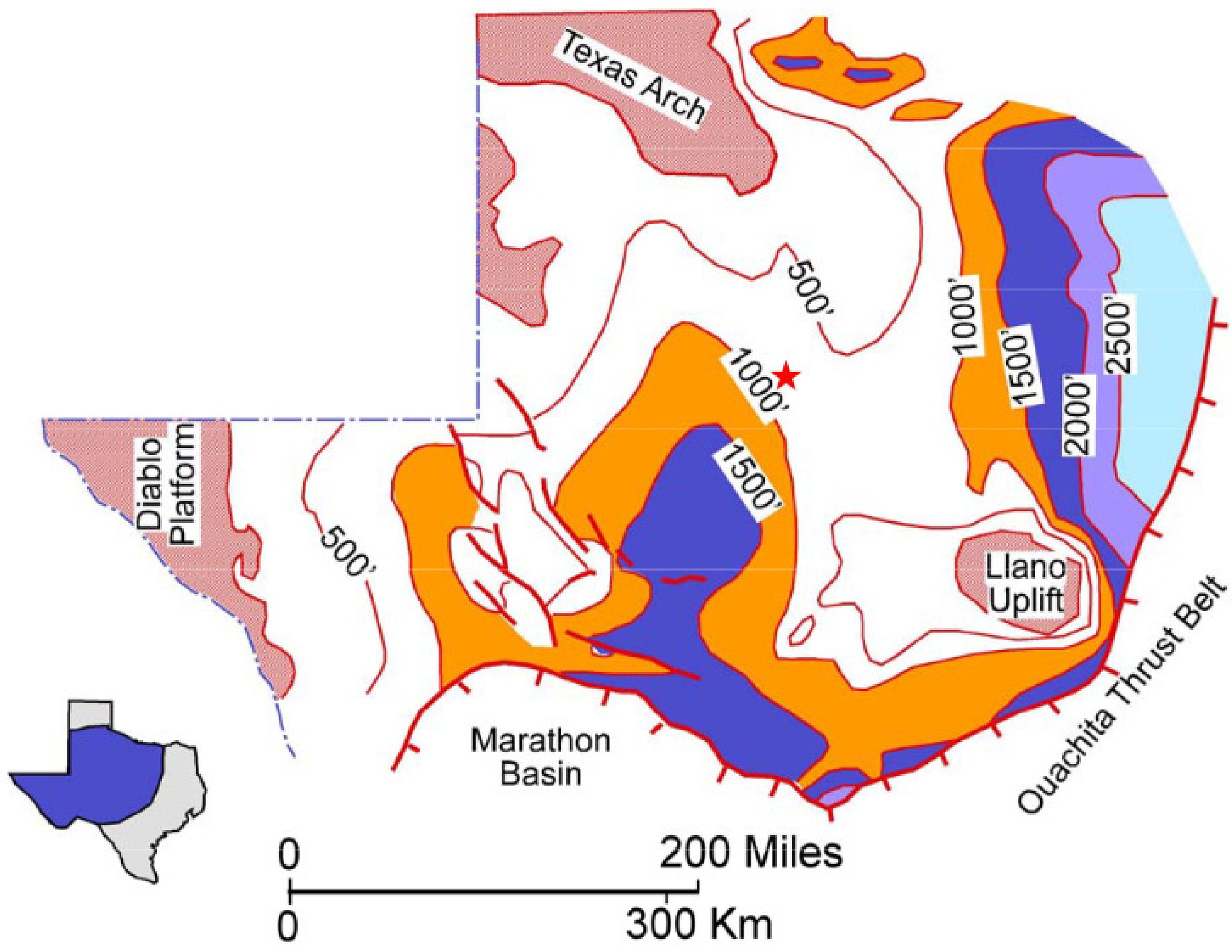


Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)

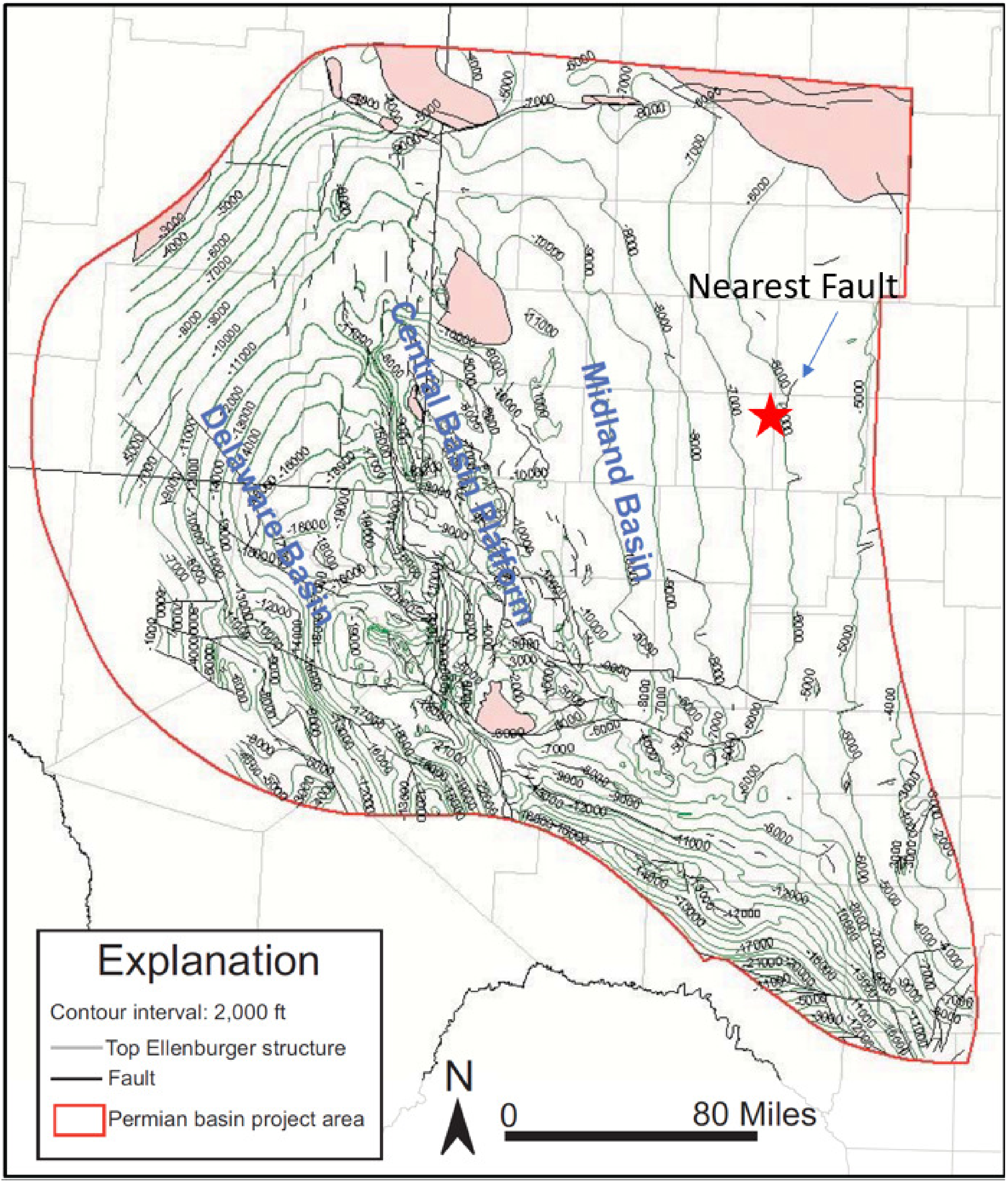


Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant “karsting” and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).

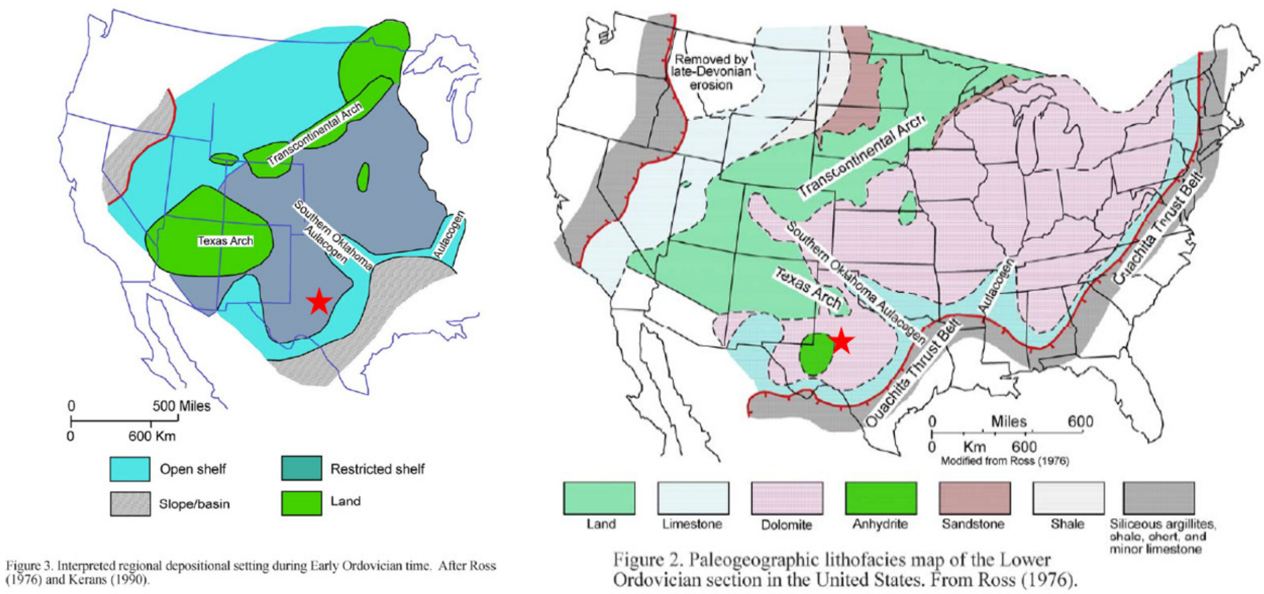


Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).

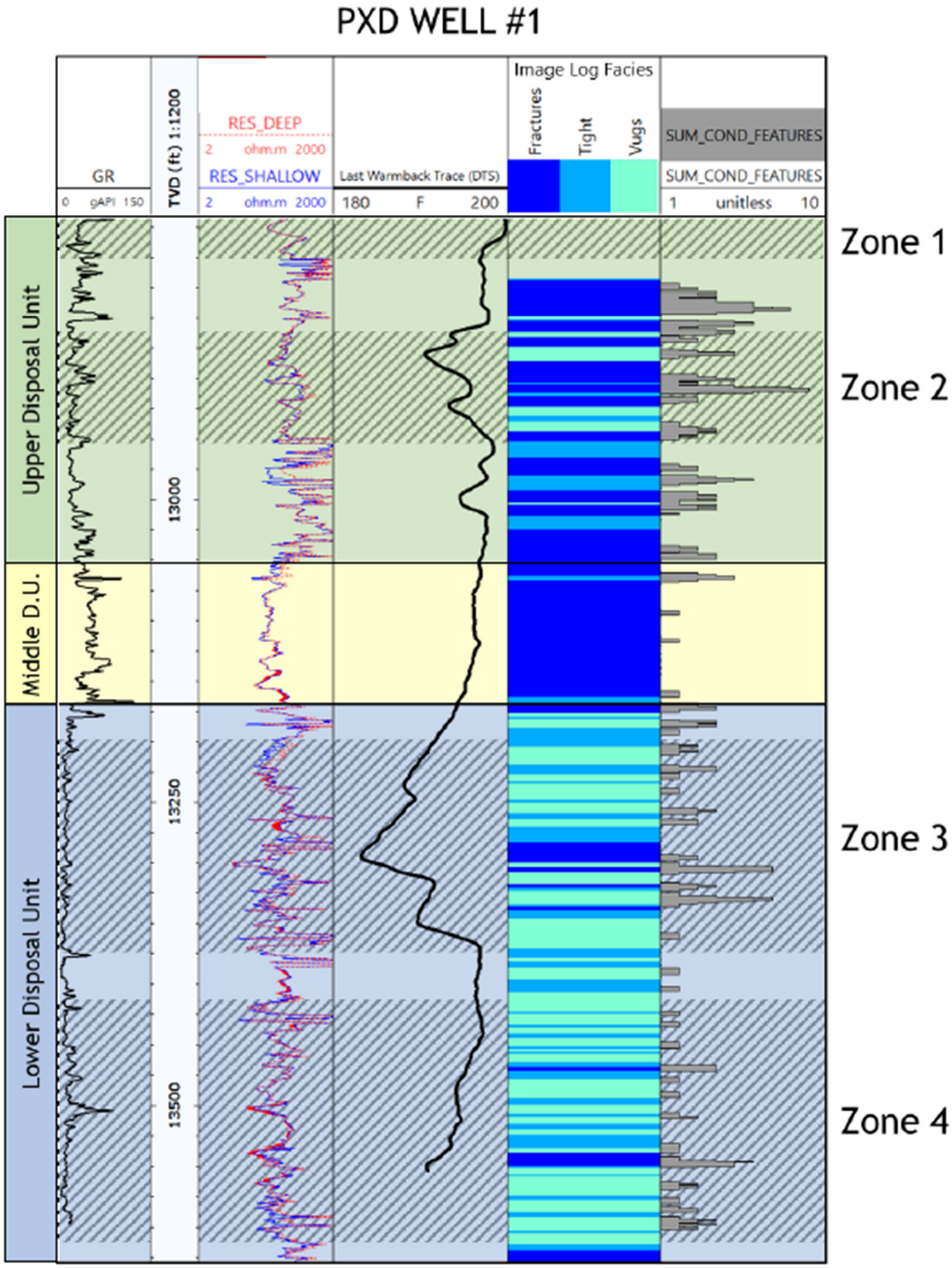


Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, & Coringrato, 2019)

2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.

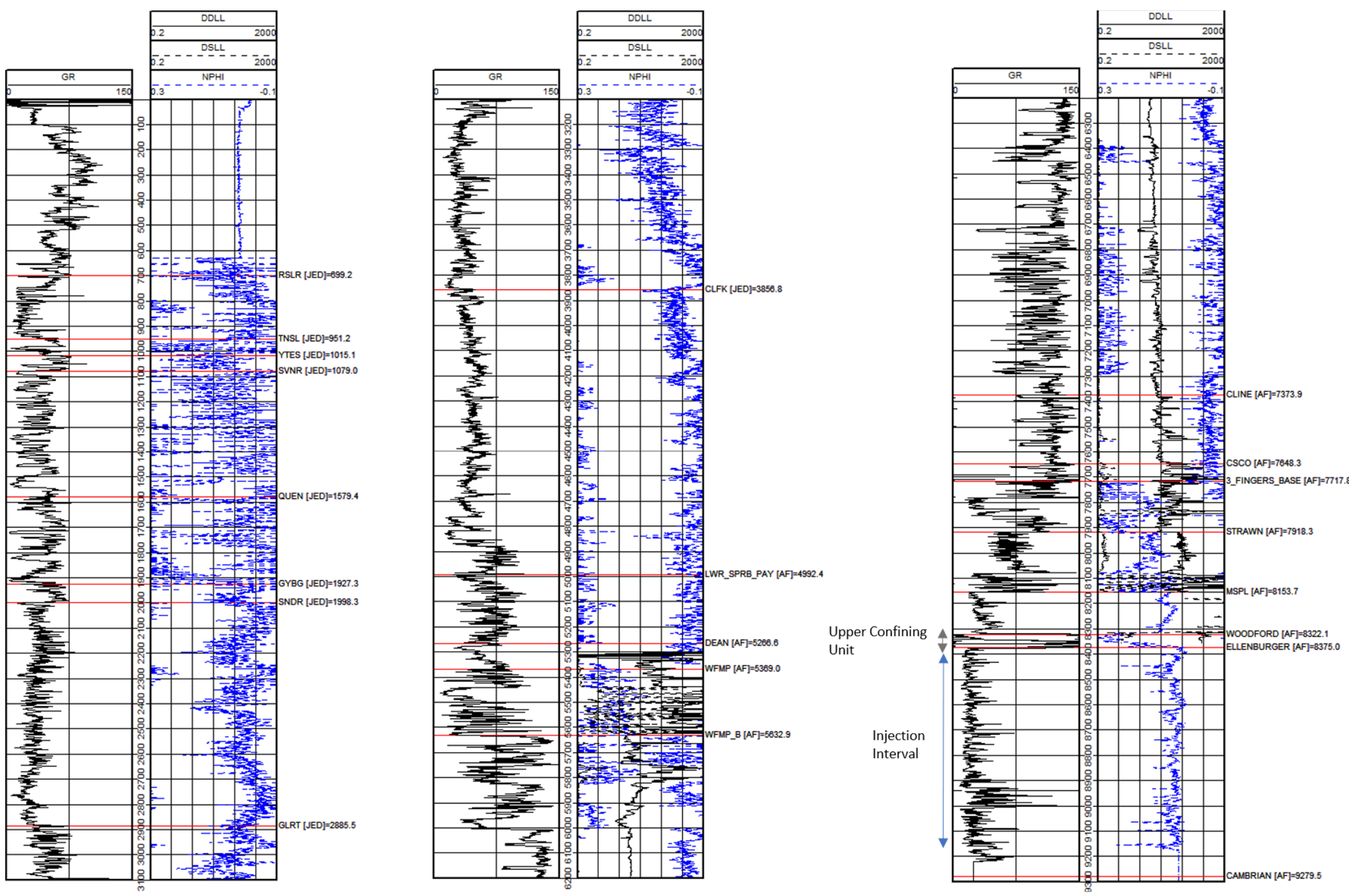


Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO_2 Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.

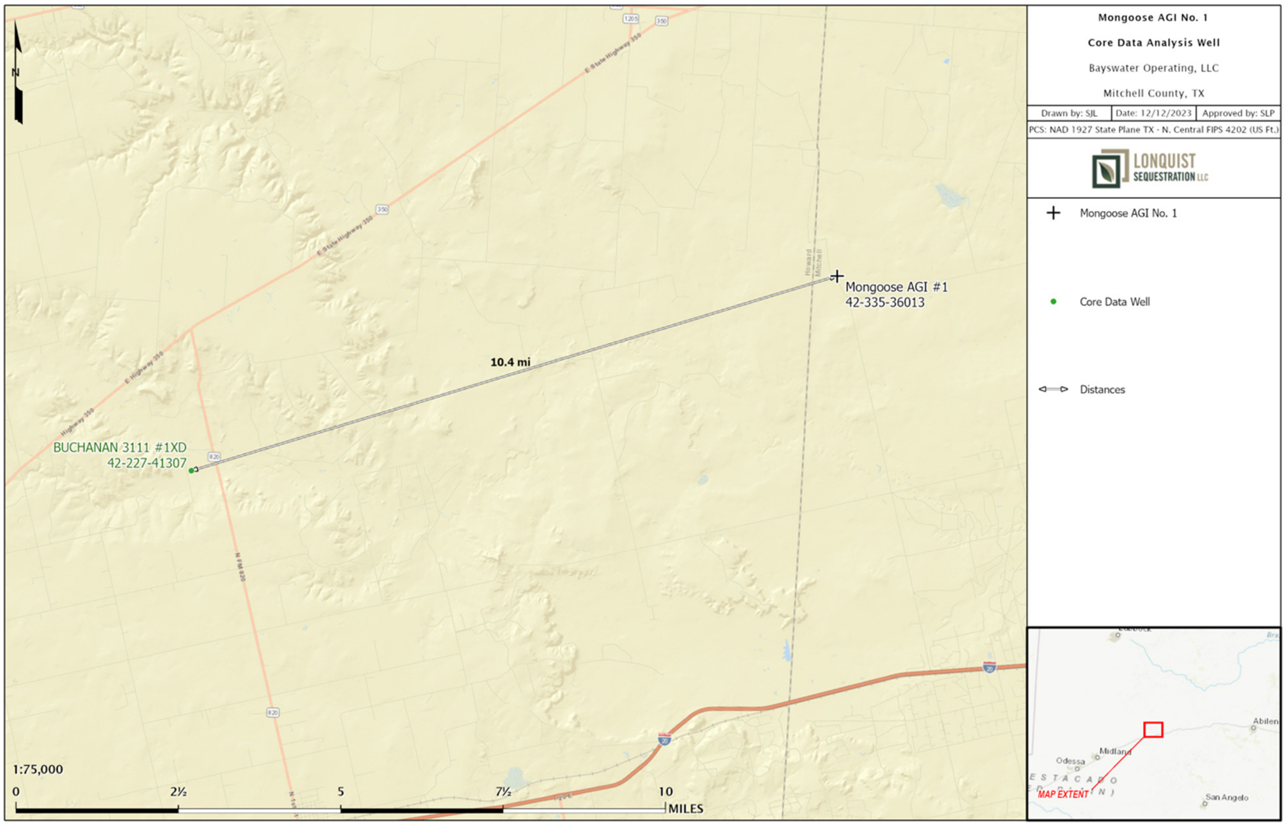


Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data

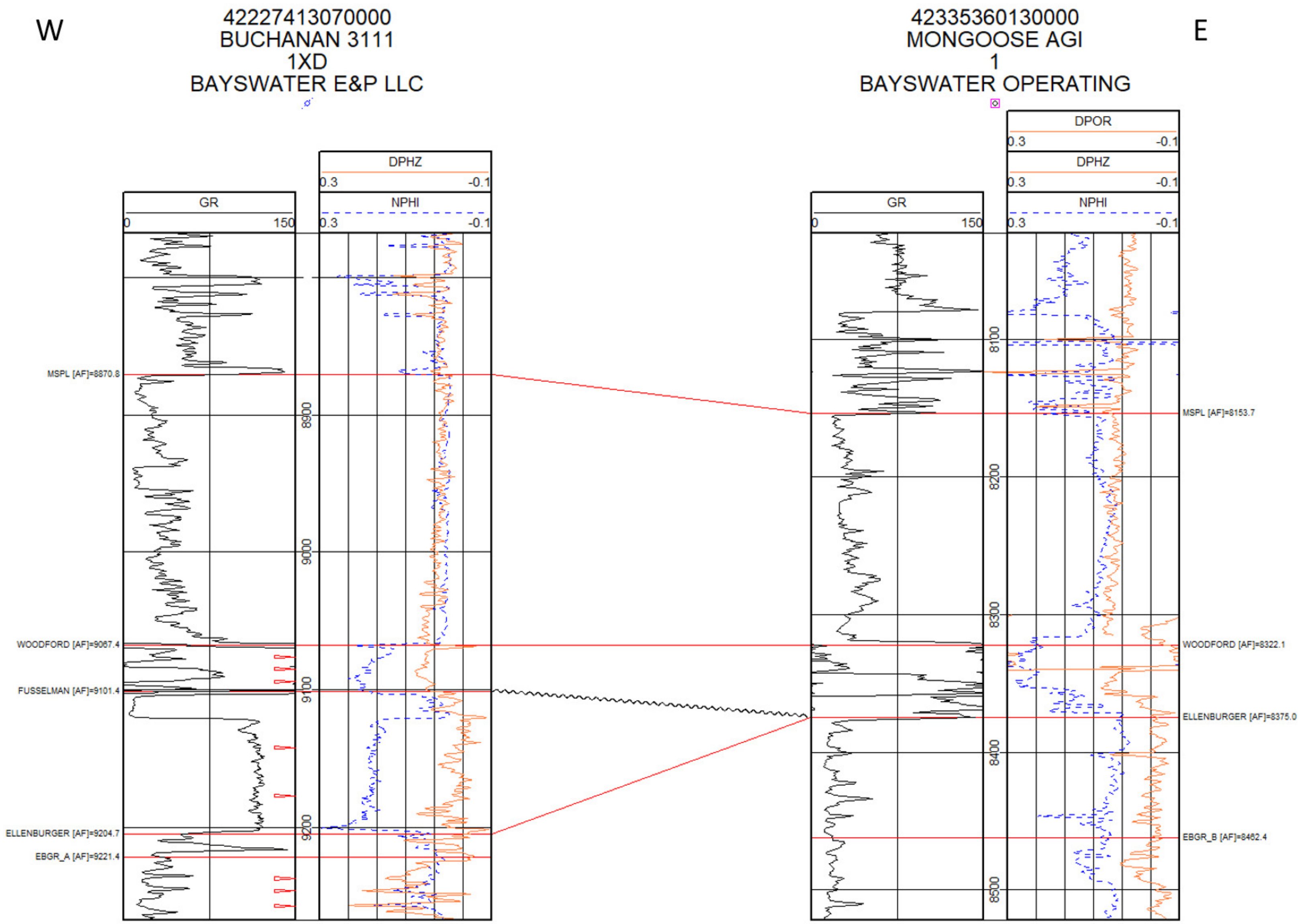


Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.

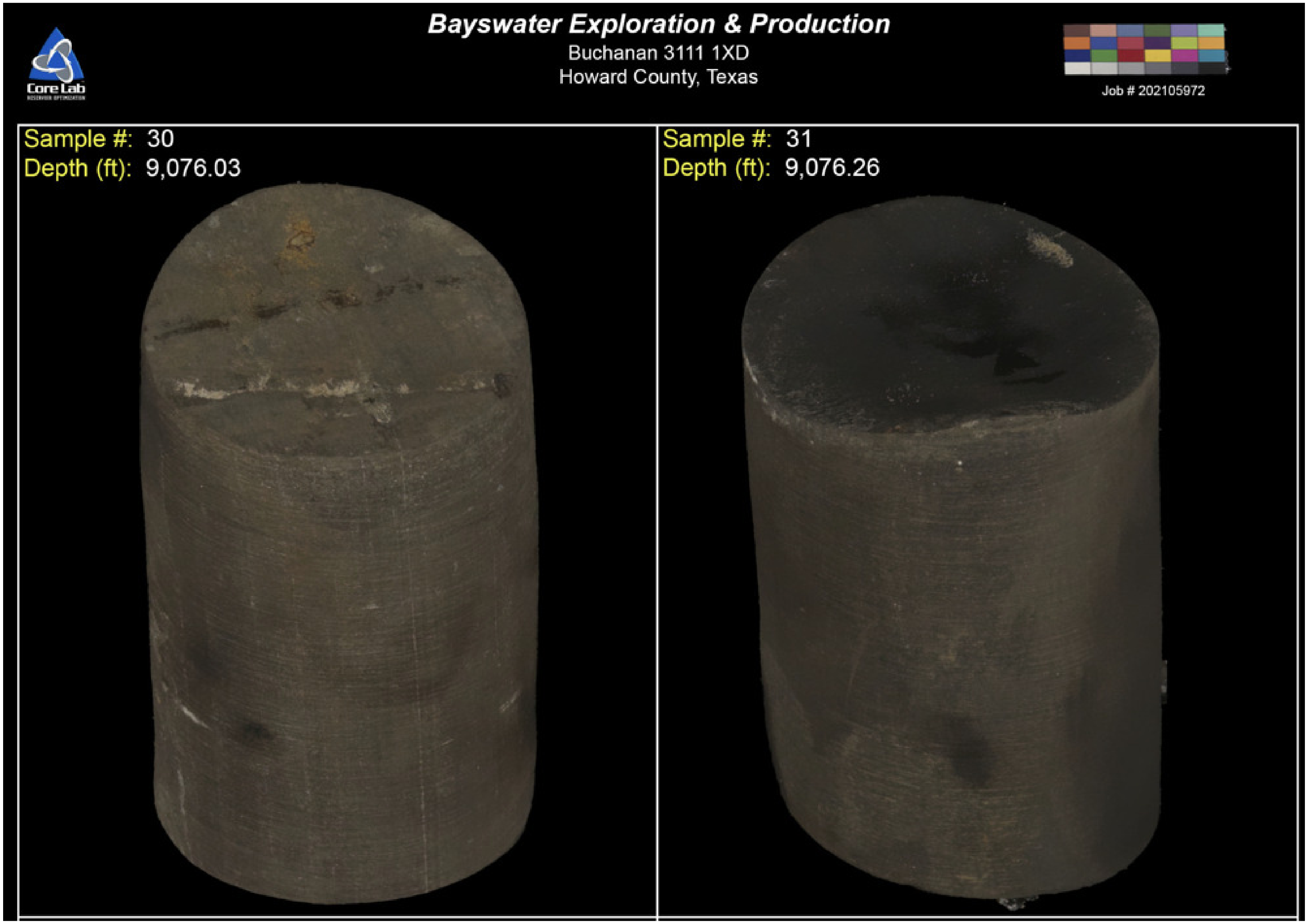


Figure 13 – Core Photo of Samples Within the Woodford Formation

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: February 04, 2022
Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

		As received				Dry & Dean Stark Extracted Conditions (2)				
Sample	**Depth** (ft)	**Bulk Density** (g/cc)	**Matrix Permeability (1)** (mD)	**Gas-filled Porosity** (%)	**Gas Saturation** (%)	**Grain Density** (g/cc)	**Matrix Permeability (5)** (mD)	**Porosity** (%)	**Oil Saturation (3)** (%)	**Water Saturation (4)** (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:
Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.
(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.
(3) Oil volume computed assuming an oil density of 0.844 g/cc
(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc
(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

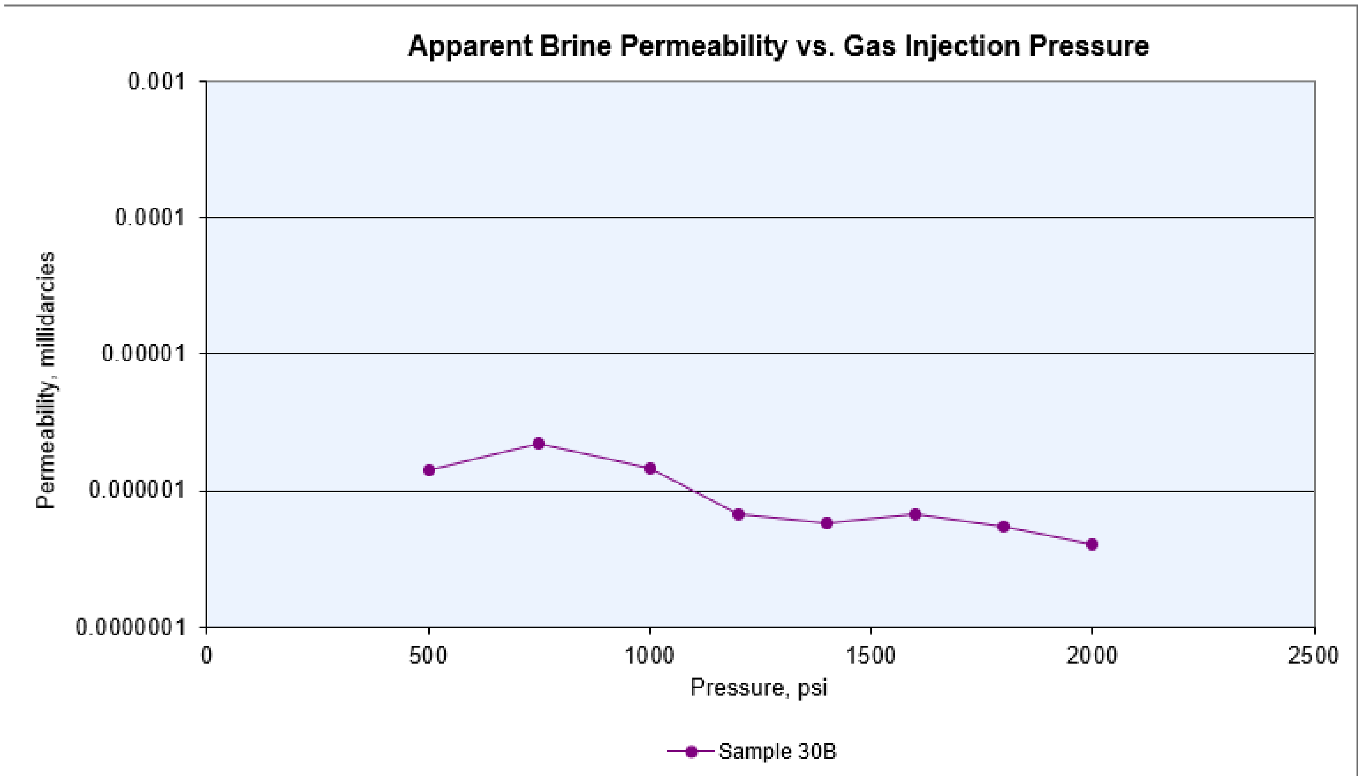


Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi   Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample 30B	
Gas Injection Pressure, psi	Permeability to Brine*, mD
500	1.44E-06
750	2.20E-06
1000	1.46E-06
1200	6.73E-07
1400	5.77E-07
1600	6.72E-07
1800	5.39E-07
2000	4.03E-07

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi   Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production

Well: Buchanan 3111 1XD

Field: Spraberry

Location: Howard County, Texas

File: HOU-2105972

Sample Number	Depth, feet	Length, cm	Diameter, cm	Final Permeability to Brine*, millidarcies	Threshold Entry Pressure, psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 <u>Ellenburger</u>

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 <u>Ellenburger Porosity/Permeability Development</u>

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and non-applicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A two-function porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

If Effective Porosity (Φeff) < 6.5%: $K(mD) = 7E{-}08e^{3.3028*\Phi\text{eff}}$

If Effective Porosity (Φeff) > 6.5%: $K(mD) = 277.39\ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: March 31, 2022
Analyst(s): MP

Core Lab

CMS-300 ROTARY SIDEWALL ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Klinkenberg (md)	Permeability Kair (md)	b(air) psi	Beta ft(-1)	Alpha (microns)	Saturation Oil % Pore Volume	Saturation Water % Pore Volume	Grain Density (g/cm3)	Footnote
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

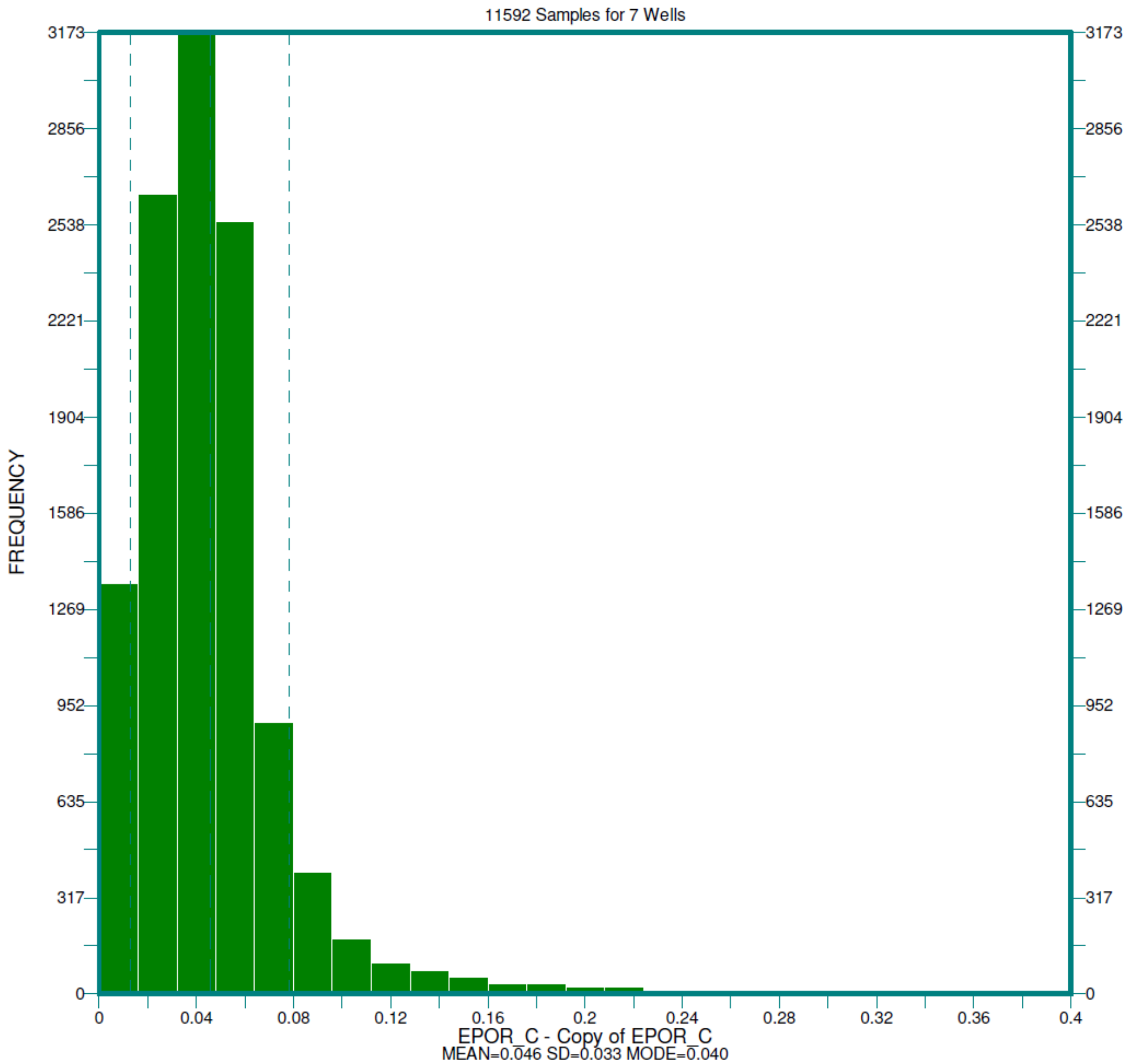


Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

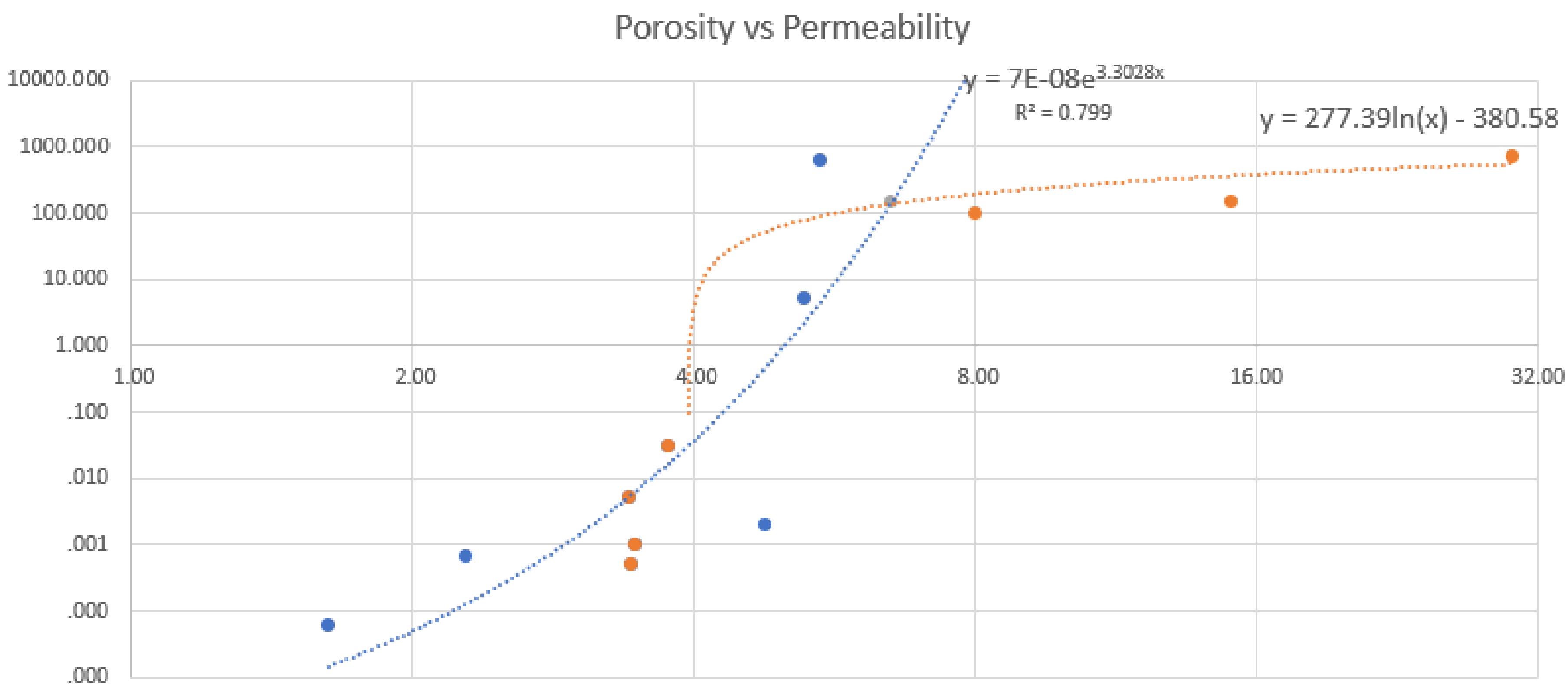


Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data

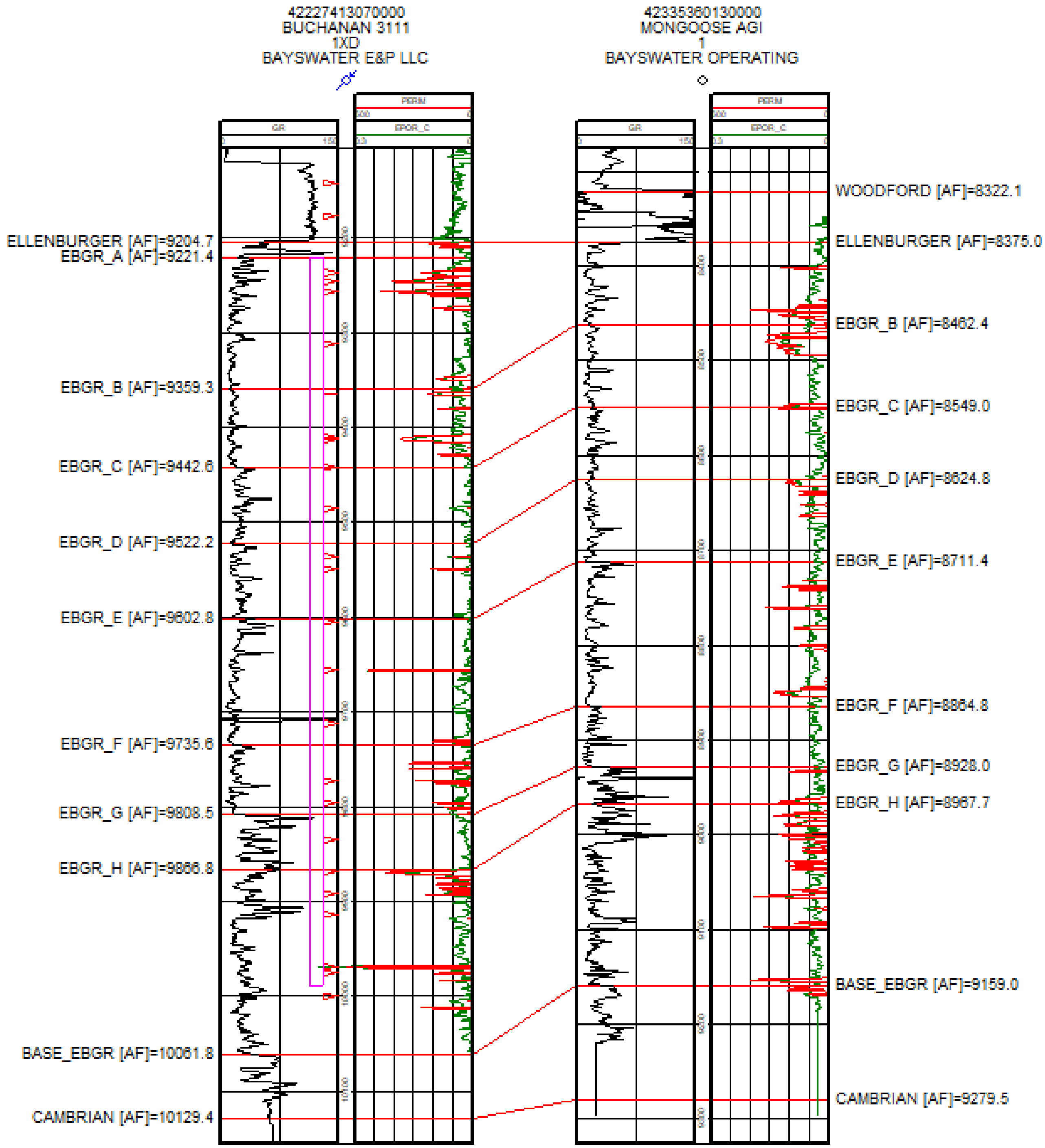


Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.

Figure 23 – Core photo of Ellenburger sample displaying vug features.

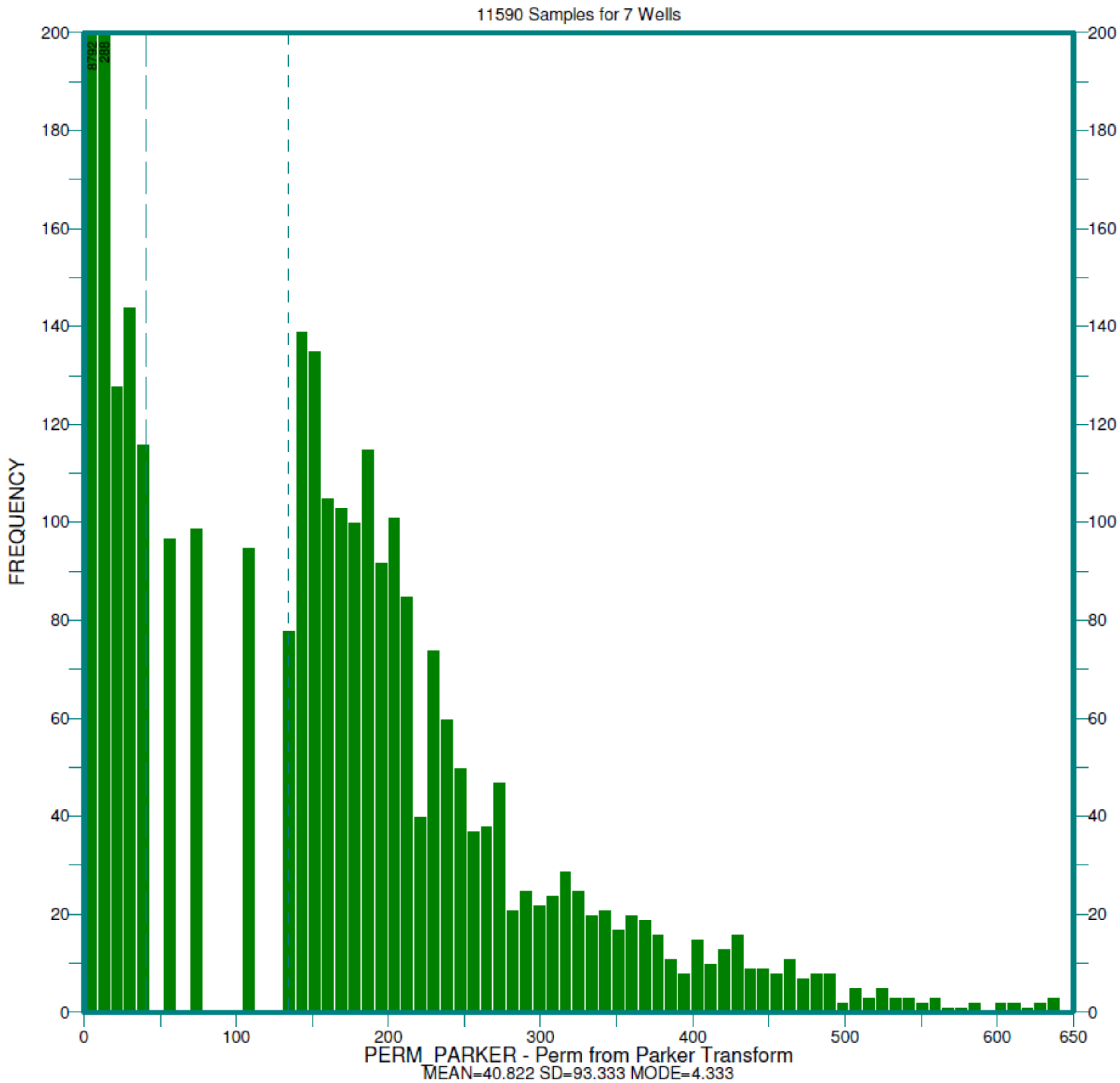


Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 <u>Formation Fluid</u>

Two wells were identified within approximately 30 miles of the Mongoose through a review of oil-field brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.

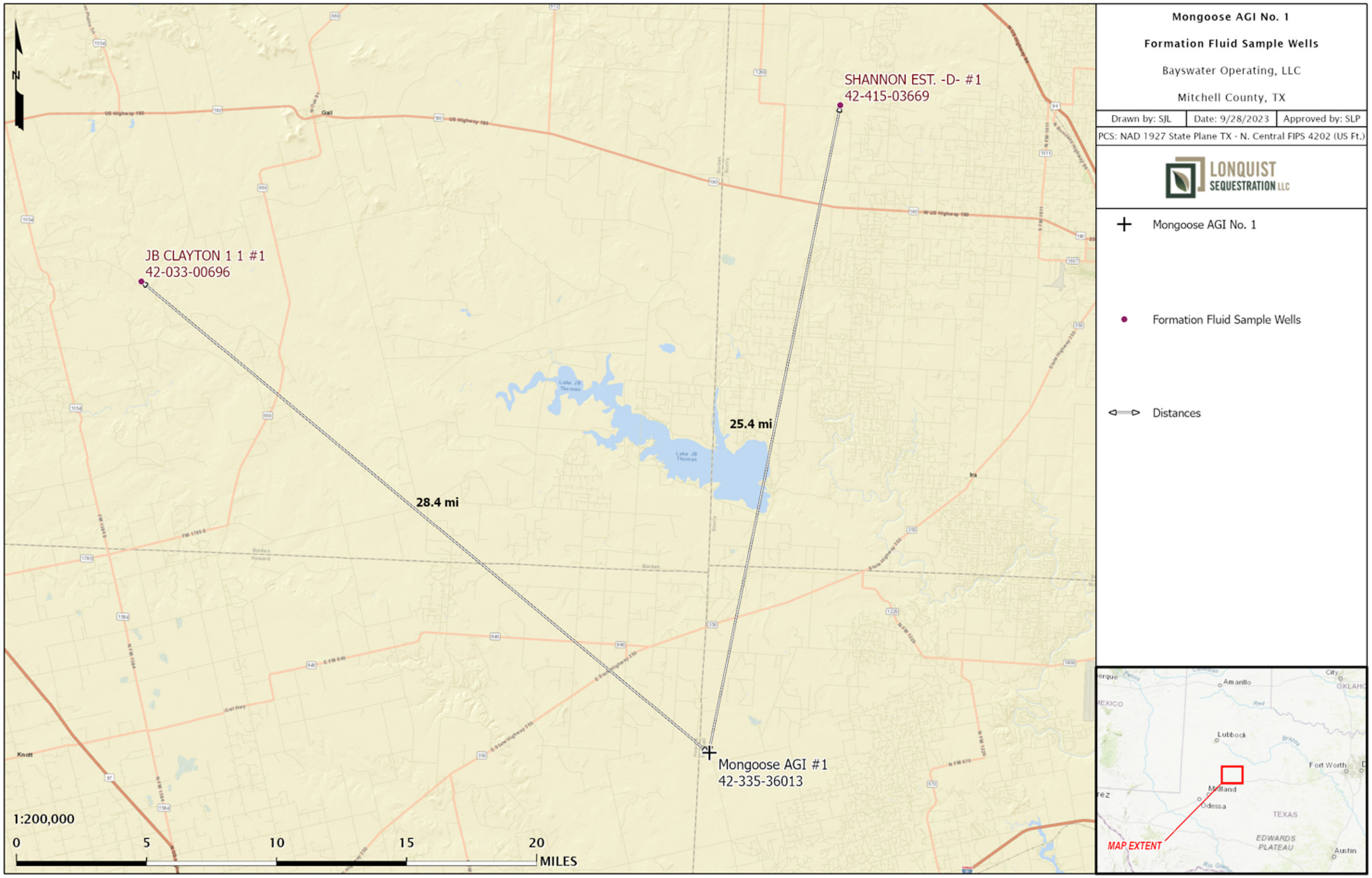


Figure 25 – Offset wells used for formation fluid characterization.

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
pH	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

2.2.4 Lower Confining Zone – Precambrian

Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sources from outcrops in central Texas and in the Trans-Pecos region of Texas and centra New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which lead to the interpretation of “granitic bodies in the upper crust” (Adams & Keller, 1996).

Offset Ellenburger injector wells drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.

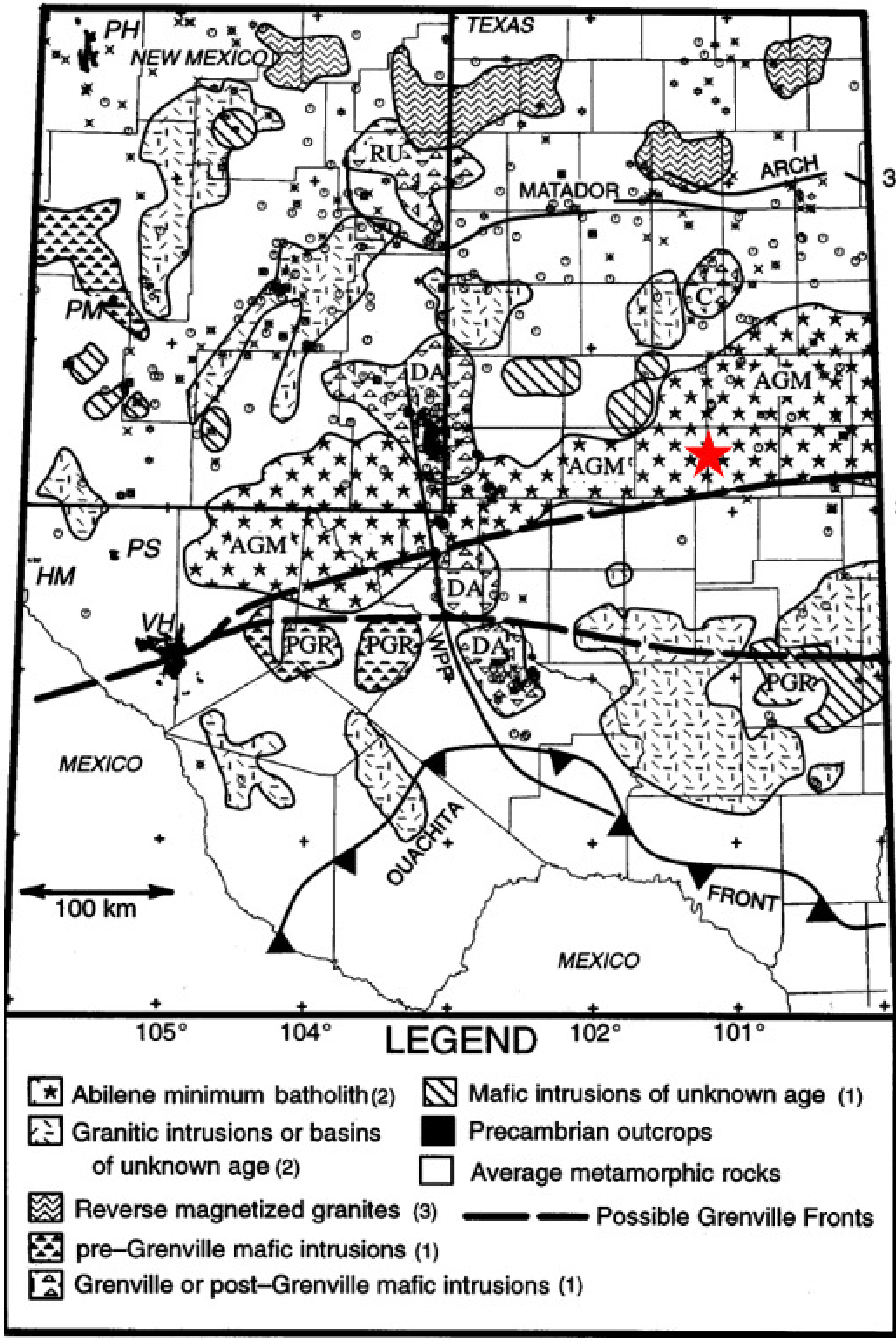


Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_V) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Table 4 – Calculated Vertical Stresses

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$\nu = \frac{\frac{1}{2}\left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

ν = Poisson's Ratio
v_p = Compressional Velocity
v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1 - 0.261}(1.029 - 0.465) + 0.465 = 0.664\, psi/ft$$

$$FG\ with\ SF = 0.689\ \times 90\% = \mathbf{0.598\, psi/ft}$$

Table 5 – Fracture Gradient Calculation Inputs and Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix D*.

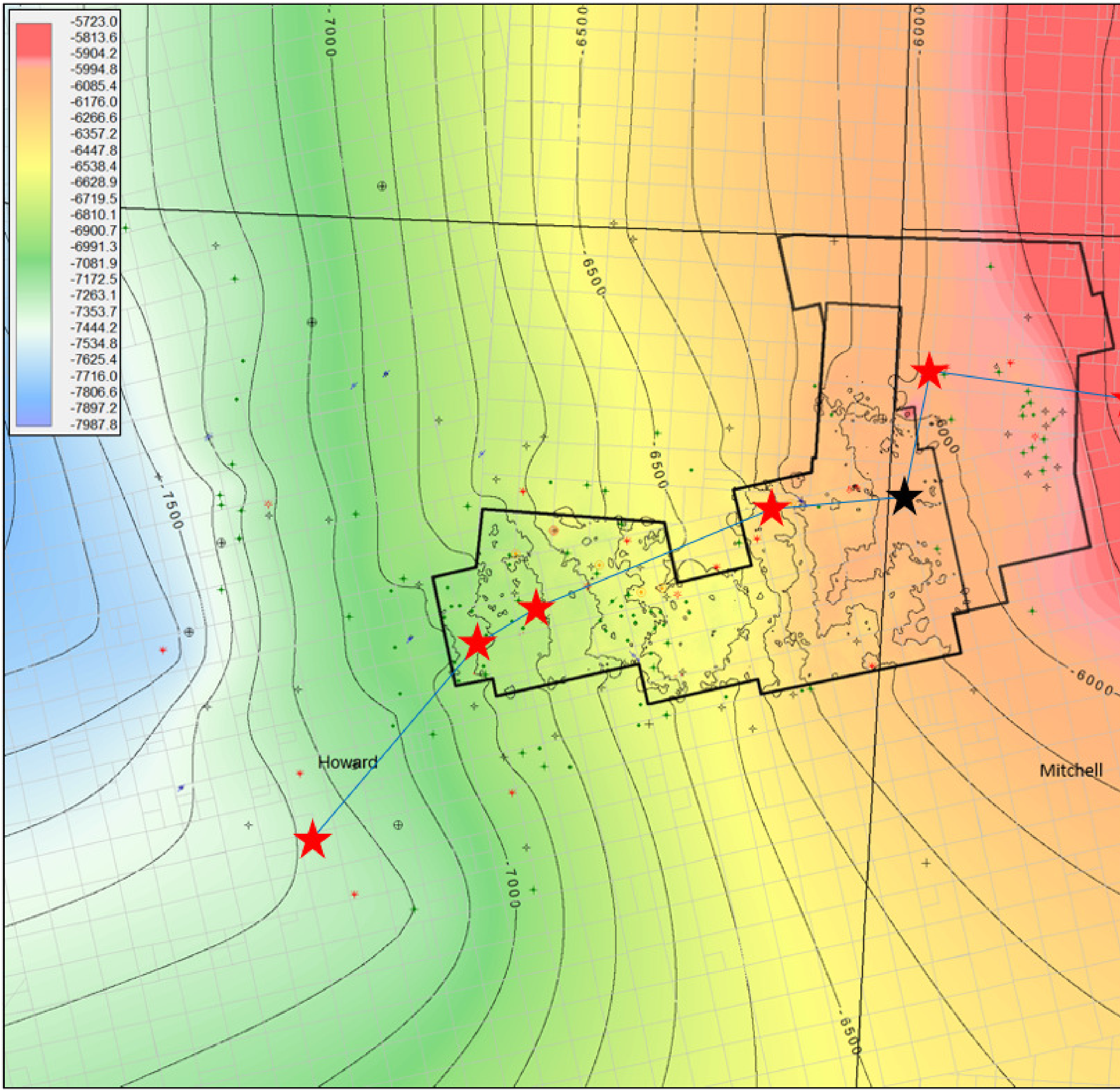


Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.

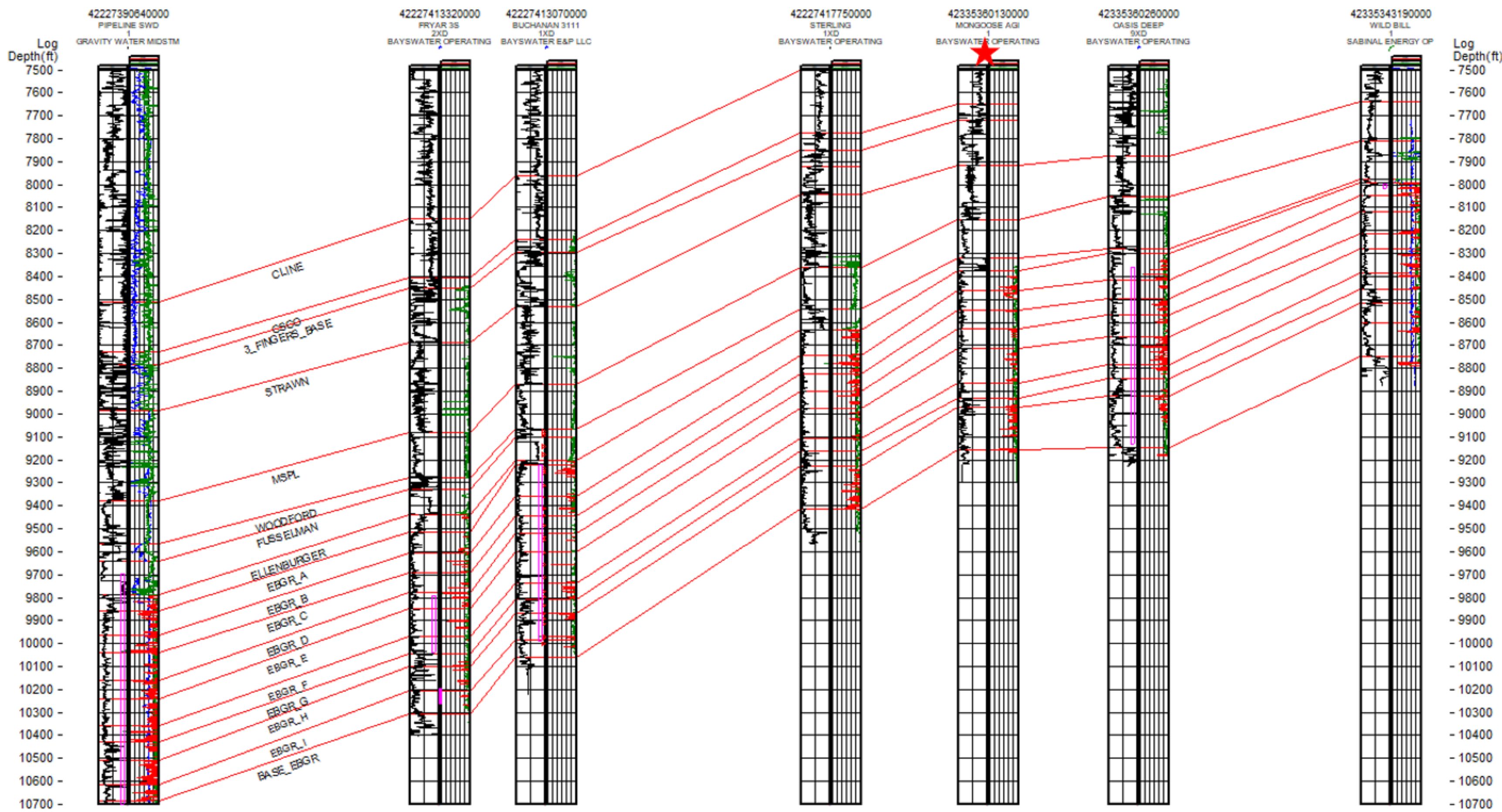


Figure 28 – Structural cross section depicting the Ellenburger.

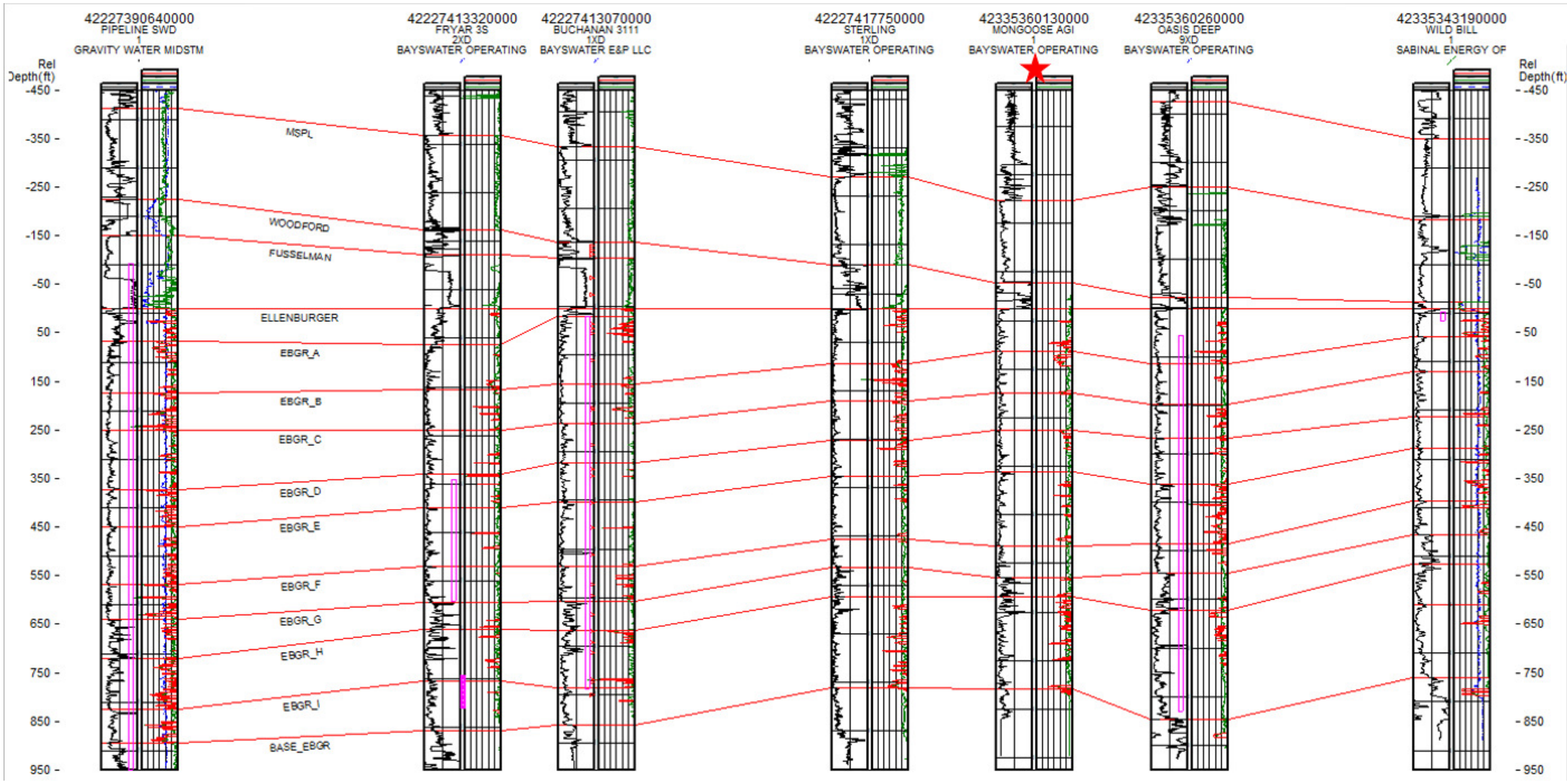


Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colorado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
Cretaceous	Comanche	Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous limestone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potable but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
Triassic		Dockum	Chinle	0-640	Predominantly red to maroon and purplish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sandstone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
			Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaceous and carbonaceous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capacity of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to highly mineralized water to livestock and domestic wells.

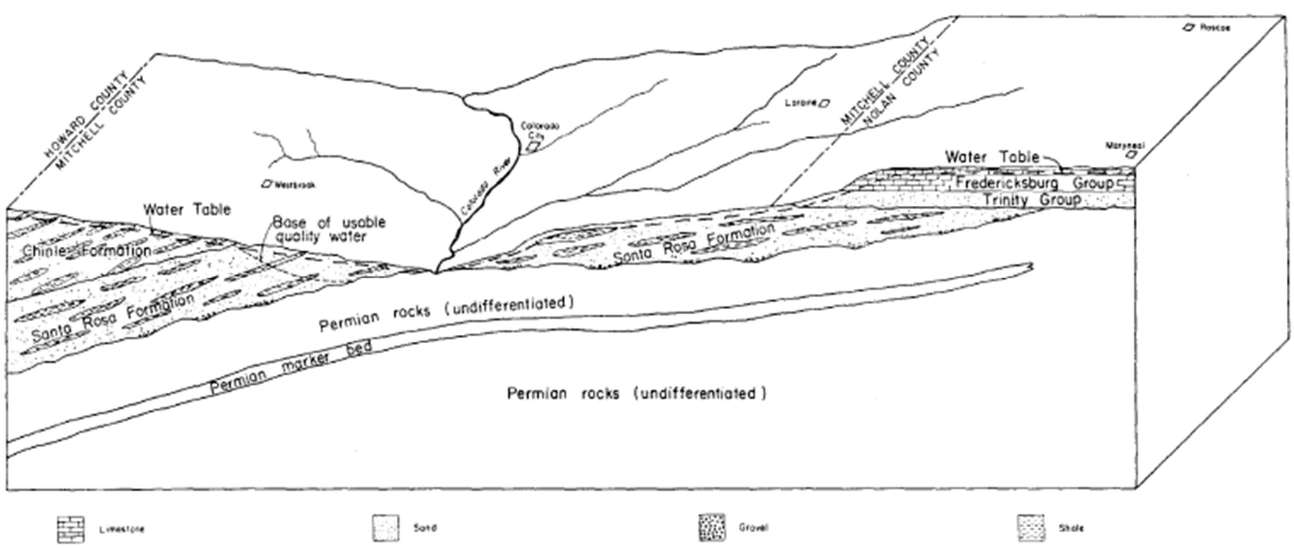


Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.

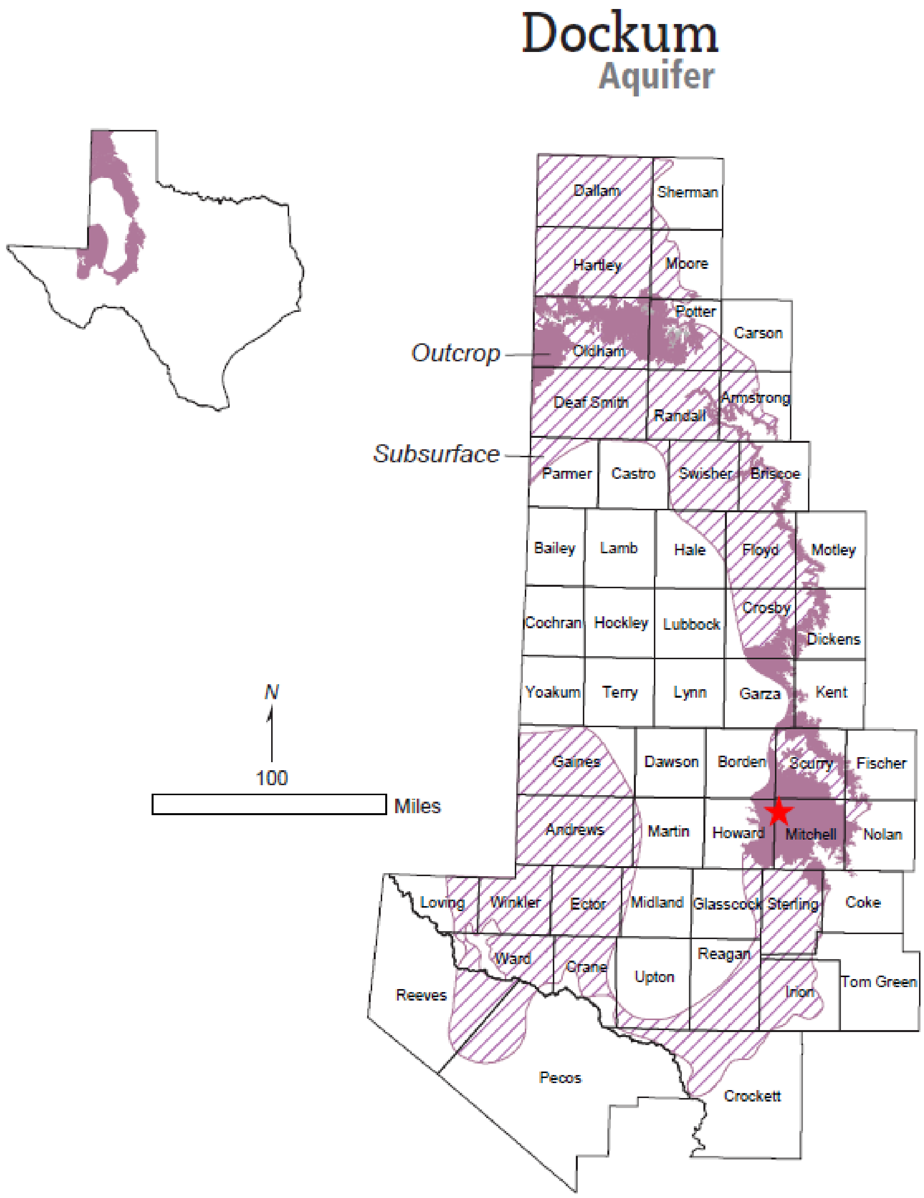


Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).

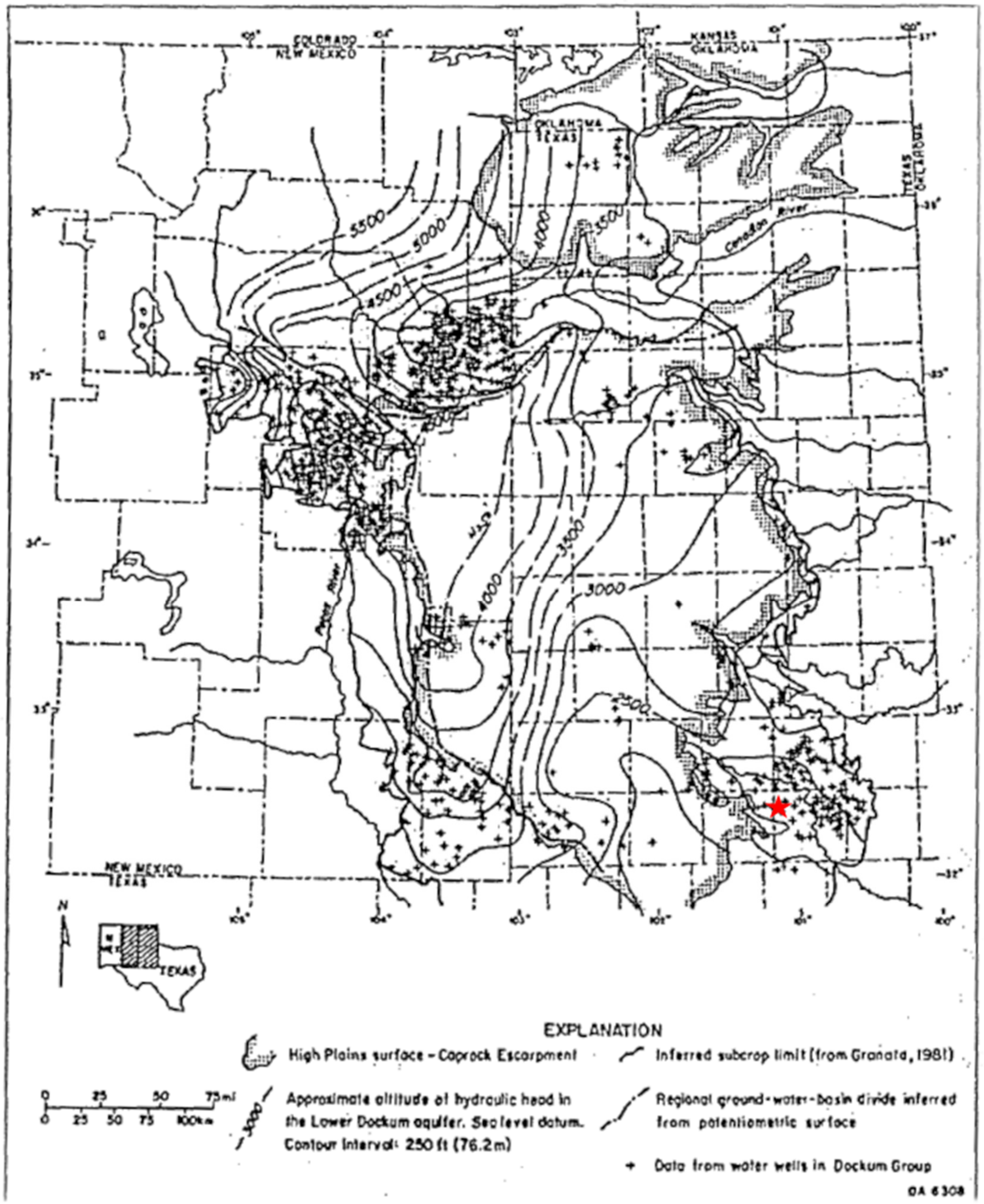


Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).

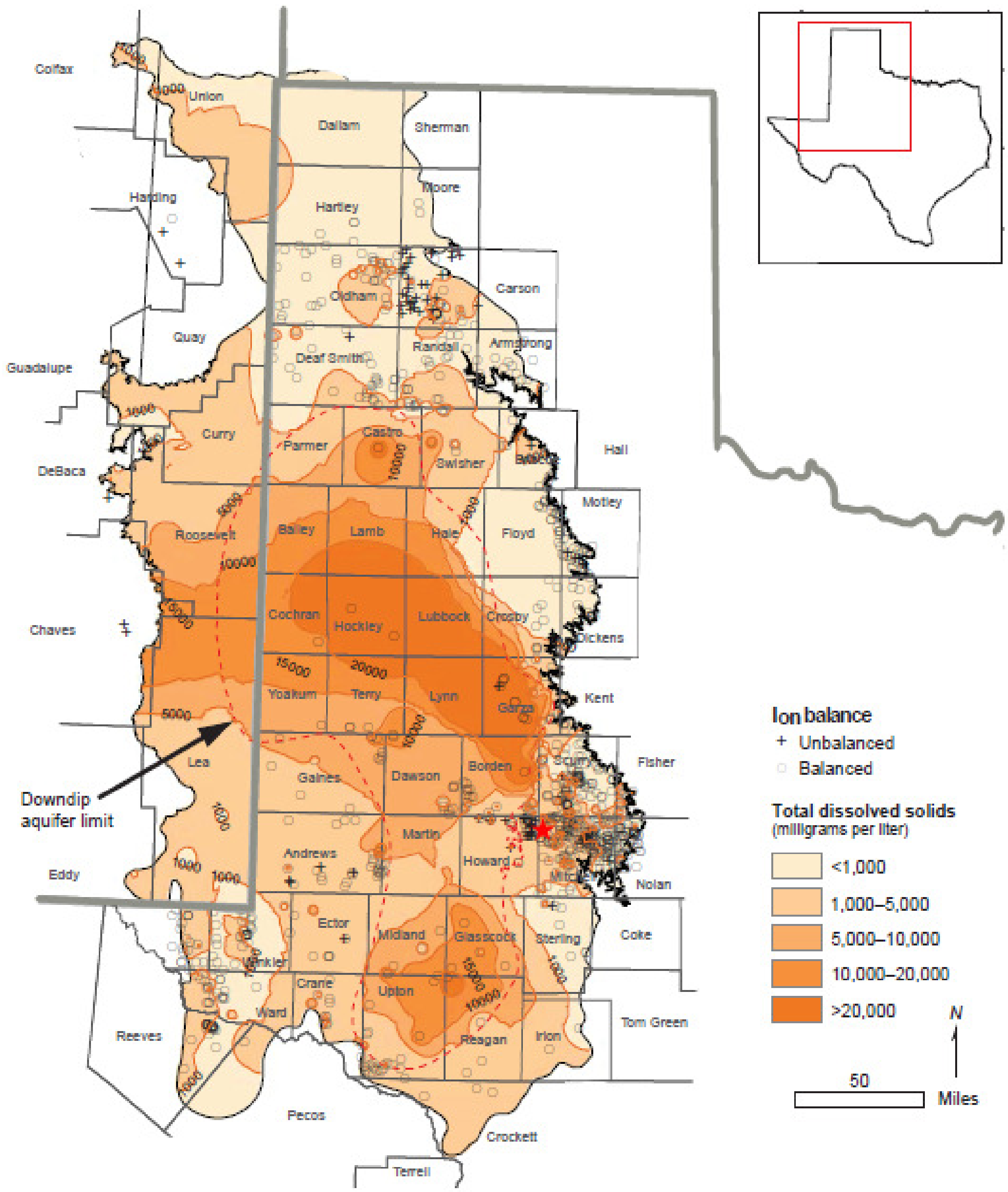


Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 Description of the Injection Process

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO_2, which equates to 155.3 MT/yr of CO_2 each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

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

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction of true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite-acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S and CO_2 based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H_2S and 41.2% CO_2. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H_2S and 41.2% CO_2.

Table 8 – Modeled Initial Gas Composition

Component	**Expected Composition (mol %)**	**Modeled Composition (mol %)**
Hydrogen Sulfide (H_2S)	58.8	58.8
Carbon Dioxide (CO_2)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.

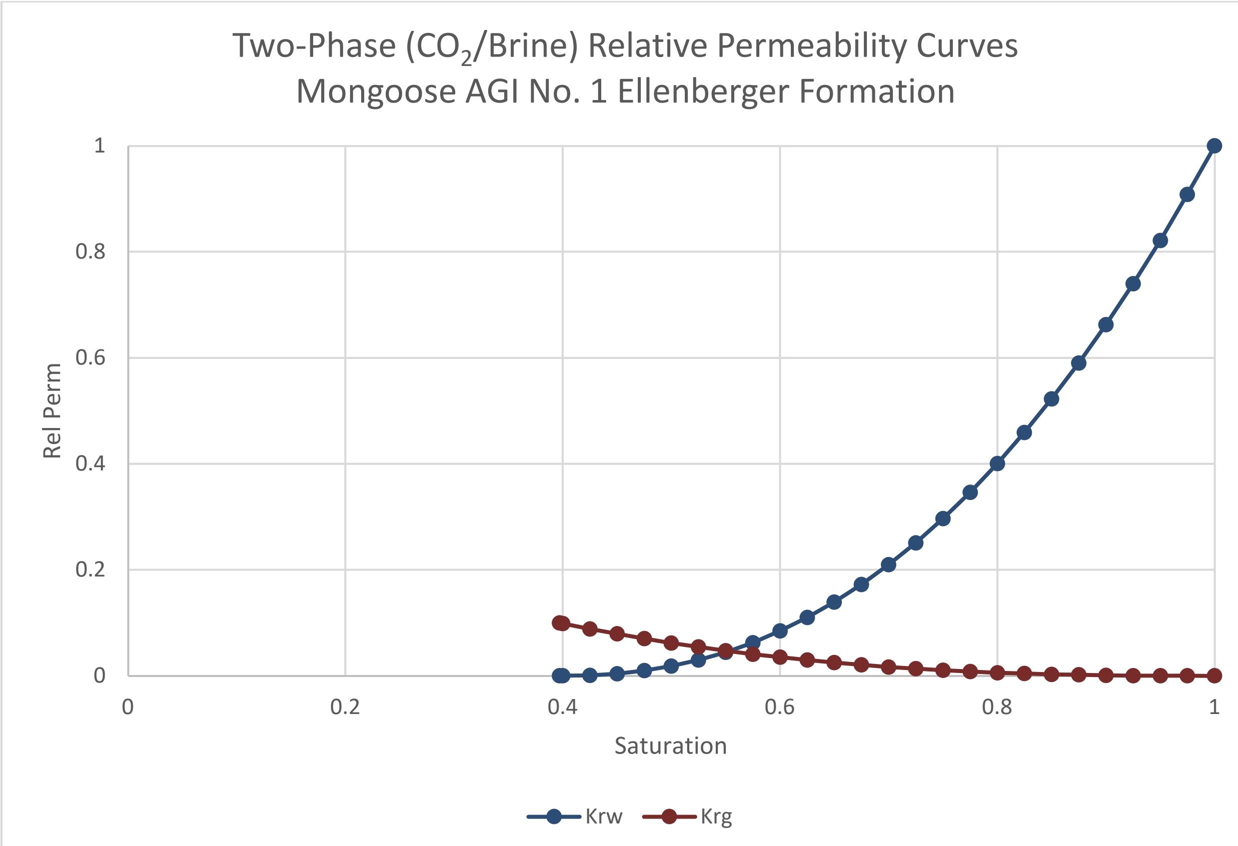


Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (north-south), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Table 9 – GEM Model Layer Package Properties

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

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

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

Table 10 – Offset SWD Wells Included in GEM Model

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.

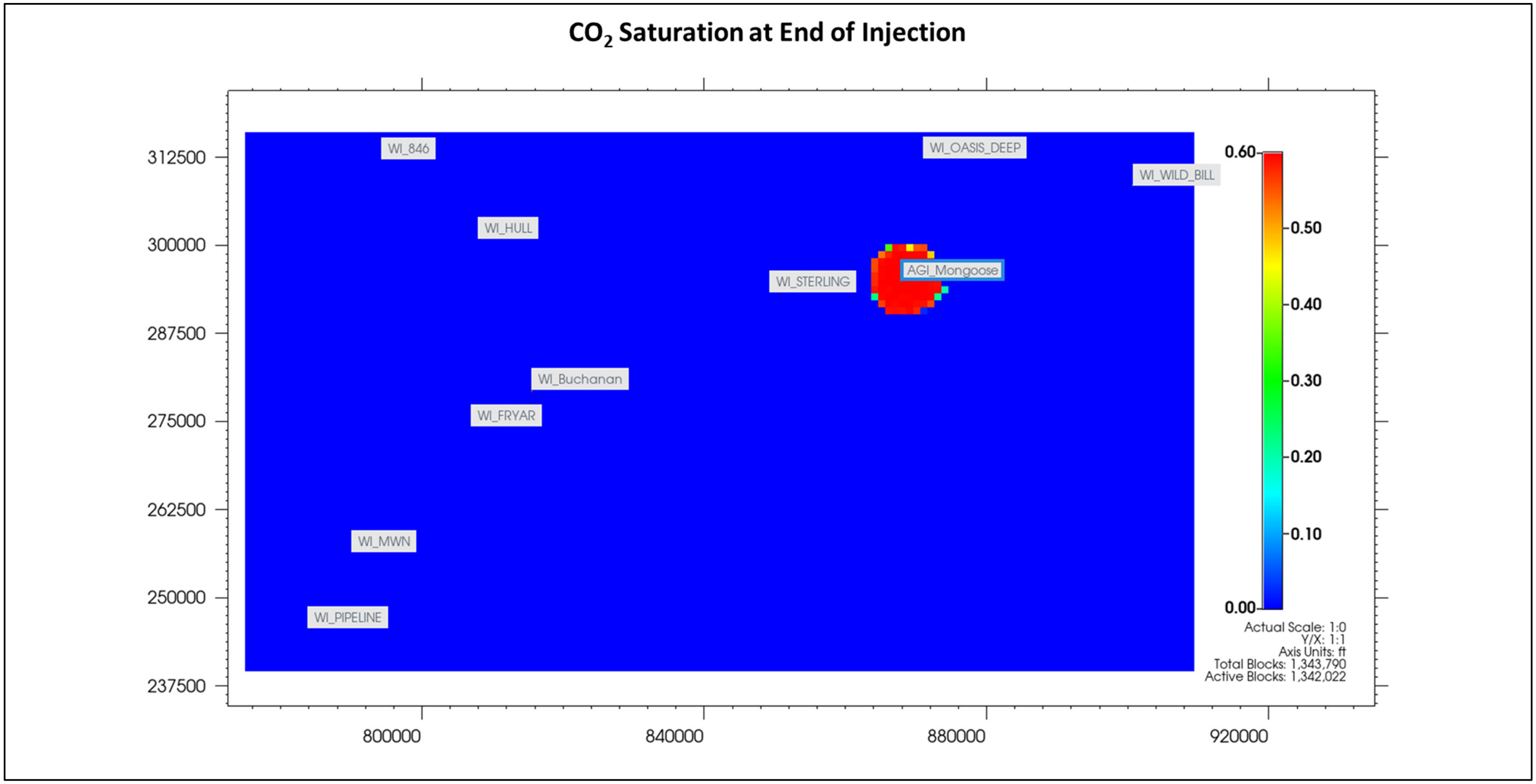


Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)

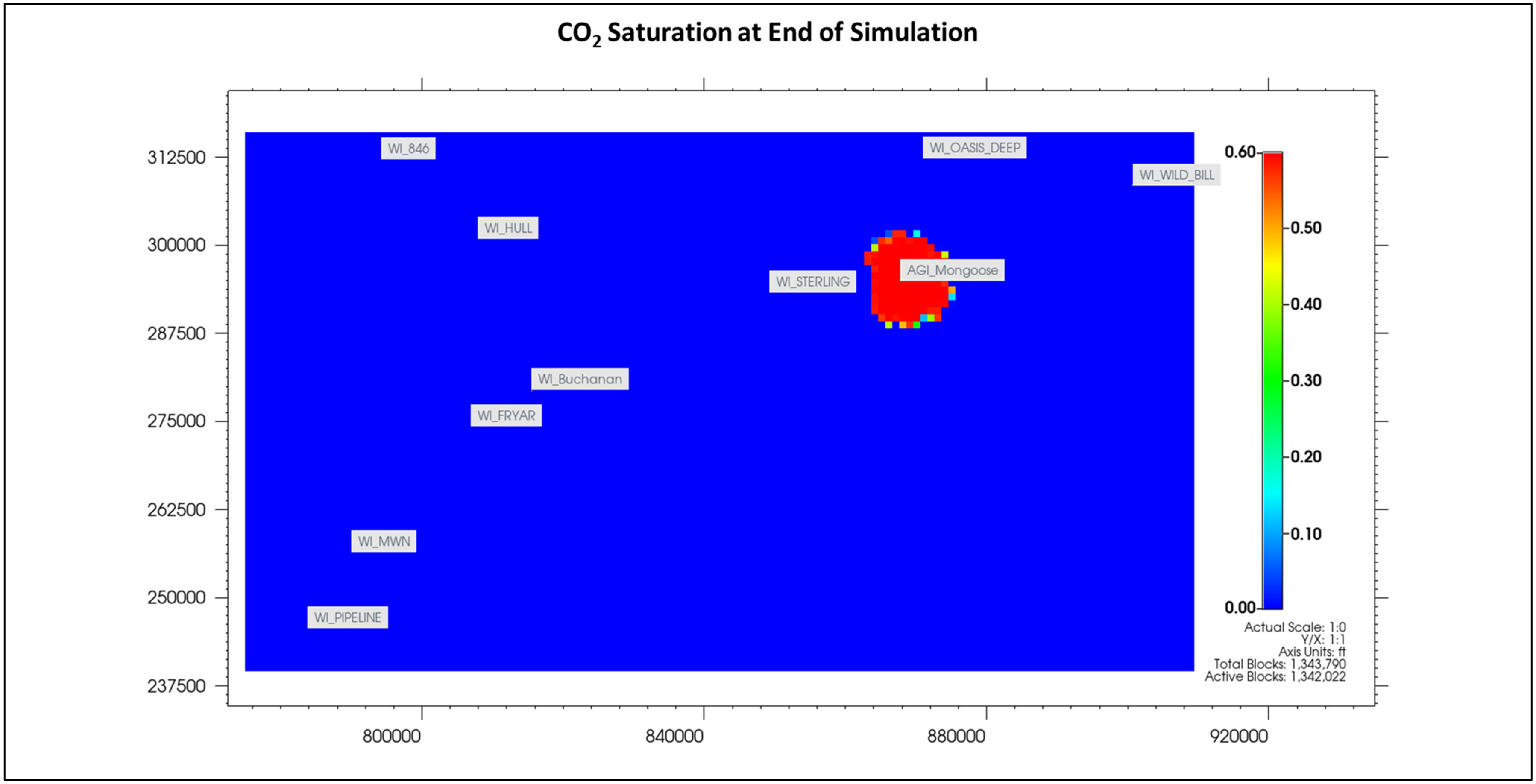


Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

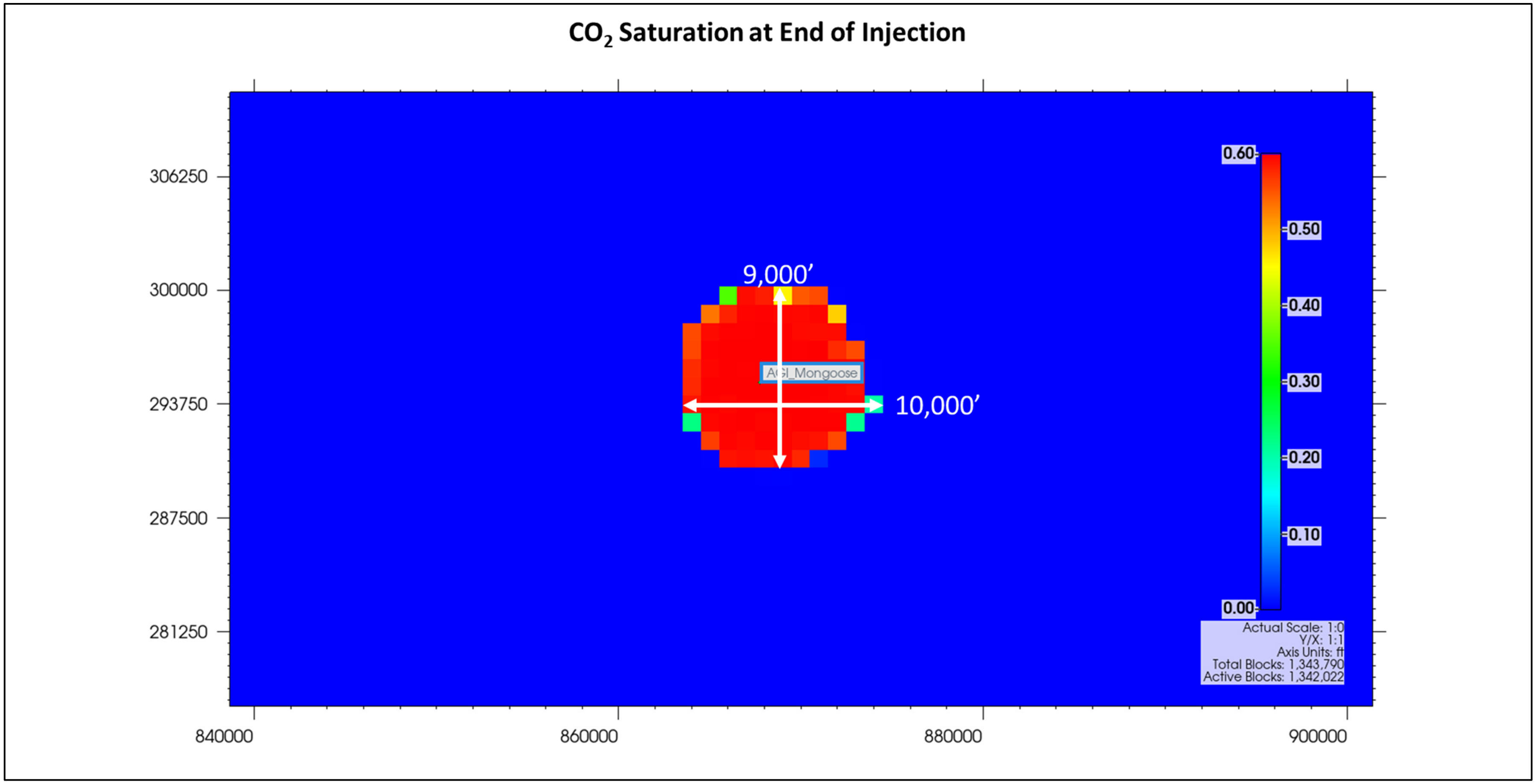


Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)

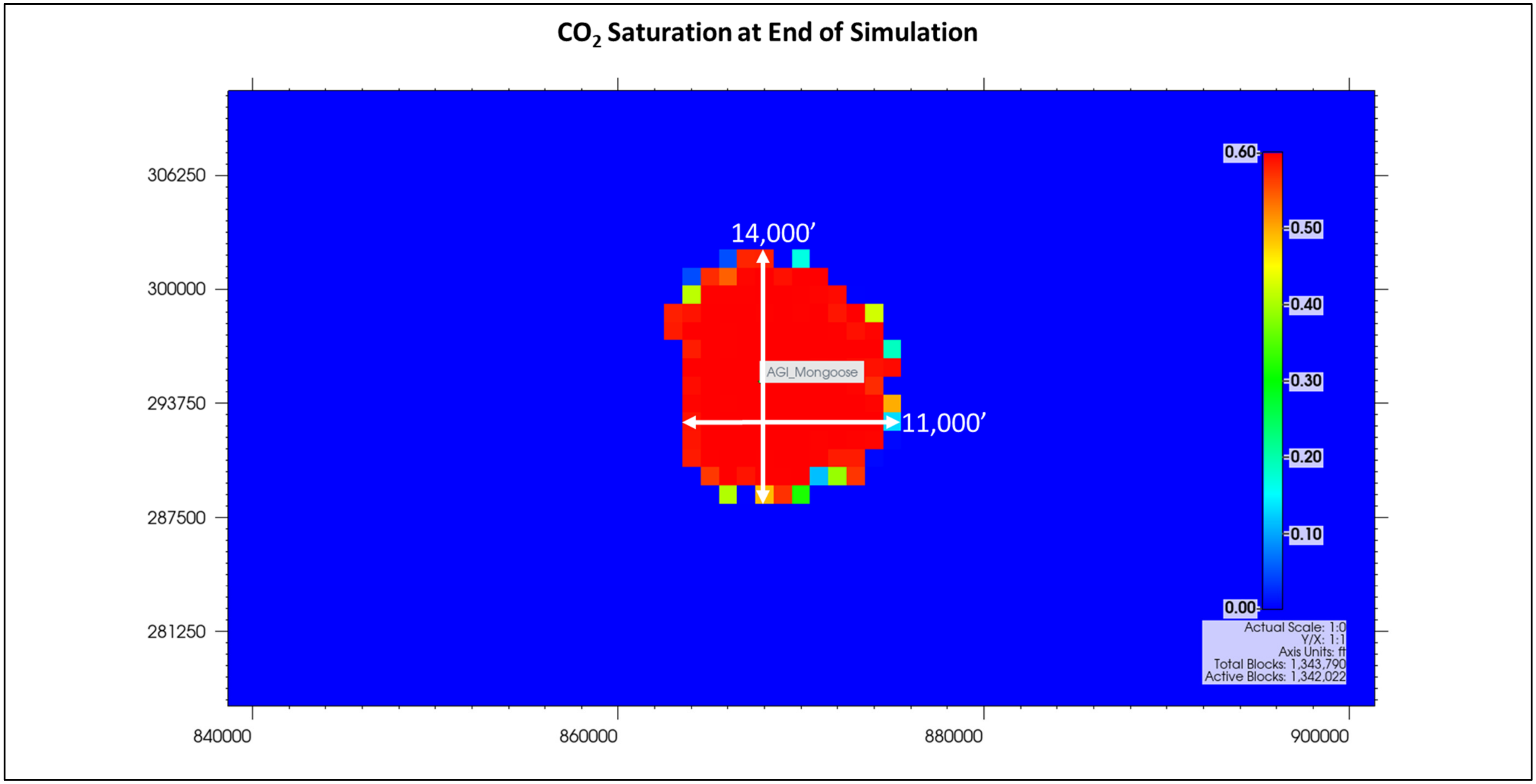


Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.

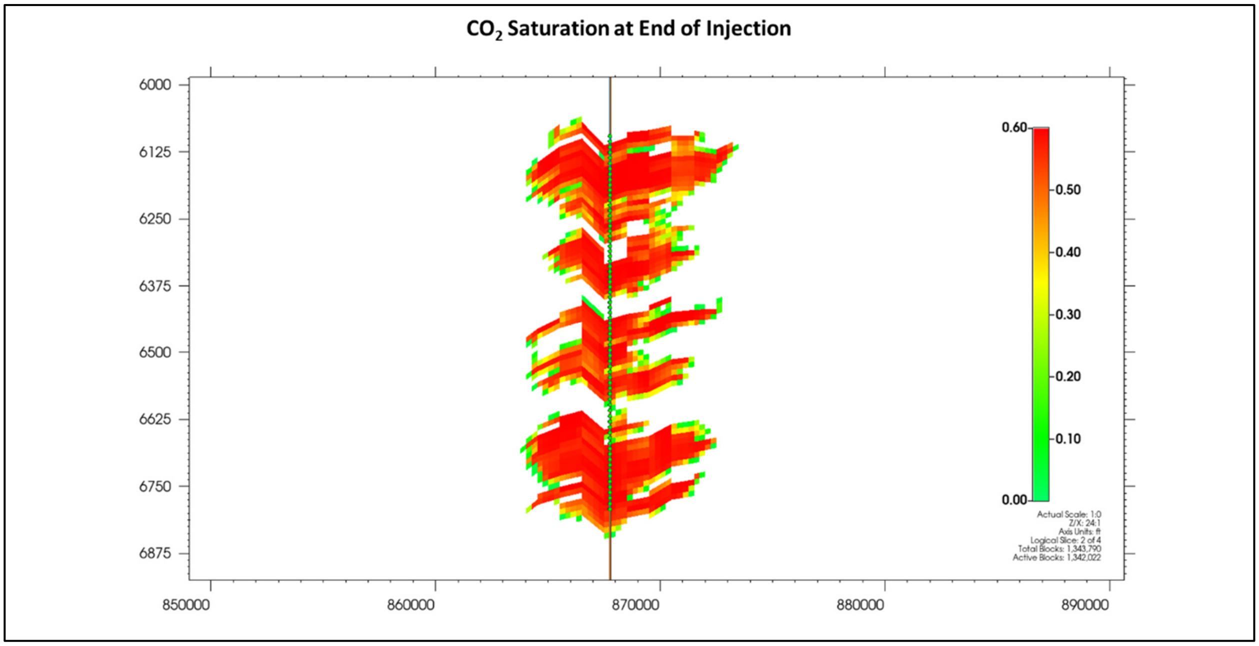


Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

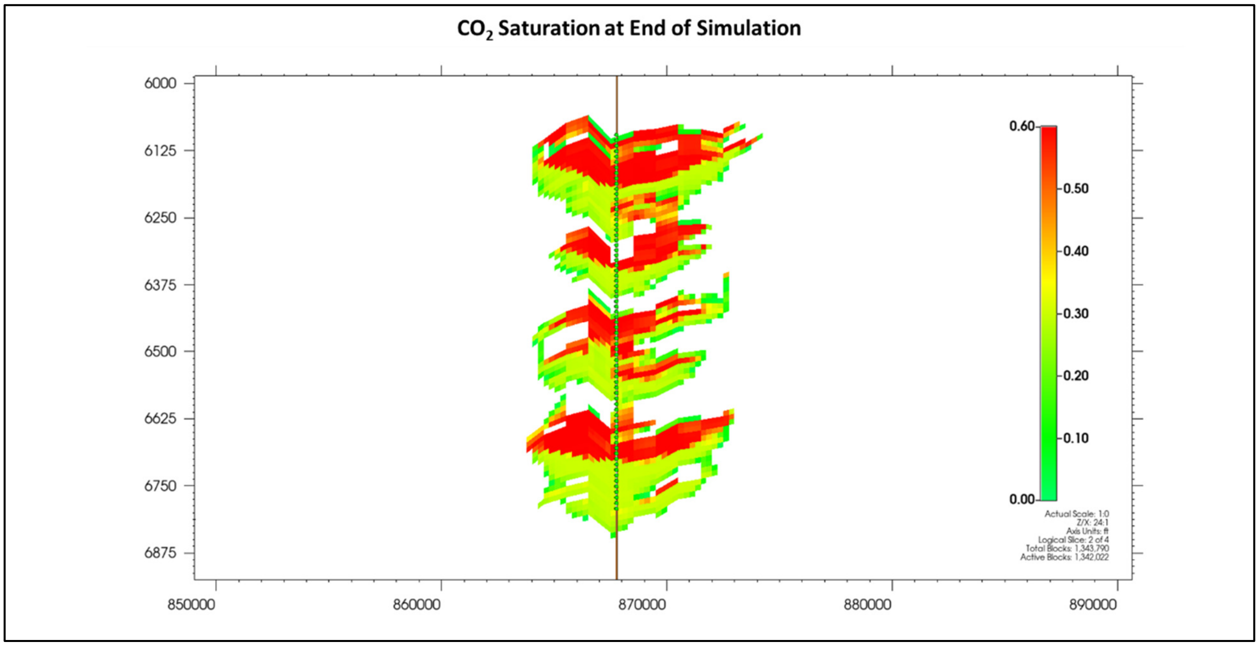


Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.

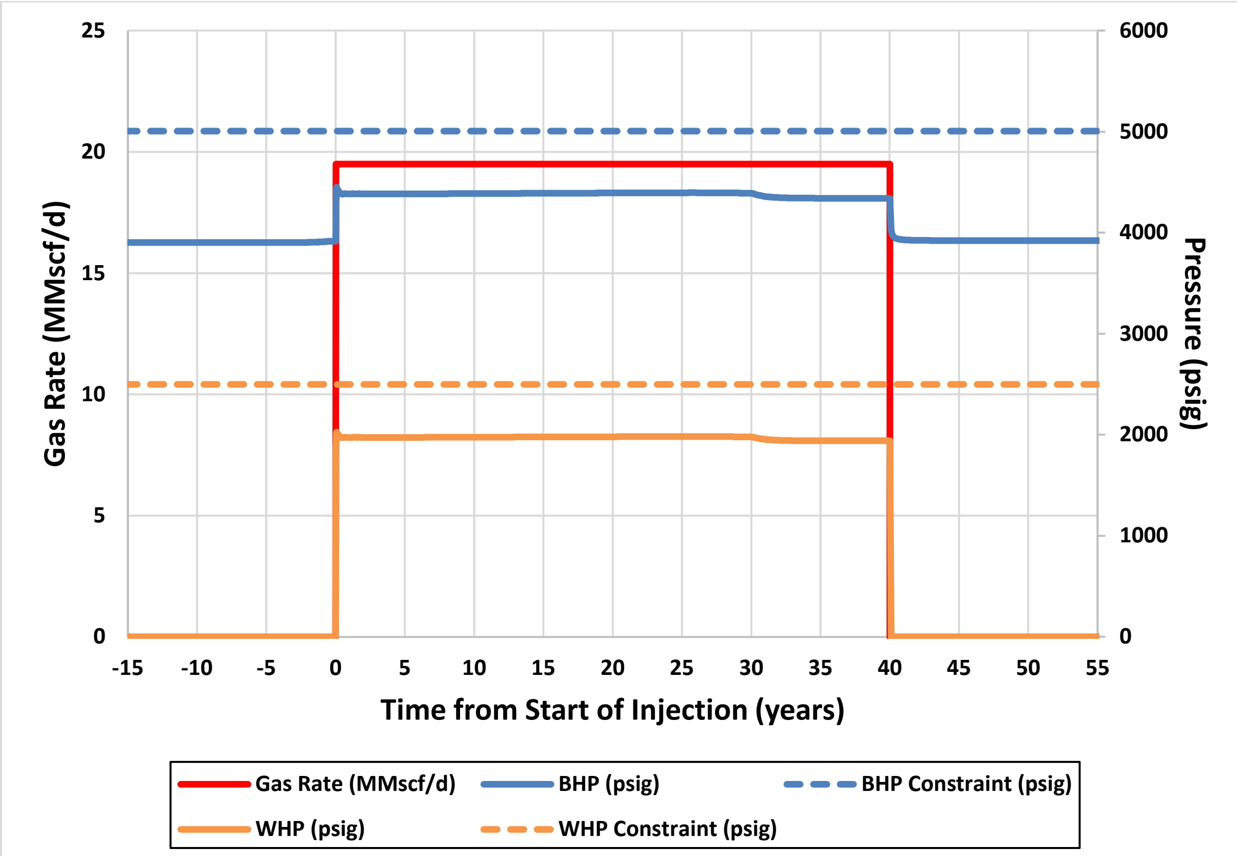


Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H_2S and 41.2% CO_2, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.

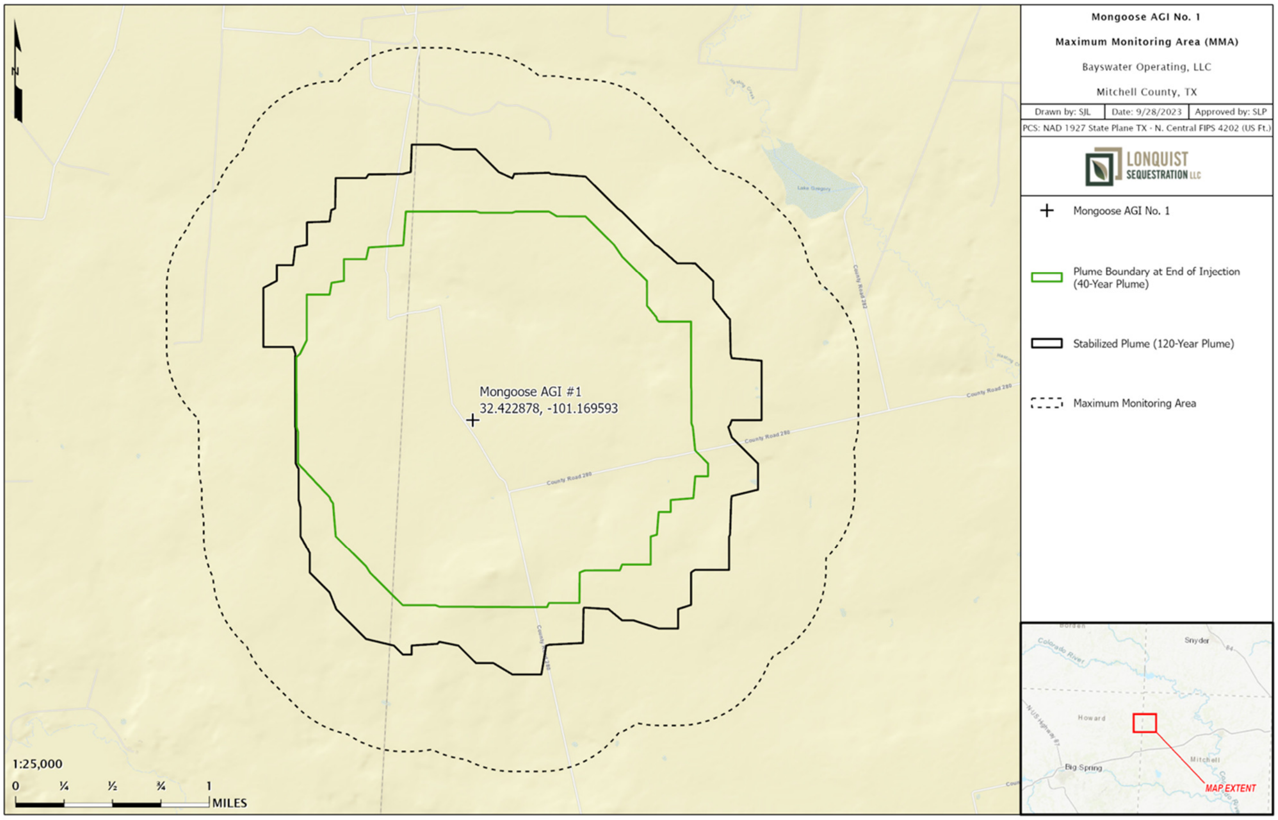


Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop their asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.

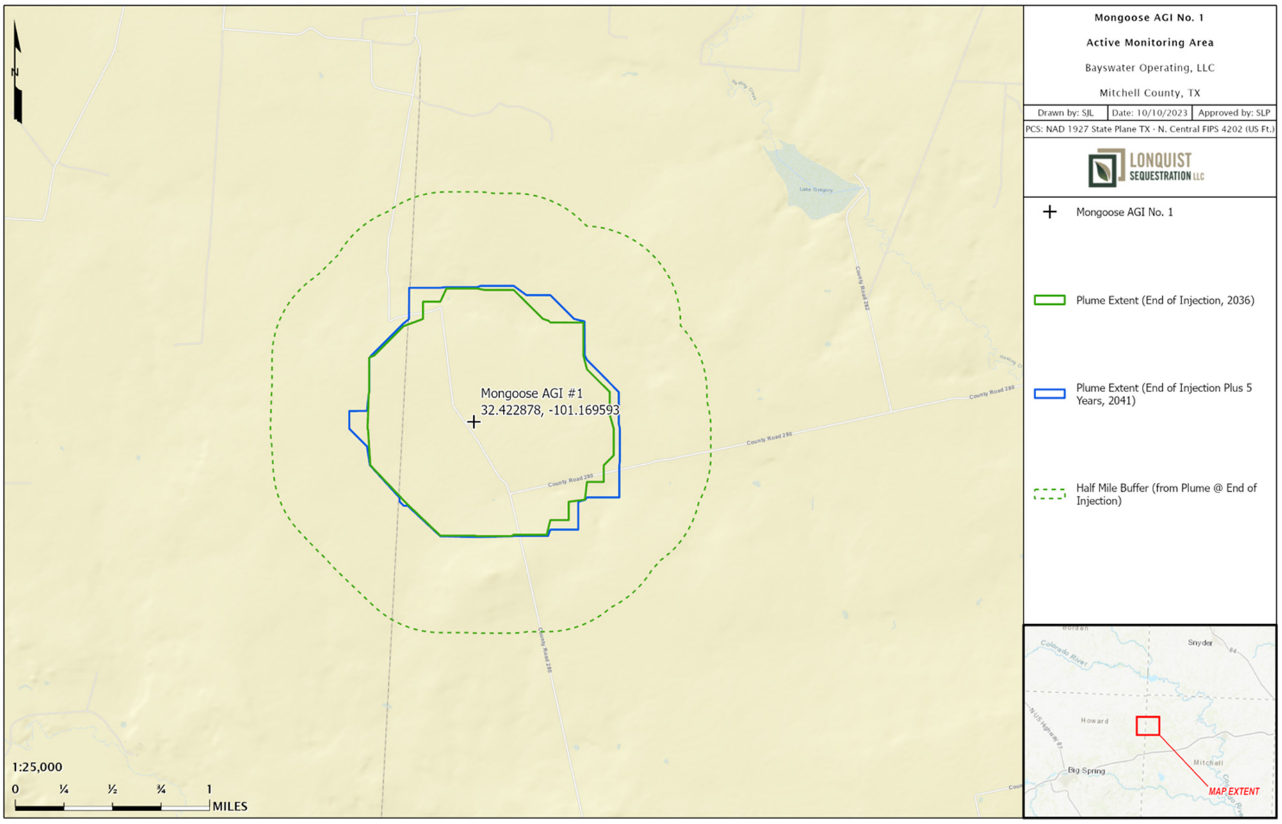


Figure 43 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

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

Table 12 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. The lateral continuity of the UCZ[1] is recognized as a very competent seal.	Low. Any vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care[2] period.
Faults and fractures	Possible. The lateral continuity of UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO_2 to the production zone.	During active injection and Post Injection Site Care period.

1 - UCZ is defined as the Upper Confining Zone.

2 - Post Injection Site Care is the period of time from the end of injection throught plume stabilization and site closure.

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

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with a fundamental objective to ensure maximum safety to the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H_2S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H_2S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the Mongoose, and gas monitors and the gas meter are called out in the detailed site plan in Appendix B-2. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs.

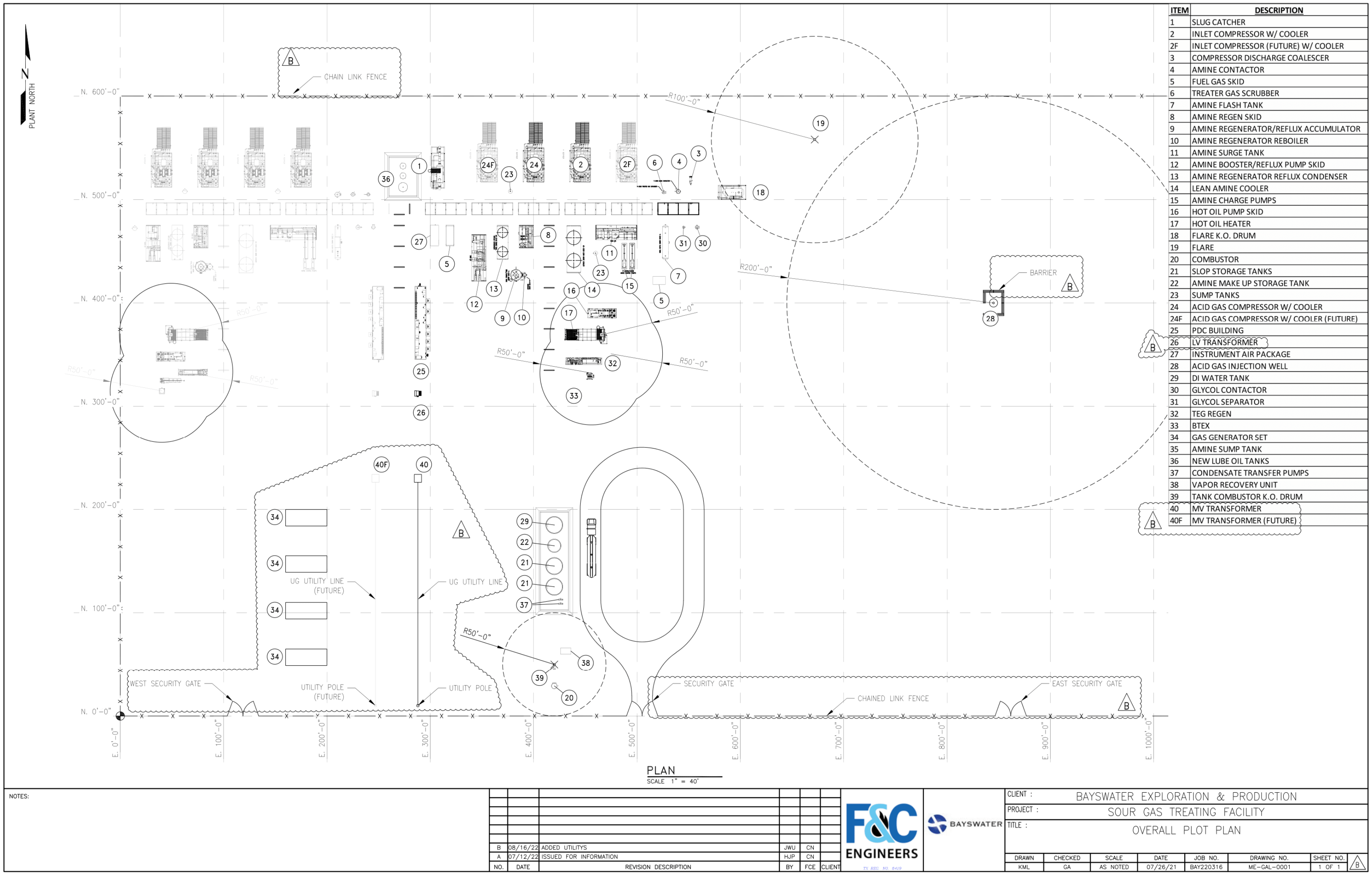
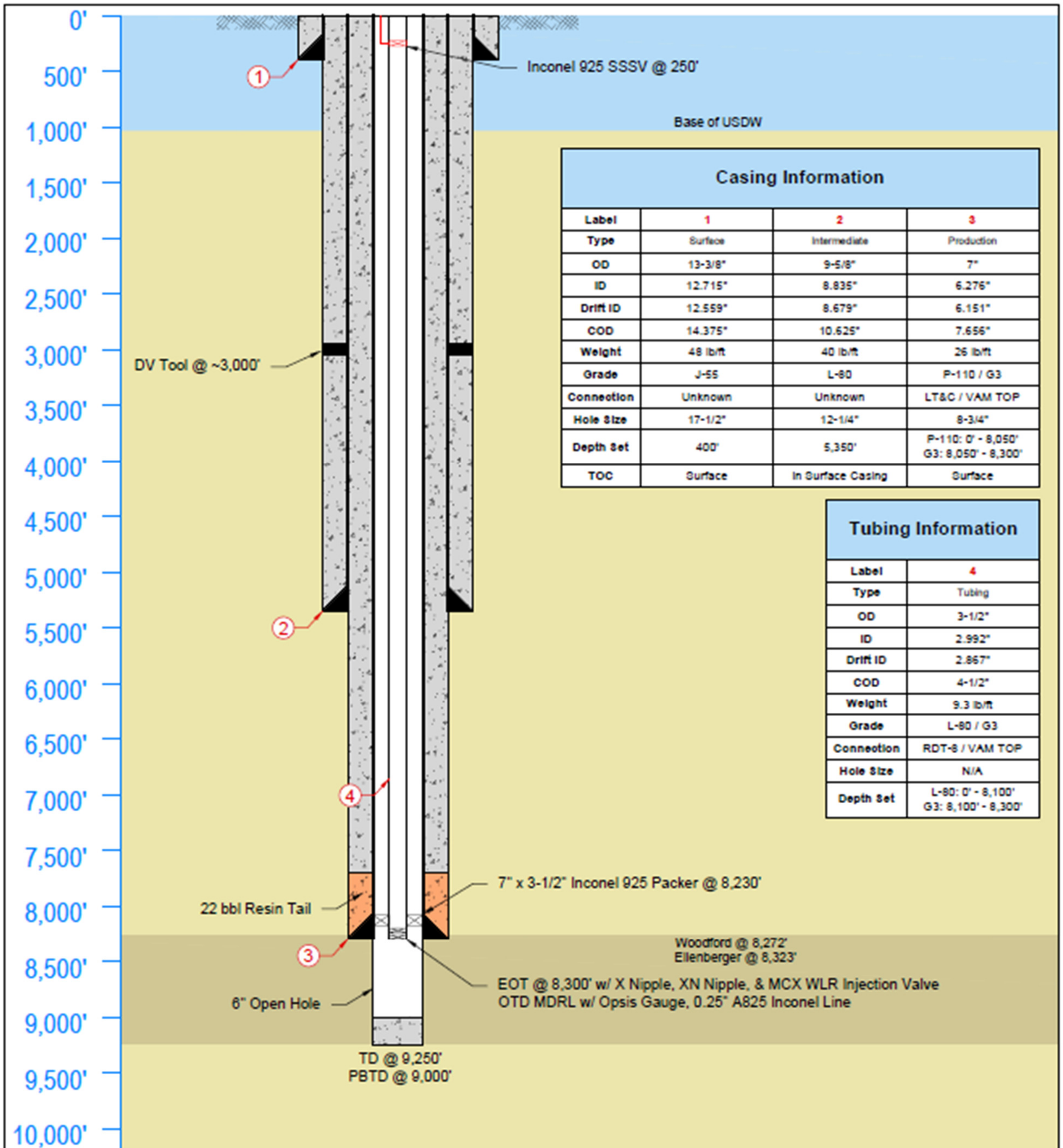


Figure 44 – Site Plan



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
ID	12.715"	8.835"	6.276"
Drift ID	12.559"	8.679"	6.151"
COD	14.375"	10.625"	7.656"
Weight	48 lb/ft	40 lb/ft	26 lb/ft
Grade	J-55	L-80	P-110 / G3
Connection	Unknown	Unknown	LT&C / VAM TOP
Hole Size	17-1/2"	12-1/4"	8-3/4"
Depth Set	400'	5,350'	P-110: 0' - 8,050' G3: 8,050' - 8,300'
TOC	Surface	In Surface Casing	Surface

Tubing Information

Label	4
Type	Tubing
OD	3-1/2"
ID	2.992"
Drift ID	2.867"
COD	4-1/2"
Weight	9.3 lb/ft
Grade	L-80 / G3
Connection	RDT-8 / VAM TOP
Hole Size	N/A
Depth Set	L-80: 0' - 8,100' G3: 8,100' - 8,300'

LONQUIST FIELD SERVICE	Bayswater Operating Company LLC	Mongoose AGI #1	
	Country: USA	State/Province: TX	County/Parish: Mitchell
	API No: 42-335-36013	Field: Sprayberry Trend	Well Type/Status: Acid Gas Injection
Texas License F-9147	RRC District No:	Project No: LS188	Date: 09/07/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved:
	Rev No: 1	Notes:	

Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possible other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix D*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO_2 will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix D* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in Section 2.2.2. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset AP's is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the effected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.

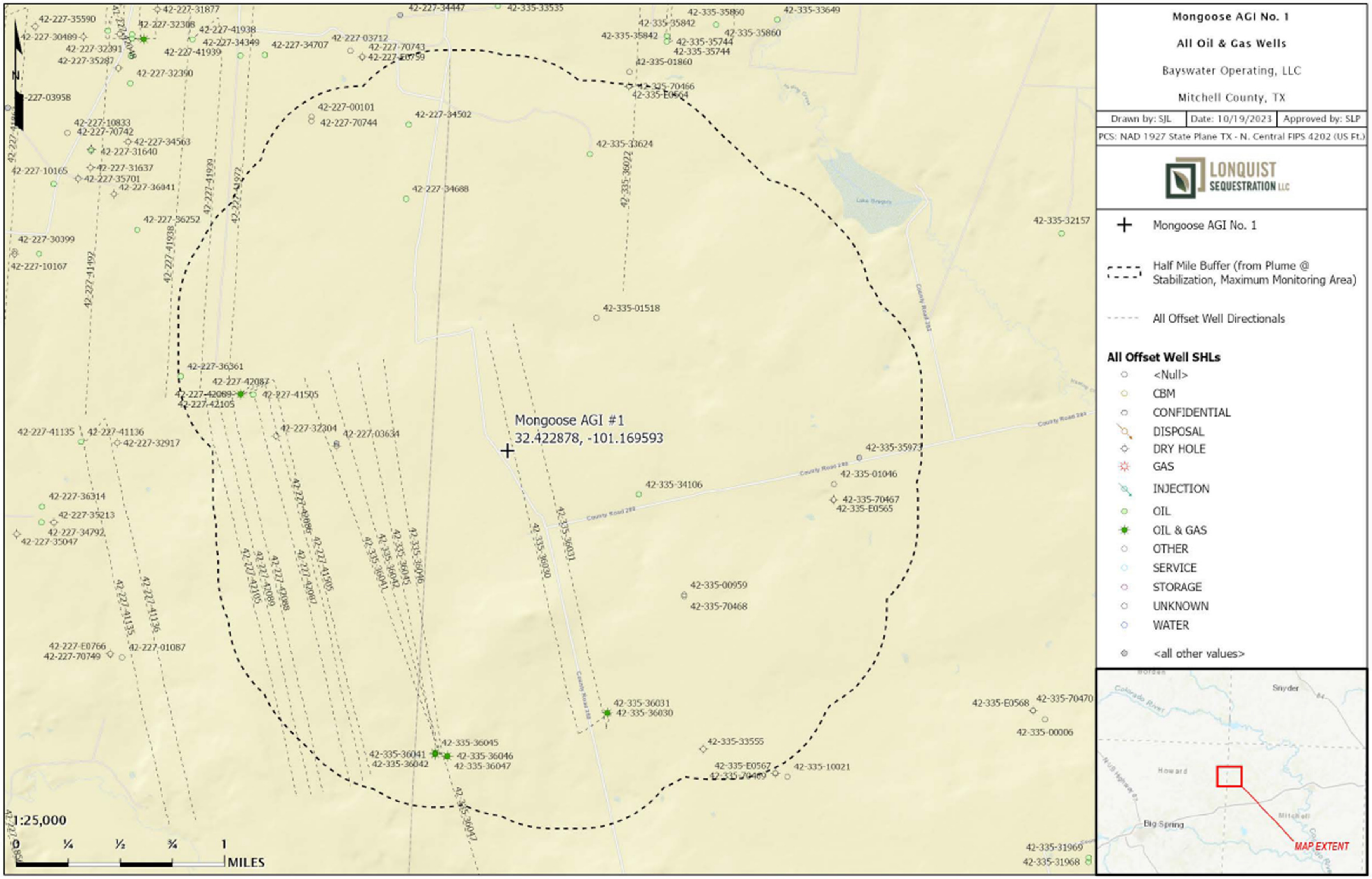


Figure 46 – All Oil and Gas Wells Within the MMA

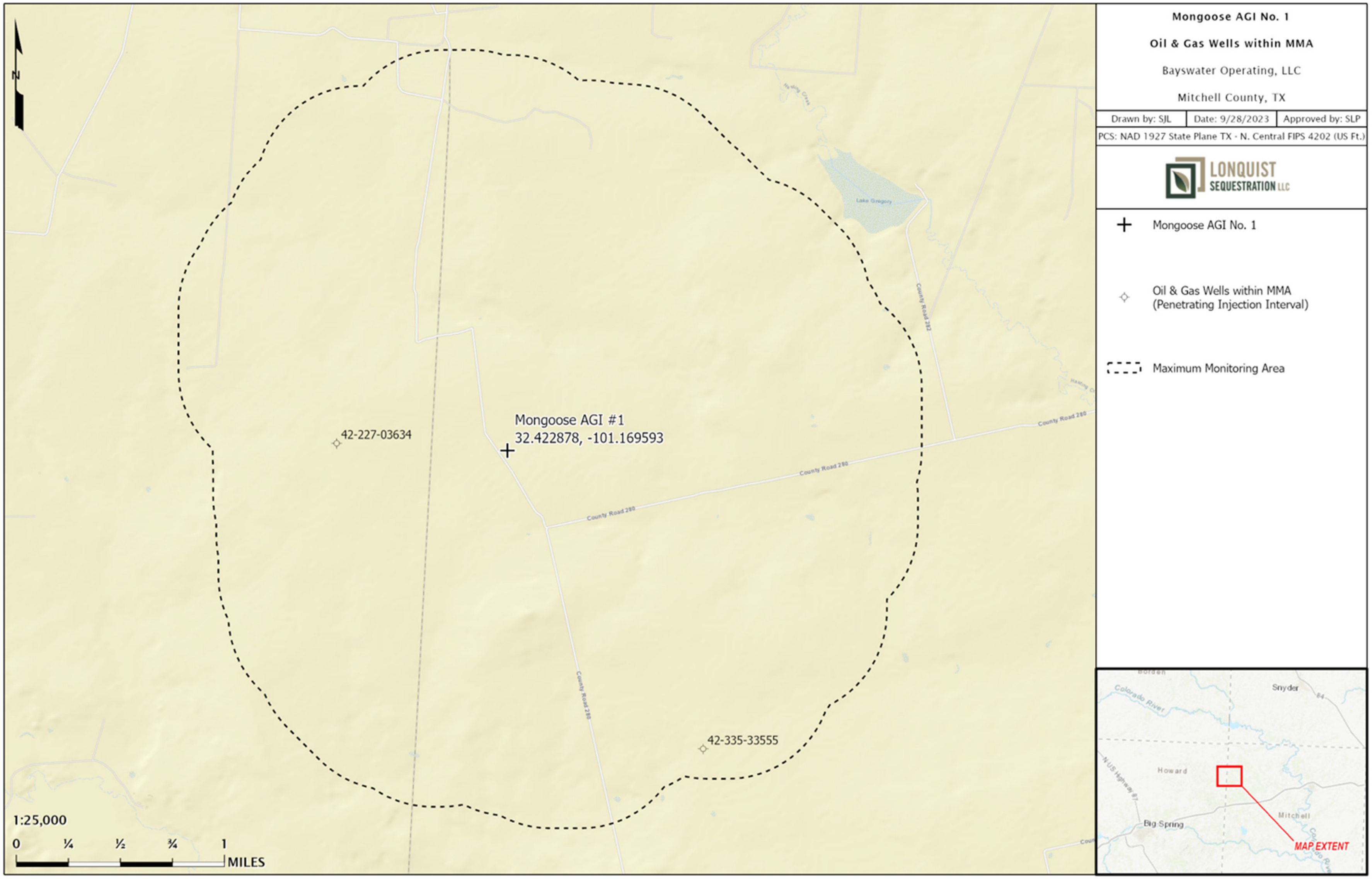


Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Mongoose drilling permit, provided in *Appendix A*, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a quarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued (also provided in the permit in *Appendix A*).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater acquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

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

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale that would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

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

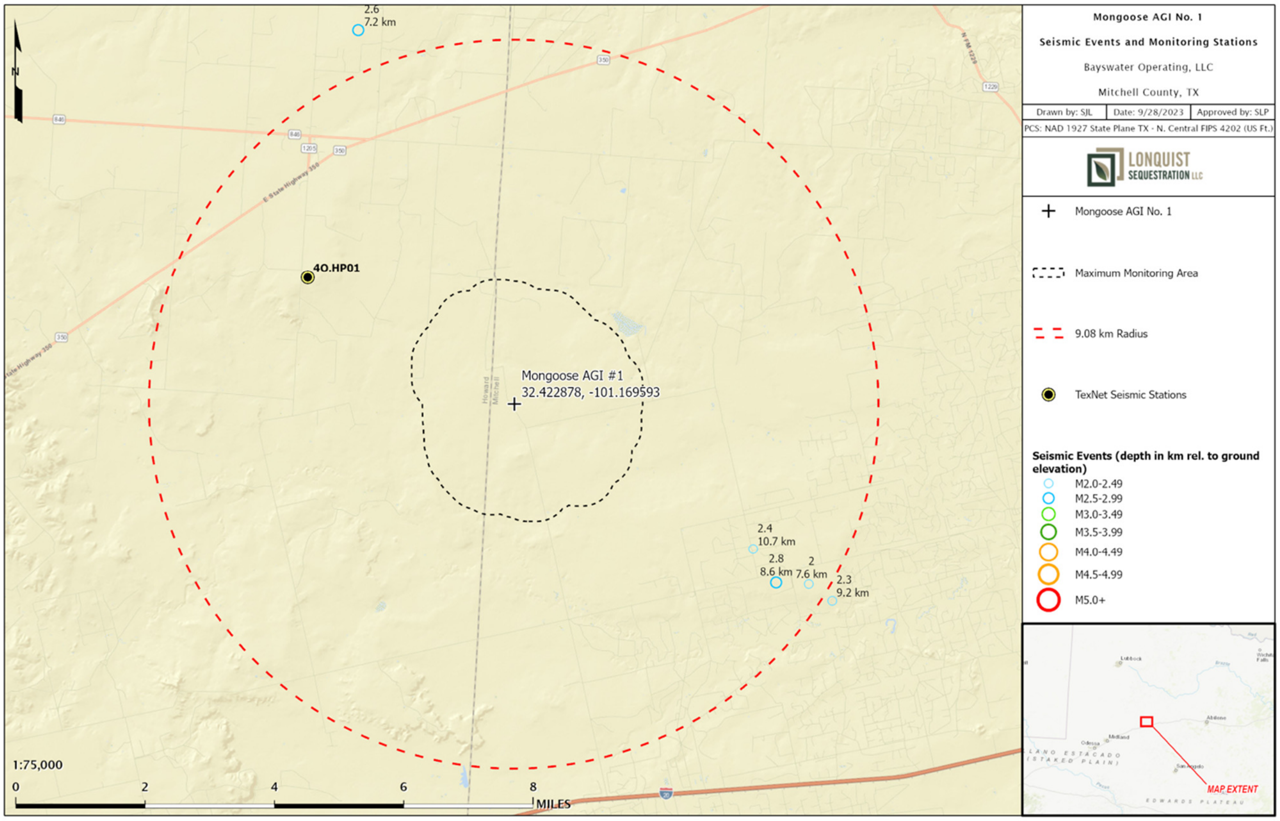


Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Table 13 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Visual inspections
	SCADA continuous monitoring of the AGI facility
Leakage through existing wells	SCADA continuous monitoring of the AGI well
	Monitor CO_2 levels in Above Zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Leakage from natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established during commissioning of the Plant. Ambient H_2S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix E*. The locations of H_2S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

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

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas sample will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above zone monitoring well. If any CO_2, migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario, but to use this as an indication of an event warranting further investigation.

5.2.1.1 Groundwater Quality Monitoring

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 Leakage Through Faults, Fractures, or Confining Seals

Bayswater continuously monitors the operations of the Mongoose well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO_2 content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO_2 content would be an early indicator of a potential issue. Should the CO_2 migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

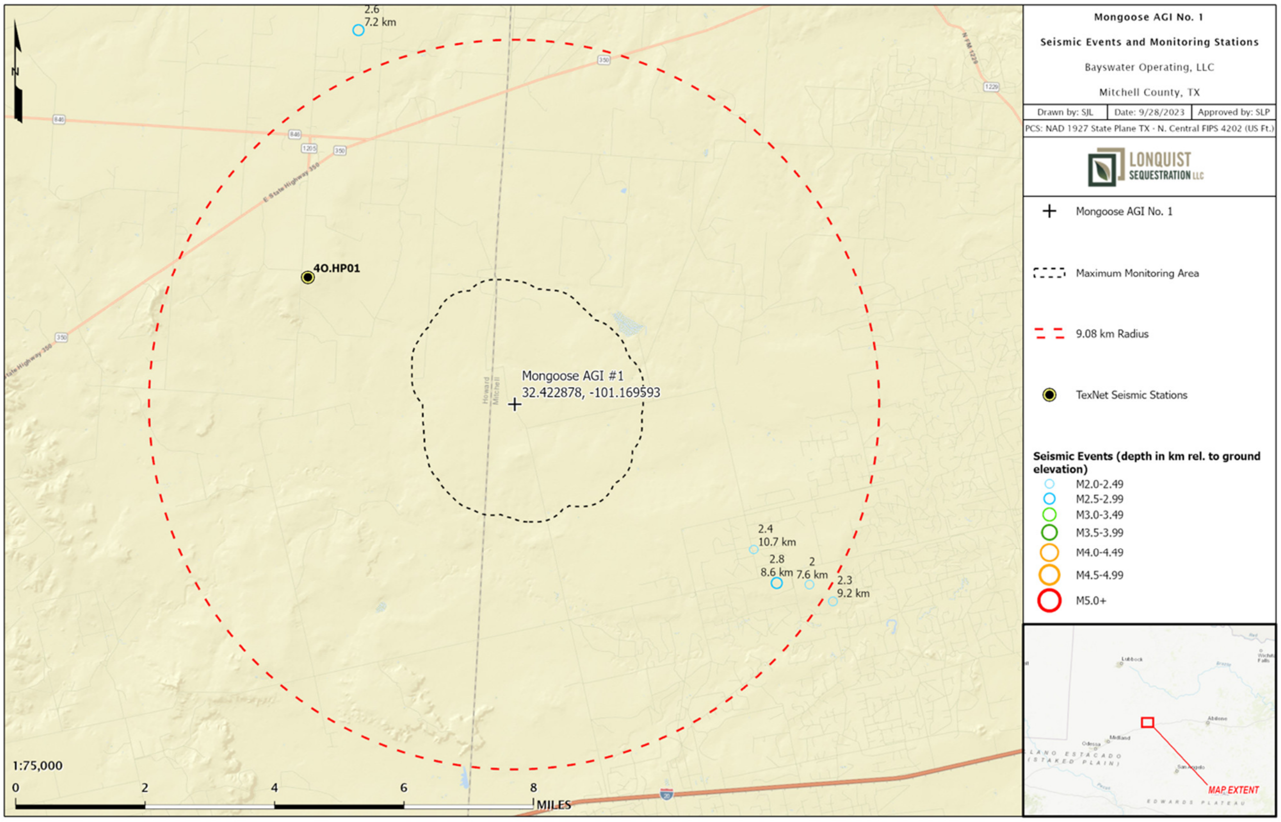


Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

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

6.2 CO_2/H_2S Detection

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H_2S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

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

7.2 Mass of CO_2 Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

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

7.4 Mass of CO_2 Emitted by Surface Leakage

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

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

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

Where:

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

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

X = Leakage pathway

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

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

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead

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

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Bayswater plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

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

CO_2 Emissions from Leaks and Vented Emissions

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

Measurement Devices

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

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

9.2 Missing Data

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

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

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

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Bayswater will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

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

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

SECTION 11 - REFERENCES

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APPENDICES

APPENDICES

APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN
WAYNE CHRISTIAN, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
DEPUTY EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS, P.E.
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17174

BAYSWATER OPERATING COMPANY LLC
730 17TH STREET
SUITE 500
DENVER CO 80202

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE
SPRABERRY (TREND AREA) FIELD
MITCHELL COUNTY
DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO_2); Hydrogen Sulfide (H_2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33536013	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.** **3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;

Note: This document will only be distributed electronically.

c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON March 10, 2023.

FOR Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	04 March 2022	**GAU Number:**	336979

Attention:	BAYSWATER OPERATING 730 17TH STREET SUITE 500 DENVER, CO 80202	**API Number:**	33536013
		County:	MITCHELL
		Lease Name:	Mongoose AGI
		Lease Number:	
Operator No.:	058827	**Well Number:**	1
		Total Vertical	9250
		Latitude:	32.422884
		Longitude:	-101.169661
		Datum:	NAD27

Purpose: Injection into Non-producing Zone (W-14)

Location: Survey-T&P RR CO; Abstract-1545; Block-29; Township-1N; Section-4

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 350 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 475 feet at the site of the referenced well.

This recommendation is applicable to all wells within a radius of 200 feet of this location.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 03/02/2022. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary. If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRICT * 08
API NUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03, 2022	COUNTY MITCHELL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 40
OPERATOR 058827 BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER, CO 80202-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (432) 684-5581
LEASE NAME MONGOOSE AGI		WELL NUMBER 1
LOCATION 10.4 miles NW direction from WESTBROOK		TOTAL DEPTH 10000
Section, Block and/or Survey SECTION 4 BLOCK 29 T1N ABSTRACT 1545 SURVEY T&P RR CO/MORRISON, W		
DISTANCE TO SURVEY LINES 551 ft. EAST 2164 ft. SOUTH		DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 400 ft. EAST 650 ft. SOUTH		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
SPRABERRY (TREND AREA) MONGOOSE AGI	40.00	10,000 0	1	08

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

A-4

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Submitted
Date: 09/11/2023
Tracking No.: 298516

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator BAYSWATER OPERATING COMPANY LLC **Operator** 058827
Operator 730 17TH STREET SUITE 500 DENVER, CO 80202-

WELL INFORMATION

API 42-335-36013
County: MITCHELL
Well No.: 1
RRC District 08
Lease MONGOOSE AGI
Field SPRABERRY (TREND AREA)
RRC Lease
Field No.: 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRISON, W, Abstract: 1545

Latitude 32.423000
Longitud -101.170059
This well is 10.4 **miles in a** NW
direction from WESTBROOK,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC
Completion or Recompletion 04/28/2023

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	02/10/2022	876754
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal		17174
Other:		

COMPLETION INFORMATION

Spud 10/12/2022
Date of first production after rig 04/28/2023
Date plug back, deepening, drilling operation 10/12/2022
Date plug back, deepening, recompletion, drilling operation 04/28/2023
Number of producing wells on this lease this field (reservoir) including this 1
Distance to nearest well in lease & reservoir
Total number of acres in 40.00
Elevation 2252 GL
Total depth TVD 9289
Total depth MD
Plug back depth TVD 9036
Plug back depth MD
Was directional survey made other inclination (Form W- Yes
Rotation time within surface casing 41.0
Is Cementing Affidavit (Form W-15) Yes
Recompletion or No
Multiple No
Type(s) of electric or other log(s) Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease
Off Lease : No
of lease on which this well is 400.0 **Feet from the** East **Line and**
650.0 **Feet from the** South **Line of the**
MONGOOSE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

	Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type
PACKET: N/A				

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination	**Depth**	350.0	**Date**	03/04/2022
SWR 13 Exception	**Depth**			

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		**Production**	
Number of hours	24	**Choke**	
Was swab used during this	No	**Oil produced prior to**	

PRODUCTION DURING TEST PERIOD:

Oil		**Gas**	
Gas - Oil	0	**Flowing Tubing**	
Water			

CALCULATED 24-HOUR RATE

Oil		**Gas**	
Oil Gravity - API - 60.:		**Casing**	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	569			C	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		C	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			C	610	1175.0	3001	Calculation
4	Conventional Production	7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL 925

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	Yes	L 8343	9036.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1	Other	OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H	9036	9289

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

OPERATOR'S CERTIFICATION

Printed	James Clark	**Title:**	Consulting Petroleum Engineer
Telephone	(512) 415-4191	**Date**	09/11/2023

A-5

0 0 0 0 5 7 0 7 0 8

- Return each W-1 with plat and $100.00 fee. Make a check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas, Oil and Gas Division, Drilling Permits, P. O. Drawer 12967, Capitol Station, Austin, Texas 78711
- File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS

Oil and Gas Division

Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

~~Cat 13~~

► Read Instructions on Back

Form W-1
Rev. 9/1/83
483-080

080 VMC

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: API No. 42-335-33555 Permit No. 379724 Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report)	3. RRC Operator No.	4. RRC District No.	5. County of Well Site
Bright & Company 10-18-90	093125	8	Mitchell

2. Address (including city and zip code)
3200 West Cuthbert, Suite 2-C
Midland, Texas 79701

6. Lease Name (32 spaces maximum)	7. RRC Lease/ID No.	8. Well No.	9. Total Depth
Van Tuyle	--	1	8500'

10. Location
- Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1-N~~ Abstract No. A-584
- This well is to be located 5 miles in a north direction from Iatan, which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.

12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

Granted 10/29/90

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
~~Wolfcamp (Wildcat)~~	~~5200'~~	~~467-1200~~	~~40~~	~~40~~	~~NO~~	~~NA~~	~~0~~	~~1~~	
~~Strawn (Wildcat)~~ per Tracey	~~7800'~~	~~467-1200~~	~~40~~	40	NO	NA	0	1	
~~Ellenburger~~ (Wildcat) 18001	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
- Lease/Unit 1000' FNL & 2500' FEL
- Survey/Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
- Lease/Unit Code C
- Survey/Section Code C @ 8500

23. Is this a pooled unit? Yes [ ] ► (Attach Form P-12 and certified plat.) No [X]

24. Is Item 17 less than Item 16 (substandard acreage for any field applied for)? Yes [X] ► (Attach Form W-1A) No [X]

25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ► If not filed, explain in Remarks.

26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? Yes [X] No [ ] If not, and if the well requires a Rule 37 or 38 exception, see instructions for Rule 37.

Remarks
W/C per Cindy 10/26/90

I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison — Signature
Tracy D. Tenison, Engineer — Name and title of operator's representative

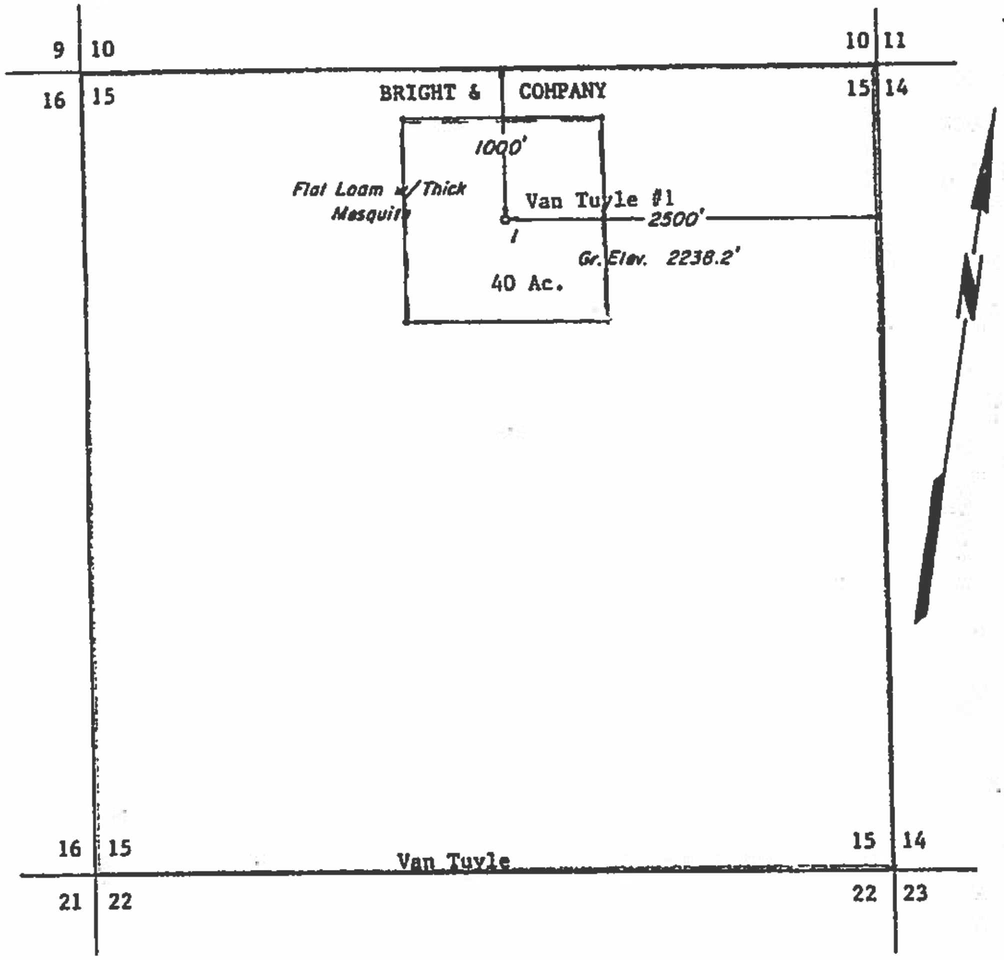
Date: 9/26/90 (mo. day yr.)
Tel: 915-697-2214 (Area Code Number)

► RRC Use Only ●

203091 OCT 1890

379724

335-33555



THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

OCT 1990

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON	TEXAS P.L.S. NO. 1883
GARY G. EIDSON	TEXAS P.L.S. NO. 4735
JERRY A. DUNN	TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES
MIDLAND TEXAS

Scale: 1" = 1000'	Drawn by: MED
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

0 9 0 5 7 0 7 1 0

020

▶ Return each W-1 with plat and $100.00 fee. Make a check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas, Oil and Gas Division, Drilling Permits, P. O. Drawer 12967, Capitol Station, Austin, Texas 78711
▶ File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1
Rev. 9/1/83
483-080

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ▶ API No. 42- ▶ Permit No. ▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): Bright & Company
2. Address (including city and zip code): 3200 West Cuthbert, Suite 2-C, Midland, Texas 79701
3. RRC Operator No.: 093125
4. RRC District No.: 8
5. County of Well Site: Mitchell
6. Lease Name (32 spaces maximum): Van Tuyle
7. RRC Lease/ID No.: --
8. Well No.: 1
9. Total Depth: 8500'
10. Location
• Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1 N~~ Abstract No. A-584
• This well is to be located 5 miles in a north direction from Iatan, which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.
12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well (Specify)	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
Wolfcamp (Wildcat)	5200'	467-1200	40	40	NO	NA	0	1	
Strawn (Wildcat)	7800'	467-1200	40	40	NO	NA	0	1	
Ellenburger (Wildcat)	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
• Lease/Unit 1000' FNL & 2500' FEL
• Survey Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
• Lease/Unit
• Survey/Section

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]
24. Is item 17 less than item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]
25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.
26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? If not, and if the well requires a Rule 37 or 38 exception, see instructions for Rule 37. Yes [X] No [ ]

Remarks

I certify that information stated in this application is true and complete, to the best of my knowledge.

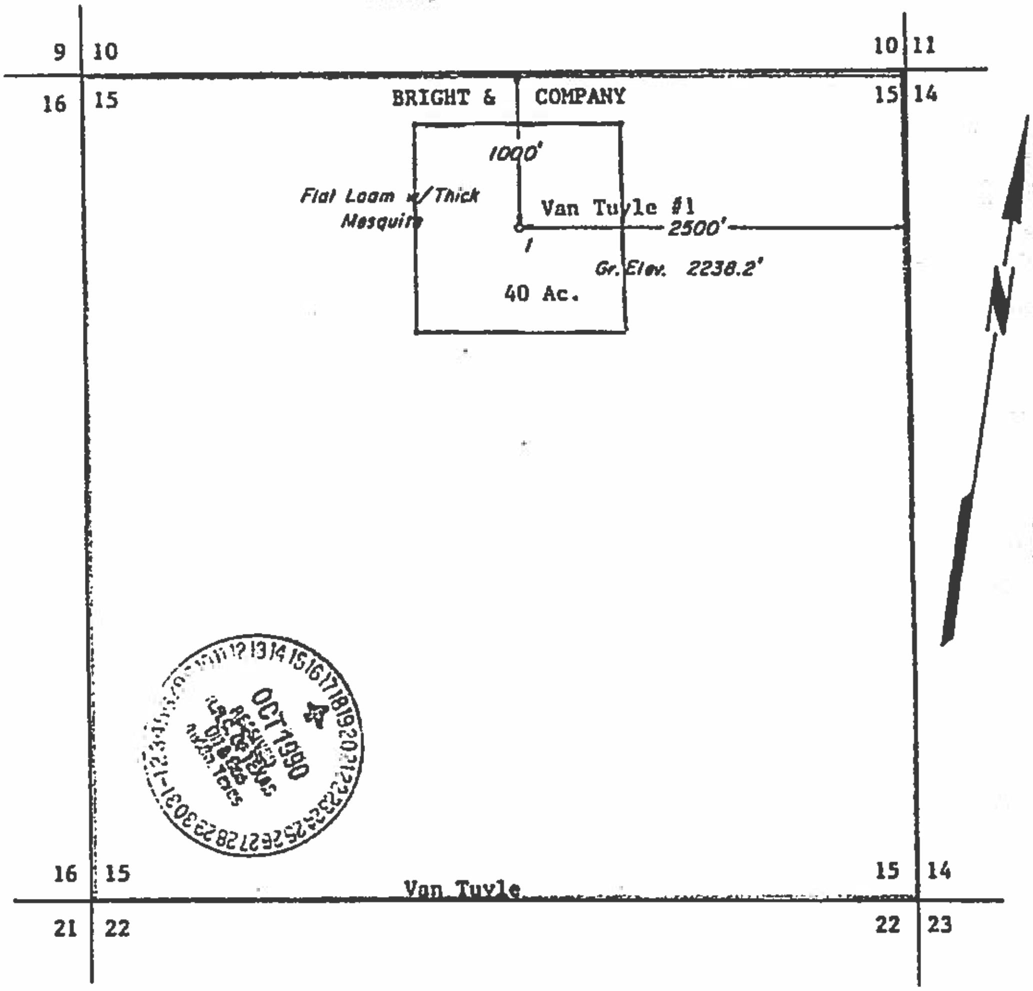
Tracy D. Tenison
Signature

Tracy D. Tenison, Engineer
Name and title of operator's representative

9/26/90
Date: mo. day yr.

915-697-2214
Tel.: Area Code Number

• RRC Use Only •



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DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON	TEXAS P.L.S. NO. 1883
GARY G. EIDSON	TEXAS P.L.S. NO. 4735
JERRY A. DUNN	TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1" = 1000'	Drawn by: NEG
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

WATER BOARD LETTER DATED 10-1990 1 2

Plugging Record Depth 350

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

13(A) Exception Dated N/A

13 3/8 - 361

API NO. 42-335-33555 (if available)

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

D.V. @

2. FIELD NAME (as per RRC Records): Wildcat	3. Lease Name: Van Tuyle	1. RRC District: 8
		4. RRC Lease or Id. Number:
		5. Well Number: 1
6. OPERATOR: Bright & Company	6a. Original Form W-1 Filed in Name of:	10. County: Mitchell
7. ADDRESS: 2911 Turtle Creek Blvd #700 Dallas, TX 75219	6b. Any Subsequent W-1's Filed in Name of:	11. Date Drilling Permit Issued: 10/18/90
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located	1000 Feet From north Line and 2500 Feet From east Line of the Van Tuyle Lease	12. Permit Number: 379724
9a. SECTION, BLOCK, AND SURVEY: Sec 15, Blk 29, T1N, T&P RR Co	9b. Distance and Direction From Nearest Town in this County: 8.7 miles NW of Westbrook	13. Date Drilling Commenced: 11/26/90
16. Type Well (Oil, Gas, Dry): Dry — Total Depth: 8360'	17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s — GAS ID or OIL LEASE # / Oil-O Gas-G / WELL #	14. Date Drilling Completed: 12/18/90
18. If Gas, Amt. of Cond. on Hand at time of Plugging		15. Date Well Plugged: 12-17-90

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	12-17	12-17	12-17	12-17	12-17			
20. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8			
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15			
*22. Sacks of Cement Used (each plug)	50	50	160	50	10			
*23. Slurry Volume Pumped (cu. ft.)	59	59	189	59	11.8			
*24. Calculated Top of Plug (ft.)	8076	2526	1792	325	Surf.			
25. Measured Top of Plug (if tagged) (ft.)			1790					
*26. Slurry Wt. #/Gal.	15.6	15.6	15.6	15.6	15.6			
*27. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.			

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
13-3/8	48	361	361	17-1/2
8-5/8	32	2274	2274	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well: Yes [ ] No [X]

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM 2274	TO 8360	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

APR 15 1991

Return to Central Records

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

D L Hamill
Signature of Cementer or Authorized Representative

Halliburton Services, Big Spring, TX
Name of Cementing Company

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

W. J. Morris — W. J. Morris — REPRESENTATIVE OF COMPANY | Agent — TITLE | 1/11/91 — DATE | Phone 214 550-0880 — A/C NUMBER

Did not Witness
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

RECEIVED
RRC OF TEXAS
MAR 05 1991
OIL & GAS
MIDLAND, TEXAS

/38

335-33555

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission [X] Yes [ ] No	32. How was Mud Applied? Drilling Rig	33. Mud Weight 9.1 LBS/GAL
34. Total Depth 8360 Depth of Deepest Fresh Water 210	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No 36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Halliburton, P. O. Box 380, Snyder, Texas 79549

Date RRC District Office notified of plugging 12/15/90

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Ben Van Tuyle, 432 Hilldale Dr, Ann Arbor, MI 48105

39. Was Notice Given Before Plugging to Each of the Above?

Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______ Date ______

Type Logs:

[ ] Driller's [X] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging ______ bbls*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ______

REMARKS ______

000 57 9713

[illegible]
Operator: Fill in other items.

Form W-15
Cementing Report
Rev. 4/1/83
483-046

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1. Operator's Name (As shown on Form P-5, Organization Report)	2. RRC Operator No.	3. RRC District No.	4. County of Well Site
Bright & Co.	093125	8	Mitchell

5. Field Name (Wildcat or exactly as shown on RRC records)	6. API No.	7. Drilling Permit No.
Wildcat	42- 335-33555	379724

8. Lease Name	9. Rule 37 Case No.	10. Oil Lease/Gas ID No.	11. Well No.
Van Tuyle			1

CASING CEMENTING DATA:	SURFACE CASING	INTERMEDIATE CASING	PRODUCTION CASING: Single String	PRODUCTION CASING: Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS: Tool	MULTI-STAGE CEMENTING PROCESS: Shoe
12. Cementing Date	[illegible]	[illegible]				
13. *Drilled hole size	17-1/2	11				
*Est. % wash or hole enlargement						
14. Size of casing (in. O.D.)	13-3/8	8-5/8				
15. Top of liner (ft.)						
16. Setting depth (ft.)	361	2274				
17. Number of centralizers used	3	3				
18. Hrs. waiting on cement before drill out	12	12				
1st Slurry — 19. API cement used: No. of sacks	390	300				
1st Slurry — Class	Premium Plus	Hall.Light Prem Plus				
1st Slurry — Additives	2% Calcium Chloride	2% CaCl2				
2nd Slurry — No. of sacks						
2nd Slurry — Class						
2nd Slurry — Additives						
3rd Slurry — No. of sacks						
3rd Slurry — Class						
3rd Slurry — Additives						
1st — 20. Slurry pumped: Volume (cu. ft.)	514.8	591				
1st — Height (ft.)	Surface	2268				
2nd — Volume (cu. ft.)						
2nd — Height (ft.)						
3rd — Volume (cu. ft.)						
3rd — Height (ft.)						
Total — Volume (cu. ft.)	514.8	591				
Total — Height (ft.)	Surface	2268				
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?	Yes	No				

RECEIVED
R.R.C. OF TEXAS
JAN 14 1991
O.G.
MIDLAND, TEXAS

22. Remarks

RECEIVED
R.R.C. OF TEXAS
MAR 05 1991

OIL & GAS DIV
MIDLAND TEXAS

OVER

[illegible] TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
[illegible]								
[illegible]. Size of hole or pipe plugged (in.)								
[illegible]. Depth to bottom of tubing or drill pipe (ft.)								
[illegible]								
[illegible]								
[illegible] top of plug (ft.)								
[illegible]. Measured top of plug, if tagged (ft.)								
[illegible]								
[illegible]								

[illegible] CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this [illegible] and that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my [illegible] and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. [illegible]

[illegible], Jr. Cementer | Halliburton | [signature]

[illegible] cementer's representative | Cementing Company | Signature

[illegible] 300 | Snyder, Texas 79549 | 915-573-3526 | 11-26-90

Address | City, State, Zip Code | Tel.: Area Code Number | Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data.

W. J. Morris | Agent | [signature]

Typed or printed name of operator's representative | Title | Signature

2911 Turtle Creek Blvd, #700, Dallas, TX 75219 | 214-559-0889 | 1/11/91

Address | City, State, Zip Code | Tel.: Area Code Number | Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For offshore operations, see the requirements of Rule 13 (c).

A. What to file. An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, Form W-2 or G-1, as required by Statewide or special field rules;
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, **in addition to Form W-3, to show any casing cemented in the hole.**

B. Where to file. The appropriate Commission District Office for the county in which the well is located.

C. Surface casing. An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. Centralizers. Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. Exceptions and alternative casing programs. The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F. Intermediate and production casing. For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. Plugging and abandoning. Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

R.R.C. Midland

Please Refer to File No.

Form 2A

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD
FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

8

Name of Company or Operator: The Texas Company — Address: Box 1720, Fort Worth, Texas

County: Howard — Survey: T&P RRCo. — Blk. 29 T-1-N — Sec. 4

Name of Lease: A. L. Wasson — No. of Acres: 1760 — Well No. 1 — Elev. 2300 (DF)

Located: Approx. 21 Miles NE Direction from Big Spring, Texas (Nearest P. O. or Town)

Name of Field in which well is located: Wildcat

Form 1, "Notice of Intention to Drill," was filed in name of: The Texas Company

Drilling Commenced: 12-28, 19 52, Drilling Completed: 3-28, 19 52

Has this well ever produced oil? No — or Gas? No

Character of Well (Oil, Gas or Dry): Dry — Total Depth: 8670'

Date you wish to Plug: 3-27-, 19 52

Name of Party Plugging Well: Livermore Drilling — Address: 610 Lubbock Nat'l Bank, Lubbock, Texas

Correspondence regarding this well should be sent to: Name: The Texas Company

Address: Box 1720, Fort Worth, Texas

CASING RECORD

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
13 3/8"	196		None		196		Texas Pattern
9 5/8"	2115		100		2015		Halliburton F & S

IF CASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS

Initial Production of Gas: Volume (MCF) None 24 hrs. Pressure None

Initial Production of Oil: Barrels None

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

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APR 10 1952
Railroad Commission of Texas
OIL & GAS DIVISION

NOTE: If no log available, so state and give all information that can be obtained as to total depth, casing record, formation, water sands, and as near as possible date well was drilled.

General Remarks: This well drilled to a total depth of 8670' without encountering oil or gas. We therefore desire to abandon salvage and plug well in the following manner: (Cut 9 5/8" casing at 100' and pull same) (Over)

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Caliche	0	100	At depth 206' cemented 13 3/8"
Red Beds	100	206	casing at 206' with 250 sacks.
Shale & Anhy	206	945	Cement circulated.
Anhy	945	1254	
Anhy & Shale	1254	1499	At depth 2125' cemented 9 5/8" casing
Anhy & Salt	1499	1750	at 2125' with 600 sacks.
Anhy & Shale	1750	1837	
Anhy	1837	1955	
Anhy & Lime	1955	2125	
Lime	2125	2290	
Lime & Shale	2290	2322	
Lime	2322	3116	
Lime & Shale	3116	3612	
Lime & Chert	3612	3820	
Lime & Sand	3820	3979	
Lime & Chert	3979	4155	
Lime & Sand	4155	4538	
Lime & Chert	4538	4900	
Lime & Sand	4900	5114	
Lime & Chert	5114	5232	
Lime & Shale	5232	6203	
Shale	6203	7953	
Lime & Chert	7953	8670	
Total Depth		8670	

All Measurements from Rotory Table or 12' above ground.

Remarks Cont'd

Using Heavy mud between plugs, spot the following cement plugs, 95 sacks 8670'-8373'; 15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7655'; 15 sacks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sacks 4680'-4630'; 15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1070'; 40 sacks. 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing.

Drill Stem Tests

DST # 1: Pkr. failed

DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 2250' salt water cut with drlg. mud.

DST # 3: 5100-5218, Tool open 1 1/2 hrs. Recovered 300' drlg. mud.

DST # 4: 5440-5485, Tool open 1 hr. Recovered 75' slightly gas cut drlg. mud.

DST # 5: 5902-6000, Tool open 1 hr. Recovered 100' drlg. mud.

DST # 6: 780[illegible], Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120' [illegible] gas cut drlg. mud.

DST # 7: 783[illegible] hrs., Recovered 5' drlg. mud & 180' slightly [illegible] mud.

Method of shutting off water: Cased off Is water completely shut off? Yes

Amount of water with oil: None per cent: None

I, T. P. [illegible] being first duly sworn [illegible] that I have knowledge of the facts and matter herein [illegible] and that the same are true and correct.

[signature]

Representative of Company.

Subscribed and sworn to before me this 7 day of April, 1952

[signature] W. E. BRUZEK

Notary Public

Midland County, Texas.

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A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.

DST # 10: 8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

Please Refer to
File No.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 4
Plugging Record

8

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company The Texas Company Address Box 1720, Ft. Worth, Texas

Sec. No. 4 Block No. 29 T-I-N Survey T & P RRCO County Howard

Well No. 1 Name of Lease A. L. Wasson No. of Acres 1760

Name of Field in which well is located Wildcat Date well was plugged 3-27- 19 52

Form 1 (Notice of Intention to Drill) Was Filed in Name of The Texas Company

Character of Well at the time of completion: Oil - bbls. (Initial Production); Gas - Cu. ft. (Initial Production); Dry Yes

Amount well producing when plugged: Oil None bbls.; Gas None Cu. ft.; Water None bbls.

Has this well ever produced oil or gas? No

Total Depth 8670 feet. Top of each producing sand - feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Thru drill pipe

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depths placed. Also amount of cement and rock. Was well shot? No

Spotted the following plugs: 95 sx 8670-8373, 15 sx 8213-8163, 15 sx 7860-7810, 15 sx 7705-7655, 15 sx 5600-5550, 15 sx 5430-5380, 15 sx [redacted] 50-25-4975, 15 sx 4680-4630, 15 sx 2810-2760, 15 sx 2093-2043, Cut off 9 5/8" casing @ 100' and pulled, spot 40 sx 1125-1070, 40 sx 1025-975, 40 sx 875-825, 30 sx in top of casing.

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: All 13 3/8" casing left in hole & 2015' 9 5/8" casing left in hole. All strata protected by casing left in hole or cassed of with cement.

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:
All adjacent property leased by The Texas Company

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, T. P. Drew, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name T P Drew Title Dist. Supt.

Subscribed and sworn to before me this 15 day of May, 19 52

[signature]

Notary Public Midland County, Texas

Correspondence regarding this well should be addressed to:

Name The Texas Company Address Box 1720, Ft. Worth, Texas

0 0022 .077

FORM W-1 (6/78)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

☐ Directional Well ☐ Amended or Corrected Permit

API Well No. 42
Instruction (7a&b) on back side.

RRC Permit Number, if previously assigned. 084247

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

Check one: ☐ DRILL ☐ DEEPEN (Below Casing) ☐ DEEPEN (Within Casing) ☐ PLUG BACK ☒ OTHER (Specify) re-entry

If Amended Application, explain fully in Remarks or Attach Separate Page.

1. Operator: McCann Corporation 538853	4. Lease Name and RRC Lease or ID No. (If Assigned): Stewart
2. Address (Including City and Zip Code): P. O. Box 448, Big Spring, TX 79720	5. Location (Sec., Blk., Survey): Sec. 4, Blk. 29, T-1-N, T & P RR Co.
	6. This well is to be located 4 miles Southeast Direction from Vincent, TX Nearest Post Office or Town.
3. Is Form P-5 (Organization Report) in Exact Operator Name Filed? YES ☒ NO ☐ (Instruction (2) on back side.)	

7. RRC District	8
8. County	Howard
9. Well Number	1
10. Number of Acres in Lease	640
11. Distance from Proposed Location to Nearest Property or Lease Line (ft.)	660'
12. Total Depth	4600'

EACH PROPOSED COMPLETION

REFER TO INSTRUCTIONS ON BACK SIDE. READ CAREFULLY AND FURNISH COMPLETE DATA.

13. FIELD NAME (Exactly as shown on R.R.C. Proration Schedule including Reservoir if applicable.) If Wildcat, so state below. 00018 001	14. Completion Depth	15. All Prior Rule 37 Exc. Case Numbers for this wellbore. If none, State None.	16. Applicable Field Rules Spacing Pattern. If no Rules, State 467-1200. (ft.)	17. Applicable Field Rules Density Pattern. If no Rules, State 40. (acres)	18. Number of Acres in Drilling Unit for this Well AND DESIGNATE ON PLAT.	19. Is this acreage presently assigned to another well in same field? (Yes or No; If yes explain in remarks.)	20. Distance and Direction from proposed location to nearest drilling completed or applied for well in same res. on same lease (ft.)	21. Is this a 1. Regular or 2. Rule 37 Exc. Location? Check the appropriate box.	22. Oil, Gas, or other Type Well (Specify)	23. Number of Wells or Permitted locations on this Lease in same Reservoir for which this Permit is Requested? OIL	GAS
Wildcat	4210'	None	467 / 1200	40	40	No	None	Regular 1 ☒ Rule 37 2 ☐	Oil	0	0
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			

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24. PERPENDICULAR LOCATION FROM TWO DESIGNATED:
A. Lease Lines 660' FWL & 1980' FNL
B. Survey Lines 660' FWL & 1980' FNL

25. (a) Is this wellbore subject to SWR 36? Yes ☒ No ☐
(b) If subject to SWR 36, has Form H-9 been filed? Yes ☒ No ☐
(If no, attach explanation.)

NOTICE
NO ALLOWABLE WILL BE ASSIGNED to any well which does not have sufficient surface casing to protect all fresh water sands. Where Commission rules do not specify surface casing requirements, it will be necessary to contact Texas Water Development Board, Austin, Texas, to ascertain the depth to which fresh water sands must be protected.

CERTIFICATE
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

REMARKS: Original Operator: The Texas Company
Original Lease Name: A.L. Wasson, Well #1.
Plugged and Abandoned: 3-27-52

Signature: Ellis W. Bills
Title: Administrative Assistant
Date: June 12, 1980
Telephone: Area Code 915 267-7415

READ INSTRUCTIONS ON BACK SIDE AND FURNISH COMPLETE DATA.

0 0022 0775

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. (if available) 42-227-00000

1. RRC District: 08

4. RRC Lease or ID Number:

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

2. FIELD NAME (as per RRC Records): Wildcat

3. Lease Name: Stewart

5. Well Number: 1

6. OPERATOR: McCann Corporation

6a. Original Form W-1 Filed in Name of: McCann Corporation

10. County: Howard

7. ADDRESS: P. O. Box 448, Big Spring, TX

6b. Any Subsequent W-1's Filed in Name of:

11. Date Drilling Permit Issued: 8-17-80

8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 660 Feet From West Line and 1980 Feet From North Line of the Stewart Lease

12. Permit Number: 084247

9a. SECTION, BLOCK, AND SURVEY: Sec. 4, Blk. 29, T-1-N, T&P RR Co.

9b. Distance and Direction From Nearest Town in this County: 4 miles SE of Vincent

13. Date Drilling Commenced: 10-10-80

16. Type Well (Oil, Gas, Dry): DRY

Total Depth: 1100

17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s

GAS ID or OIL LEASE #	Oil-O Gas-G	WELL #

14. Date Drilling Completed: 10-12-

18. If Gas, Amt. of Cond. on Hand at time of Plugging:

15. Date Well Plugged: 10-12-

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	10-12-80	10-13	10-13					
20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8					
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1100	250	Top Out					
*22. Sacks of Cement Used (each plug)	50	100	10					
*23. Slurry Volume Pumped (cu. ft.)	66	133	13					
*24. Calculated Top of Plug (ft.)	990	70	Surf.					
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	1.33	1.33	1.33					
*27. Type Cement	C	C	C					

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
8 5/8	24#	200	200	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well? ☐ Yes ☒ No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

[signature]
Signature of Cementer or Authorized Representative

Dowell Division of Dow Chemical Co.
Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Tom McCann — REPRESENTATIVE OF COMPANY
President — TITLE
April 9, 1981 — DATE
Phone 915 (A/C) 267-7488 (NUMBER)

Did Not Witness
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

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APR 20 1981
O.G.
MIDLAND, TEXAS

DR 80

[illegible] Was [illegible] filled with Mud-Laden Fluid, [illegible] to the regulations of the [illegible]? [X] Yes [ ] No	32. How was Mud Applied? Circulated		33. Mud Weight 8.[illegible] LBS/GAL
[illegible] Total Depth 1100	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No	
Depth of Deepest Fresh Water 150		36. If NO, Explain	

[illegible] Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well: Dowell Division of Dow Chemical Co. - Colorado City, TX

Date RRC District Office notified of plugging: 10-1[illegible]-85

[illegible] Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Danny Stewart - P. O. Box 26, Sterling City, Tx. 76951

[illegible] Was Notice Given Before Plugging to Each of the Above?

Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______ Date ______

Type Logs: [ ] Driller's [ ] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Was FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging None bbls*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ______

REMARKS ______

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[illegible]

ROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form W-15
(Rev. 1975)

CEMENTING REPORT

*1. Field Name (as per RRC Records or Wildcat): Wildcat	*2. RRC District: 08
*3. Operator: Mc Cann Corporation	*4. County: Howard
*5. Lease Name(s) and RRC Lease Number(s) or I. D. Number(s): Stewart	*6. Well Number: 1
*7. Location (Section, Block, and Survey): Sec. 4, Blk. 29, T-1-N, T&P RR Co. Survey	

CASING CEMENTING DATA:	SURFACE CASING	INTERMEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
8. Cementing Date						
*9. (a) Size of Drill Bit (inches)						
(b) Estimated % Wash or Hole Enlargement Used in Calculations.						
*10. Size of Casing (inches O.D.)						
*11. Top of Liner (if liner used) (ft.)						
*12. Setting Depth of Casing (ft.)						
13. Type API Class Cement & Amount of Additives Used: (a) In First (Lead) or Only Slurry (if additional space is needed, use "REMARKS" on reverse side.)						
(b) In Second Slurry						
(c) In Third Slurry						
14. Sacks of Cement Used: (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Sacks of Cement Used						
15. Slurry Volume per Sack of Cement (cu.ft./sack): (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
16. Volume of Slurry Pumped: (cu.ft.) (Item 14 x Item 15) (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Slurry Volume Pumped (cu.ft.)						
17. Calculated Annular Height of Cement Slurry behind Pipe (ft.)						
18. Was cement circulated to ground surface (or bottom of cellar) outside casing? (Yes or No)						

CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6
19. Cementing Date	10-12-80	10-13-80	10-13			
*20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8			
*21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1000	250	Top Out			
22. Sacks of Cement Used (each plug)	50	100	10			
23. Slurry Volume Pumped (cu. ft.)	66	133	13			
24. Calculated Top of Plug (ft.)	990	70	Surf.			
*25. Measured Top of Plug (if tagged) (ft.)						

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APR 20 1981
MIDLAND, TEXAS

(CEMENTING COMPANY AND OPERATOR MUST COMPLY WITH THE INSTRUCTIONS ON REVERSE SIDE HEREOF.)

— OVER —

* Designates items to be completed by Operator. Items not so designated shall be completed by Cementing Company.

Remarks:

*27. Remarks:

CEMENTING COMPANY

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

P.N. Shackelford
Signature of Cementer or Authorized Representative

P. N. Shackelford, Sr.District Clerk
Name of Person and Title (type or print)

Dowell Division of Dow Chemical Co.
Cementing Company

Route 3, Box 178
Street Address or P.O. Box

Colorado City, Tx 79512
City, State — Zip Code

Telephone 915 728-5291
Area Code

10-14-80
Date

*OPERATOR

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data and information presented herein.

Tom McCann
*Signature of Operator or Authorized Representative

Tom McCann - President
*Name of Person and Title (type or print)

McCann Corporation
*Operator

P. O. Box 448
*Street Address or P.O. Box

Big Spring, Texas 79720
*City, State — Zip Code

*Telephone 915 267-7488
Area Code

4-6-81
*Date

INSTRUCTIONS

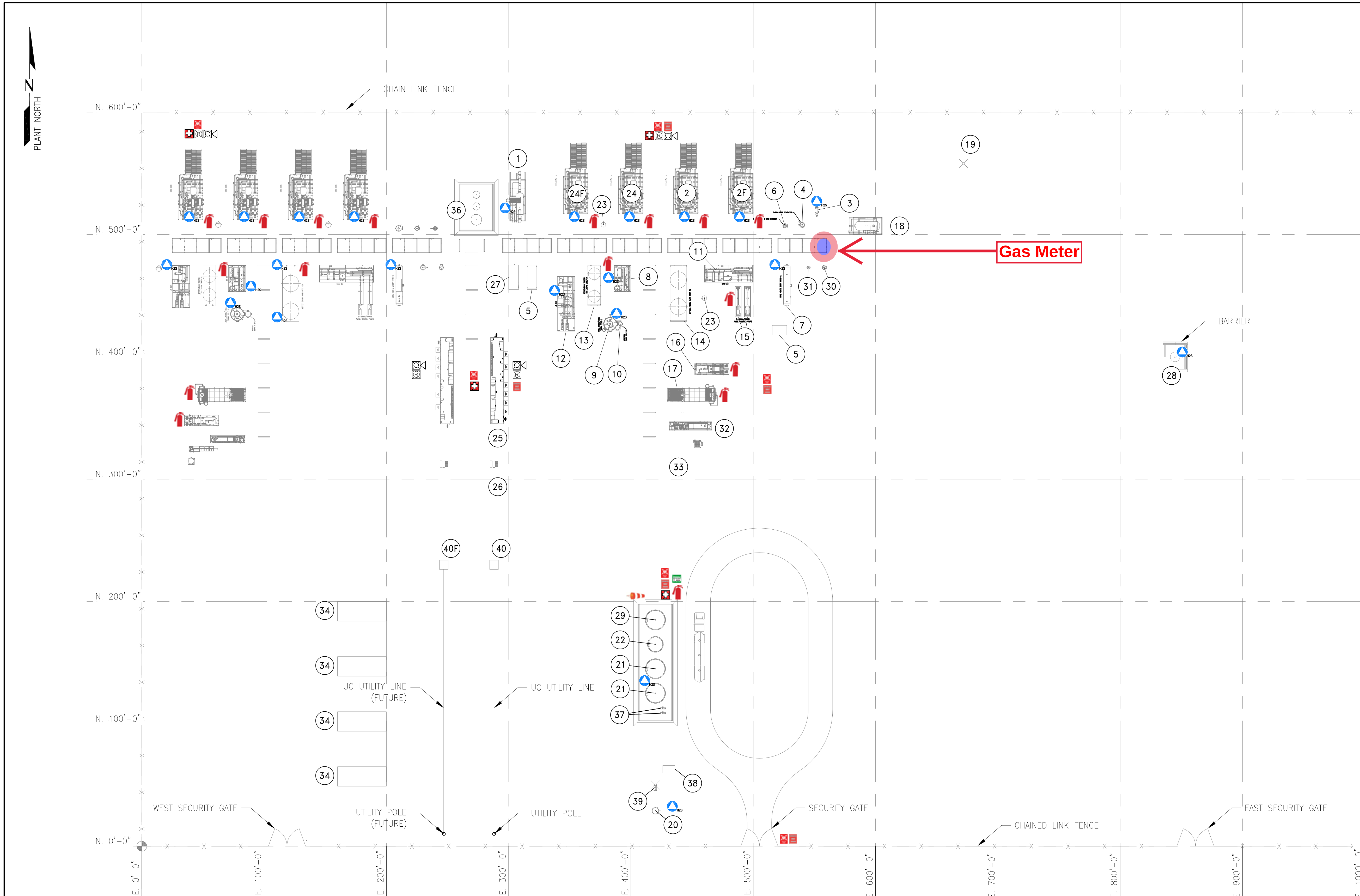
1. A. This form shall be filed by the operator in the RRC District Office with:
   (1) Each copy of an initial Form G-1 or W-2 if a cementing report is required by Statewide or Special Rules, or if exception is needed to cementing requirements in Statewide or Special Rules;
   (2) Each copy of Form W-3;
   (3) Each copy of Form W-4 if a multiple parallel casing completion.
   B. At least an original and one copy of this form shall be filed for each cementing company used on a well.
   C. The cementing of different casing strings on a well by one cementing company may be consolidated on one form (to be filed in duplicate)
2. Cementing Company and Operator shall comply with the applicable portions of Statewide Rules 8, 13, and 14. For offshore operations, Cementing Company and Operator shall comply with Statewide Rule 13(E).
3. If setting FULL AMOUNT OF SURFACE CASING
   A. Depth to protect fresh water determined by:
   (1) Fi[illegible] Rule
   (2) T[illegible]s Water Development Board, if no Field Rule
   B. Set surface casing below depth to be protected and cement from casing shoe to ground surface.
4. IF SETTING ANYTHING OTHER THAN THE FULL AMOUNT OF SURFACE CASING, PERMISSION SHALL BE OBTAINED FROM THE RAILROAD COMMISSION.
5. If setting NO SURFACE CASING (See Item 4 above.):
   A. If no multi-stage tool is used, the next deeper casing string shall be cemented from the casing shoe to the surface.
   B. If using the multi-stage tool on the next deeper string, cement from the depth that protects fresh water sands to the surface.
6. If setting SHORT SURFACE CASING (See Item 4 above.):
   A. Cement short surface casing from the shoe to the surface.
   B. Whether the multi-stage tool is or is not used on the next deeper casing string, cement from the depth that protects fresh water sands to
   (1) the surface, or
   (2) a point midway between shoe of surface string and the surface. Compliance will be considered if a temperature survey shows that the top of the cement is at least one-third of the distance from the shoe of the surface string to the surface.
7. Setting PRODUCTION STRING of Casing: (Statewide Rules, Special Rules may vary.)
   A. Cement to a point at least 600 feet above the casing shoe.
   B. When 3,000 feet or more of pipe is set for the production or protecting string, a minimum of 30 feet of cement shall be left inside the pipe
8. PLUGGING and ABANDONING:
   A. Cement plugs shall be placed in the well bore as required by Rules and Regulations of the Commission plus any additional plugs as may be specified by the RRC District Director.
   B. The minimum amount of cement normally used in each plug shall be a slurry volume equal to the amount necessary to fill the calculated volume of 100 feet of the hole in which the plug is placed.
   C. A 10 foot cement plug is required to be placed in the top of the well.

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H_2S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.

B-2



PLAN
SCALE 1" = 40'

ITEM	DESCRIPTION
1	SLUG CATCHER
2	INLET COMPRESSOR W/ COOLER
2F	INLET COMPRESSOR (FUTURE) W/ COOLER
3	COMPRESSOR DISCHARGE COALESCER
4	AMINE CONTACTOR
5	FUEL GAS SKID
6	TREATER GAS SCRUBBER
7	AMINE FLASH TANK
8	AMINE REGEN SKID
9	AMINE REGENERATOR/REFLUX ACCUMULATOR
10	AMINE REGENERATOR REBOILER
11	AMINE SURGE TANK
12	AMINE BOOSTER/REFLUX PUMP SKID
13	AMINE REGENERATOR REFLUX CONDENSER
14	LEAN AMINE COOLER
15	AMINE CHARGE PUMPS
16	HOT OIL PUMP SKID
17	HOT OIL HEATER
18	FLARE K.O. DRUM
19	FLARE
20	COMBUSTOR
21	SLOP STORAGE TANKS
22	AMINE MAKE UP STORAGE TANK
23	SUMP TANKS
24	ACID GAS COMPRESSOR W/ COOLER
24F	ACID GAS COMPRESSOR W/ COOLER (FUTURE)
25	PDC BUILDING
26	LV TRANSFORMER
27	INSTRUMENT AIR PACKAGE
28	ACID GAS INJECTION WELL
29	DI WATER TANK
30	GLYCOL CONTACTOR
31	GLYCOL SEPARATOR
32	TEG REGEN
33	BTEX
34	GAS GENERATOR SET
35	AMINE SUMP TANK
36	NEW LUBE OIL TANKS
37	CONDENSATE TRANSFER PUMPS
38	VAPOR RECOVERY UNIT
39	TANK COMBUSTOR K.O. DRUM
40	MV TRANSFORMER
40F	MV TRANSFORMER (FUTURE)

LEGEND

- FIRE EXTINGUISHER = 9 ea.
- HYDROGEN SULFIDE DETECTOR = 10 ea.
- AUDIBLE ALARM SOUNDER = 4 ea.
- STROBE LIGHT (RED) – FIRE = 4 ea.
- PLANT EMERGENCY SHUTDOWN = 6 ea.
- FIRST AID & SCBA KIT = 3 ea.
- EYE WASH STATION = 3 ea.
- WIND SOCK = 1 ea.
- MUSTER POINT = 3 ea.

NOTES:

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
C	08/16/22	ISSUED FOR INFORMATION	HJP	CN	–
B	07/12/22	ISSUED FOR INFORMATION	RDC	CN	–
A	06/13/22	ISSUED FOR INFORMATION	RDC	RAF	–

F&C ENGINEERS
TX REG. NO. 8419

BAYSWATER

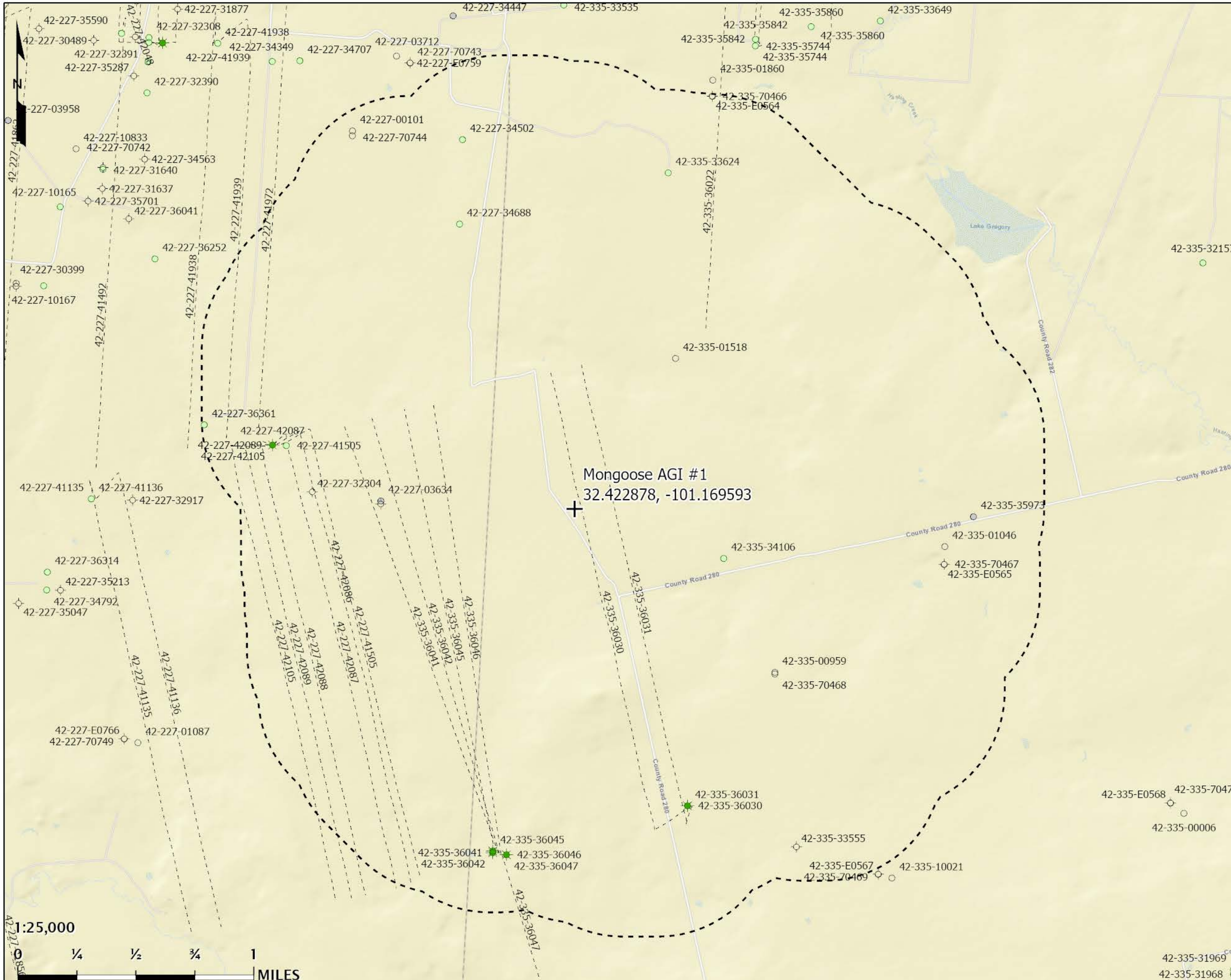
CLIENT : BAYSWATER EXPLORATION & PRODUCTION
PROJECT : SOUR GAS TREATING FACILITY
TITLE : INSTRUMENTATION FACILITY SAFETY LOCATION PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.	SHEET NO.	
RDC	GA	AS NOTED	06/09/22	BAY220316	IN-PLN-0790	1 OF 1	C

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST



C-1

Mongoose AGI No. 1

All Oil & Gas Wells

Bayswater Operating, LLC

Mitchell County, TX

Drawn by: SJL	Date: 10/19/2023	Approved by: SLP

PCS: NAD 1927 State Plane TX - N. Central FIPS 4202 (US Ft.)

LONQUIST SEQUESTRATION LLC

Mongoose AGI No. 1

Half Mile Buffer (from Plume @ Stabilization, Maximum Monitoring Area)

All Offset Well Directionals

All Offset Well SHLs

- <Null>
- CBM
- CONFIDENTIAL
- DISPOSAL
- DRY HOLE
- GAS
- INJECTION
- OIL
- OIL & GAS
- OTHER
- SERVICE
- STORAGE
- UNKNOWN
- WATER
- <all other values>

Mongoose AGI No. 1

Area of Review: Oil & Gas Wells List

API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022
4222741505	KAMIKAZE 5-8-17-20	3W	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023

LONQUIST SEQUESTRATION LLC

Mongoose AGI No. 1

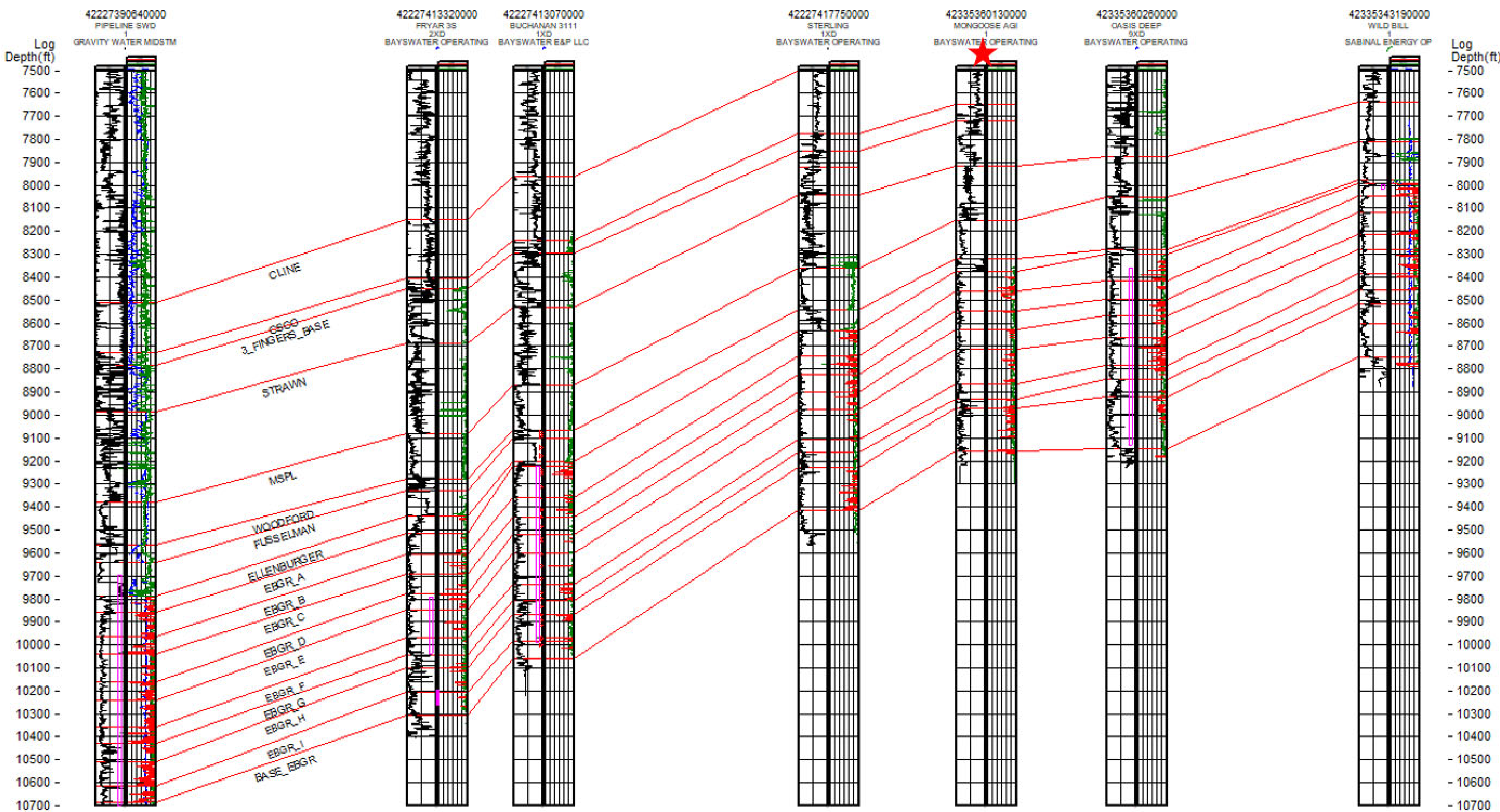
4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.

APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 27 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 28 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER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GRAVITY WATER MIDSTM
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FRYAR 3S
2XD
BAYSWATER OPERATING
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BUCHANAN 3111
1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Log Depth(ft)
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7600
7700
7800
7900
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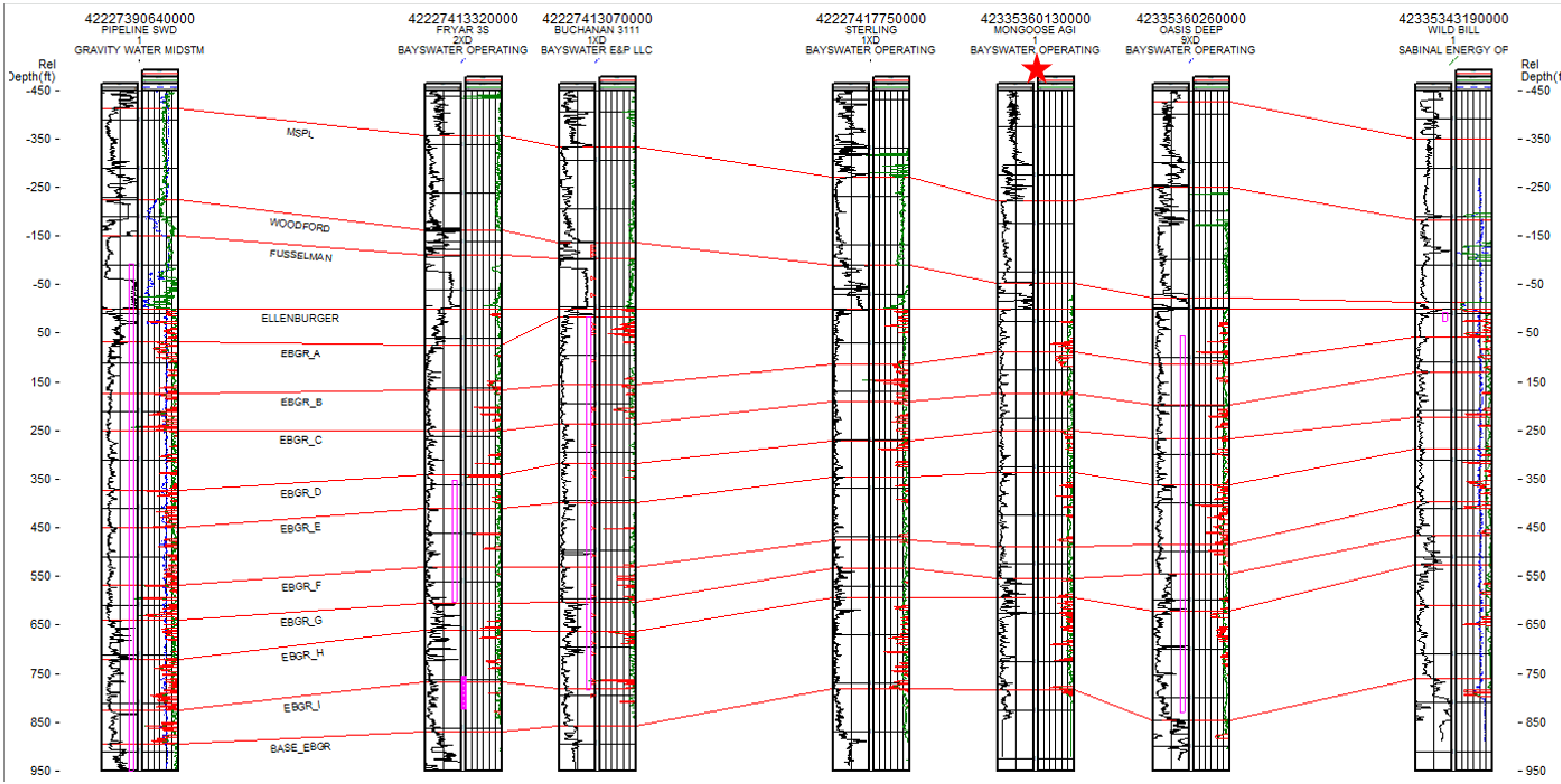
10200
10300
10400
10500
10600
10700
CLINE
CSCO
3_FINGERS_BASE
STRAWN
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR

D-2


42227390640000
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1
GRAVITY WATER MIDSTM
42227413320000
FRYAR 3S
2XD
BAYSWATER OPERATING
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BUCHANAN 3111
1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Rel Depth(ft)
-450
-350
-250
-150
-50
50
150
250
350
450
550
650
750
850
950
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR

Request for Additional Information: Mongoose Amine Treating Facility
December 6, 2023

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses/Responsible Person
	Section	Page		
1.	N/A	N/A	The MRV plan mentions the Mongoose Amine Treating Facility, the Bayswater Amine Facility, and the Mongoose Gas Plant when referencing the facility's name, however, the facility is listed as the "Mongoose Amine Treating Facility" on e-GGRT. For clarity, we recommend reviewing the MRV plan to ensure that all references to the facility and CO_2 supplier are consistent. Does the Bayswater Amine Facility report any GHG data?	All facility naming references have been edited for consistency to Mongoose Amine Treating Facility, the Mongoose, and the Plant as appropriate. As provided in Section 1.3 Bayswater is currently reporting to the GHGRP under ID: 586481
2.	2.1	17	"However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area." We recommend clearly labeling the fault mentioned above in Figure 7 of the MRV plan.	Figure 7 has been updated to identify the nearest fault.
3.	2.2	21	"Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose." Please clarify the distance between the Mongoose AGI No. 1 well and the offset Buchanan 3111 #1XD well. Additionally, we recommend showing the proximity of the offset well relative to the Mongoose AGI No. 1 well.	Section 2.2.2 (pg. 21) was edited to specify the offset well distance of 10.4 mi. and Figure 11 (pg. 22) was added for reference.
4.	2.3	39	"Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the **subject well**." Please clarify what is meant by "subject well".	Sec. 2.3 was edited to specify the **subject well** as the Buchanan 3111 #1XD.

No.	MRV Plan		EPA Questions	Responses/Responsible Person
	Section	Page		
5.	2.4	41	"Figure 26 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map." The statement above references Figure 26, but the description matches the label for Figure 27. Please review the MRV plan to ensure that all references to figures and tables within the text are correct.	References to figures have been corrected/updated.
6.	2.4	42	We recommend adding units to Figure 26.	Units are noted in 'subsea feet' in the figure caption.
7.	2.8	52	"The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 0.1, an irreducible water saturation of 0.397, and a maximum residual gas saturation of 30%." We recommend that saturations be consistently expressed as either decimals or percents to the extent possible.	Edited as appropriate to present saturation numbers in percent. 0.10 changed to 10% 0.397 changed to 39.7%
8.	3.1	63	Per 40 CFR 98.449, maximum monitoring area is defined as 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. While the MRV plan identifies the MMA, please state in the plan whether the MMA in Figure 41 includes a ½ mile buffer as described above.	Section 3.1 is edited to define the MMA as inclusive of a one half mile all-around buffer as depicted in Figure 41.
9.	4	66	Please provide a clear characterization of the likelihood, magnitude, and timing of leakage for each identified potential leakage pathway.	Table 12 was added on pg. 67
10.	4.1	66	"Monitors for H_2S are installed at key locations around the Plant." Please clarify the detection limit of the H_2S monitors and at what point they would trigger.	OSHA exposure limits have been added to Sec. 4.1, pg 67.

No.	MRV Plan		EPA Questions	Responses/Responsible Person
	Section	Page		
11.	4.0	67	Figure 43 of the MRV plan shows the Bayswater Amine Facility and provides a description of the surface equipment and monitors. We recommend showing the location of all flow meters relevant to subpart RR calculations in this or a similar figure.	A detailed site Plan is provided in Appendix B-2.
12.	4.2	69	"Figure 46 highlights that only two wells penetrate the MMA's gross injection zone, and these wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements." While Section 4.2 of the MRV plan states that these wells are plugged and abandoned, please provide a clear characterization of the likelihood, magnitude, and timing of potential leakage from this pathway. Please also provide any applicable monitoring/detection/quantification strategies as necessary.	Table 12, page 67 has been added. Also, penetrations of the gross injection interval within the MMA will be monitored by taking annual soil gas samples adjacent to the APs. These will be analyzed by a third-party lab and any results indicating the presence of sequestered CO_2 will be provided in the annual report.
13.	4.0	70	There are two figures labeled "Figure 45" in the MRV plan. Please address this and revise the table of contents accordingly.	Figure labels and the Table of Contents have been updated.
14.	4.0	70	Figure 45 of the MRV plan identifies several wells within the MMA/AMA. While the wells that penetrate the injection zone are discussed in Section 4.2, there is no discussion regarding wells completed to other formations. Please evaluate the possibility of leakage from these wells in the MRV plan and include any applicable monitoring/detection/quantification strategies as necessary.	Section 4.2 has been edited with commentary regarding wells completed above the Upper Confining Zone.
15.	5.4	79	"This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 50." The MRV plan does not contain a "Figure 50." Please address this and revise the table of contents accordingly.	Figure reference has been updated (pg. 80)

No.	MRV Plan		EPA Questions	Responses/Responsible Person
	Section	Page		
16.	7.4	82	"…those emissions sent to a flare stack and reported as a part of the required **GHGG** reporting for the Plant." Please define GHGG or revise this sentence as necessary.	Edits have been made for consistent reference of GHGRP and GHG.
17.	7.4	82	"**CO_2** = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year." According to 40 CFR 98.443, the correct variable for Equation RR-10 is CO_{2e}. Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443. See https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR/section-98.443 for reference.	The equation has been corrected to read CO_{2E}
18.	NA	NA	40 CFR 98.448(a)(7) requires a "Proposed date to begin collecting data for calculating total amount sequestered according to equation RR–11 or RR–12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA." Please clarify whether such a date is specified in the MRV plan.	By May 20, 2024, Bayswater shall perform the necessary air gas and soil gas sampling and analysis to establish a CO_2 baseline for the Mongoose MRV Plan. Bayswater shall begin collecting data for calculation of the sequestered volumes upon the first date that both of the following have occurred: 1) Approval of this MRV plan by the GHGRP, and 2) Completion of the baseline sampling program as provided in the MRV plan.
19.	NA	NA		There are numerous edits made to the MRV plan 1) in response to this RAI; 2) in grammatical edits subsequent to the RAI responses for better clarification; and 3) deletions of material no longer relevant based on these edits.

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC*
Denver, CO

By

Lonquist Sequestration, LLC
Austin, TX

Version 1.0
October 2023

INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Bayswater Amine Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.

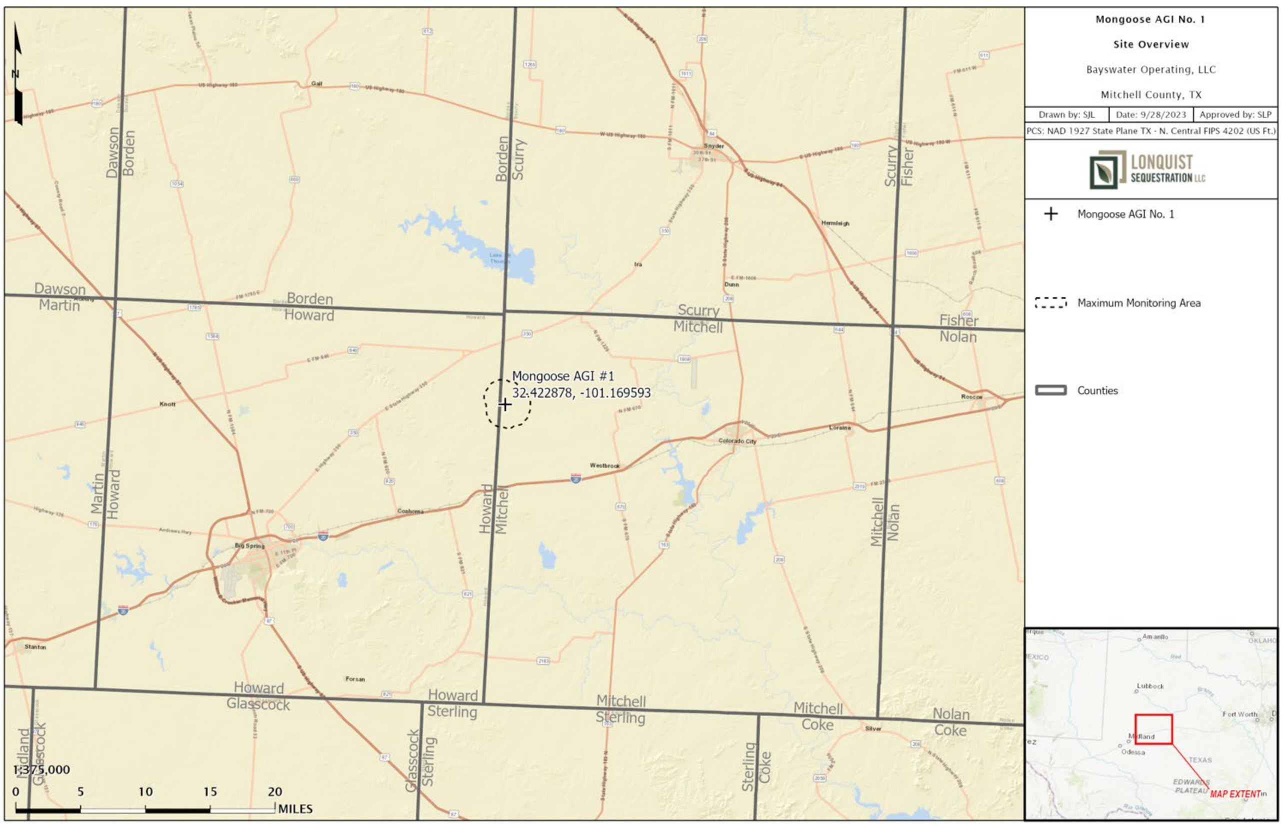


Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO_2 gas is the Bayswater Amine Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

Figures

Tables

Appendices

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 Reporter Number

- Gas Plant Facility Name: Bayswater Amine Facility
- Greenhouse Gas Reporting Program ID: 586481
    - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Bayswater Gas Plant
1625 County Road 280
Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641
Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extended across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).

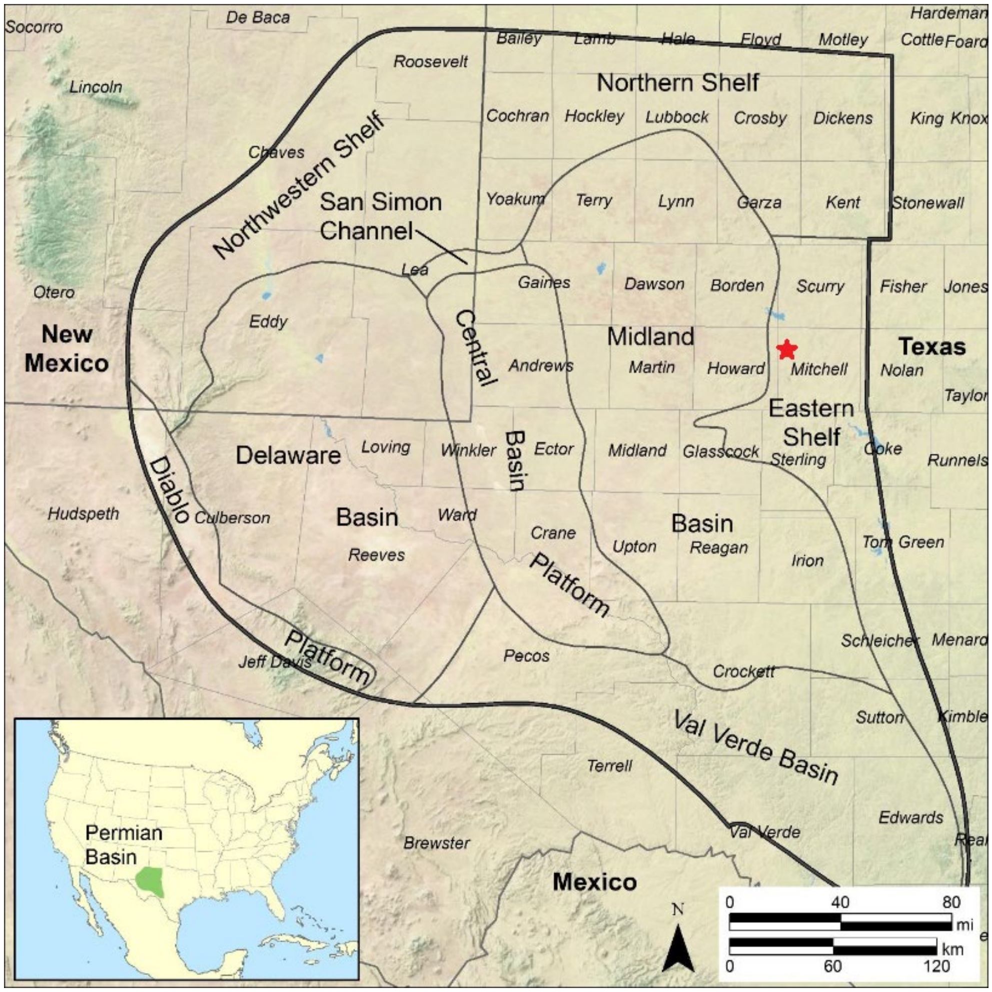


Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).

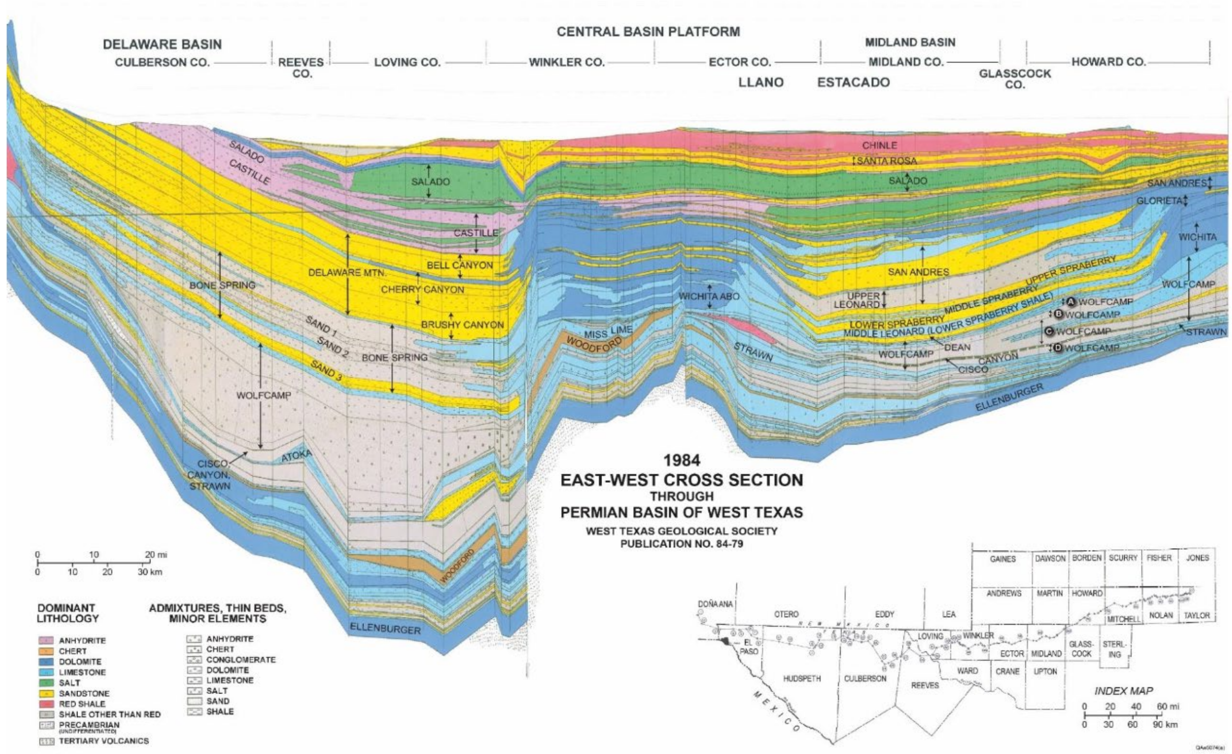


Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are “ooid grainstone; ooid-peloid packstone-grainstone”

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).

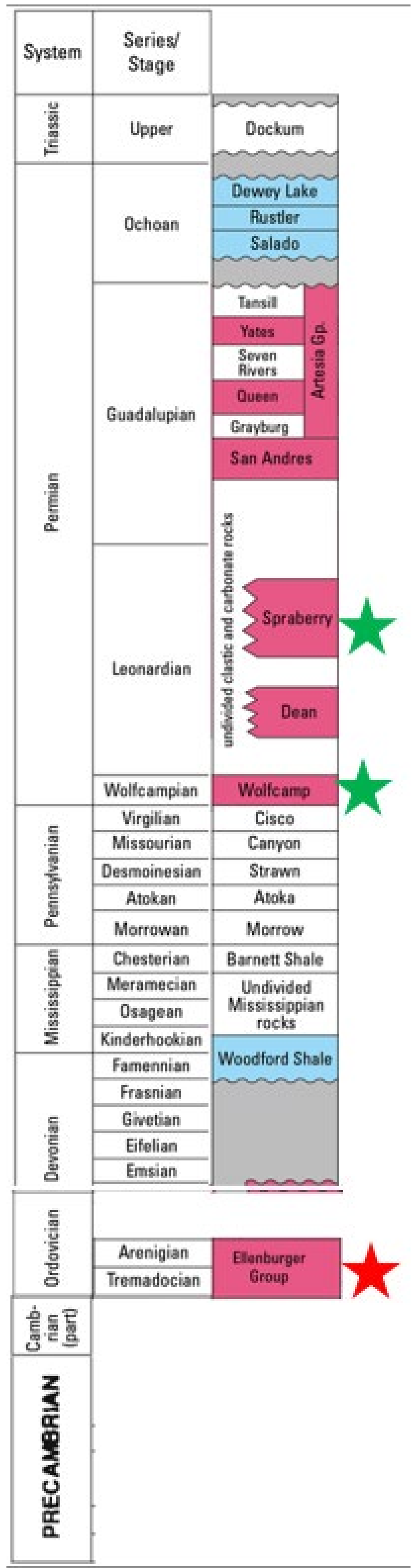


Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf

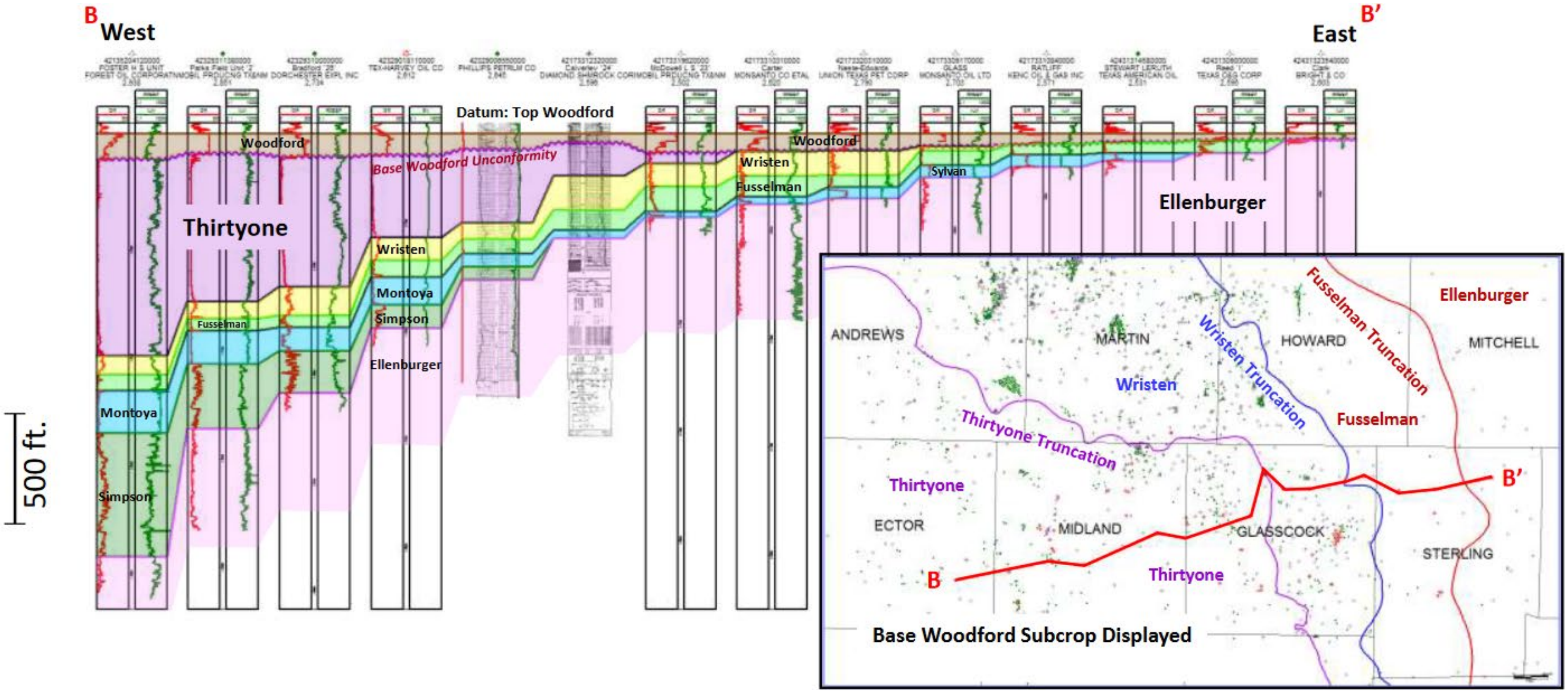


Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).

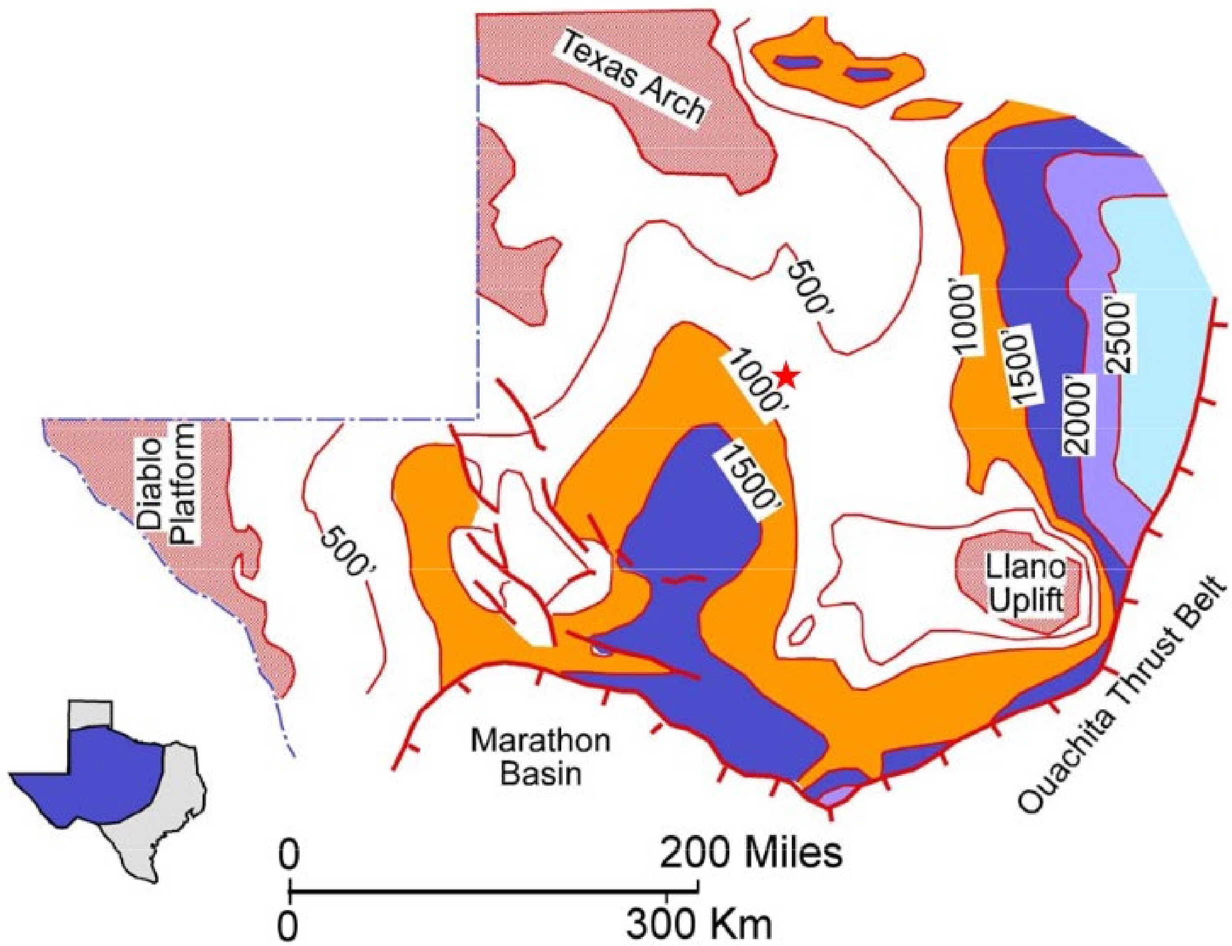


Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)

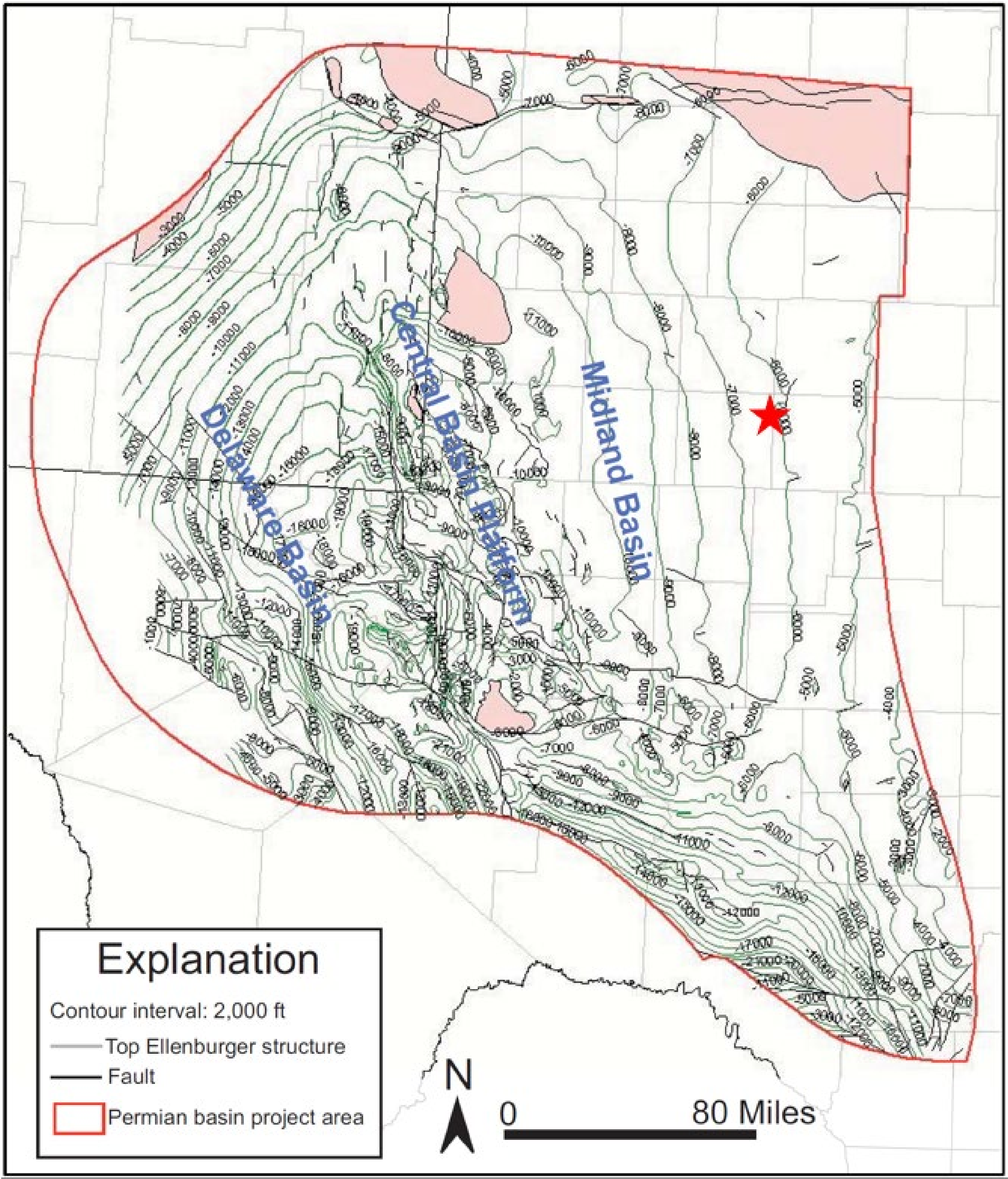


Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).

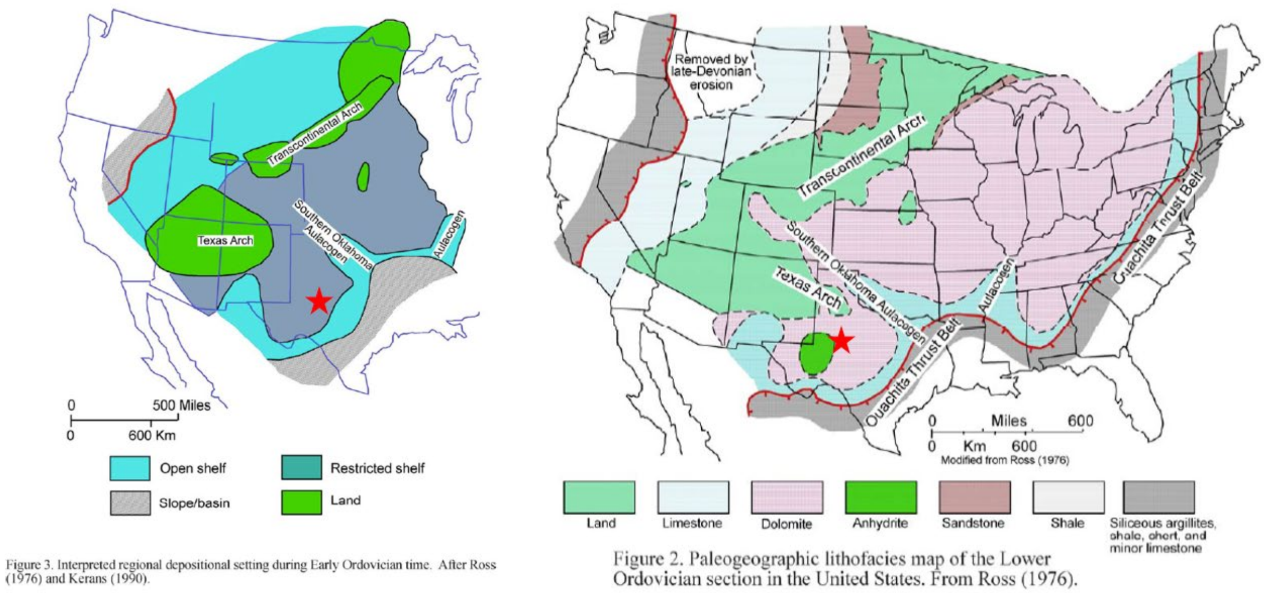


Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).

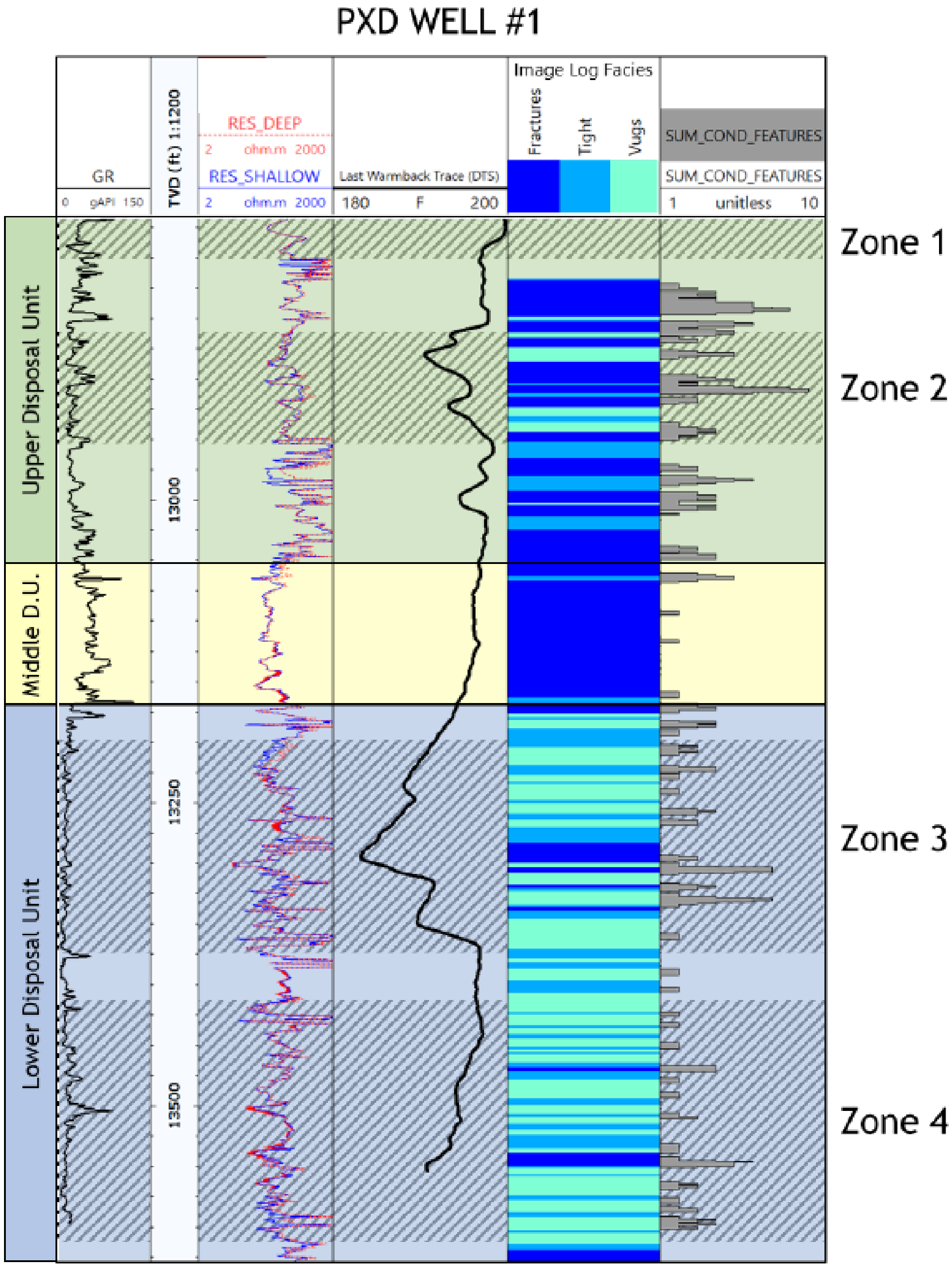


Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, & Coringrato, 2019)

2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.

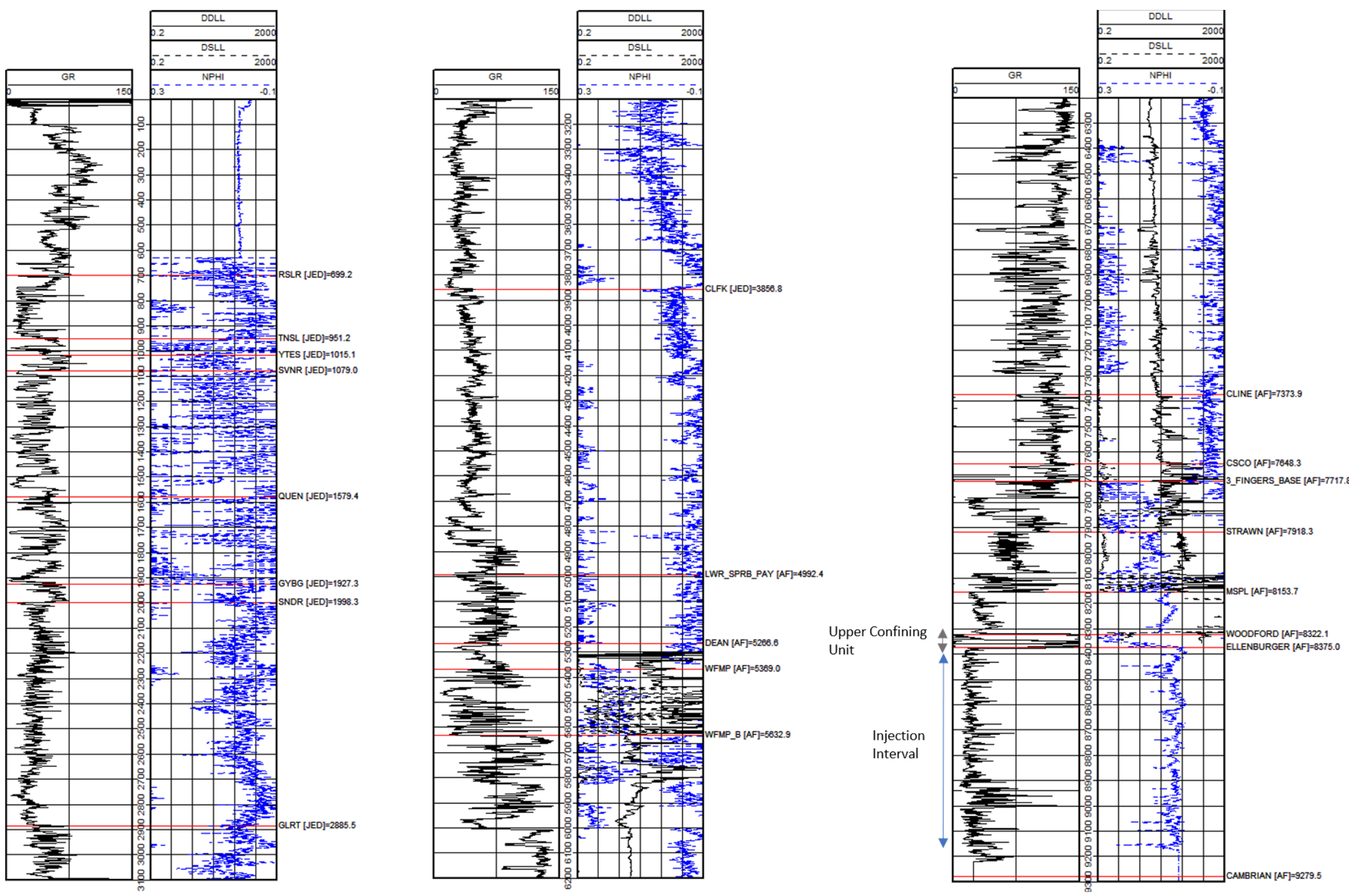


Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO_2 Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. Figure 11 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 12. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 13, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 14 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 15 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 16. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.

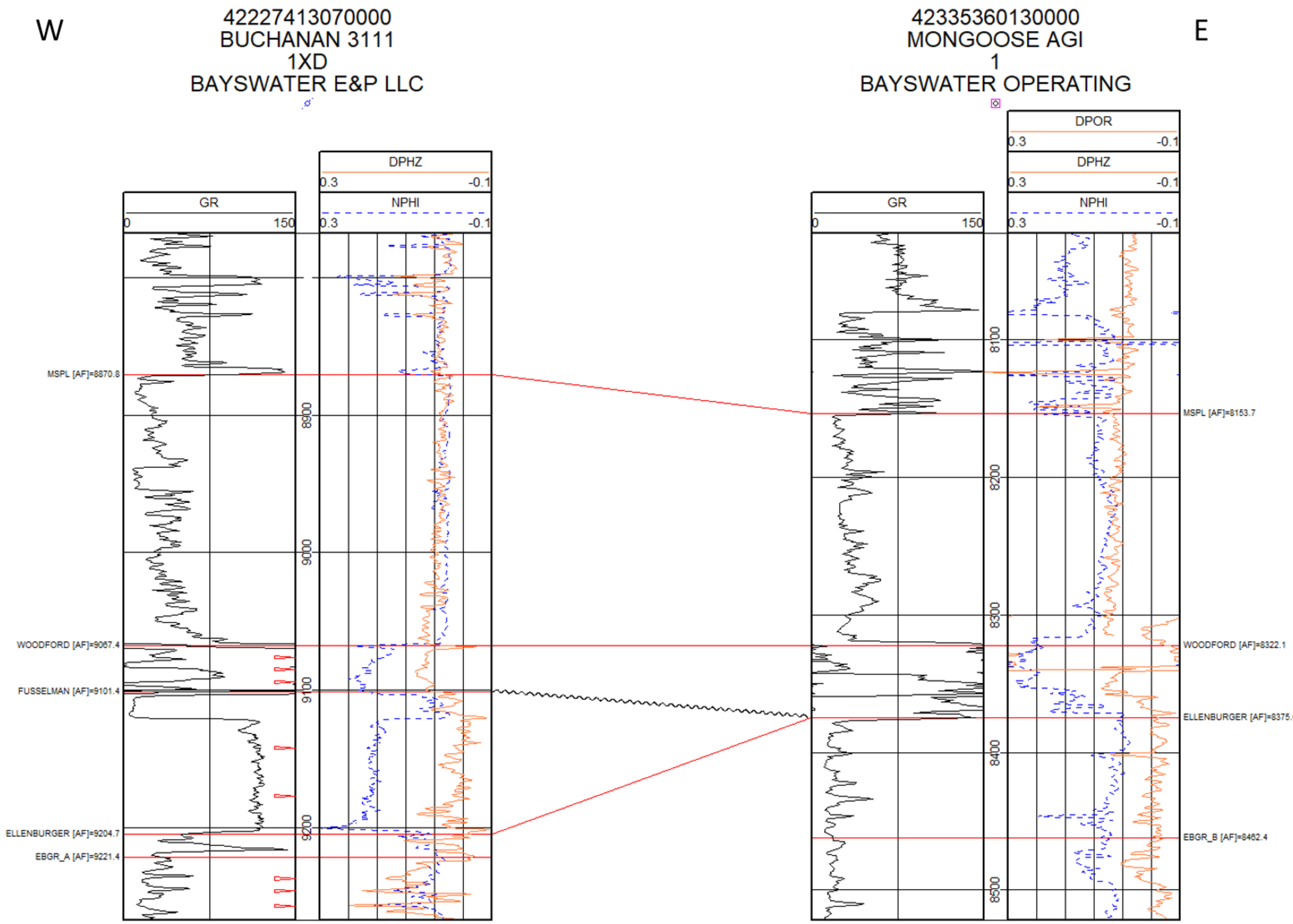


Figure 11 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.

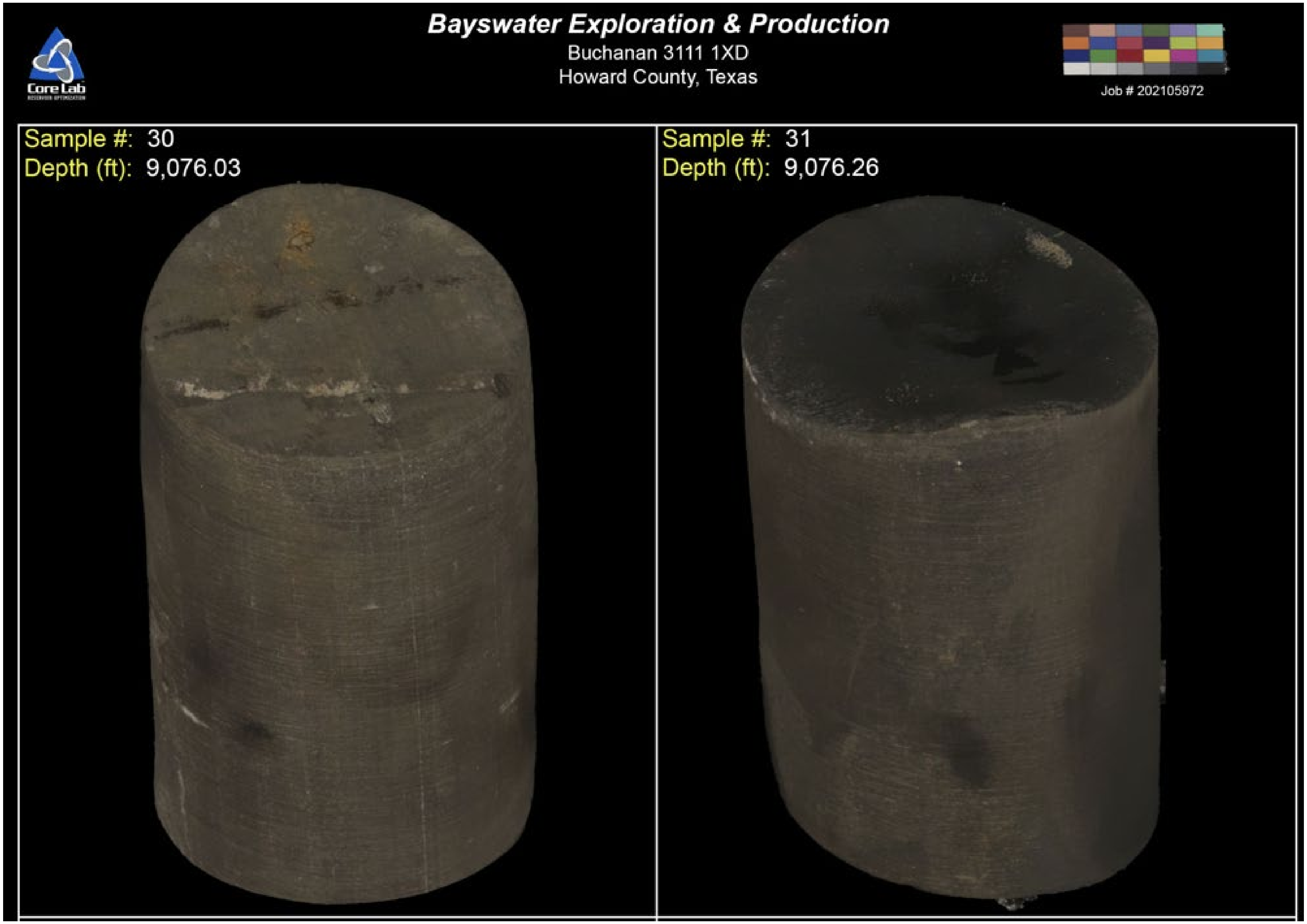


Figure 12 – Core Photo of Samples Within the Woodford Formation

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: February 04, 2022
Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

		As received				Dry & Dean Stark Extracted Conditions (2)				
Sample	**Depth** (ft)	**Bulk Density** (g/cc)	**Matrix Permeability (1)** (mD)	**Gas-filled Porosity** (%)	**Gas Saturation** (%)	**Grain Density** (g/cc)	**Matrix Permeability (5)** (mD)	**Porosity** (%)	**Oil Saturation (3)** (%)	**Water Saturation (4)** (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:
Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.
(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.
(3) Oil volume computed assuming an oil density of 0.844 g/cc
(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc
(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 13 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

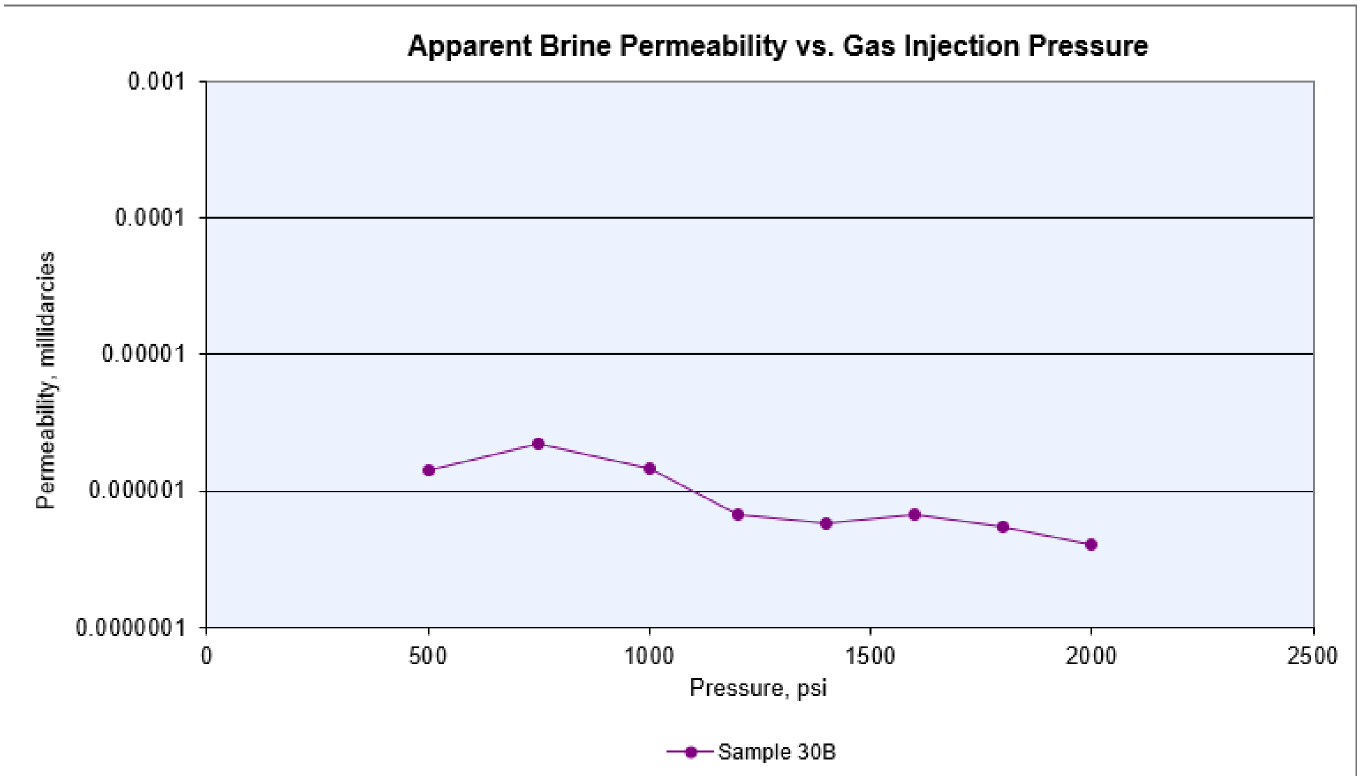


Figure 14 – Graph of Threshold Entry Pressure Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample 30B	
Gas Injection Pressure, psi	Permeability to Brine*, mD
500	1.44E-06
750	2.20E-06
1000	1.46E-06
1200	6.73E-07
1400	5.77E-07
1600	6.72E-07
1800	5.39E-07
2000	4.03E-07

Figure 15 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi   Temperature: 68°F

Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production
Well: Buchanan 3111 1XD
Field: Spraberry
Location: Howard County, Texas

File: HOU-2105972

Sample Number	Depth, feet	Length, cm	Diameter, cm	Final Permeability to Brine*, millidarcies	Threshold Entry Pressure, psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 16 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 17 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 18 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and non-applicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 19. A two-function porosity-permeability curve was developed from the regional and local core data. Figure 20 shows the equations and relationships where:

If Effective Porosity (Φeff) < 6.5%: $K(mD) = 7E{-}08e^{3.3028*\Phi\mathrm{eff}}$

If Effective Porosity (Φeff) > 6.5%: $K(mD) = 277.39\ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 21, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 22 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 23. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production
Buchanan 3111 1XD
Spraberry
Howard County, Texas

CL File No.: 202105972
Date: March 31, 2022
Analyst(s): MP

CMS-300 ROTARY SIDEWALL ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Klinkenberg (md)	Permeability Kair (md)	b(air) psi	Beta ft(-1)	Alpha (microns)	Saturation Oil (% Pore Volume)	Saturation Water (% Pore Volume)	Grain Density (g/cm3)	Footnote
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 17 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

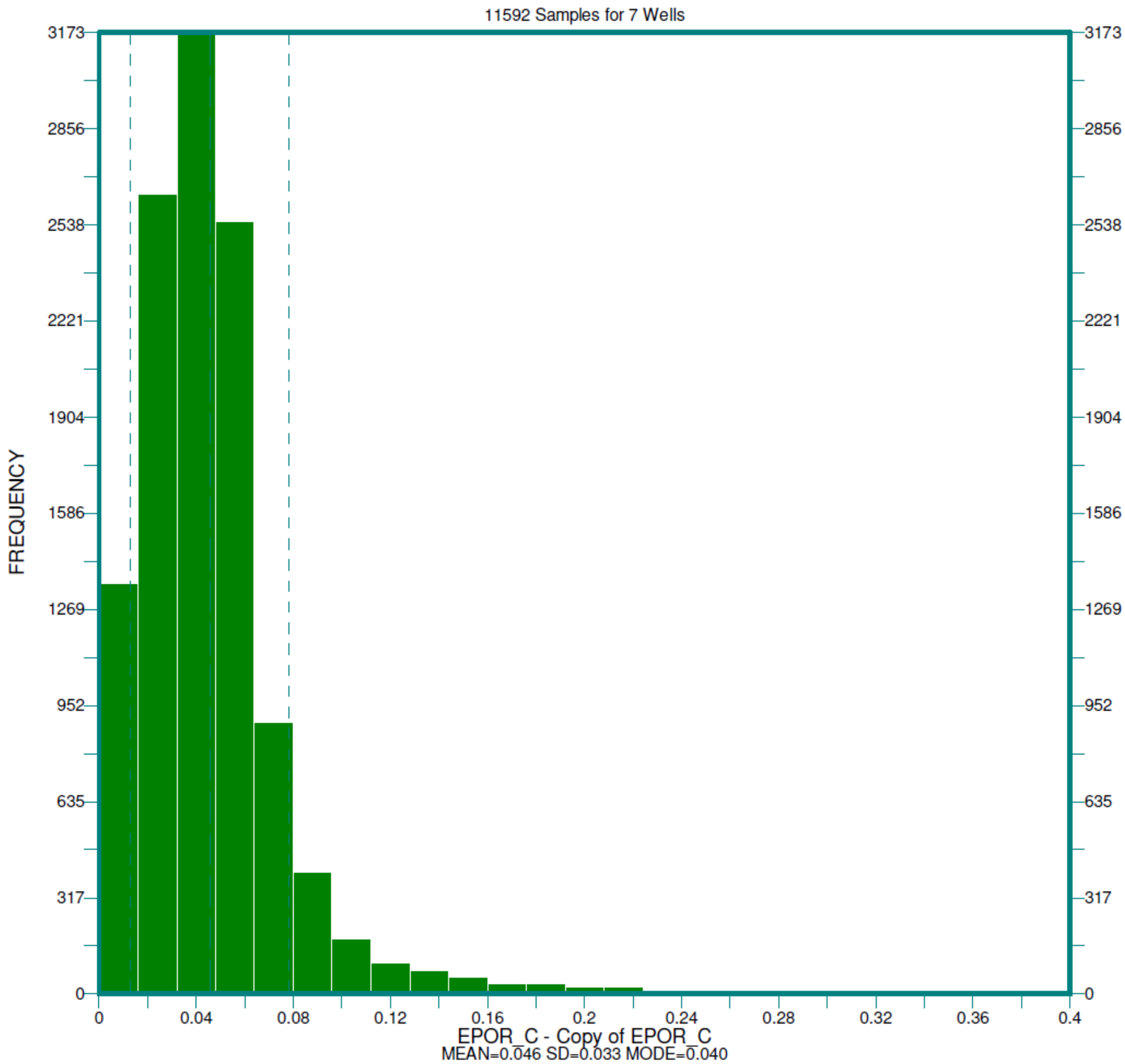


Figure 18 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 19 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

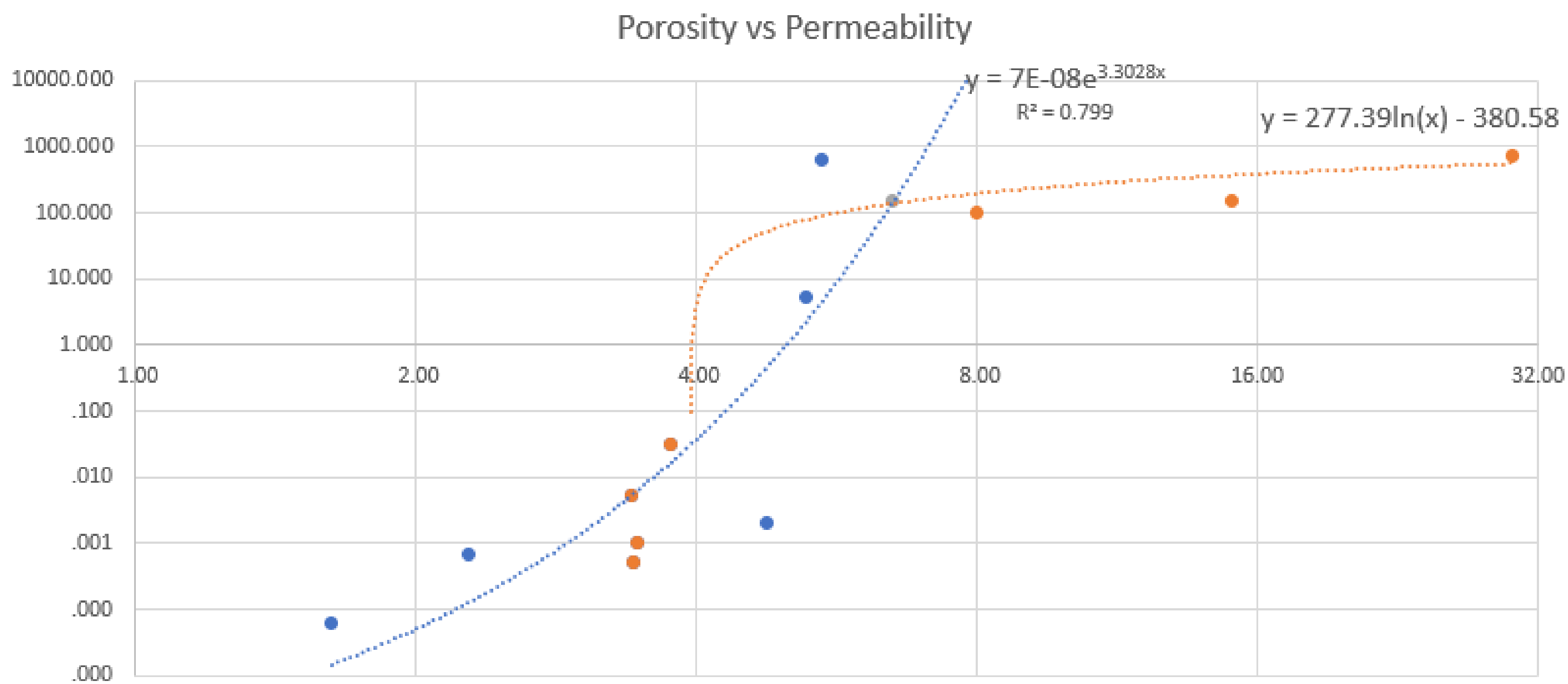


Figure 20 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data

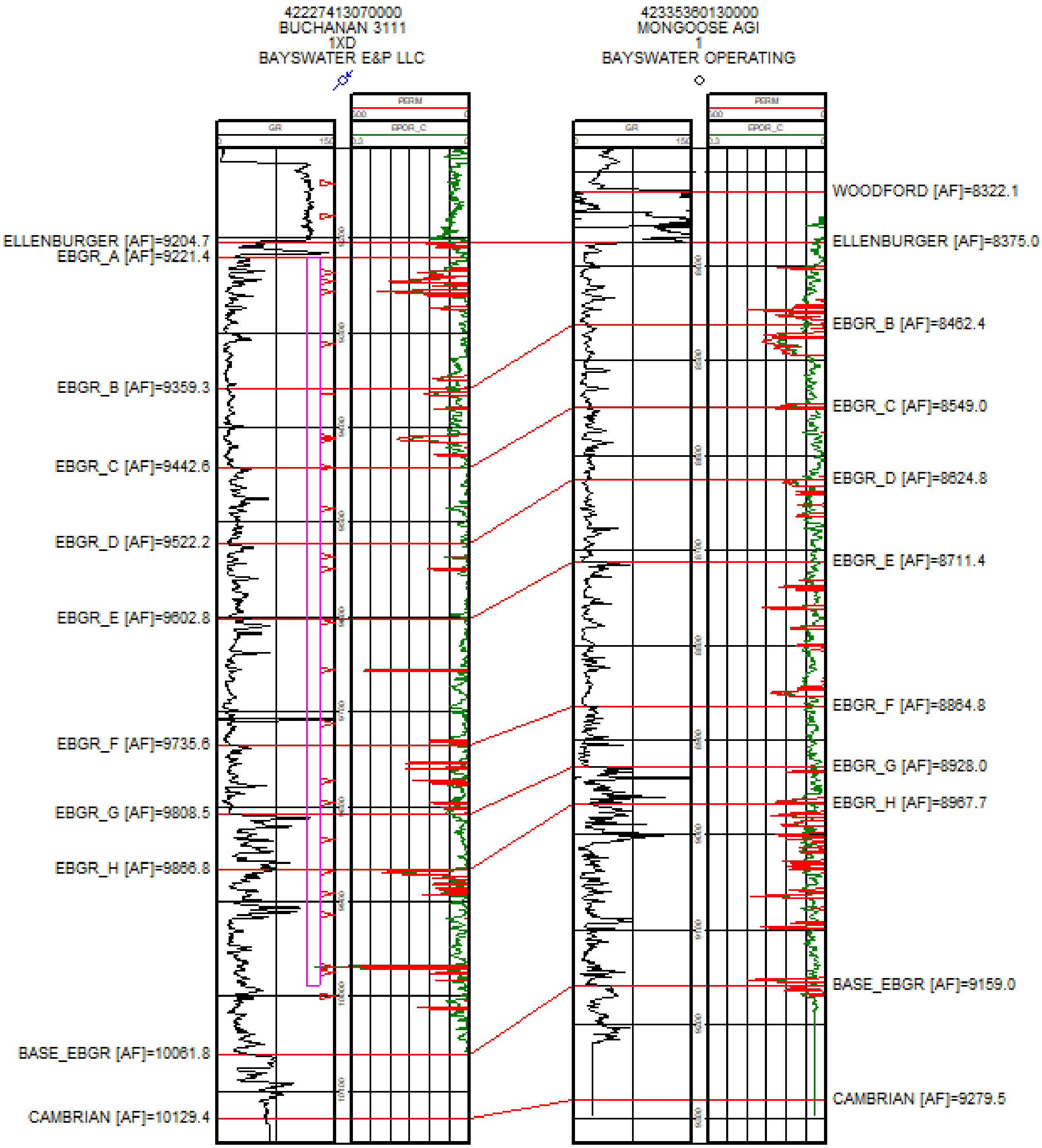


Figure 21 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.

Figure 22 – Core photo of Ellenburger sample displaying vug features.

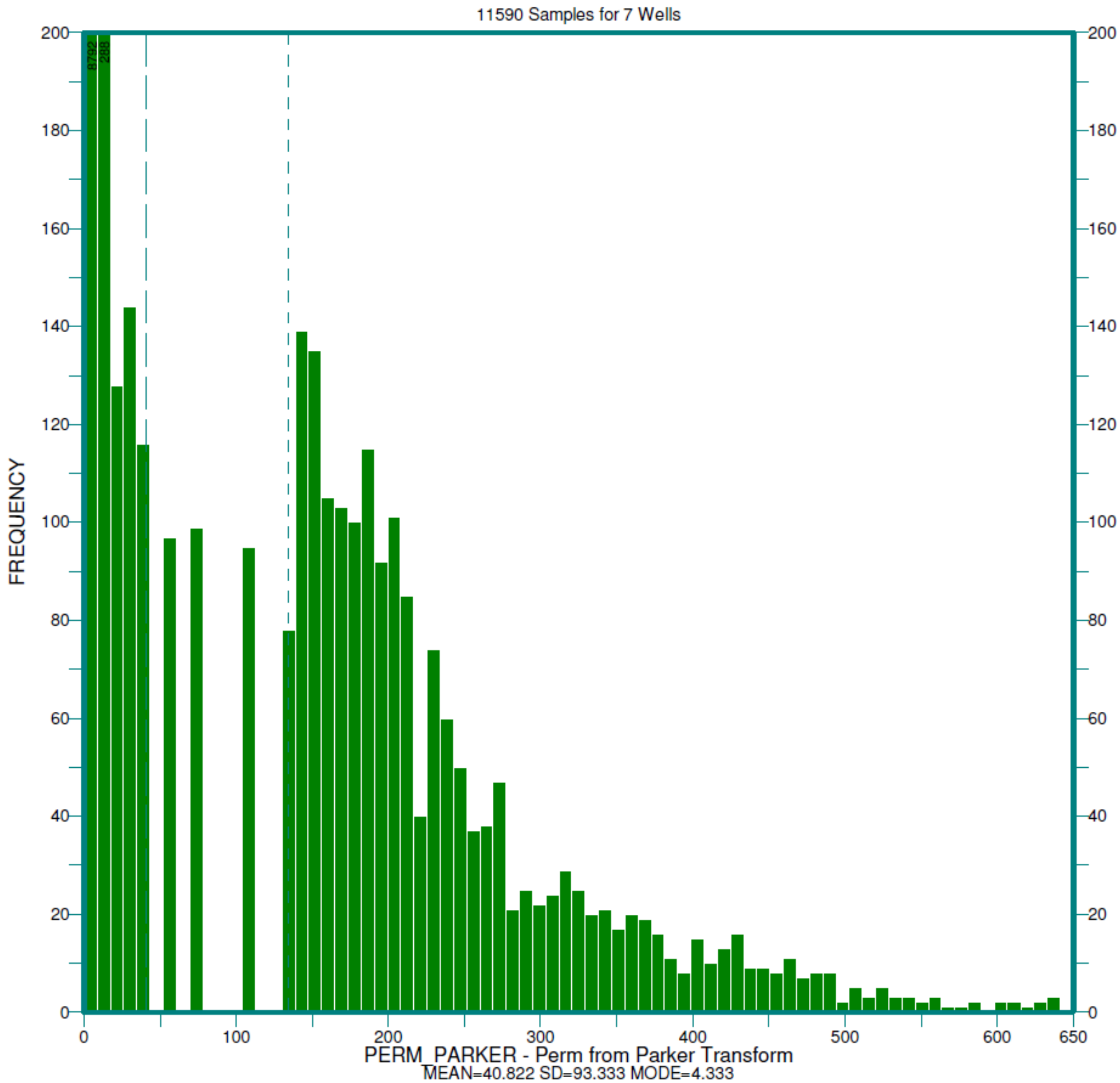


Figure 23 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oil-field brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 24. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.

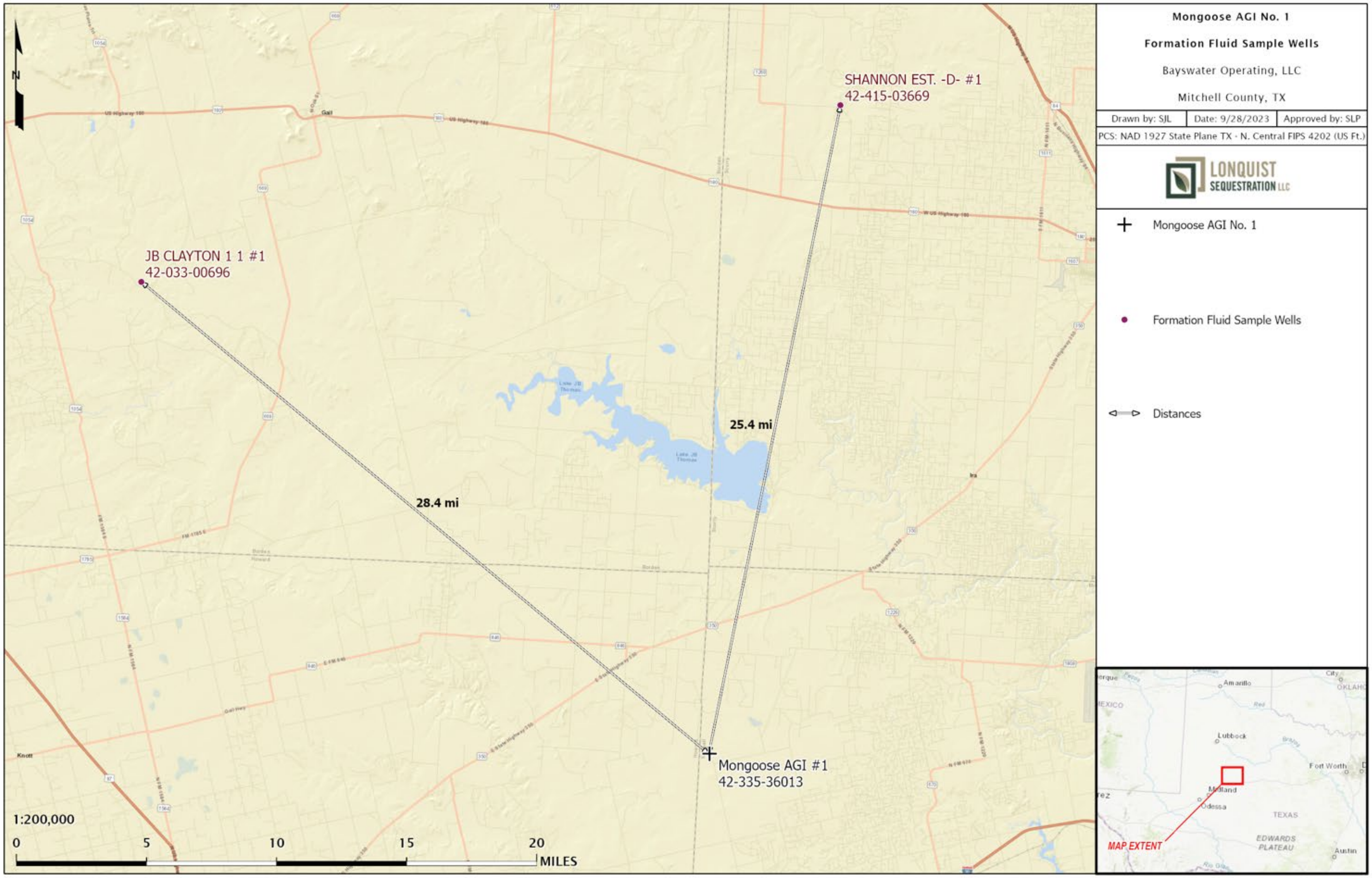


Figure 24 – Offset wells used for formation fluid characterization.

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
pH	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

2.2.4 Lower Confining Zone – Precambrian

Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sources from outcrops in central Texas and in the Trans-Pecos region of Texas and centra New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 25 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which lead to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.

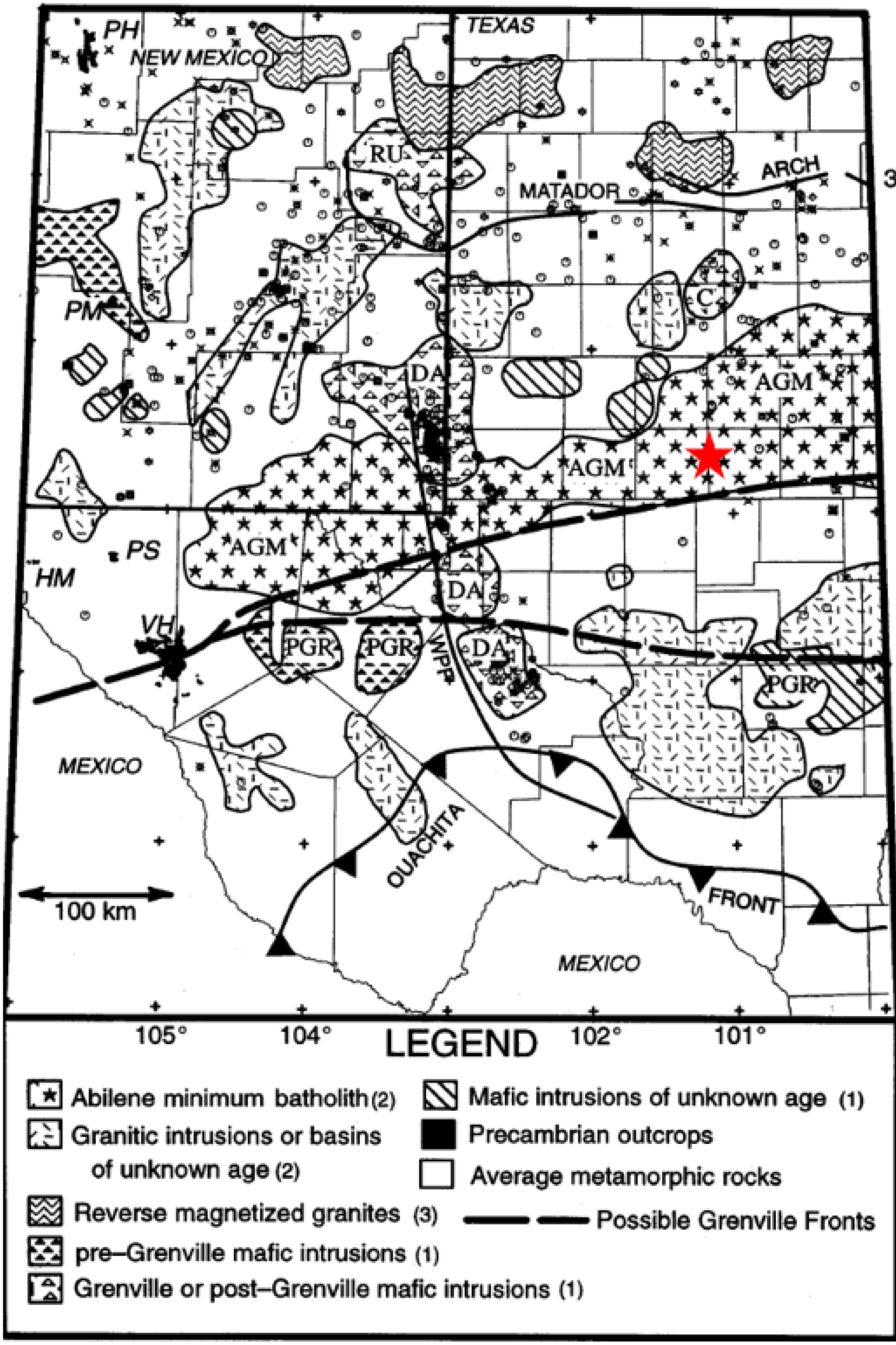


Figure 25 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Table 4 – Calculated Vertical Stresses

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the subject well. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$\nu = \frac{\frac{1}{2}\left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

ν = Poisson's Ratio

v_p = Compressional Velocity

v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1-0.261}(1.029 - 0.465) + 0.465 = 0.664\ psi/ft$$

$$FG\ with\ SF = 0.689\ \times 90\% = \mathbf{0.598\ psi/ft}$$

Table 5 – Fracture Gradient Calculation Inputs and Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 <u>Local Structure</u>

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 26 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 26 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 28 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 27 and 28 are provided in *Appendix D*.

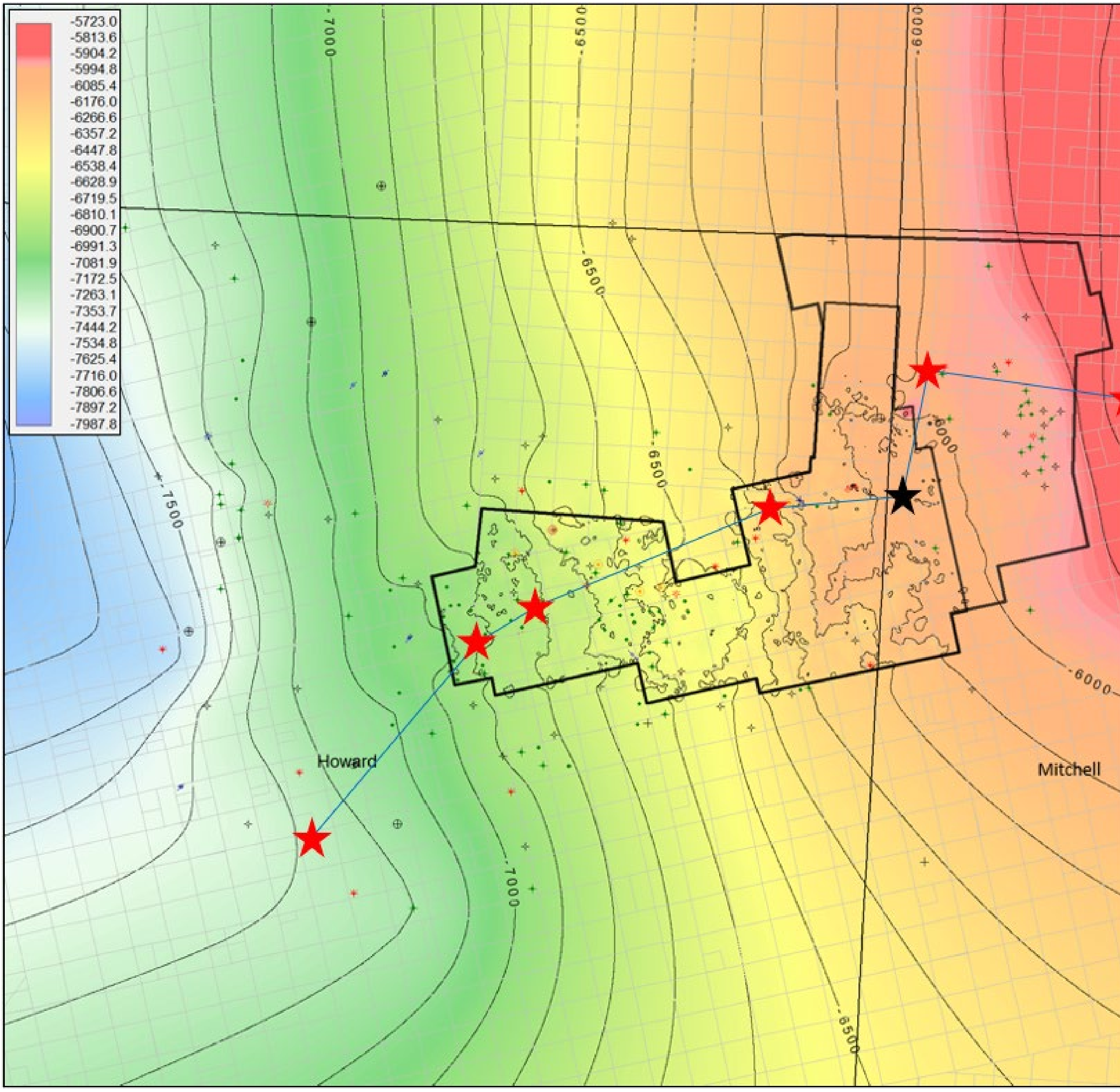


Figure 26 – Ellenburger structure map in subsea. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.

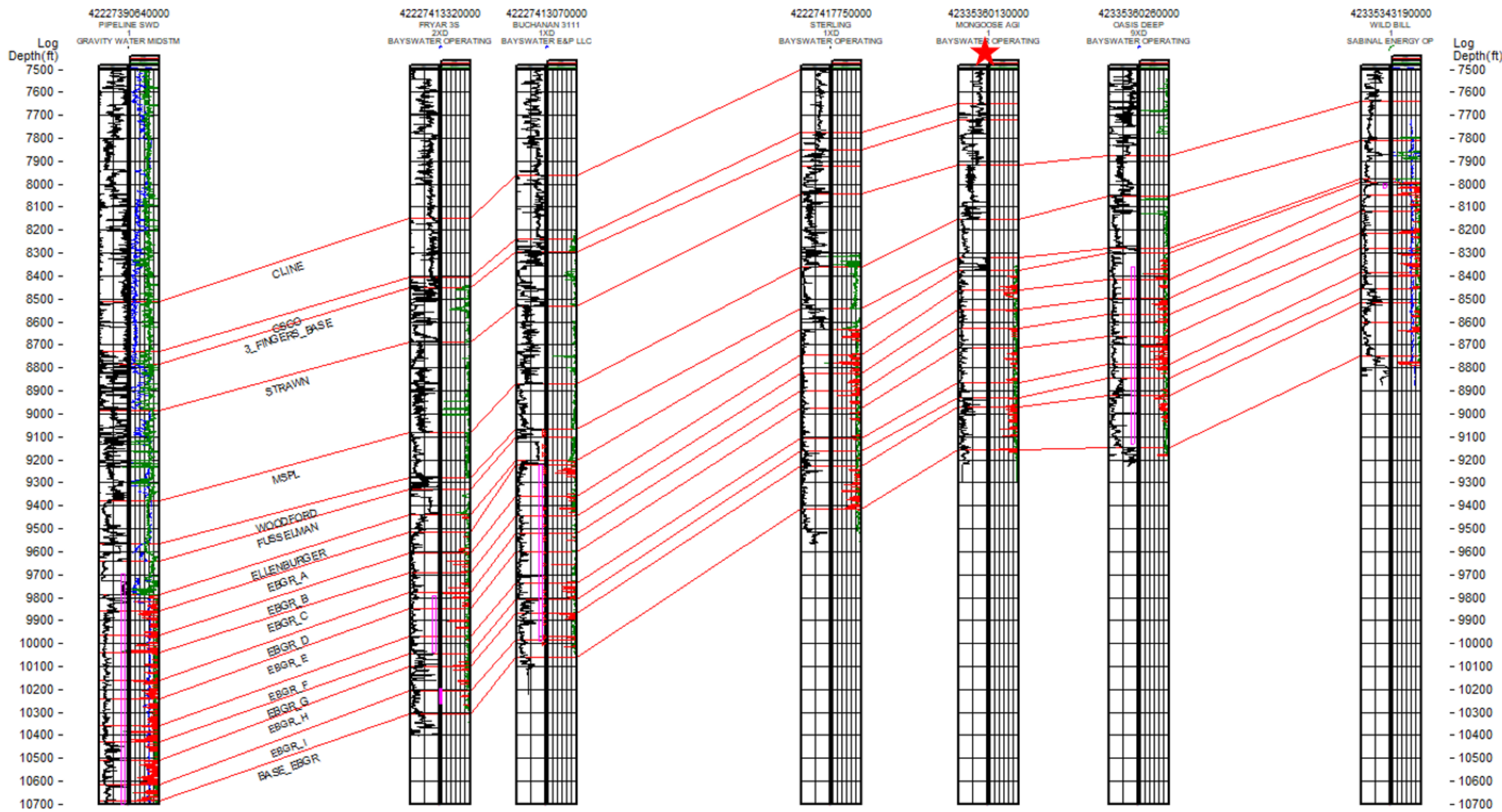


Figure 27 – Structural cross section depicting the Ellenburger.

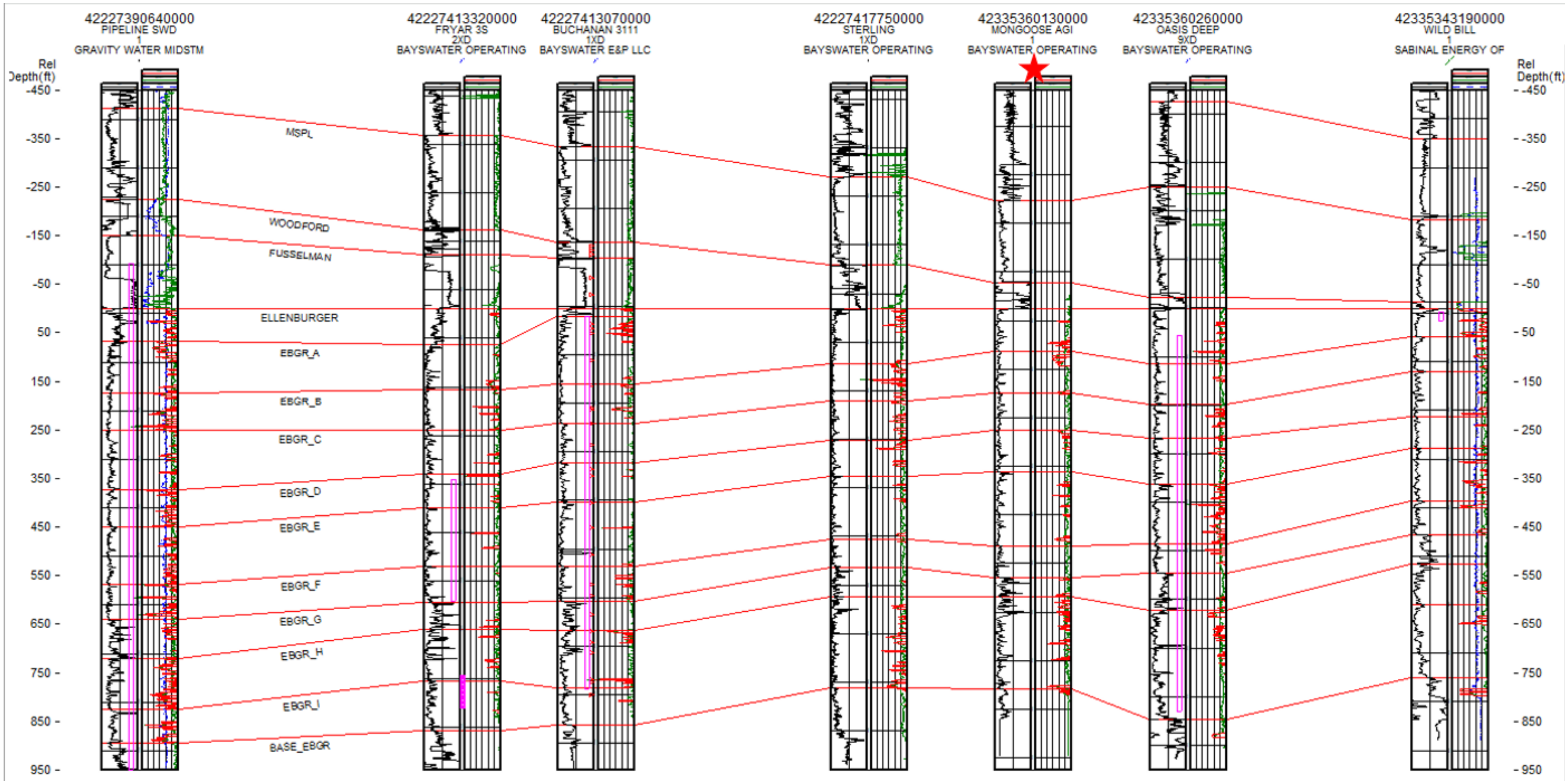


Figure 28 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 29 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colorado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
Cretaceous	Comanche	Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous limestone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potable but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
Triassic		Dockum	Chinle	0-640	Predominantly red to maroon and purplish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sandstone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
			Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaceous and carbonaceous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capacity of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to highly mineralized water to livestock and domestic wells.

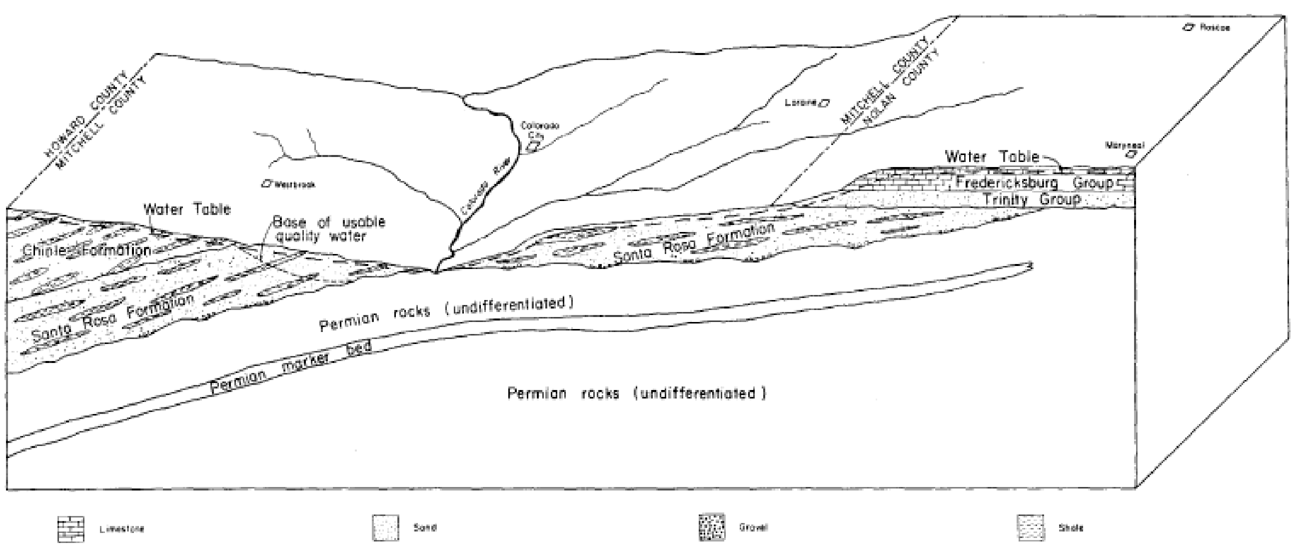


Figure 29 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 30, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 31. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 32.

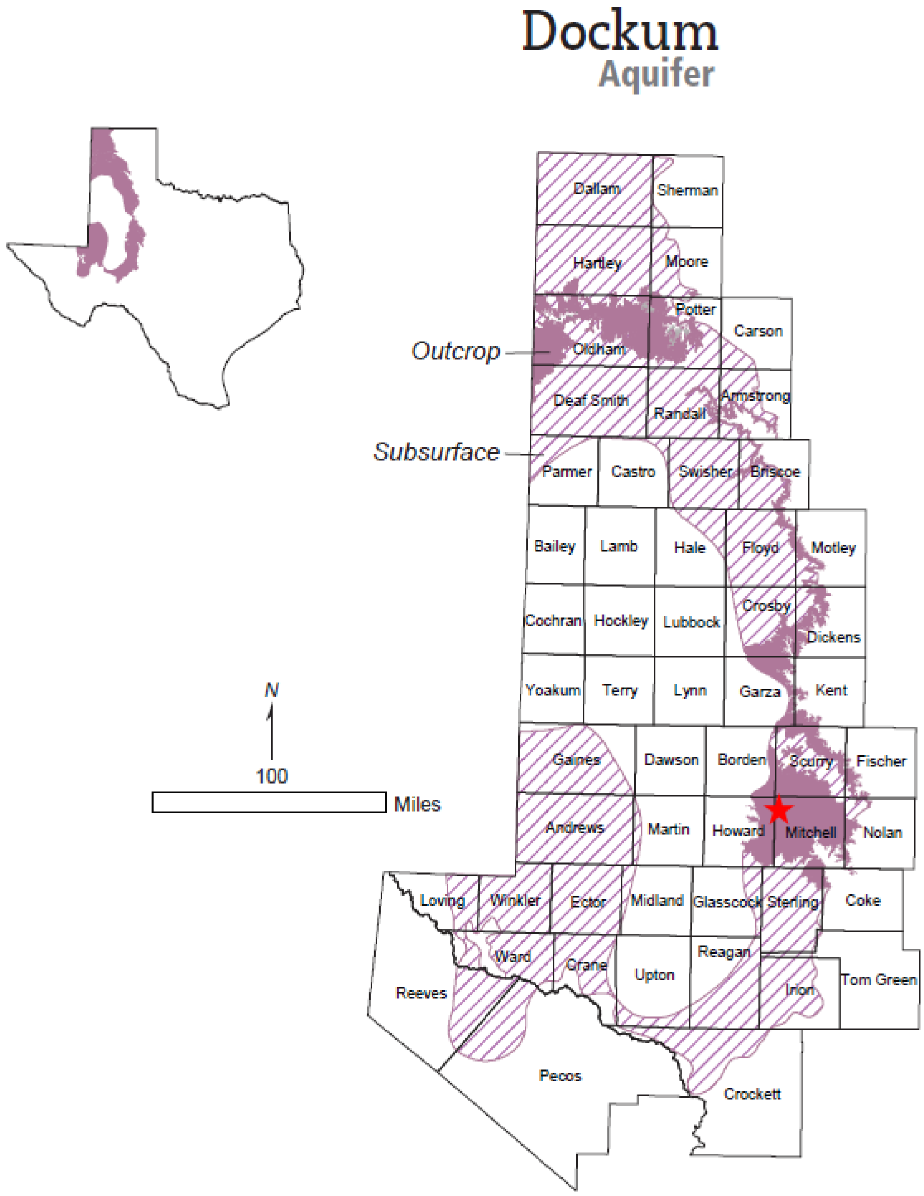


Figure 30 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).

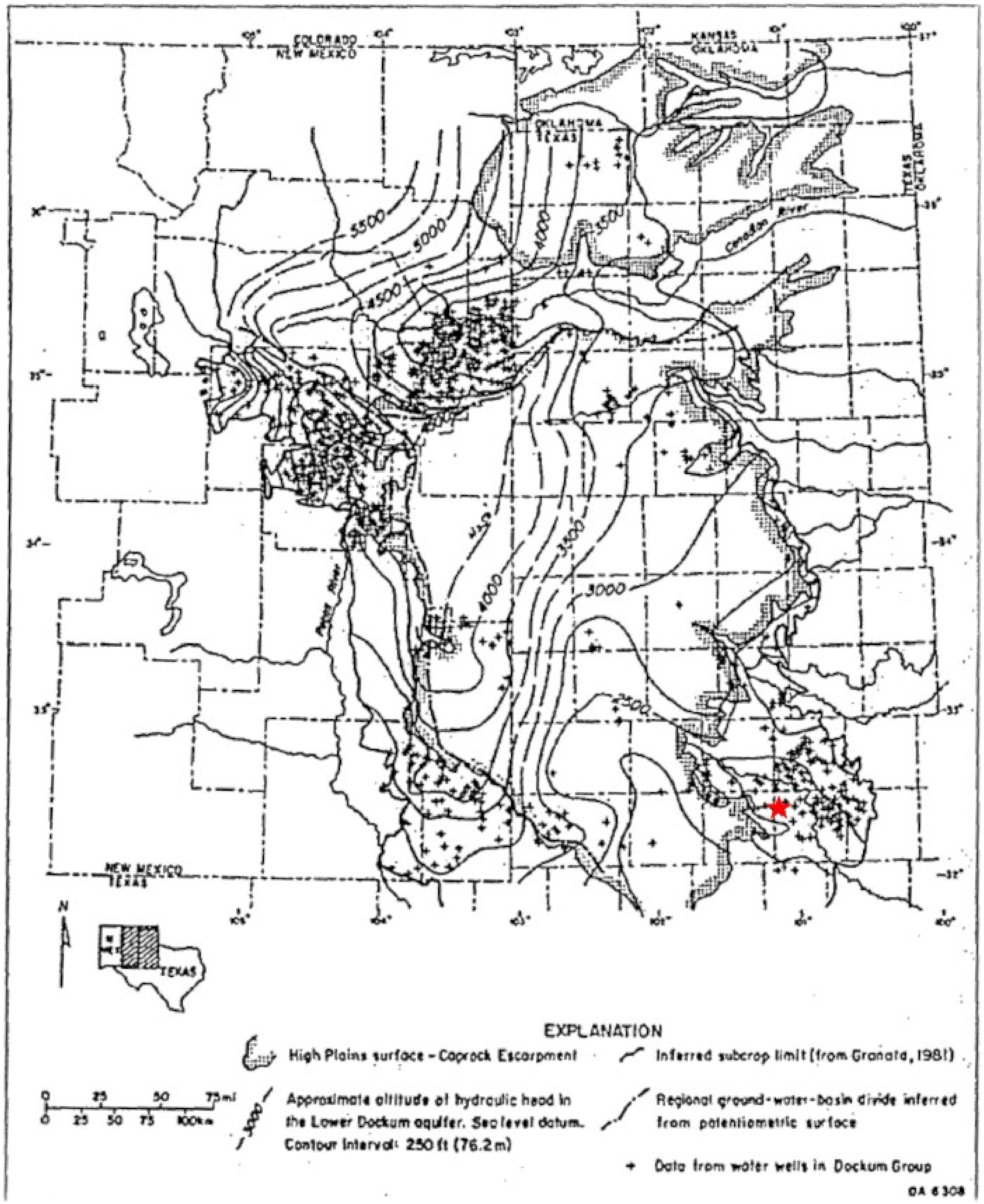


Figure 31 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).

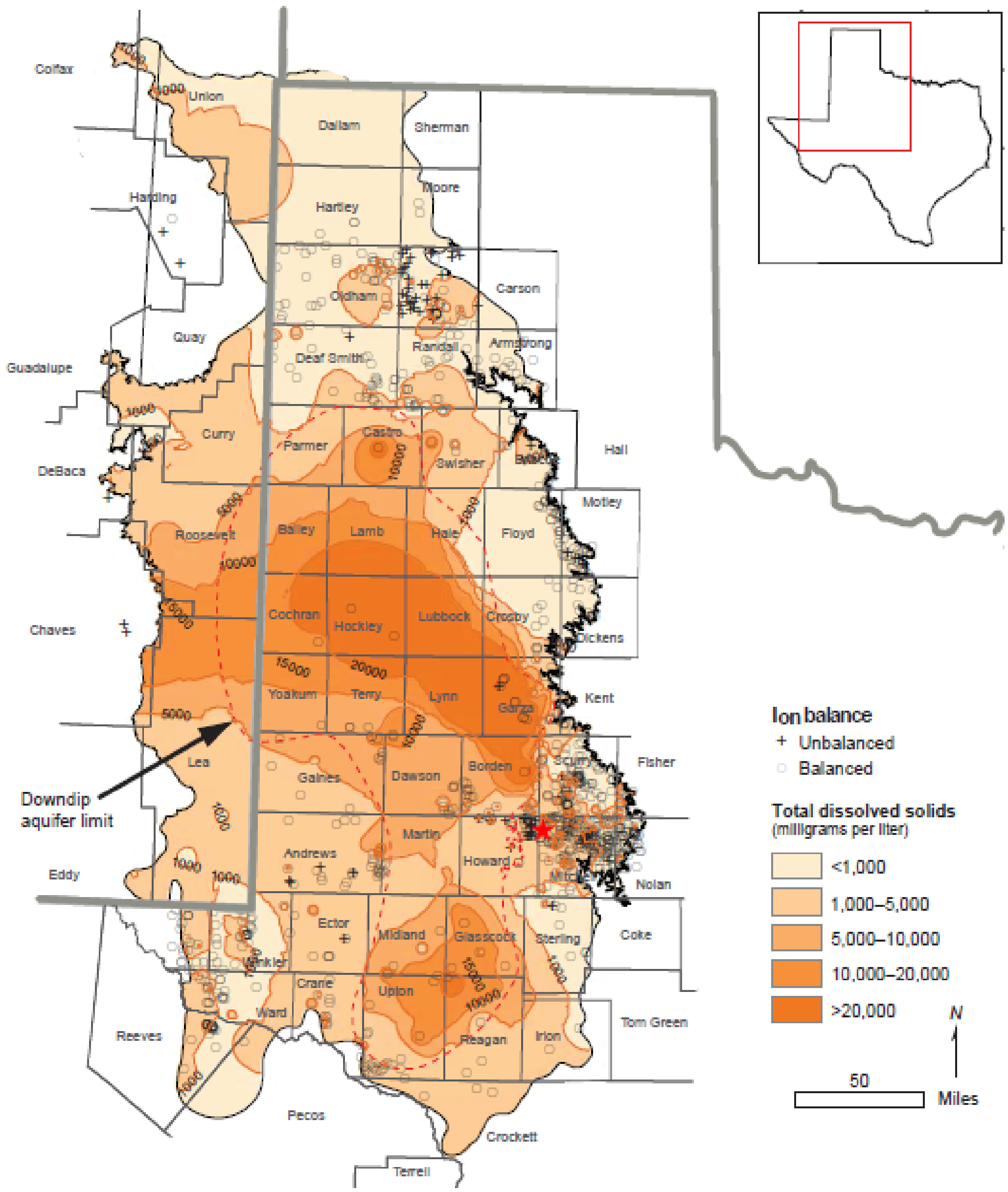


Figure 32 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 Description of the Injection Process

2.7.1 Current Operations

The Mongoose Gas Plant and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO_2, which equates to 155.3 MT/yr of CO_2 each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Mongoose Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

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

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction of true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite-acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S and CO_2 based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H_2S and 41.2% CO_2. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H_2S and 41.2% CO_2.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H_2S)	58.8	58.8
Carbon Dioxide (CO_2)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 0.1, an irreducible water saturation of 0.397, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 33.

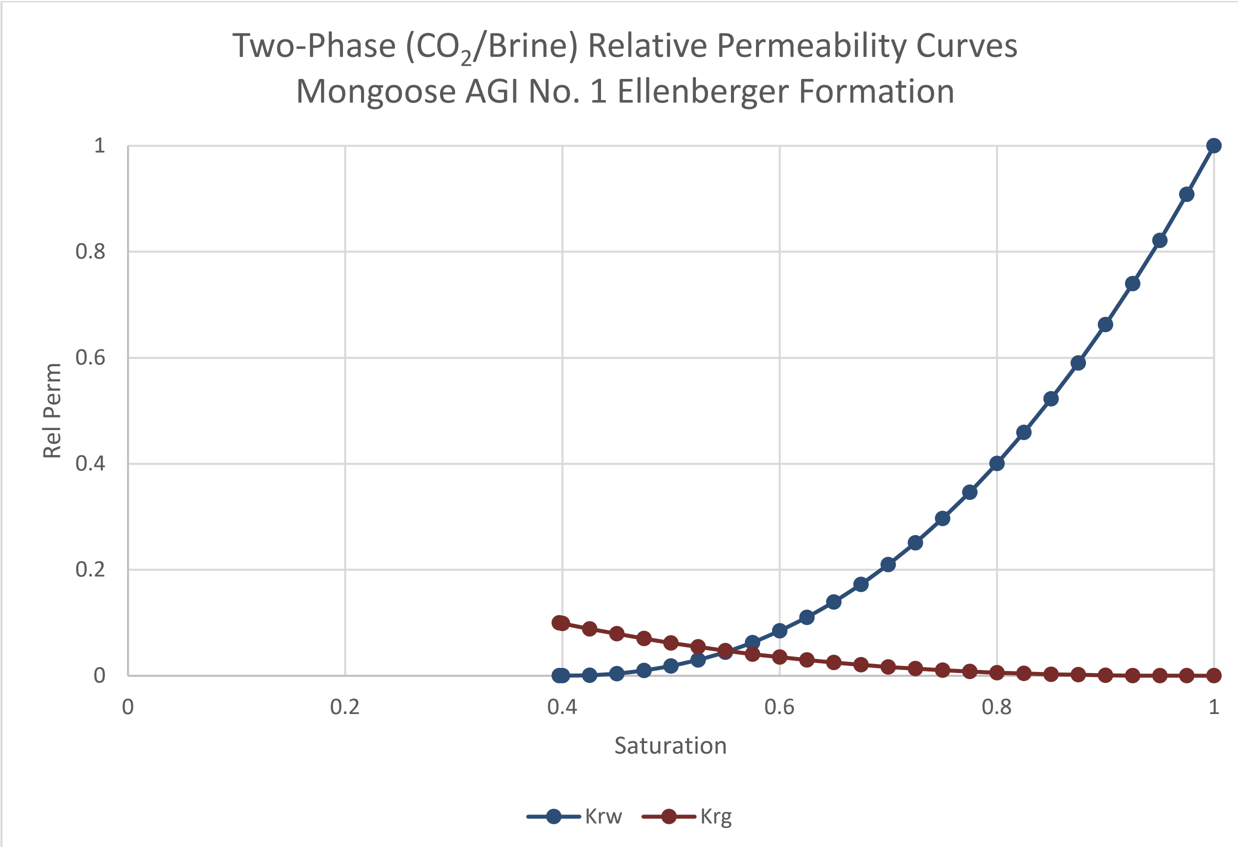


Figure 33 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (north-south), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Table 9 – GEM Model Layer Package Properties

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

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

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

Table 10 – Offset SWD Wells Included in GEM Model

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 34. The final extent after 120 years of density drift after injection ceases is shown in Figure 35. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 36 and the final extent after 120 years of density drift after injection ceases is shown in Figure 37.

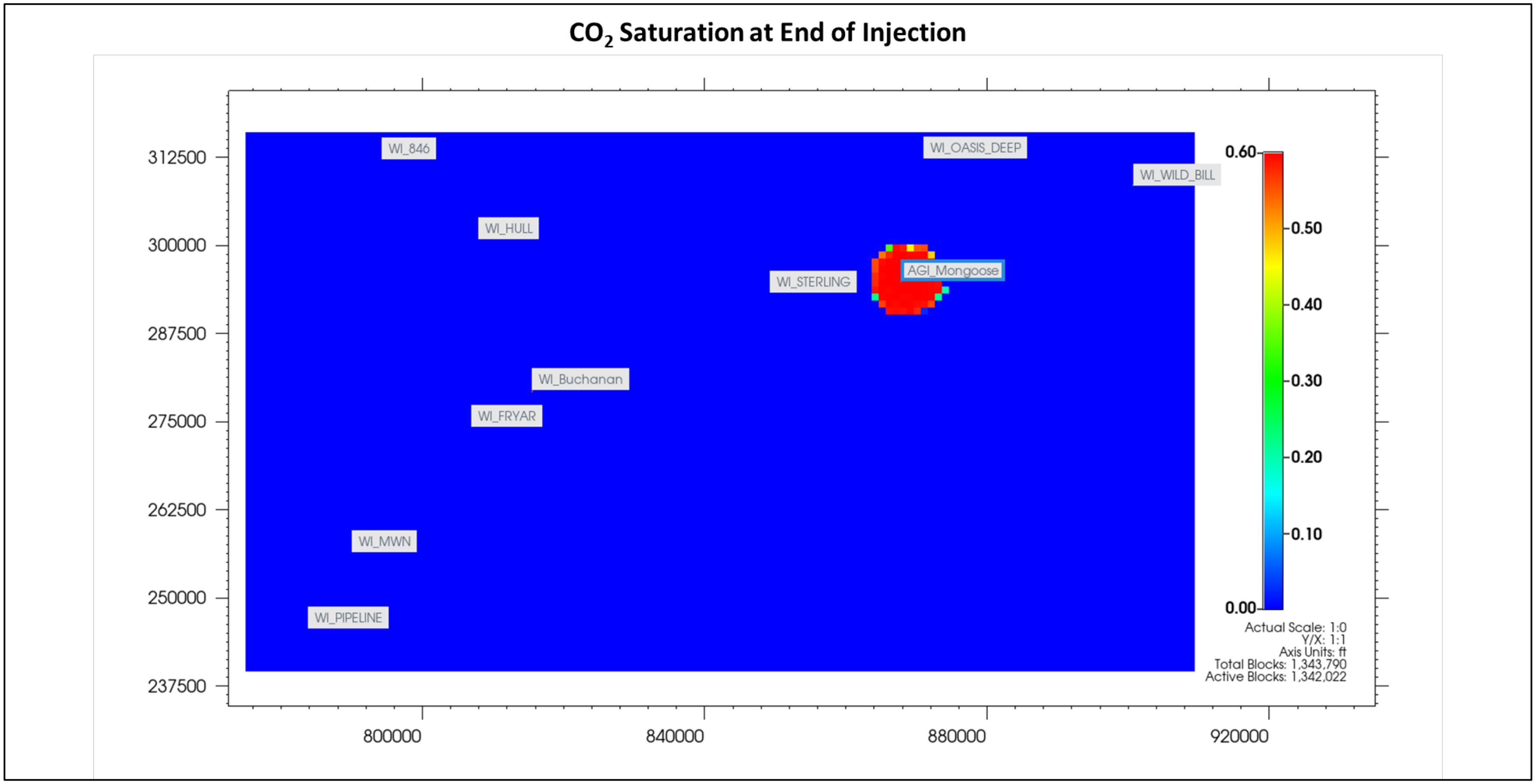


Figure 34 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)

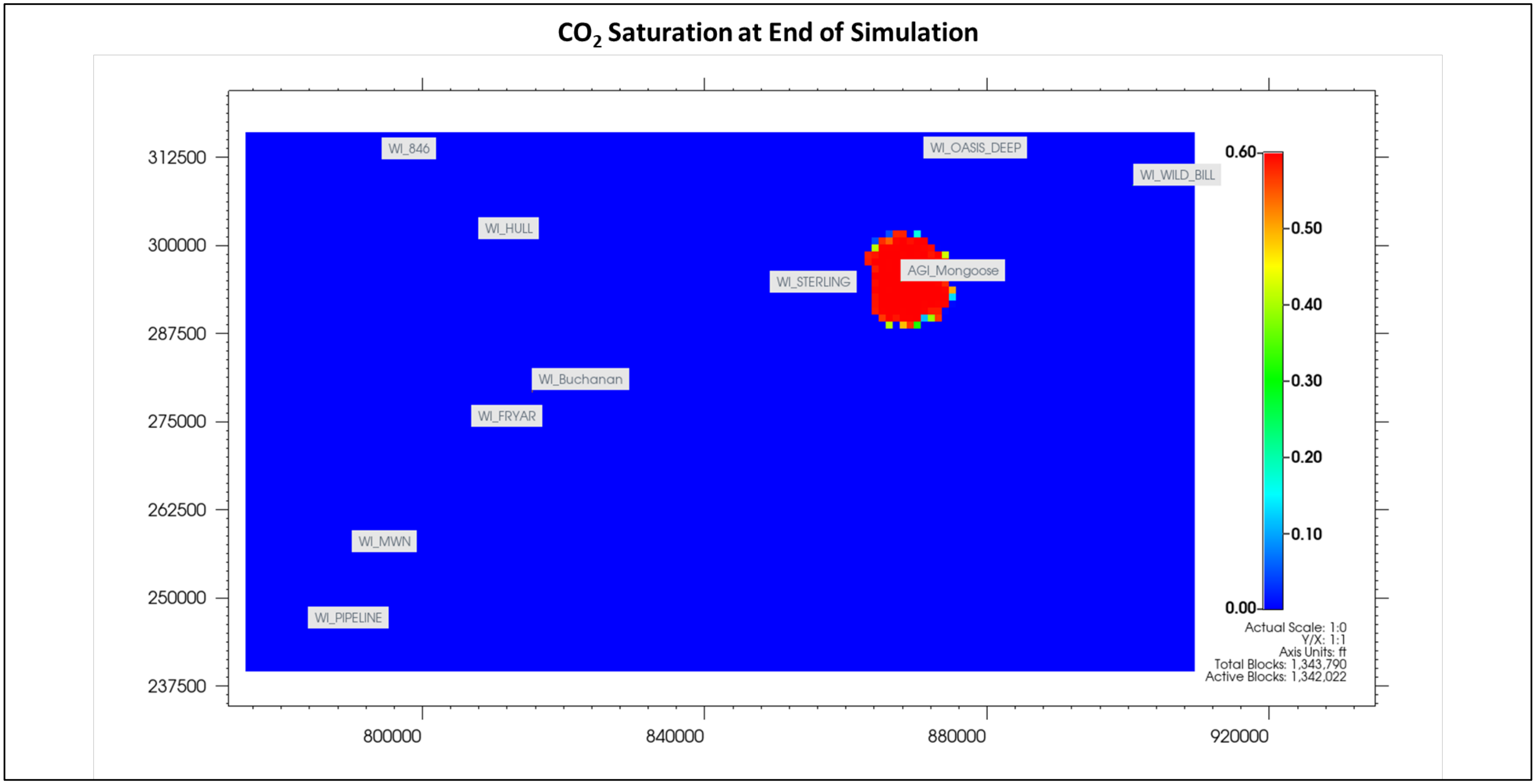


Figure 35 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

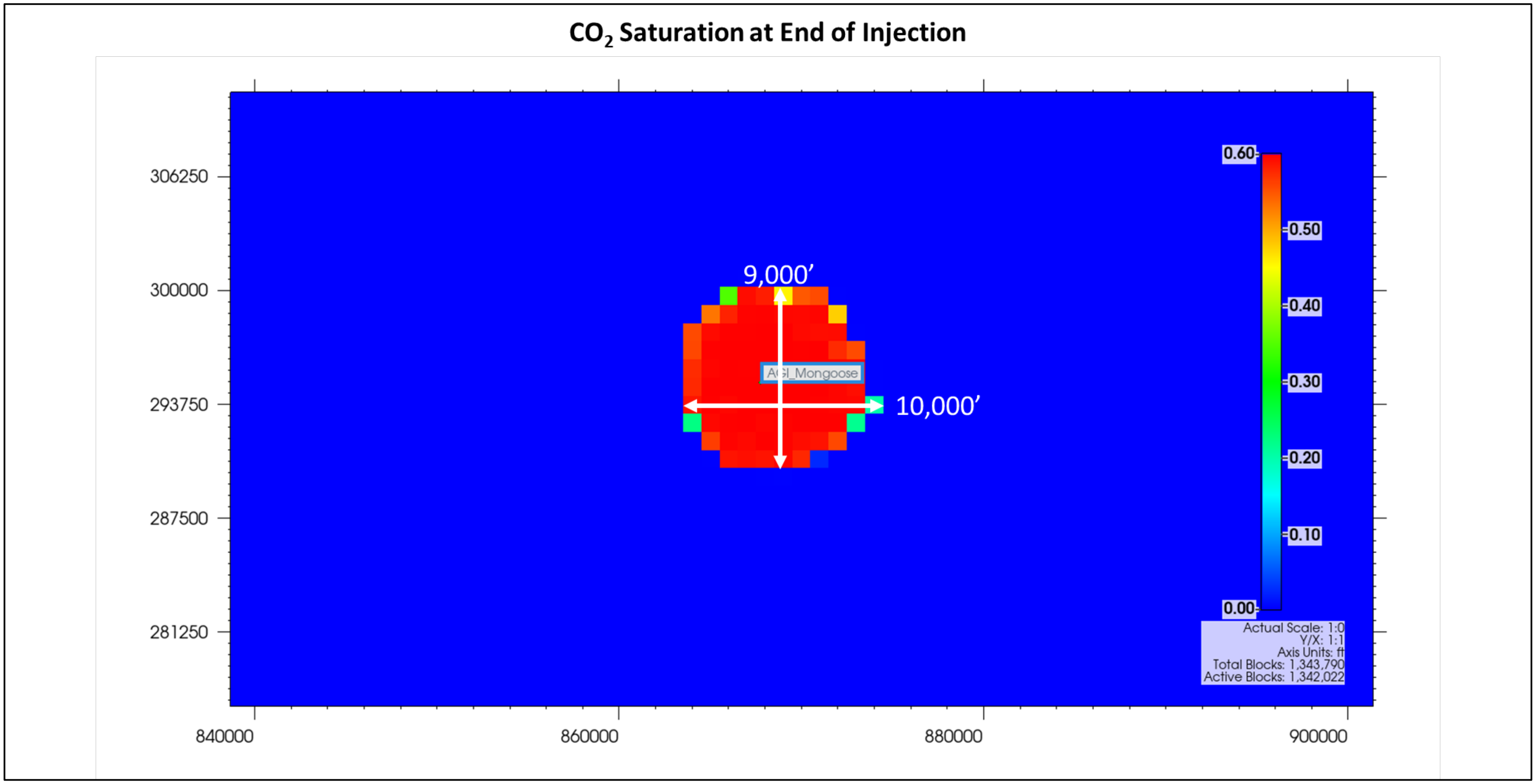


Figure 36 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)

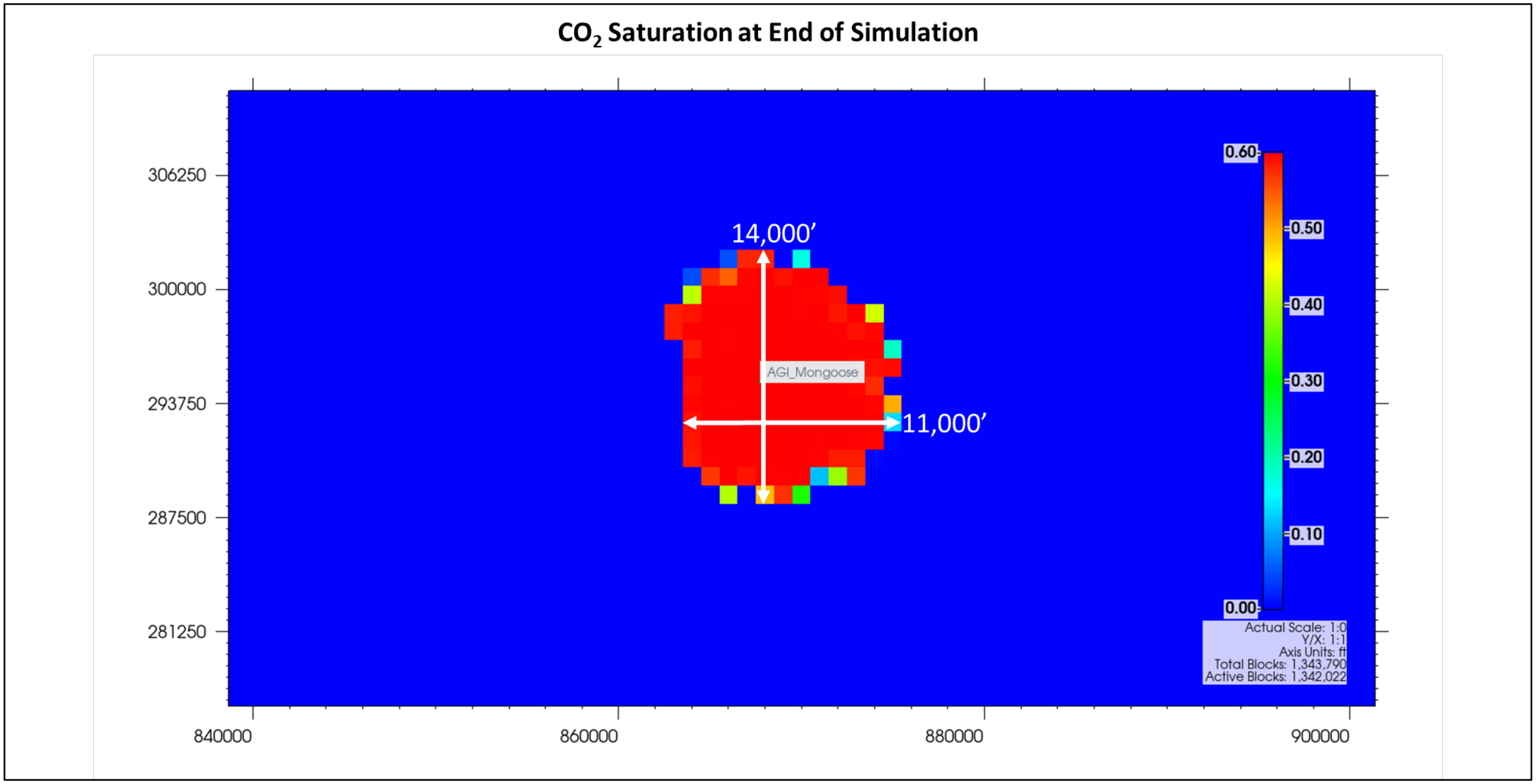


Figure 37 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 38 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 39 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.

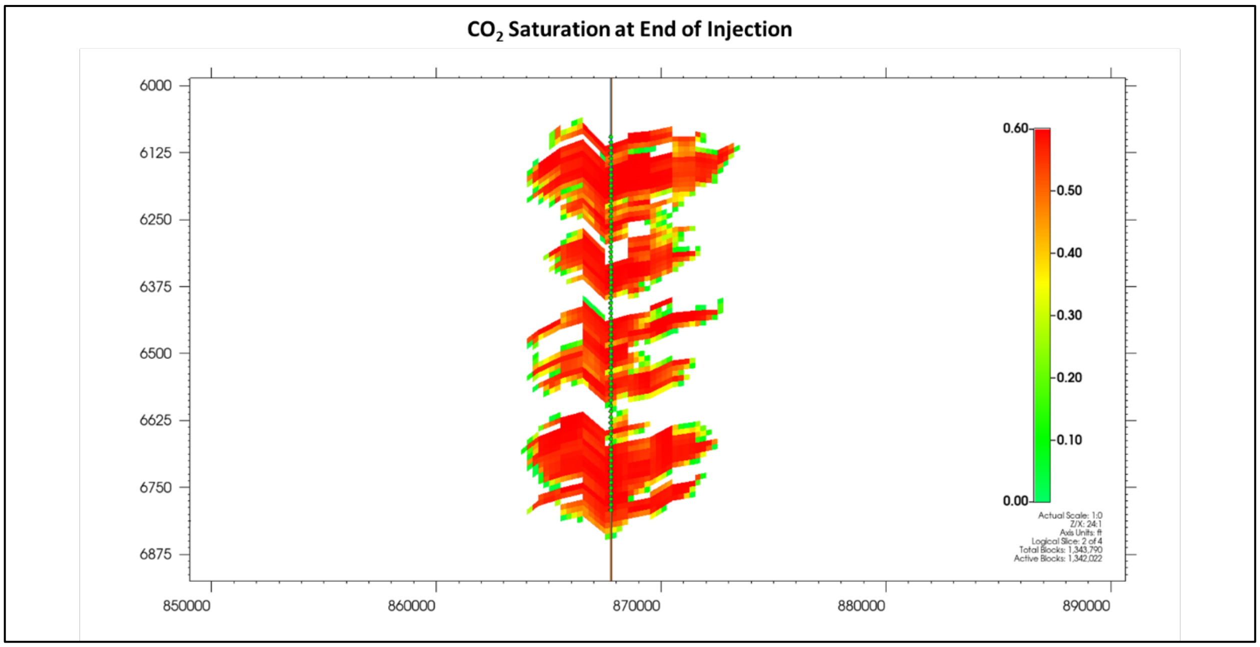


Figure 38 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

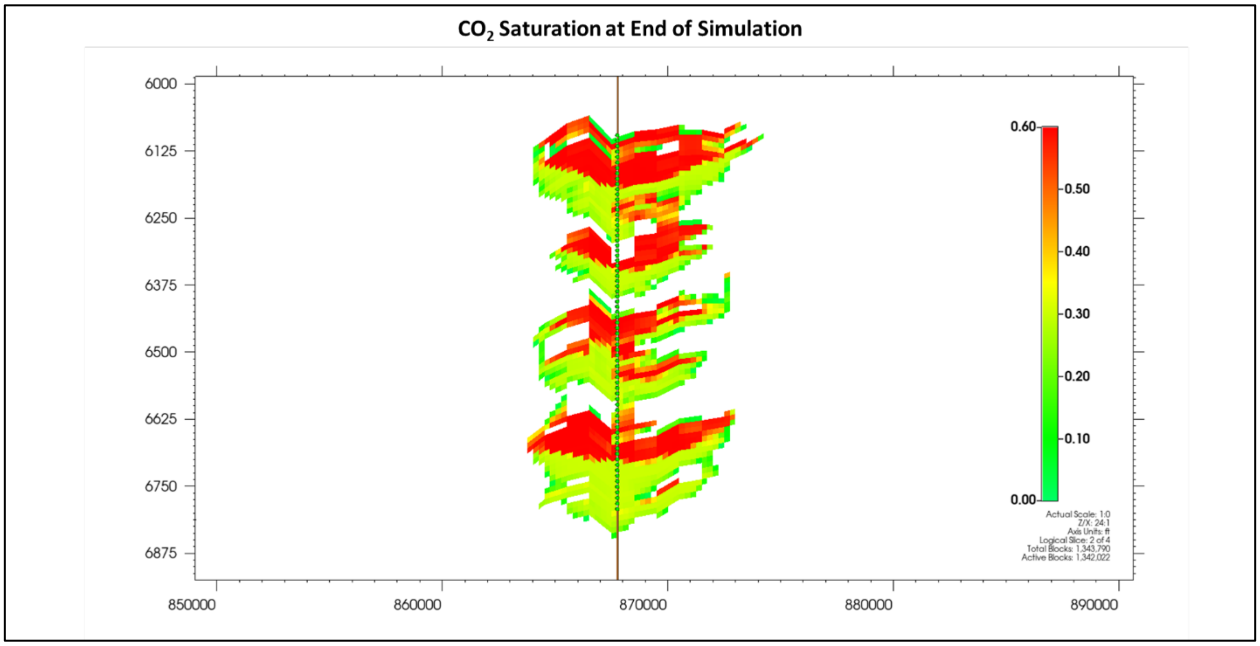


Figure 39 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 40 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.

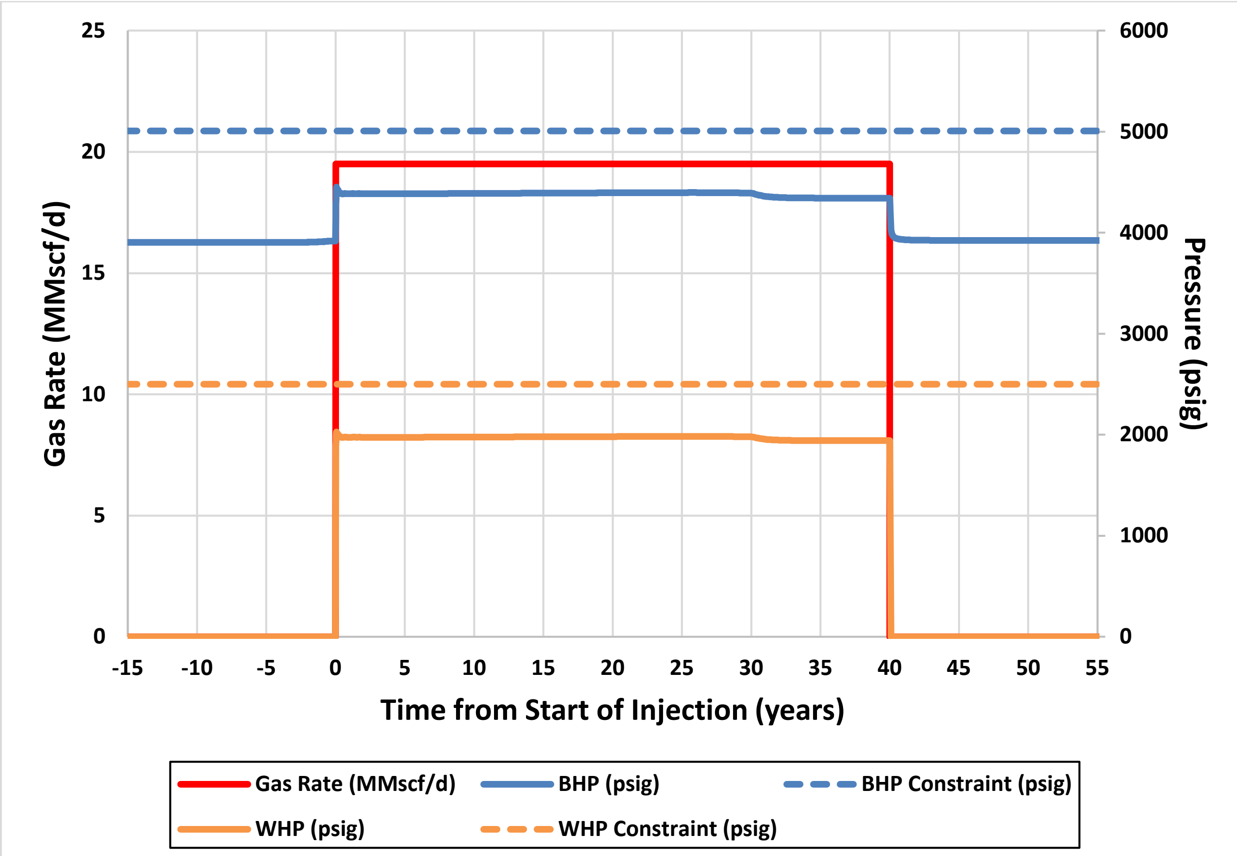


Figure 40 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H_2S and 41.2% CO_2, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 41 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA.

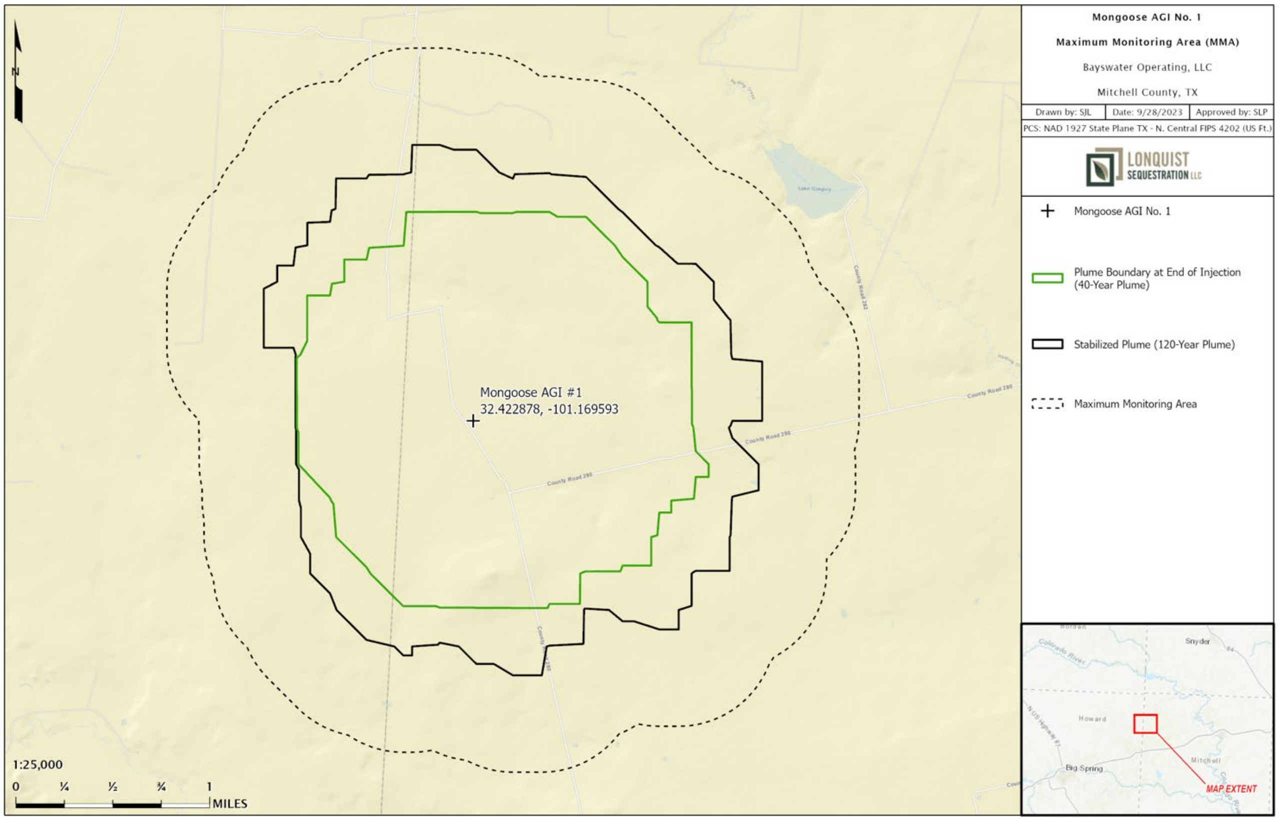


Figure 41 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop their asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 42 shows the area covered by the AMA.

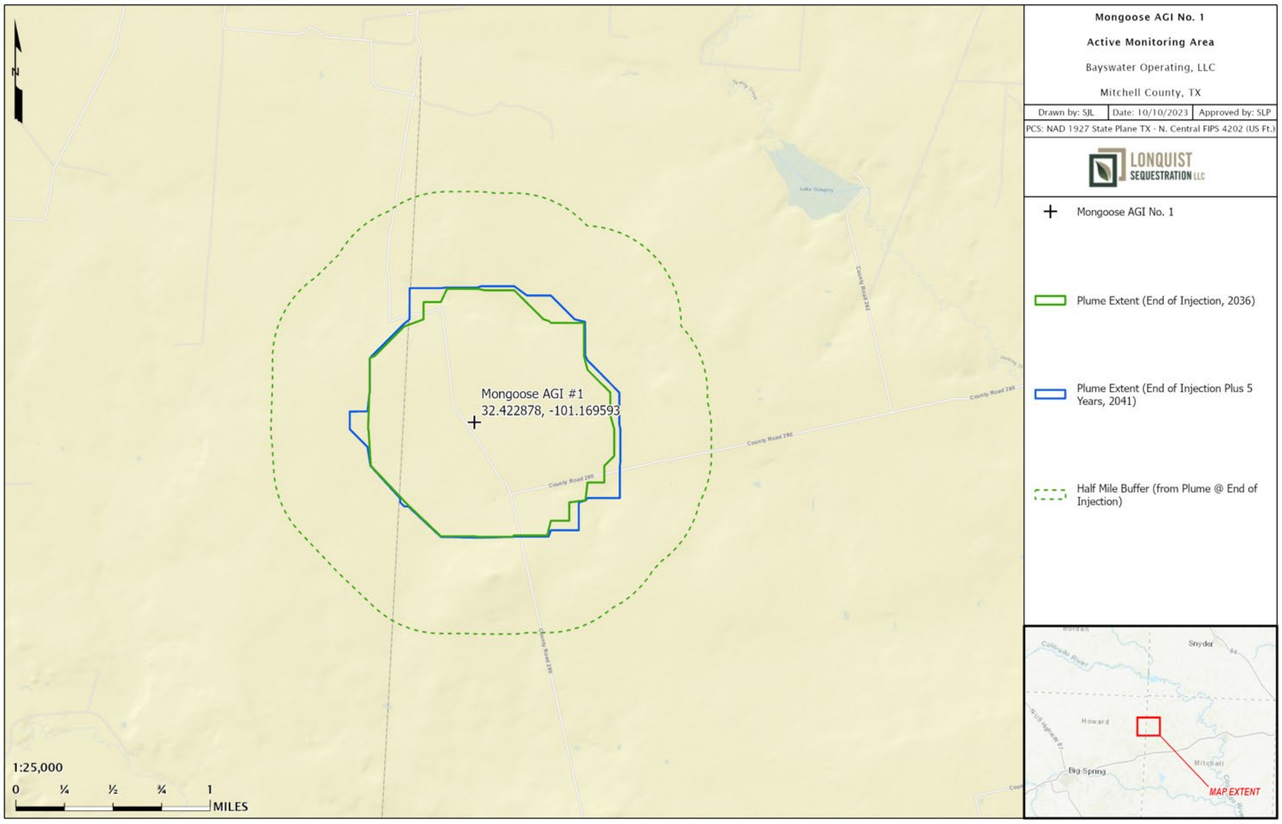


Figure 42 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

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

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with a fundamental objective to ensure maximum safety to the public, the employees, and the environment. These are depicted in Figures 43 and 44. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H_2S are installed at key locations around the Plant. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points derived from the baseline study of the ambient air quality and supported by a gas dispersion model.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the Mongoose, and other components of the facility. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs.

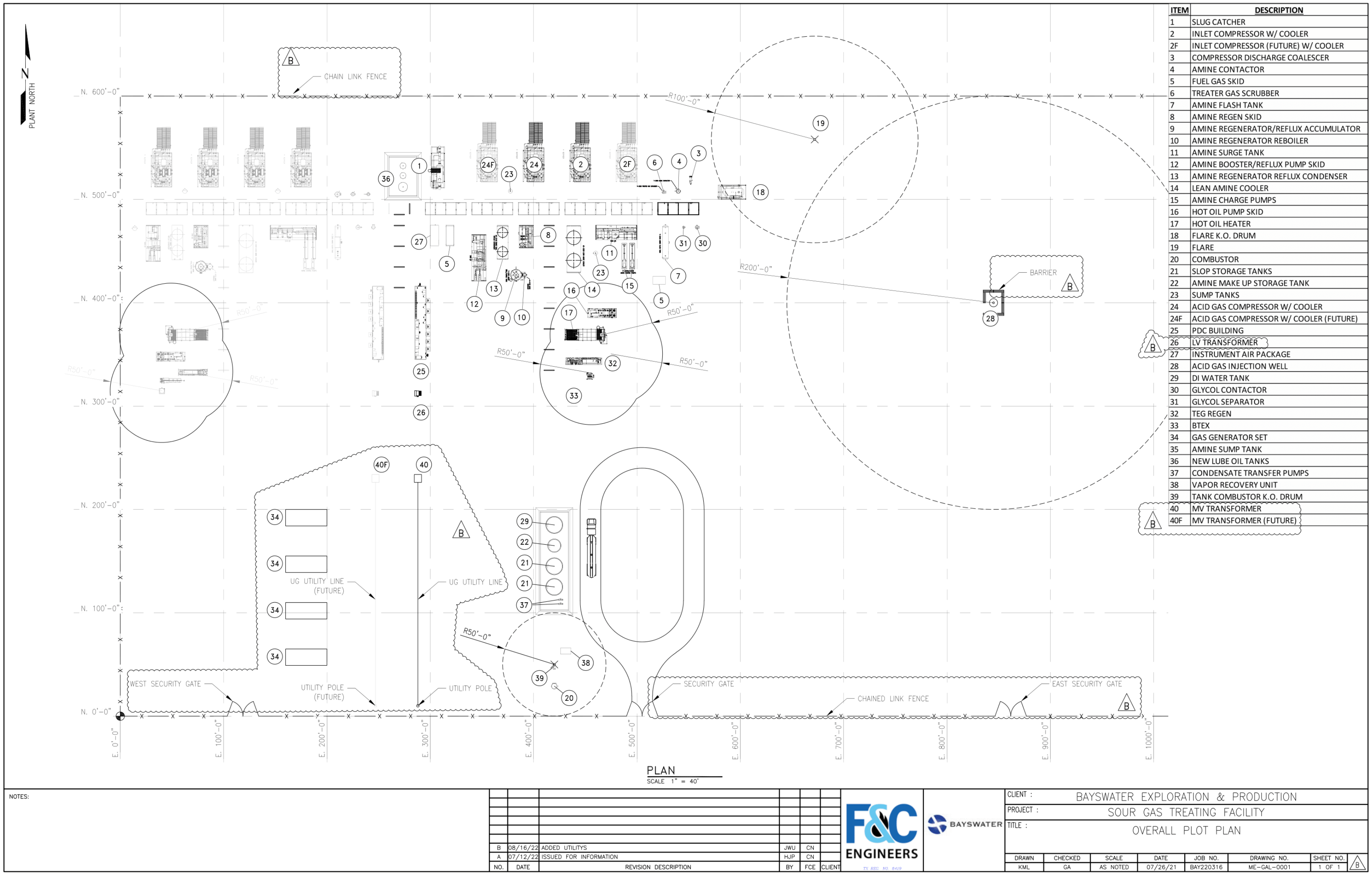
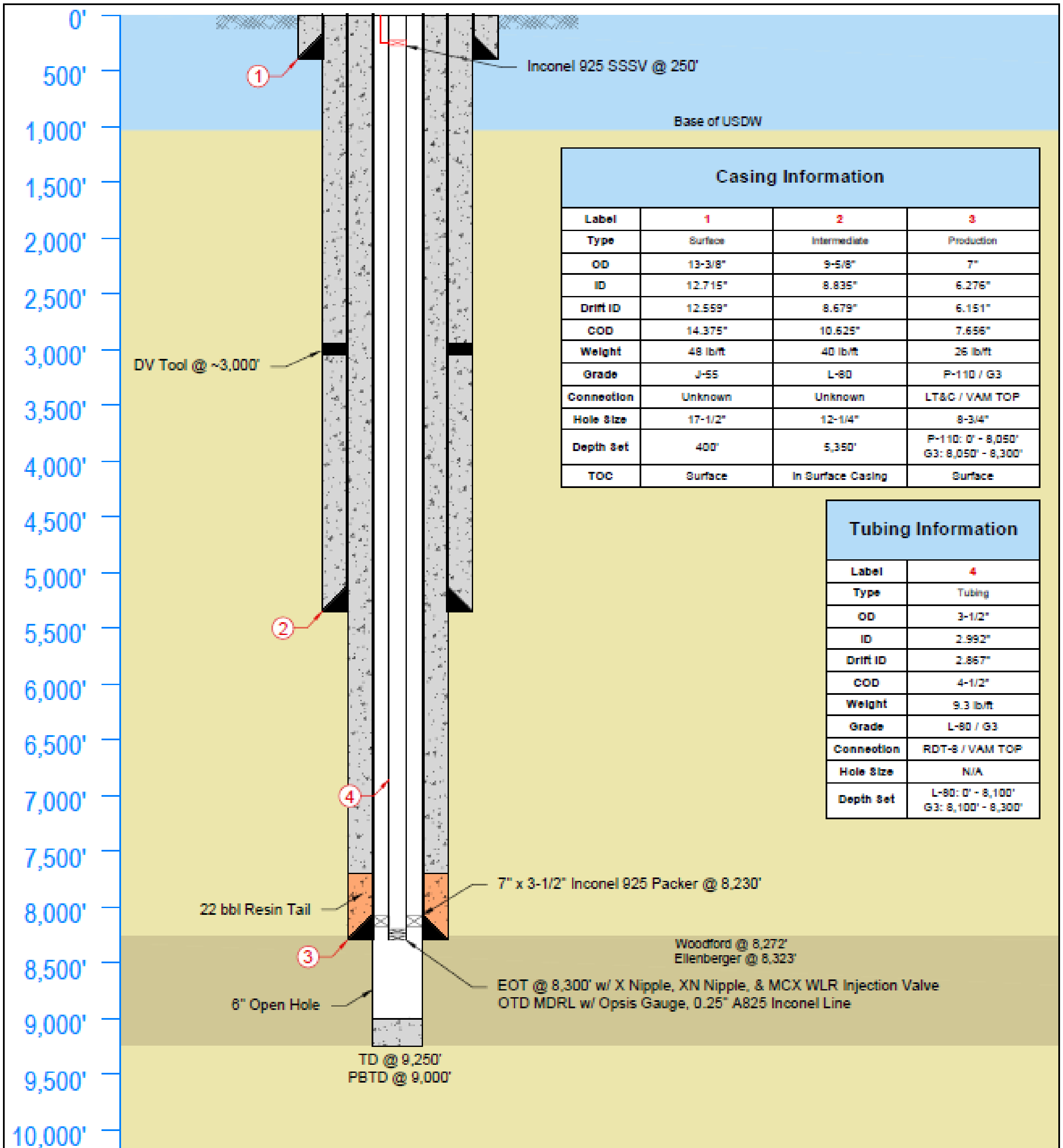


Figure 43 – Site Plan



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
ID	12.715"	8.835"	6.276"
Drift ID	12.559"	8.679"	6.151"
COD	14.375"	10.625"	7.656"
Weight	48 lb/ft	40 lb/ft	26 lb/ft
Grade	J-55	L-80	P-110 / G3
Connection	Unknown	Unknown	LT&C / VAM TOP
Hole Size	17-1/2"	12-1/4"	8-3/4"
Depth Set	400'	5,350'	P-110: 0' - 8,050' G3: 8,050' - 8,300'
TOC	Surface	In Surface Casing	Surface

Tubing Information

Label	4
Type	Tubing
OD	3-1/2"
ID	2.992"
Drift ID	2.867"
COD	4-1/2"
Weight	9.3 lb/ft
Grade	L-80 / G3
Connection	RDT-8 / VAM TOP
Hole Size	N/A
Depth Set	L-80: 0' - 8,100' G3: 8,100' - 8,300'

LONQUIST FIELD SERVICE	Bayswater Operating Company LLC	Mongoose AGI #1	
	Country: USA	State/Province: TX	County/Parish: Mitchell
	API No: 42-335-36013	Field: Sprayberry Trend	Well Type/Status: Acid Gas Injection
Texas License F-9147	RRC District No:	Project No: LS188	Date: 09/07/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved:
	Rev No: 1	Notes:	

Figure 44 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own production and possible other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 44. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 45. The MMA review map and a summary of all the wells in the MMA are provided in *Appendix D*. Figure 46 highlights that only two wells penetrate the MMA's gross injection zone, and these wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements.

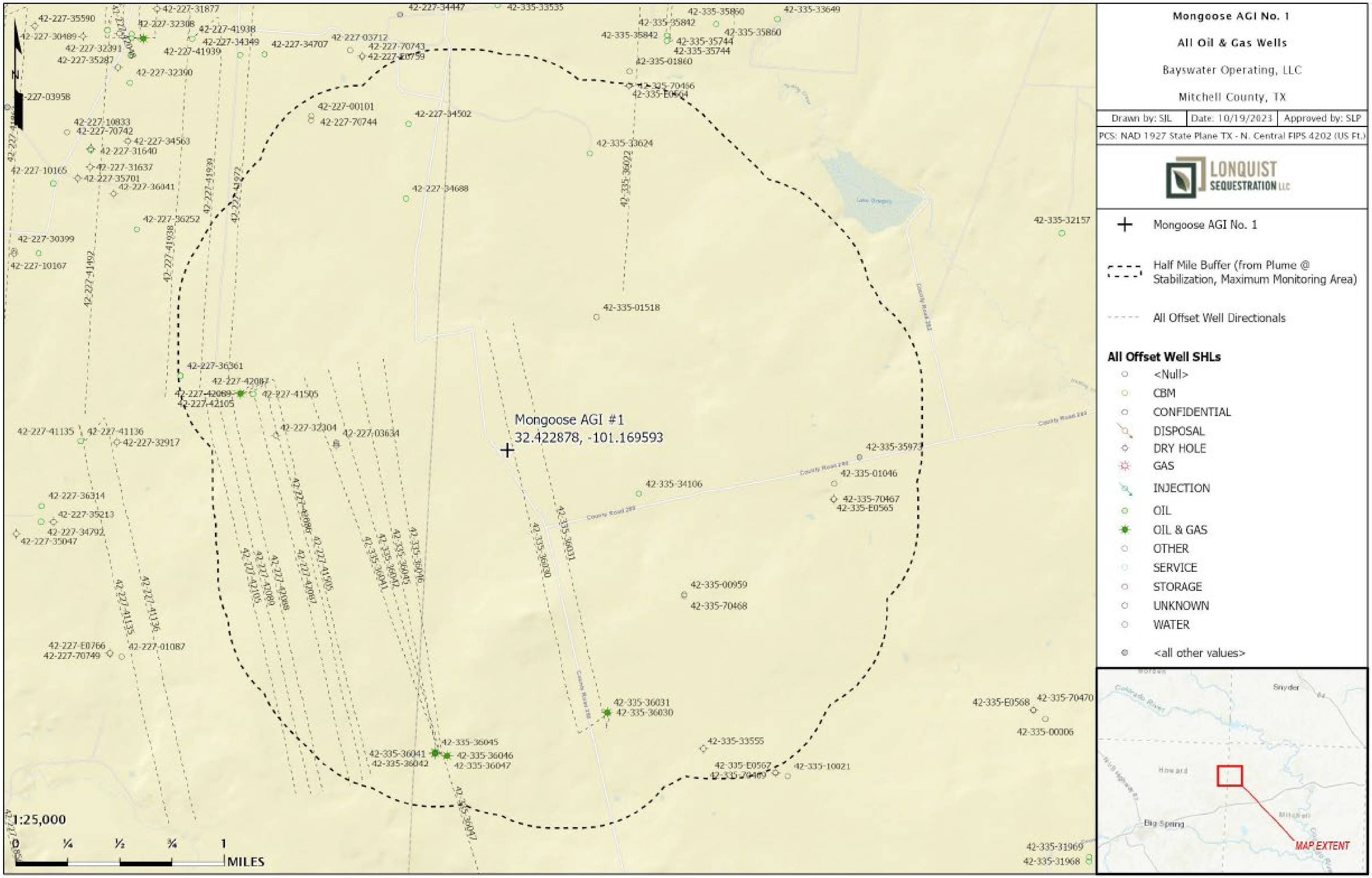


Figure 45 – All Oil and Gas Wells Within the MMA

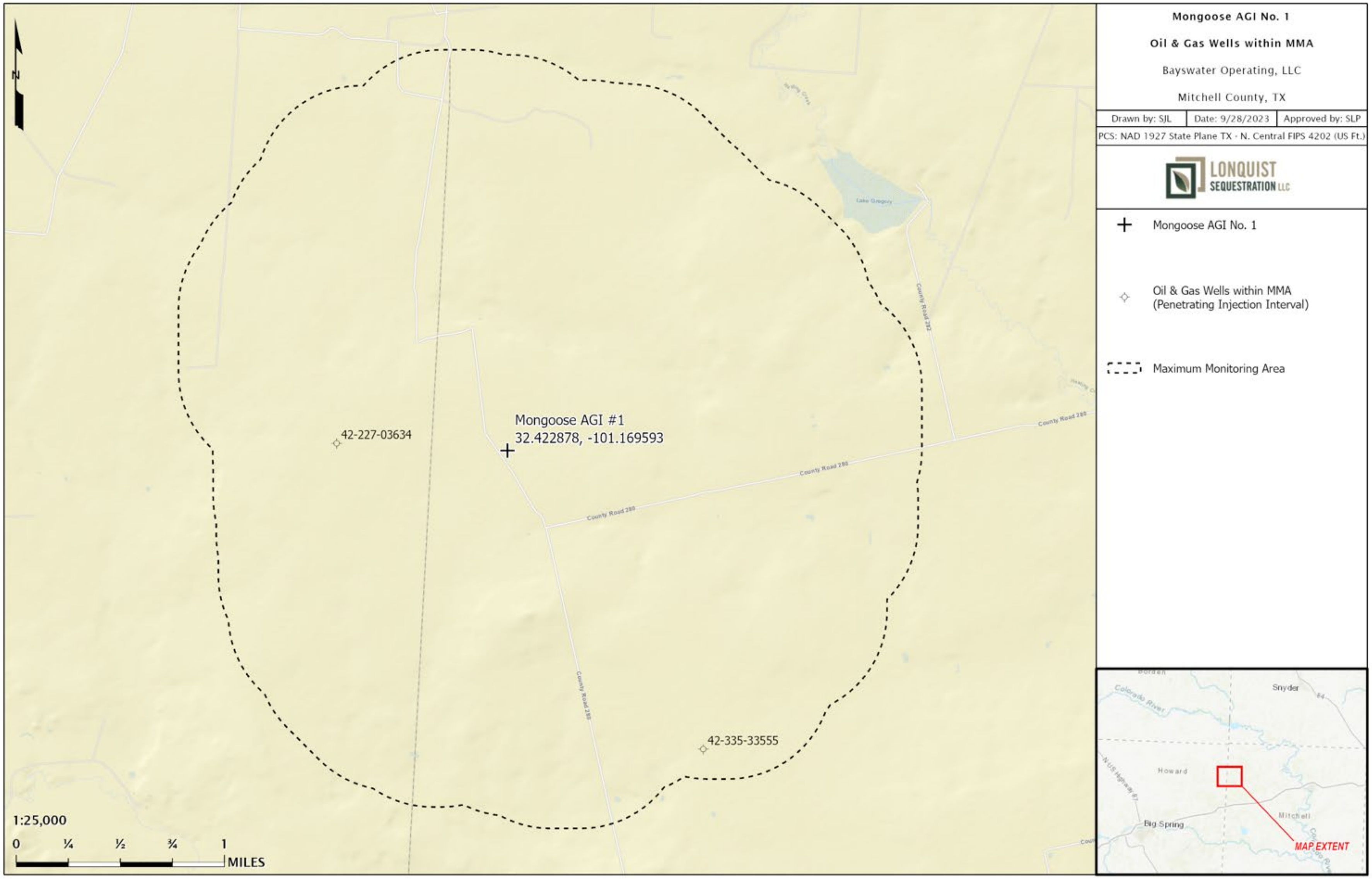


Figure 45 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Mongoose drilling permit, provided in *Appendix A*, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a quarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued (also provided in the permit in *Appendix A*).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board and shown in Figure 47.

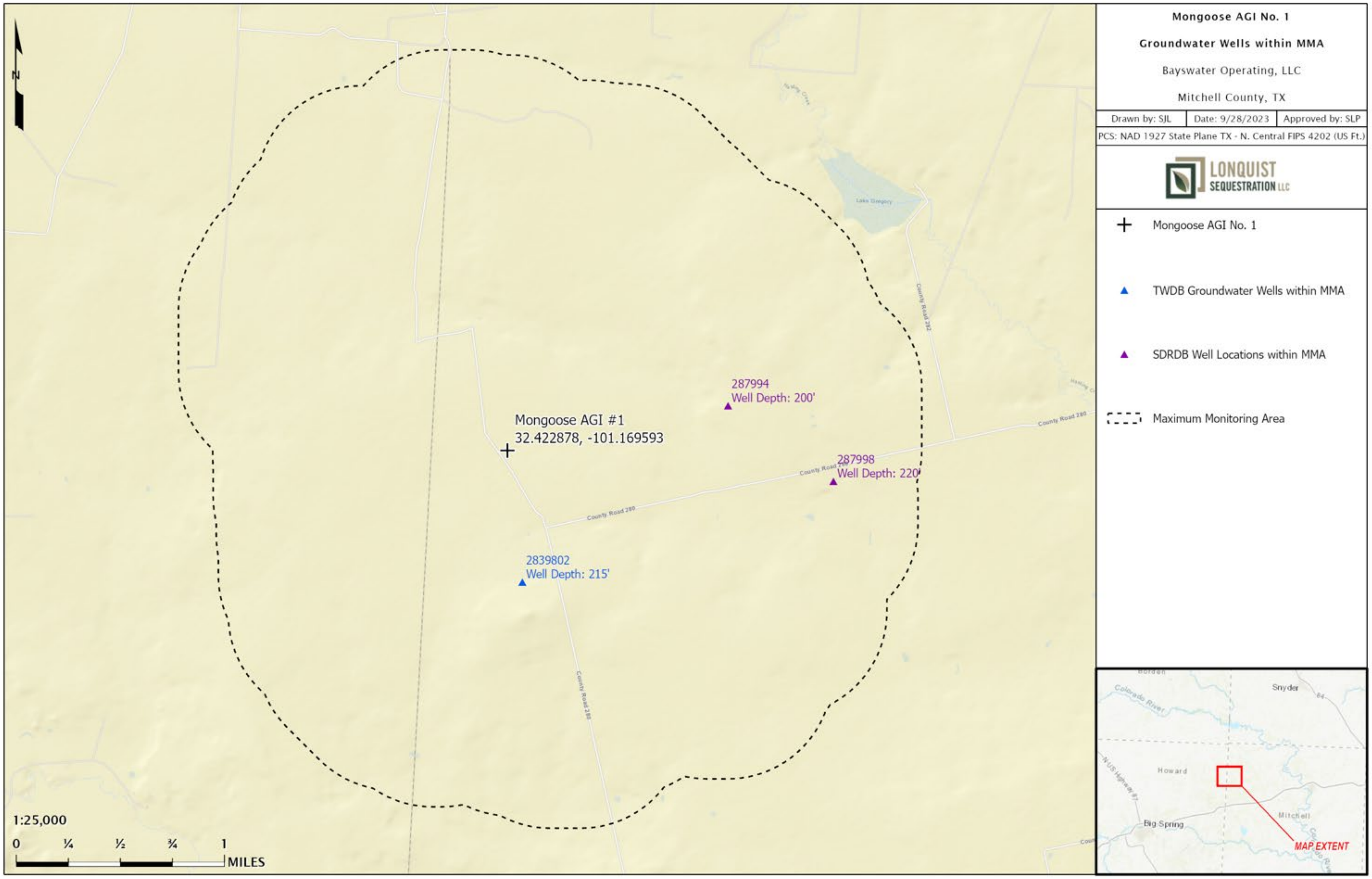


Figure 46 – Groundwater Wells Within the MMA

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 44, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

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

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale that would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

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

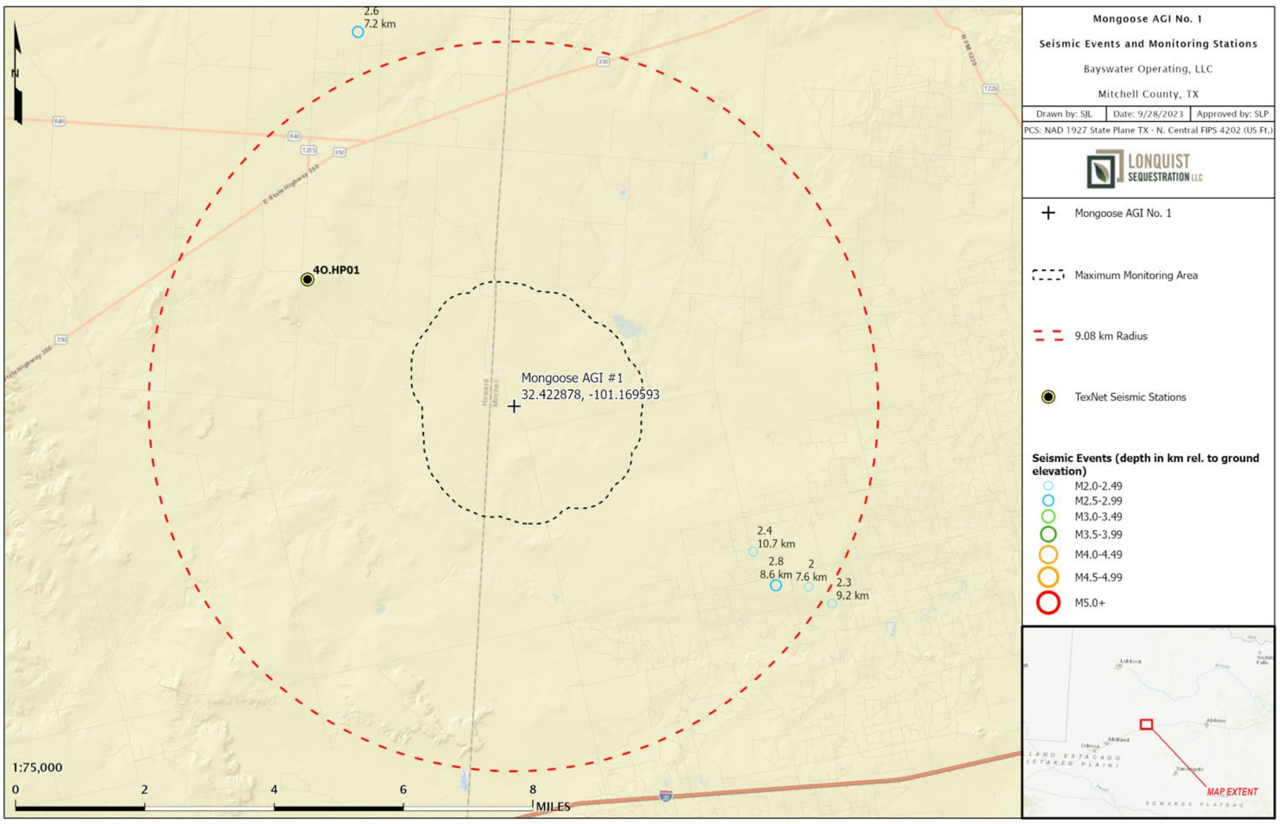


Figure 47 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 12 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Table 12 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Visual inspections
	Remote operated control room 24 hours per day, 7 days per week, 52 weeks per year
Leakage through existing wells	Fixed H_2S monitor at the AGI well
	Continuous monitoring of the AGI well from remote operated control room
	Mechanical Integrity Tests (MIT) of the AGI well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations the penetrate the Upper Confining Layer within the AMA
Leakage through groundwater wells	Annual groundwater samples from existing water wells
Leakage from future wells	CO_2 monitoring during offset drilling operations
Leakage through faults and fractures	Remote, continuous monitoring of the AGI well (volumes and pressures)
	Annual report from in-field soil gas sampling
Leakage through the confining layer	Remote, continuous monitoring of the AGI well (volumes and pressures)
	Annual report from in-field soil gas sampling
Leakage from natural or induced seismicity	Monitor existing TexNet seismic station for activity

5.1 Leakage from Surface Equipment

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established. Ambient H_2S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix E*. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

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

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, MITs performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

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

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Layer. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. However, a soil gas sample will be taken annually and analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2.1.1 Groundwater Quality Monitoring

Bayswater will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the facility and analyzing the sample with a third-party laboratory on an annual basis. In the case of the Mongoose, three existing groundwater wells have been identified within the AMA (Figure 49).

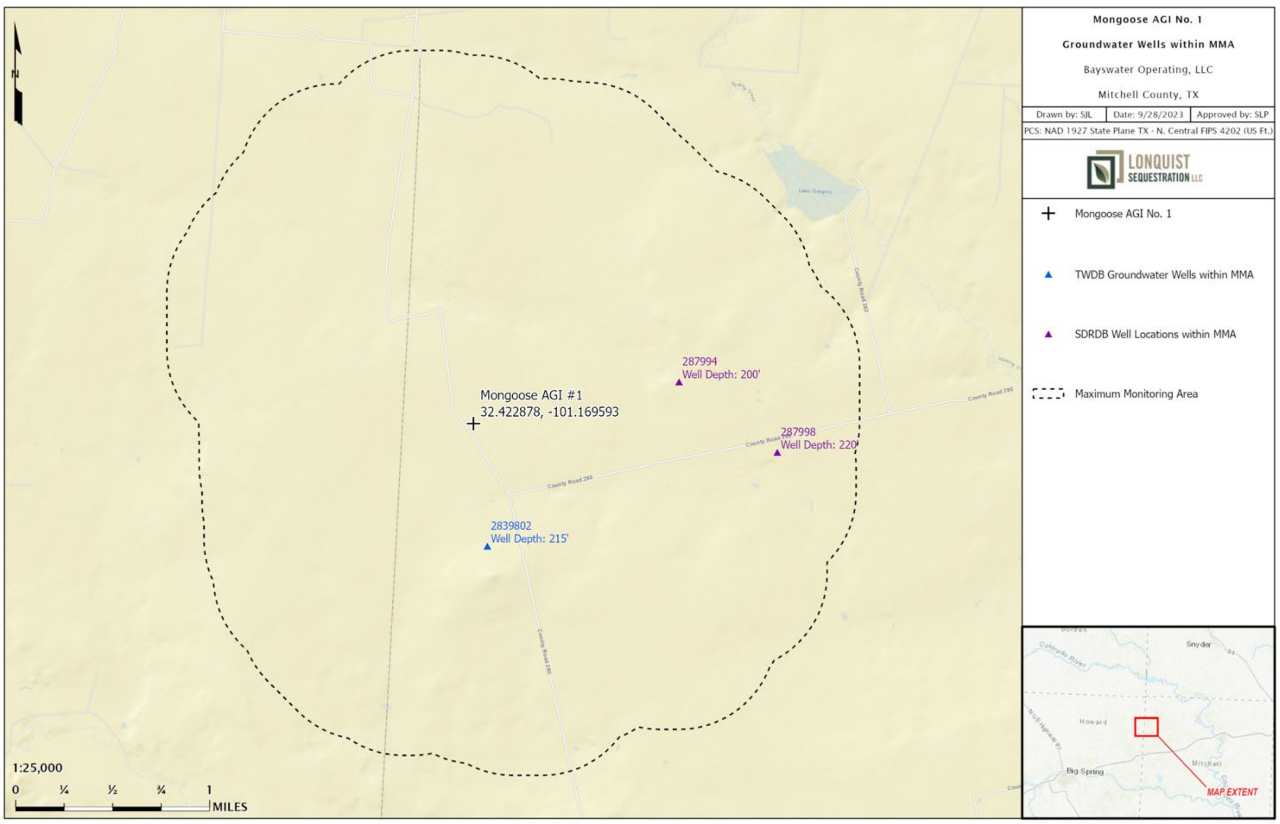


Figure 48 – Groundwater Monitoring Wells

5.3 Leakage Through Faults, Fractures, or Confining Seals

Bayswater continuously monitors the operations of the Mongoose well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 50. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

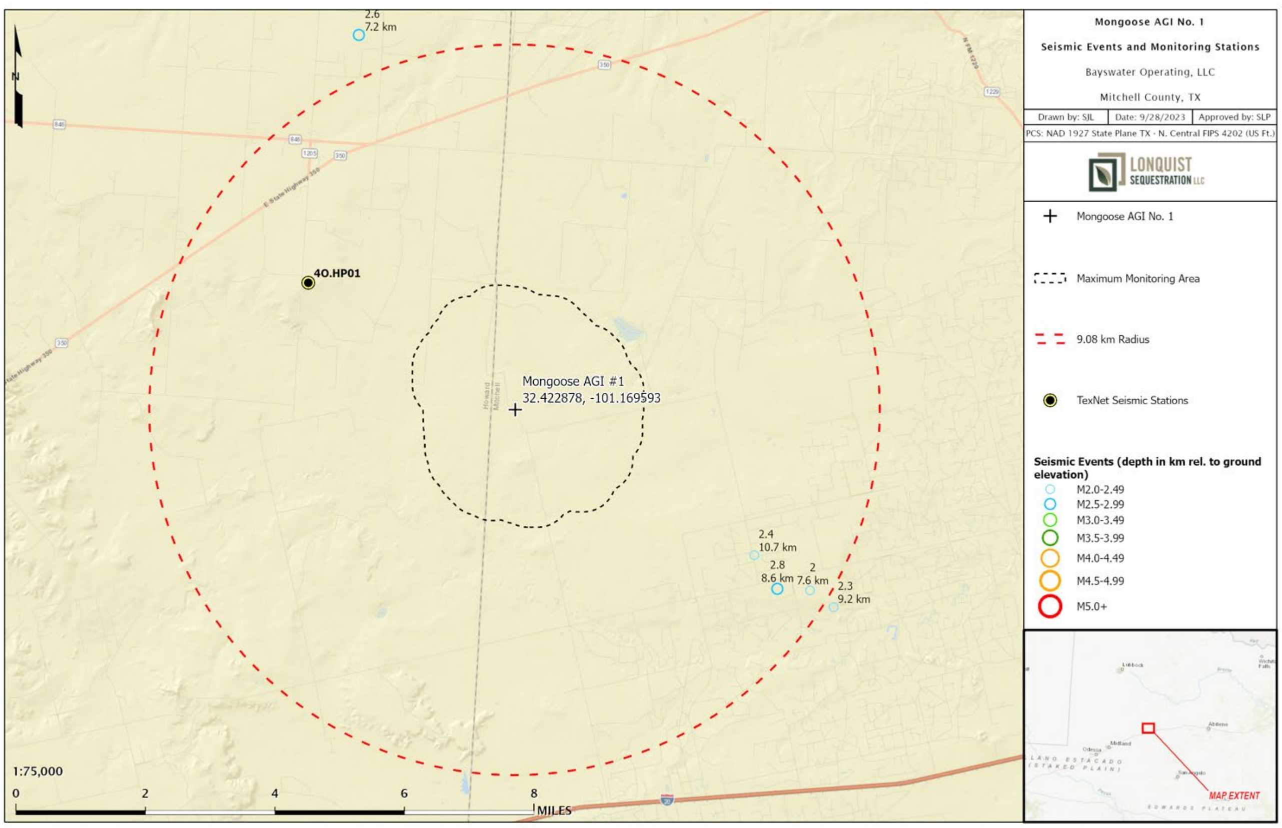


Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

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

6.2 CO_2/H_2S Detection

In addition to the fixed monitors at the well site described previously, Bayswater will establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of baseline determination will include atmospheric H_2S measurements at the AGI well and soil gas sampling for CO_2 near the two identified abandoned wells within the AMA. Initial readings will be taken to establish baseline values for CO_2.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO_2.

6.4 Continuous Monitoring

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

In the case of a de-pressuring event, the acid gas will be sent to a flare stack to safely process and vent the gas stream and will be reported as required for the operation of the well.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

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

7.2 Mass of CO_2 Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

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

7.4 Mass of CO_2 Emitted by Surface Leakage

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

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

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

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

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

X = Leakage pathway

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

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

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose is in operation, the date Bayswater will begin collecting data for calculating the total amount of CO_2 will be the date the MRV Plan is approved. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on an unusual event that a blowdown is required and those emissions are sent to a flare stack and reported as part of the required GHGG reporting for the Plant.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGG to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Bayswater plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

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

CO_2 Emissions from Leaks and Vented Emissions

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

Measurement Devices

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

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

9.2 Missing Data

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

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

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

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Bayswater will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

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

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

SECTION 11 - REFERENCES

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APPENDICES

APPENDICES

APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN
WAYNE CHRISTIAN, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
DEPUTY EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS, P.E.
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17174

BAYSWATER OPERATING COMPANY LLC
730 17TH STREET
SUITE 500
DENVER CO 80202

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE
SPRABERRY (TREND AREA) FIELD
MITCHELL COUNTY
DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO_2); Hydrogen Sulfide (H_2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33536013	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.** **3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO_2. Geologic sequestration of CO_2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;

Note: This document will only be distributed electronically.

c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON March 10, 2023.

FOR Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	04 March 2022	**GAU Number:**	336979
Attention:	BAYSWATER OPERATING 730 17TH STREET SUITE 500 DENVER, CO 80202	**API Number:**	33536013
		County:	MITCHELL
		Lease Name:	Mongoose AGI
Operator No.:	058827	**Lease Number:**	
		Well Number:	1
		Total Vertical	9250
		Latitude:	32.422884
		Longitude:	-101.169661
		Datum:	NAD27

Purpose: Injection into Non-producing Zone (W-14)

Location: Survey-T&P RR CO; Abstract-1545; Block-29; Township-1N; Section-4

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 350 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 475 feet at the site of the referenced well.

This recommendation is applicable to all wells within a radius of 200 feet of this location.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 03/02/2022. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary. If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRICT * 08
API NUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03, 2022	COUNTY MITCHELL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 40
OPERATOR 058827 BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER, CO 80202-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (432) 684-5581
LEASE NAME MONGOOSE AGI		WELL NUMBER 1
LOCATION 10.4 miles NW direction from WESTBROOK		TOTAL DEPTH 10000
Section, Block and/or Survey SECTION 4 BLOCK 29 T1N ABSTRACT 1545 SURVEY T&P RR CO/MORRISON, W		
DISTANCE TO SURVEY LINES 551 ft. EAST 2164 ft. SOUTH		DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 400 ft. EAST 650 ft. SOUTH		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
SPRABERRY (TREND AREA) MONGOOSE AGI	40.00	10,000	1 0	08

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

A-4

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Submitted
Date: 09/11/2023
Tracking No.: 298516

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator BAYSWATER OPERATING COMPANY LLC **Operator** 058827
Operator 730 17TH STREET SUITE 500 DENVER, CO 80202-

WELL INFORMATION

API 42-335-36013 **County:** MITCHELL
Well No.: 1 **RRC District** 08
Lease MONGOOSE AGI **Field** SPRABERRY (TREND AREA)
RRC Lease **Field No.:** 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRISON, W, Abstract: 1545

Latitude 32.423000 **Longitud** -101.170059
This well is 10.4 **miles in a** NW
direction from WESTBROOK,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC **Completion or Recompletion** 04/28/2023

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	02/10/2022	876754
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal		17174
Other:		

COMPLETION INFORMATION

Spud 10/12/2022 **Date of first production after rig** 04/28/2023
Date plug back, deepening, drilling operation 10/12/2022 **Date plug back, deepening, recompletion, drilling operation** 04/28/2023
Number of producing wells on this lease this field (reservoir) including this 1 **Distance to nearest well in lease & reservoir**
Total number of acres in 40.00 **Elevation** 2252 GL
Total depth TVD 9289 **Total depth MD**
Plug back depth TVD 9036 **Plug back depth MD**
Was directional survey made other inclination (Form W- Yes **Rotation time within surface casing** 41.0
Is Cementing Affidavit (Form W-15) Yes
Recompletion or No **Multiple** No
Type(s) of electric or other log(s) Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease **Off Lease :** No
of lease on which this well is 400.0 **Feet from the** East **Line and**
650.0 **Feet from the** South **Line of the**
MONGOOSE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

	Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type
PACKET: N/A				

W2:	N/A				

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination		**Depth**	350.0	**Date**	03/04/2022
SWR 13 Exception		**Depth**			

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		**Production**	
Number of hours	24	**Choke**	
Was swab used during this	No	**Oil produced prior to**	

PRODUCTION DURING TEST PERIOD:

Oil		**Gas**	
Gas - Oil	0	**Flowing Tubing**	
Water			

CALCULATED 24-HOUR RATE

Oil		**Gas**	
Oil Gravity - API - 60.:		**Casing**	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	569			C	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		C	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			C	610	1175.0	3001	Calculation
4	Conventional Production	7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL 925

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	Yes	L 8343	9036.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1	Other	OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H	9036	9289

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

OPERATOR'S CERTIFICATION

Printed	James Clark	**Title:**	Consulting Petroleum Engineer
Telephone	(512) 415-4191	**Date**	09/11/2023

A-5

000057 0708

▶ Return each W-1 with plat and $100.00 fee. Make check or money order payable to the State Treasurer of Texas. Address to: Railroad Commission of Texas Oil and Gas Division, Drilling Permits P. O. Drawer 12967, Capitol Station Austin, Texas 78711
▶ File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1 Rev. 9/1/83 483-080

080 VMC

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ▶ API No. 42-335-33555 ▶ Permit No. 379724 ▶ Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): Bright & Company 10-18-90
2. Address (including city and zip code): 3200 West Cuthbert, Suite 2-C Midland, Texas 79701
3. RRC Operator No.: 093125
4. RRC District No.: 8
5. County of Well Site: Mitchell
6. Lease Name (32 spaces maximum): Van Tuyle
7. RRC Lease/ID No.: --
8. Well No.: 1
9. Total Depth: 8500'
10. Location
- Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1-N~~ Abstract No. A-584
- This well is to be located 5 miles in a north direction from Iatan which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.
12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

Granted 10/29/90

13. FIELD NAME (Exactly as shown on RRC proration schedule.) List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
~~Wolfcamp (Wildcat)~~	~~5200'~~	~~467-1200~~	~~40~~	~~40~~	~~NO~~	~~NA~~	~~0~~	~~1~~	
~~Strawn (Wildcat)~~ per Tracy	~~7800'~~	~~467-1200~~	~~40~~	40	NO	NA	0	1	
~~Ellenburger~~ (Wildcat) 18001	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
- Lease/Unit 1000' FNL & 2500' FEL
- Survey/Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
- Lease/Unit Code C
- Survey/Section 0-8500

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat.) No [X]
24. Is Item 17 less than Item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X] Code C
25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.
26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? If not, and if the well requires a Rule 37 or 38 exception, see Instructions for Rule 37. Yes [X] No [ ]

Remarks
W/C per Cindy 10/26/90

I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison
Signature

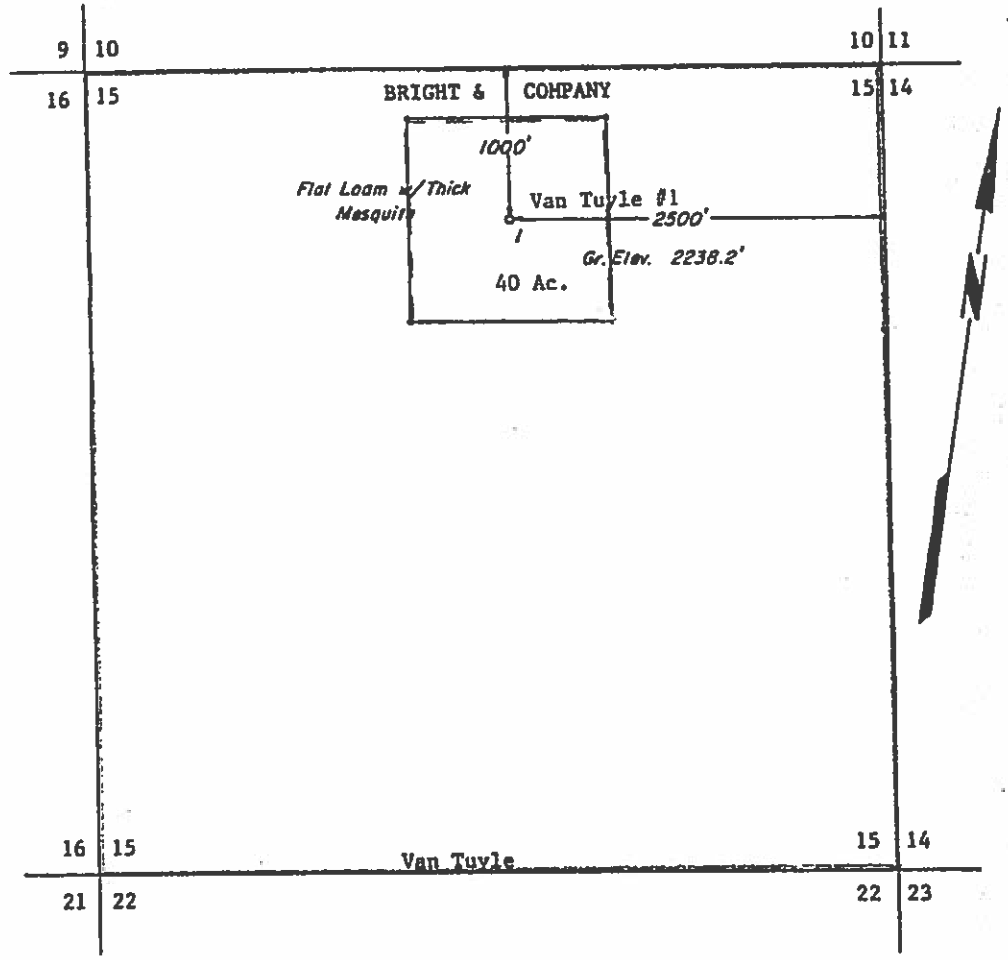
Tracy D. Tenison, Engineer
Name and title of operator's representative

9/26/90
Date: mo. day yr.

915-697-2214
Tel: Area Code Number

RRC Use Only
203091 OCT 1890
379724

335-33555



THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

OCT 1990

STATE OF TEXAS
REGISTERED
RONALD J. EIDSON
1883
PROFESSIONAL
LAND SURVEYOR

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

Ronald J. Eidson

RONALD J. EIDSON TEXAS P.L.S. NO. 1883
GARY G. EIDSON TEXAS P.L.S. NO. 4735
JERRY A. DUNN TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES
MIDLAND TEXAS

Scale: 1"= 1000'	Drawn by: MED
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

► Return each W-1 with plat and $100.00 fee. Make a check or money order payable to the State Treasurer of Texas. Address to:
Railroad Commission of Texas
Oil and Gas Division, Drilling Permits
P. O. Drawer 12967, Capitol Station
Austin, Texas 78711
► File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

► Read Instructions on Back

Form W-1
Rev. 9/1/83
483-080

020

Purpose of filing (mark appropriate boxes): [X] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter [ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no. at right & explain fully in Remarks)

Enter here, if assigned: ► API No. 42- ► Permit No. ► Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report)	3. RRC Operator No.	4. RRC District No.	5. County of Well Site
Bright & Company	093125	8	Mitchell

2. Address (including city and zip code)
3200 West Cuthbert, Suite 2-C
Midland, Texas 79701

6. Lease Name (32 spaces maximum)	7. RRC Lease/ID No.	8. Well No.	9. Total Depth
Van Tuyle	--	1	8500'

10. Location
• Section 15 Block 29, T-1-N Survey T&P RR Co., ~~TWP 1-N~~ Abstract No. A-584
• This well is to be located 5 miles in a north direction from Iatan which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 1000 ft.

12. Number of contiguous acres in lease, pooled unit, or unitized tract 640 (OUTLINE ON PLAT.)

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well (Specify)	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
Wolfcamp (Wildcat)	5200'	467-1200	40	40	NO	NA	0	1	
Strawn (Wildcat)	7800'	467-1200	40	40	NO	NA	0	1	
Ellenburger (Wildcat)	8300'	467-1200	40	40	NO	NA	0	1	

22. Perpendicular surface location from two nearest designated lines:
• Lease/Unit 1000' FNL & 2500' FEL
• Survey Section 1000' FNL & 2500' FEL ~~of Section 15~~

If a directional well, show also projected bottom-hole location:
• Lease/Unit
• Survey/Section

23. Is this a pooled unit? Yes [ ] ► (Attach Form P-12 and certified plat.) No [X]

24. Is item 17 less than item 16 (substandard acreage for any field applied for)? Yes [ ] ► (Attach Form W-1A) No [X]

25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X] If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ► If not filed, explain in Remarks.

26. Do you have the right to develop the minerals under any right of way that crosses, or is contiguous to, this tract? If not, and if the well requires a Rule 37 or 38 exception, see instructions for Rule 37. Yes [X] No [ ]

Remarks

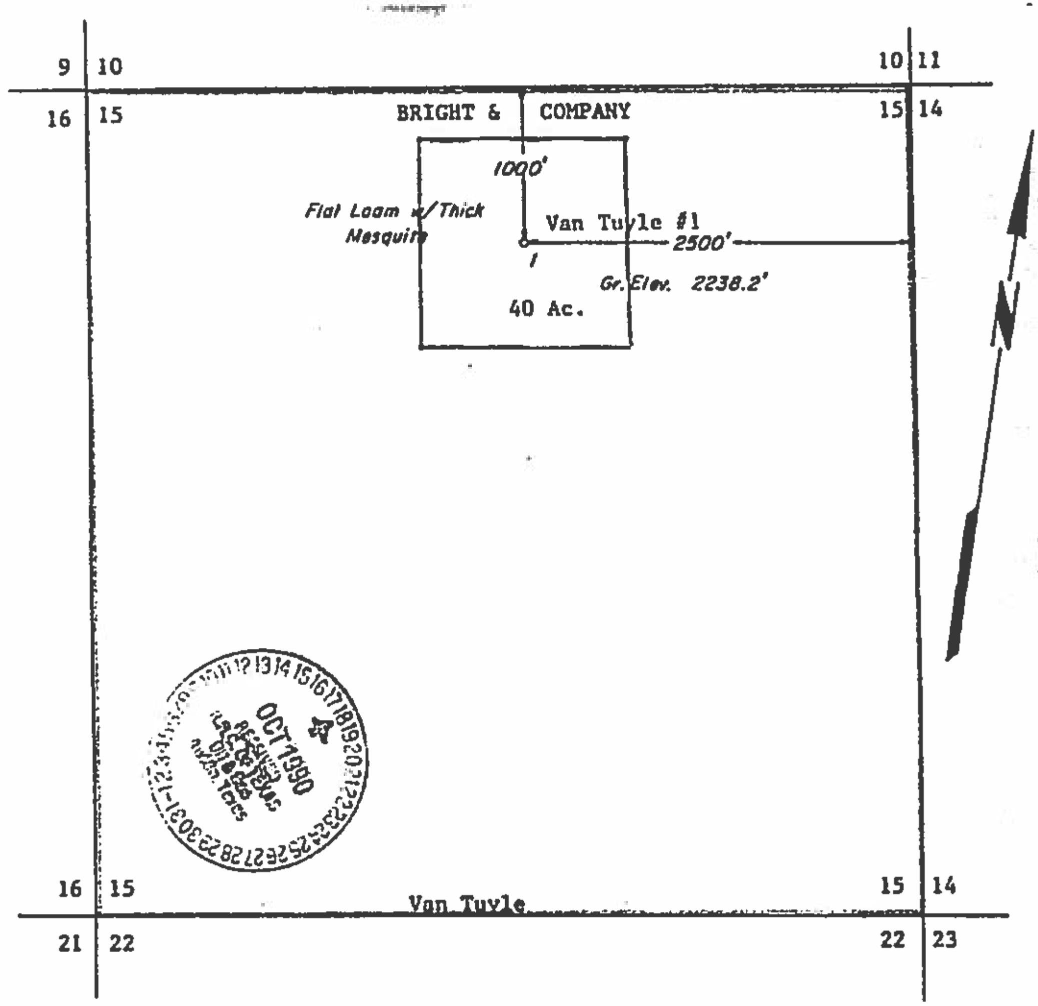
I certify that information stated in this application is true and complete, to the best of my knowledge.

Tracy D. Tenison — Signature
Tracy D. Tenison, Engineer — Name and title of operator's representative

Date: 9/26/90 (mo. day yr.)
Tel: 915-697-2214 (Area Code Number)

• RRC Use Only •

0 8 0 5 7 0 7 1 0



THE VAN TUYLE #1 IS LOCATED 8.7 MILES NORTHWEST OF WESTBROOK, TEXAS.

DATE SURVEYED: 10-2-90

WEATHER: 70° & RAIN

I HEREBY CERTIFY THAT THIS PLAT WAS MADE FROM NOTES TAKEN IN THE FIELD IN A BONA FIDE SURVEY MADE UNDER MY SUPERVISION, AND THAT THE SAME IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

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RONALD J. EIDSON TEXAS P.L.S. NO. 1883
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JERRY A. DUNN TEXAS P.L.S. NO. 4839

BRIGHT & COMPANY

The Van Tuyle #1 is 1000' FNL & 2500' FEL, Section 15, Block 29, T-1-N, T.& P. RR. Co. Survey, Mitchell County, Texas.

JOHN WEST & ASSOCIATES

MIDLAND TEXAS

Scale: 1" = 1000'	Drawn by: NEG
Date: 10-2-90	Sheet 1 of 1 sheets
Revision Date:	W.O. No.: L 900763

WATER BOARD LETTER DATED 10-1990 1 2

Plugging Record

Depth 350

13(A) Exception Dated N/A

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. 42-335-33555 (If available)

1. RRC District: 8

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

13 3/8 - 361

4. RRC Lease or Id. Number:

2. FIELD NAME (as per RRC Records): Wildcat

3. Lease Name: Van Tuyle

5. Well Number: 1

6. OPERATOR: Bright & Company

6a. Original Form W-1 Filed in Name of:

10. County: Mitchell

7. ADDRESS: 2911 Turtle Creek Blvd #700 Dallas, TX 75219

6b. Any Subsequent W-1's Filed in Name of:

11. Date Drilling Permit Issued: 10/18/90

8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 1000 Feet From north Line and 2500 Feet From east Line of the Van Tuyle Lease

12. Permit Number: 379724

9a. SECTION, BLOCK, AND SURVEY: Sec 15, Blk 29, T1N, T&P RR Co

9b. Distance and Direction From Nearest Town in this County: 8.7 miles NW of Westbrook

13. Date Drilling Commenced: 11/26/90

16. Type Well (Oil, Gas, Dry): Dry

Total Depth: 8360'

17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s — GAS ID or OIL LEASE # | Oil-O Gas-G | WELL #

14. Date Drilling Completed: 12/18/90

18. If Gas, Amt. of Cond. on Hand at time of Plugging:

15. Date Well Plugged: 12-17-90

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	12-17	12-17	12-17	12-17	12-17			
20. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8			
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15			
*22. Sacks of Cement Used (each plug)	50	50	160	50	10			
*23. Slurry Volume Pumped (cu. ft.)	59	59	189	59	11.8			
*24. Calculated Top of Plug (ft.)	8076	2526	1792	325	Surf.			
25. Measured Top of Plug (if tagged) (ft.)			1790					
*26. Slurry Wt. #/Gal.	15.6	15.6	15.6	15.6	15.6			
*27. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.			

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
13-3/8	48	361	361	17-1/2
8-5/8	32	2274	2274	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well: [ ] Yes [X] No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM 2274	TO 8360	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

APR 15 1991

Return to Central Records

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

D L Harrell
Signature of Cementer or Authorized Representative

Halliburton Services, Big Spring, TX
Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

W. J. Morris — REPRESENTATIVE OF COMPANY | Agent — TITLE | 1/11/91 — DATE | Phone 214 550-0889 — A/C NUMBER

RECEIVED RRC OF TEXAS MAR 05 1991 OIL & GAS MIDLAND, TEXAS

Did not Witness
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

1/38

335-33555

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission [X] Yes [ ] No	32. How was Mud Applied? Drilling Rig		33. Mud Weight 9.1 LBS/GAL
34. Total Depth 8360 Depth of Deepest Fresh Water 210	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No 36. If NO, Explain	
37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well: Halliburton, P. O. Box 380, Snyder, Texas 79549		Date RRC District Office notified of plugging 12/15/90	

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Ben Van Tuyle, 432 Hilldale Dr, Ann Arbor, MI 48105

39. Was Notice Given Before Plugging to Each of the Above?

Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______________ Date ______

Type Logs:

[ ] Driller's [X] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging ______ bbls*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field ______

REMARKS ______

000 57 0713

Operator: Fill in other items.

Form W-15
Cementing Report
Rev. 4/1/83

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1. Operator's Name (As shown on Form P-5, Organization Report): Bright & Co.	2. RRC Operator No.: 093125	3. RRC District No.: 8	4. County of Well Site: Mitchell
5. Field Name (Wildcat or exactly as shown on RRC records): Wildcat	6. API No.: 42- 335-33555	7. Drilling Permit No.: 379724	
8. Lease Name: Van Tuyle	9. Rule 37 Case No.:	10. Oil Lease/Gas ID No.:	11. Well No.: 1

CASING CEMENTING DATA:		SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING: Single String	PRODUCTION CASING: Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS: Tool	MULTI-STAGE CEMENTING PROCESS: Shoe
12. Cementing Date		[illegible]	[illegible]				
13. •Drilled hole size		17-1/2	11				
•Est. % wash or hole enlargement							
14. Size of casing (in. O.D.)		13-3/8	8-5/8				
15. Top of liner (ft.)							
16. Setting depth (ft.)		361	2274				
17. Number of centralizers used		3	3				
18. Hrs. waiting on cement before drill out		12	12				
1st Slurry	19. API cement used: No. of sacks	390	300				
	Class	Premium Plus	Hall.Light Prem Plus				
	Additives	2% Calcium Chloride	2% CaCl2				
2nd Slurry	No. of sacks						
	Class						
	Additives						
3rd Slurry	No. of sacks						
	Class						
	Additives						
1st	20. Slurry pumped: Volume (cu. ft.)	514.8	591				
	Height (ft.)	Surface	2268				
2nd	Volume (cu. ft.)						
	Height (ft.)						
3rd	Volume (cu. ft.)						
	Height (ft.)						
Total	Volume (cu. ft.)	514.8	591				
	Height (ft.)	Surface	2268				
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?		Yes	No				

22. Remarks

RECEIVED R.R.C. OF TEXAS JAN 14 1991 O.G. MIDLAND, TEXAS

RECEIVED R.R.C. OF TEXAS MAR 05 1991 OIL & GAS DIV MIDLAND TEXAS

OVER

[illegible] TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
[illegible]								
[illegible]. Size of hole or pipe plugged (in.)								
[illegible]. Depth to bottom of tubing or drill pipe (ft.)								
[illegible] cement used (each plug)								
[illegible] pumped (cu. ft.)								
[illegible] top of plug (ft.)								
[illegible]. Measured top of plug, if tagged (ft.)								
[illegible]								
[illegible]								

[illegible] CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this [illegible] and that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my [illegible] and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This [illegible]

[illegible], Jr. - Cementer | Halliburton | [signature]
[illegible] | Cementing Company | Signature

[illegible] 309 | Snyder, Texas 79549 | 915-573-3526 | 11-26-90
[illegible] | City, State, Zip Code | Tel.: Area Code Number | Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data.

W. J. Morris | Agent | [signature]
Typed or printed name of operator's representative | Title | Signature

2911 Turtle Creek Blvd, #700, Dallas, TX 75219 | 214-559-0889 | 1/11/91
Address | City, State, Zip Code | Tel.: Area Code Number | Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For offshore operations, see the requirements of Rule 13 (c).

A. What to file. An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, Form W-2 or G-1, as required by Statewide or special field rules;
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, **in addition to Form W-3, to show any casing cemented in the hole.**

B. Where to file. The appropriate Commission District Office for the county in which the well is located.

C. Surface casing. An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. Centralizers. Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. Exceptions and alternative casing programs. The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F. Intermediate and production casing. For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. Plugging and abandoning. Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

R.R.C. Midland

Please Refer to File No.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2A

APPLICATION TO PLUG AND WELL RECORD
FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Name of Company or Operator: The Texas Company Address: Box 1720, Fort Worth, Texas

County: Howard Survey: T&P RRCo. Blk: 29 T-1-N Sec: 4

Name of Lease: A. L. Wasson No. of Acres: 1760 Well No.: 1 Elev.: 2300 (DF)

Located: Approx. 21 Miles NE Direction from Big Spring, Texas (Nearest P. O. or Town)

Name of Field in which well is located: Wildcat

Form 1, "Notice of Intention to Drill," was filed in name of: The Texas Company

Drilling Commenced: 12-28, 19 52, Drilling Completed: 3-28, 19 52

Has this well ever produced oil? No or Gas? No

Character of Well (Oil, Gas or Dry): Dry Total Depth: 8670'

Date you wish to Plug: 3-27-, 19 52

Name of Party Plugging Well: Livermore Drilling Address: 610 Lubbock Nat'l Bank, Lubbock, Texas

Correspondence regarding this well should be sent to: Name: The Texas Company

Address: Box 1720, Fort Worth, Texas

CASING RECORD

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
13 3/8"	196		None		196		Texas Pattern
9 5/8"	2115		100		2015		Halliburton F & S

IF CASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS

Initial Production of Gas: Volume (MCF) None 24 hrs. Pressure None

Initial Production of Oil: Barrels None

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to, All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

RECEIVED
MIDLAND, TEXAS
APR 10 1952
Railroad Commission of Texas
OIL & GAS DIVISION

NOTE: If no log available, so state and give all information that can be obtained as to total depth, casing record, formation, water sands, and as near as possible date well was drilled.

General Remarks: This well drilled to a total depth of 8670' without encountering oil or gas. We therefore desire to abandon salvage and plug well in the following manner: (Cut 9 5/8" casing at 100' and pull same) (Over)

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Caliche	0	100	At depth 206' cemented 13 3/8"
Red Beds	100	206	casing at 206' with 250 sacks.
Shale & Anhy	206	945	Cement circulated.
Anhy	945	1254	
Anhy & Shale	1254	1499	At depth 2125' cemented 9 5/8" casing
Anhy & Salt	1499	1750	at 2125' with 600 sacks.
Anhy & Shale	1750	1837	
Anhy	1837	1955	
Anhy & Lime	1955	2125	
Lime	2125	2290	
Lime & Shale	2290	2322	
Lime	2322	3116	
Lime & Shale	3116	3612	
Lime & Chert	3612	3820	
Lime & Sand	3820	3979	
Lime & Chert	3979	4155	
Lime & Sand	4155	4538	
Lime & Chert	4538	4900	
Lime & Sand	4900	5114	
Lime & Chert	5114	5232	
Lime & Shale	5232	6203	
Shale	6203	7953	
Lime & Chert	7953	8670	
Total Depth		8670	

All Measurements from Rotory Table or 12' above ground.

Remarks Cont'd

Using Heavy mud between plugs, spot the following cement plugs, 95 sacks 8670'-8373'; 15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7655'; 15 sacks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sacks 4680'-4630'; 15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1070'; 40 sacks. 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing.

Drill Stem Tests

DST # 1: Pkr. failed

DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 2250' salt water cut with drlg. mud.

DST # 3: 5100-5210, Tool open 1 1/2 hrs. Recovered 300' drlg. mud.

DST # 4: 5440-5485, Tool open 1 hr. Recovered 75' slightly gas cut drlg. mud.

DST # 5: 5902-6000, Tool open 1 hr. Recovered 100' drlg. mud, [illegible]

DST # 6: 780[illegible]-7870, Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120' [illegible] gas cut drlg. mud.

DST # 7: 783[illegible] [illegible] hrs., Recovered 5' drlg. mud & 180' slightly [illegible] mud.

Method of shutting off water: Cased off Is water completely shut off? Yes

Amount of water with oil: None per cent: None

I, T. P. [illegible] being first duly sworn [illegible] that I have knowledge of the facts and matter herein [illegible] and that the same are true and correct.

[signature]

Representative of Company.

Subscribed and sworn to before me this 7 day of April, 1952

[signature] W. E. BRUZEK

Notary Public

Midland County, Texas.

RECEIVED

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.

DST # 10: 8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

RECEIVED
MIDLAND, TEXAS
APR 10 1952
Railroad Commission of Texas
OIL & GAS DIVISION

Please Refer to
File No.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 4
Plugging Record

8

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company The Texas Company Address Box 1720, Ft. Worth, Texas

Sec. No. 4 Block No. 29 T-I-N Survey T & P RRCO County Howard

Well No. 1 Name of Lease A. L. Wasson No. of Acres 1760

Name of Field in which well is located Wildcat Date well was plugged 3-27- 19 52

Form 1 (Notice of Intention to Drill) Was Filed in Name of The Texas Company

Character of Well at the time of completion: Oil - bbls.; (Initial Production) Gas - Cu. ft.; (Initial Production) Dry Yes

Amount well producing when plugged: Oil None bbls.; Gas None Cu. ft.; Water None bbls.

Has this well ever produced oil or gas? No

Total Depth 8670 feet. Top of each producing sand - feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Thru drill pipe

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depths placed. Also amount of cement and rock. Was well shot? No

Spotted the following plugs: 95 sx 8670-8373, 15 sx 8213-8163, 15 sx 7860-7810, 15 sx 7705-7655, 15 sx 5600-5550, 15 sx 5430-5380, 15 sx [redacted] 50-25-4975, 15 sx 4680-4630, 15 sx 2810-2760, 15 sx 2093-2043, Cut off 9 5/8" casing @ 100' and pulled, spot 40 sx 1125-1070, 40 sx 1025-975, 40 sx 875-825, 30 sx in top of casing.

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: All 13 3/8" casing left in hole & 2015' 9 5/8" casing left in hole. All strata protected by casing left in hole or cassed of with cement.

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:
All adjacent property leased by The Texas Company

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, T. P. Drew, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name T. P. Drew Dist. Supt.

Subscribed and sworn to before me this 15 day of May, 19 52

[signature]

Notary Public Midland County, Texas

Correspondence regarding this well should be addressed to:

Name The Texas Company Address Box 1720, Ft. Worth, Texas

0 0 0 0 2 2 0 7 7 7

FORM W-1 (6/78)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

☐ Directional Well ☐ Amended or Corrected Permit

API Well No. 42
Instruction (7a & b) on back side.

RRC Permit Number, if previously assigned. 084247

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

Check one: ☐ DRILL ☐ DEEPEN (Below Casing) ☐ DEEPEN (Within Casing) ☐ PLUG BACK ☒ OTHER (Specify) re-entry

If Amended Application, explain fully in Remarks or Attach Separate Page.

1. Operator: McCann Corporation 533853
2. Address (Including City and Zip Code): P. O. Box 448, Big Spring, TX 79720
3. Is Form P-5 (Organization Report) in Exact Operator Name Filed? YES ☒ NO ☐ (Instruction (2) on back side.)
4. Lease Name and RRC Lease or ID No. (If Assigned): Stewart
5. Location (Sec., Blk., Survey): Sec. 4, Blk. 29, T-1-N, T & P RR Co.
6. This well is to be located 4 miles Southeast Direction from Vincent, TX Nearest Post Office or Town.
7. RRC District: 8
8. County: Howard
9. Well Number: 1
10. Number of Acres in Lease: 640
11. Distance from Proposed Location to Nearest Property or Lease Line (ft.): 660'
12. Total Depth: 4600'

EACH PROPOSED COMPLETION

REFER TO INSTRUCTIONS ON BACK SIDE. READ CAREFULLY AND FURNISH COMPLETE DATA.

13. FIELD NAME (Exactly as shown on R.R.C. Proration Schedule including Reservoir if applicable.) If Wildcat, so state below.	14. Completion Depth	15. All Prior Rule 37 Exc. Case Numbers for this wellbore. If none, State None.	16. Applicable Field Rules Spacing Pattern. If no Rules, State 467-1200. (ft.)	17. Applicable Field Rules Density Pattern. If no Rules, State 40. (acres)	18. Number of Acres in Drilling Unit for this Well AND DESIGNATE ON PLAT.	19. Is this acreage presently assigned to another well in same field? (Yes or No; If yes explain in remarks.)	20. Distance and Direction from proposed location to nearest drilling completed or applied for well in same res. on same lease (ft.)	21. Is this a 1. Regular or 2. Rule 37 Exc. Location? Check the appropriate box.	22. Oil, Gas, or other Type Well (Specify)	23. Number of Wells or Permitted locations on this Lease in same Reservoir for which this Permit is Requested? OIL	GAS
00018 001 Wildcat	4210'	None	467-1200	40	40	No	None	Regular 1 ☒ Rule 37 2 ☐	Oil	0	0
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			
								Regular 1 ☐ Rule 37 2 ☐			

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24. PERPENDICULAR LOCATION FROM TWO DESIGNATED:
A. Lease Lines: 660' FWL & 1980' FNL
B. Survey Lines: 660' FWL & 1980' FNL

25. (a) Is this wellbore subject to SWR 36? Yes ☒ No ☐
(b) If subject to SWR 36, has Form H-9 been filed? Yes ☒ No ☐
(If no, attach explanation.)

NOTICE
NO ALLOWABLE WILL BE ASSIGNED to any well which does not have sufficient surface casing to protect all fresh water sands. Where Commission rules do not specify surface casing requirements, it will be necessary to contact Texas Water Development Board, Austin, Texas, to ascertain the depth to which fresh water sands must be protected.

CERTIFICATE
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

REMARKS: Original Operator: The Texas Company
Original Lease Name: A.L. Wasson, Well #1.
Plugged and Abandoned: 3-27-52

Signature: Ellen W. Bell
Title: Administrative Assistant
Date: June 12, 1980
Telephone: Area Code 915 267-7451

READ INSTRUCTIONS ON BACK SIDE AND FURNISH COMPLETE DATA.

776

0 0022 0775

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. (If available) 42-227-00000 | RRC District: 08

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or Id. Number:

2. FIELD NAME (as per RRC Records): Wildcat	3. Lease Name: Stewart	5. Well Number: 1
6. OPERATOR: McCann Corporation	6a. Original Form W-1 Filed in Name of: McCann Corporation	10. County: Howard
7. ADDRESS: P. O. Box 448, Big Spring, TX	6b. Any Subsequent W-1's Filed in Name of:	11. Date Drilling Permit Issued: 6-17-80
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 660 Feet From West Line and 1980 Feet From North Line of the Stewart Lease		12. Permit Number: 084247
9a. SECTION, BLOCK, AND SURVEY: Sec. 4, Blk. 29, T-1-N, T&P RR Co.	9b. Distance and Direction From Nearest Town in this County: 4 miles SE of Vincent	13. Date Drilling Commenced: 10-10-80
16. Type Well (Oil, Gas, Dry): DRY / Total Depth: 1100	17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s — GAS ID or OIL LEASE # / Oil-O Gas-G / WELL #	14. Date Drilling Completed: 10-12-
18. If Gas, Amt. of Cond. on Hand at time of Plugging:		15. Date Well Plugged: 10-12-

CEMENTING TO PLUG AND ABANDON DATA:

	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	10-12-80	10-13	10-13					
20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8					
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1100	250	Top Out					
*22. Sacks of Cement Used (each plug)	50	100	10					
*23. Slurry Volume Pumped (cu. ft.)	66	133	13					
*24. Calculated Top of Plug (ft.)	990	70	Surf.					
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	1.33	1.33	1.33					
*27. Type Cement	C	C	C					

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
8 5/8	24#	200	200	11

29. Was any Non-Drillable Material (Other than Casing) Left in This Well ☐ Yes ☒ No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

Signature of Cementer or Authorized Representative

Dowell Division of Dow Chemical Co.
Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Tom McCann	President	April 9, 1981	915	267-7488
REPRESENTATIVE OF COMPANY	TITLE	DATE	Phone A/C	NUMBER

Did Not Witness
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

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MIDLAND, TEXAS

DR 80

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Commission?	[X] Yes [ ] No	32. How was Mud Applied? Circulated	33. Mud Weight 8.6 LBS/GAL

34. Total Depth 1100	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [X] Yes [ ] No
Depth of Deepest Fresh Water 150		36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Dowell Division of Dow Chemical Co. - Colorado City, Tx

Date RRC District Office notified of plugging 10-1-85

38. Names and Addresses of Surface Owner of Well Site and Operators of Offset Producing Leases

Danny Stewart - P. O. Box 26, Sterling City, Tx. 76951

39. Was Notice Given Before Plugging to Each of the Above?
Yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[X] Log Attached [ ] Log released to ______ Date ______

Type Logs: [ ] Driller's [ ] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Was FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging None bbls.*

* File FORM P-1 (Oil Production Report) for month this oil was produced

RRC USE ONLY

Nearest Field

REMARKS

APR 2 0 1981

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form W-15
(Rev. 1-1-...)

CEMENTING REPORT

*1. Field Name (as per RRC Records or Wildcat): Wildcat	*2. RRC District: 08
*3. Operator: Mc Cann Corporation	*4. County: Howard
*5. Lease Name(s) and RRC Lease Number(s) or I. D. Number(s): Stewart	*6. Well Number: 1
*7. Location (Section, Block, and Survey): Sec. 4, Blk. 29, T-1-N, T&P RR Co. Survey	

CASING CEMENTING DATA:	SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
8. Cementing Date						
*9. (a) Size of Drill Bit (inches)						
(b) Estimated % Wash or Hole Enlargement Used in Calculations.						
*10. Size of Casing (inches O.D.)						
*11. Top of Liner (if liner used) (ft.)						
*12. Setting Depth of Casing (ft.)						
13. Type API Class Cement & Amount of Additives Used: (a) In First (Lead) or Only Slurry (if additional space is needed, use "REMARKS" on reverse side.)						
(b) In Second Slurry						
(c) In Third Slurry						
14. Sacks of Cement Used: (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Sacks of Cement Used						
15. Slurry Volume per Sack of Cement (cu.ft./sack): (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
16. Volume of Slurry Pumped: (cu.ft.) (Item 14 x Item 15) (a) In First (Lead) or Only Slurry						
(b) In Second Slurry						
(c) In Third Slurry						
(d) Total Slurry Volume Pumped (cu.ft.)						
17. Calculated Annular Height of Cement Slurry behind Pipe (ft.)						
18. Was cement circulated to ground surface (or bottom of cellar) outside casing? (Yes or No)						

CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6
19. Cementing Date	10-12-80	10-13-80	10-13			
*20. Size of Hole or Pipe in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8			
*21. Depth to Bottom of Tubing or Drill Pipe (ft.)	1000	250	Top Out			
22. Sacks of Cement Used (each plug)	50	100	10			
23. Slurry Volume Pumped (cu. ft.)	66	133	13			
24. Calculated Top of Plug (ft.)	990	70	Surf.			
*25. Measured Top of Plug (if tagged) (ft.)						

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MIDLAND, TEXAS

(CEMENTING COMPANY AND OPERATOR MUST COMPLY WITH THE INSTRUCTIONS ON REVERSE SIDE HEREOF.)

– OVER –

* Designated items to be completed by Operator. Items not so designated shall be completed by Cementing Company.

Remarks:

*27. Remarks:

CEMENTING COMPANY

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

P. N. Shackelford

Signature of Cementer or Authorized Representative

P. N. Shackelford, Sr. District Clerk

Name of Person and Title (type or print)

Dowell Division of Dow Chemical Co.

Cementing Company

Route 3, Box 178

Street Address or P.O. Box

Colorado City, Tx 79512

City, State Zip Code

Telephone 915 728-5291

Area Code

10-14-80

Date

*OPERATOR

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data and information presented herein.

Tom McCann

*Signature of Operator or Authorized Representative

Tom McCann - President

*Name of Person and Title (type or print)

McCann Corporation

*Operator

P. O. Box 448

*Street Address or P.O. Box

Big Spring, Texas 79720

*City, State Zip Code

*Telephone 915 267-7488

Area Code

4-6-81

*Date

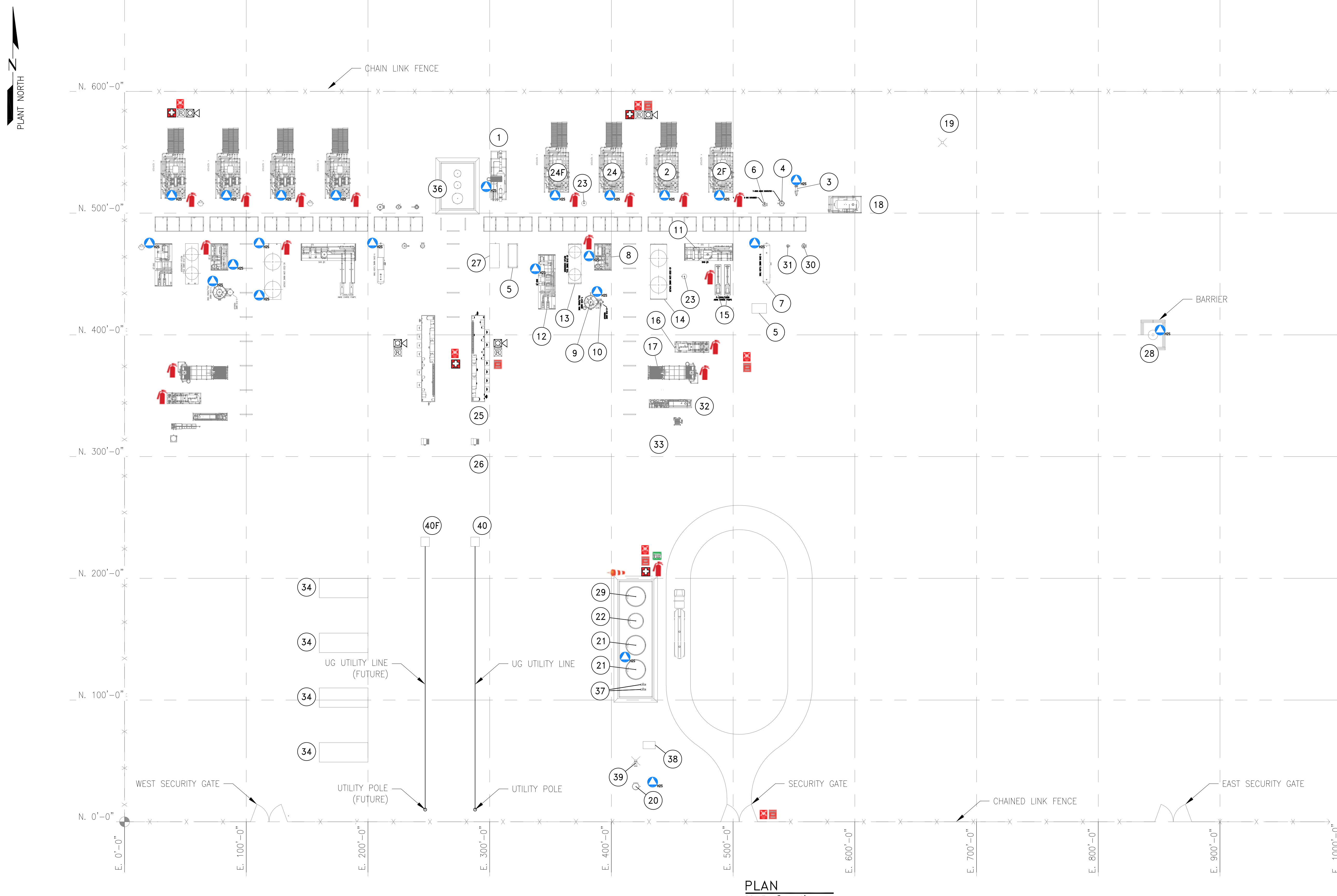
INSTRUCTIONS

1. A. This form shall be filed by the operator in the RRC District Office with:
   (1) Each copy of an initial Form G-1 or W-2 if a cementing report is required by Statewide or Special Rules, or if exception is needed to cementing requirements in Statewide or Special Rules;
   (2) Each copy of Form W-3;
   (3) Each copy of Form W-4 if a multiple parallel casing completion.
   B. At least an original and one copy of this form shall be filed for each cementing company used on a well.
   C. The cementing of different casing strings on a well by one cementing company may be consolidated on one form (to be filed in duplicate)
2. Cementing Company and Operator shall comply with the applicable portions of Statewide Rules 8, 13, and 14. For offshore operations, Cementing Company and Operator shall comply with Statewide Rule 13(E).
3. If setting FULL AMOUNT OF SURFACE CASING
   A. Depth to protect fresh water determined by:
   (1) Fi Rule
   (2) T s Water Development Board, if no Field Rule
   B. Set surface casing below depth to be protected and cement from casing shoe to ground surface.
4. IF SETTING ANYTHING OTHER THAN THE FULL AMOUNT OF SURFACE CASING, PERMISSION SHALL BE OBTAINED FROM THE RAILROAD COMMISSION.
5. If setting NO SURFACE CASING (See Item 4 above.):
   A. If no multi-stage tool is used, the next deeper casing string shall be cemented from the casing shoe to the surface.
   B. If using the multi-stage tool on the next deeper string, cement from the depth that protects fresh water sands to the surface.
6. If setting SHORT SURFACE CASING (See Item 4 above.):
   A. Cement short surface casing from the shoe to the surface.
   B. Whether the multi-stage tool is or is not used on the next deeper casing string, cement from the depth that protects fresh water sands to
   (1) the surface, or
   (2) a point midway between shoe of surface string and the surface. Compliance will be considered if a temperature survey shows that the top of the cement is at least one-third of the distance from the shoe of the surface string to the surface.
7. Setting PRODUCTION STRING of Casing: (Statewide Rules, Special Rules may vary.)
   A. Cement to a point at least 600 feet above the casing shoe.
   B. When 3,000 feet or more of pipe is set for the production or protecting string, a minimum of 30 feet of cement shall be left inside the pipe
8. PLUGGING and ABANDONING:
   A. Cement plugs shall be placed in the well bore as required by Rules and Regulations of the Commission plus any additional plugs as may be specified by the RRC District Director.
   B. The minimum amount of cement normally used in each plug shall be a slurry volume equal to the amount necessary to fill the calculated volume of 100 feet of the hole in which the plug is placed.
   C. A 10 foot cement plug is required to be placed in the top of the well.

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H_2S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



PLAN

SCALE 1" = 40'

ITEM	DESCRIPTION
1	SLUG CATCHER
2	INLET COMPRESSOR W/ COOLER
2F	INLET COMPRESSOR (FUTURE) W/ COOLER
3	COMPRESSOR DISCHARGE COALESCER
4	AMINE CONTACTOR
5	FUEL GAS SKID
6	TREATER GAS SCRUBBER
7	AMINE FLASH TANK
8	AMINE REGEN SKID
9	AMINE REGENERATOR/REFLUX ACCUMULATOR
10	AMINE REGENERATOR REBOILER
11	AMINE SURGE TANK
12	AMINE BOOSTER/REFLUX PUMP SKID
13	AMINE REGENERATOR REFLUX CONDENSER
14	LEAN AMINE COOLER
15	AMINE CHARGE PUMPS
16	HOT OIL PUMP SKID
17	HOT OIL HEATER
18	FLARE K.O. DRUM
19	FLARE
20	COMBUSTOR
21	SLOP STORAGE TANKS
22	AMINE MAKE UP STORAGE TANK
23	SUMP TANKS
24	ACID GAS COMPRESSOR W/ COOLER
24F	ACID GAS COMPRESSOR W/ COOLER (FUTURE)
25	PDC BUILDING
26	LV TRANSFORMER
27	INSTRUMENT AIR PACKAGE
28	ACID GAS INJECTION WELL
29	DI WATER TANK
30	GLYCOL CONTACTOR
31	GLYCOL SEPARATOR
32	TEG REGEN
33	BTEX
34	GAS GENERATOR SET
35	AMINE SUMP TANK
36	NEW LUBE OIL TANKS
37	CONDENSATE TRANSFER PUMPS
38	VAPOR RECOVERY UNIT
39	TANK COMBUSTOR K.O. DRUM
40	MV TRANSFORMER
40F	MV TRANSFORMER (FUTURE)

LEGEND

- FIRE EXTINGUISHER = 9 ea.
- HYDROGEN SULFIDE DETECTOR = 10 ea.
- AUDIBLE ALARM SOUNDER = 4 ea.
- STROBE LIGHT (RED) – FIRE = 4 ea.
- PLANT EMERGENCY SHUTDOWN = 6 ea.
- FIRST AID & SCBA KIT = 3 ea.
- EYE WASH STATION = 3 ea.
- WIND SOCK = 1 ea.
- MUSTER POINT = 3 ea.

NOTES:

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
C	08/16/22	ISSUED FOR INFORMATION	HJP	CN	–
B	07/12/22	ISSUED FOR INFORMATION	RDC	CN	–
A	06/13/22	ISSUED FOR INFORMATION	RDC	RAF	–

F&C ENGINEERS

TX REG. NO. 8419

BAYSWATER

CLIENT : BAYSWATER EXPLORATION & PRODUCTION

PROJECT : SOUR GAS TREATING FACILITY

TITLE : INSTRUMENTATION FACILITY SAFETY LOCATION PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.	SHEET NO.	
RDC	GA	AS NOTED	06/09/22	BAY220316	IN-PLN-0790	1 OF 1	C

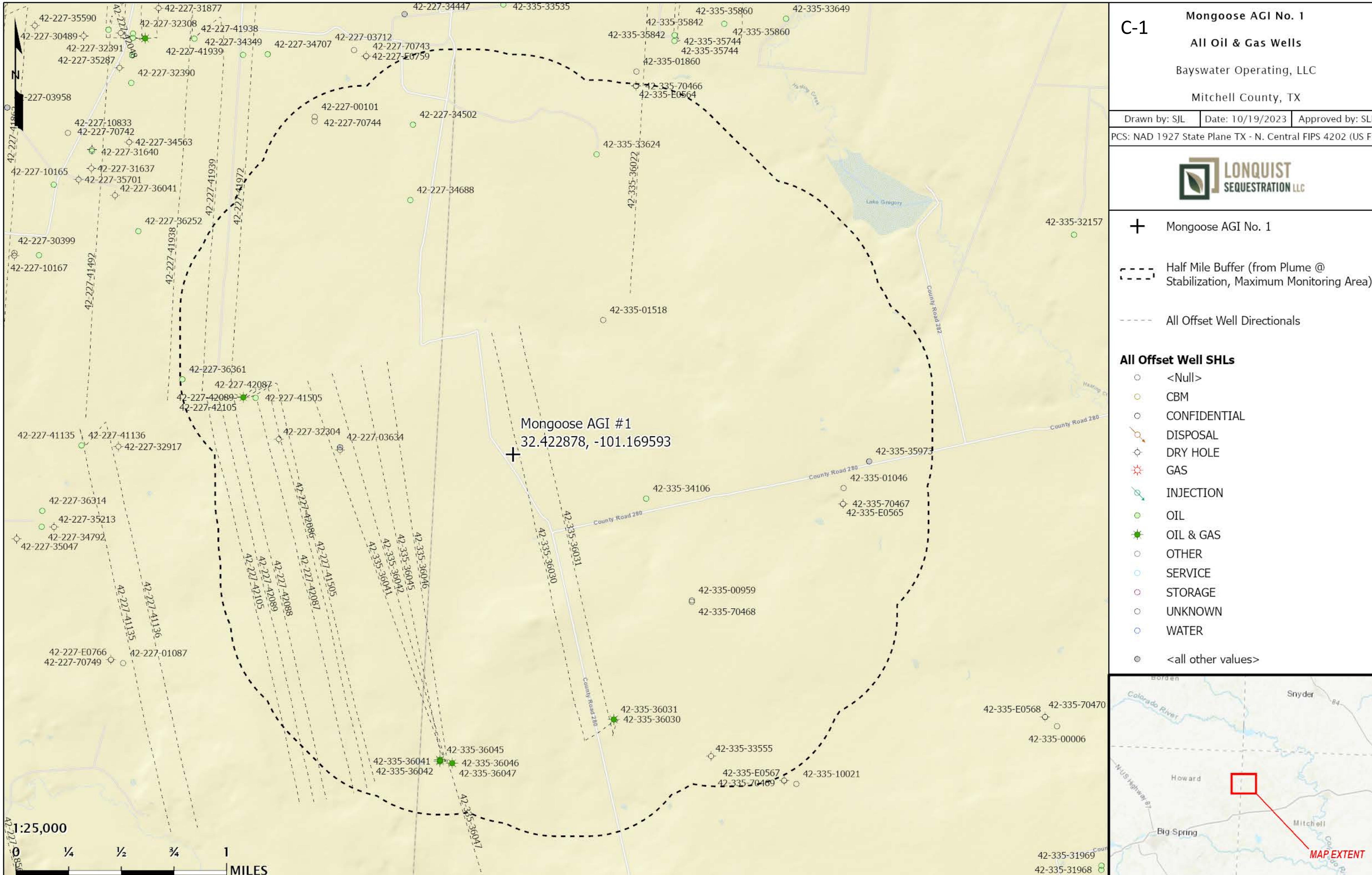
APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX C-3: WATER WELLS WITHIN THE MMA MAP

APPENDIX C-1: WATER WELLS WITHIN THE MMA LIST


C-1
Mongoose AGI No. 1
All Oil & Gas Wells
Bayswater Operating, LLC
Mitchell County, TX
Drawn by: SJL
Date: 10/19/2023
Approved by: SLP
PCS: NAD 1927 State Plane TX - N. Central FIPS 4202 (US Ft.)
LONQUIST SEQUESTRATION LLC
Mongoose AGI No. 1
Half Mile Buffer (from Plume @ Stabilization, Maximum Monitoring Area)
All Offset Well Directionals
All Offset Well SHLs
<Null>
CBM
CONFIDENTIAL
DISPOSAL
DRY HOLE
GAS
INJECTION
OIL
OIL & GAS
OTHER
SERVICE
STORAGE
UNKNOWN
WATER
<all other values>
Mongoose AGI #1
32.422878, -101.169593
N
1:25,000
0
¼
½
¾
1
MILES
County Road 280
County Road 282
Lake Gregory
Borden
Snyder
Colorado River
Howard
Mitchell
Big Spring
MAP EXTENT
42-227-35590
42-227-31877
42-227-32308
42-227-41938
42-227-30489
42-227-32391
42-227-34349
42-227-34707
42-227-03712
42-227-70743
42-227-E0759
42-227-41939
42-227-35287
42-227-32390
42-227-34447
42-335-33535
42-335-35860
42-335-33649
42-335-35842
42-335-35744
42-335-01860
42-335-70466
42-335-E0564
42-227-03958
42-227-00101
42-227-70744
42-227-34502
42-227-10833
42-227-70742
42-227-34563
42-227-31640
42-227-31637
42-227-10165
42-227-35701
42-227-36041
42-335-33624
42-335-36022
42-227-41972
42-227-34688
42-227-36252
42-335-32157
42-227-30399
42-227-10167
42-227-41492
42-227-41938
42-335-01518
42-227-36361
42-227-42087
42-227-42089
42-227-41505
42-227-42105
42-227-41135
42-227-41136
42-227-32917
42-227-32304
42-227-03634
42-335-35973
42-335-01046
42-335-34106
42-335-70467
42-335-E0565
42-227-36314
42-227-35213
42-227-34792
42-227-35047
42-227-42086
42-227-42088
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42-335-36046
42-335-36030
42-335-36031
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42-335-70468
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42-227-70749
42-227-01087
42-335-E0568
42-335-70470
42-335-00006
42-335-33555
42-335-36047
42-335-E0567
42-335-70469
42-335-10021
42-335-31969
42-335-31968

Mongoose AGI No. 1

Area of Review: Oil & Gas Wells List										
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022
4222741505	KAMIKAZE 5-8-17-20	3W	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023

LONQUIST SEQUESTRATION LLC

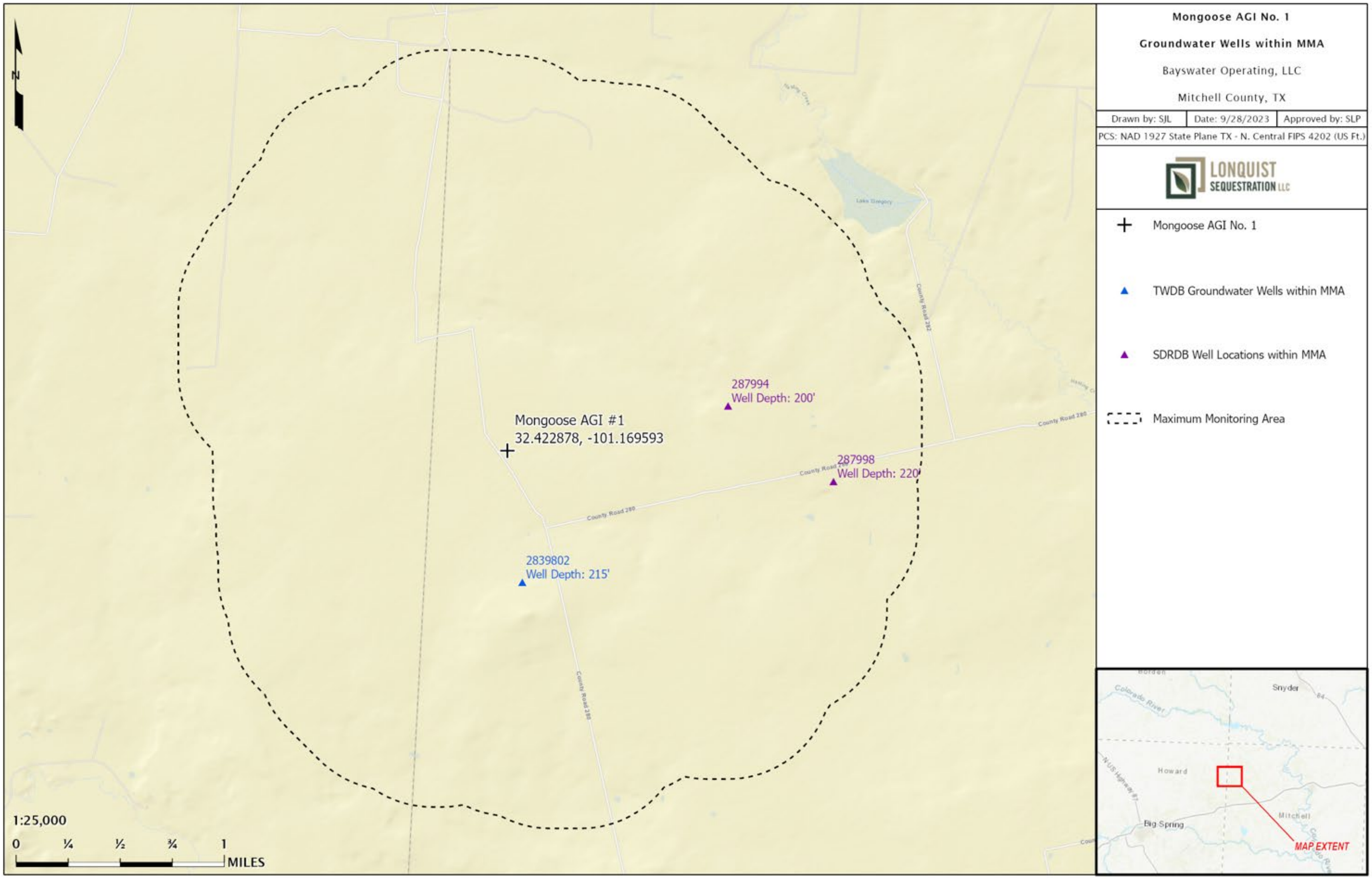
Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.

LONQUIST SEQUESTRATION LLC

C-3



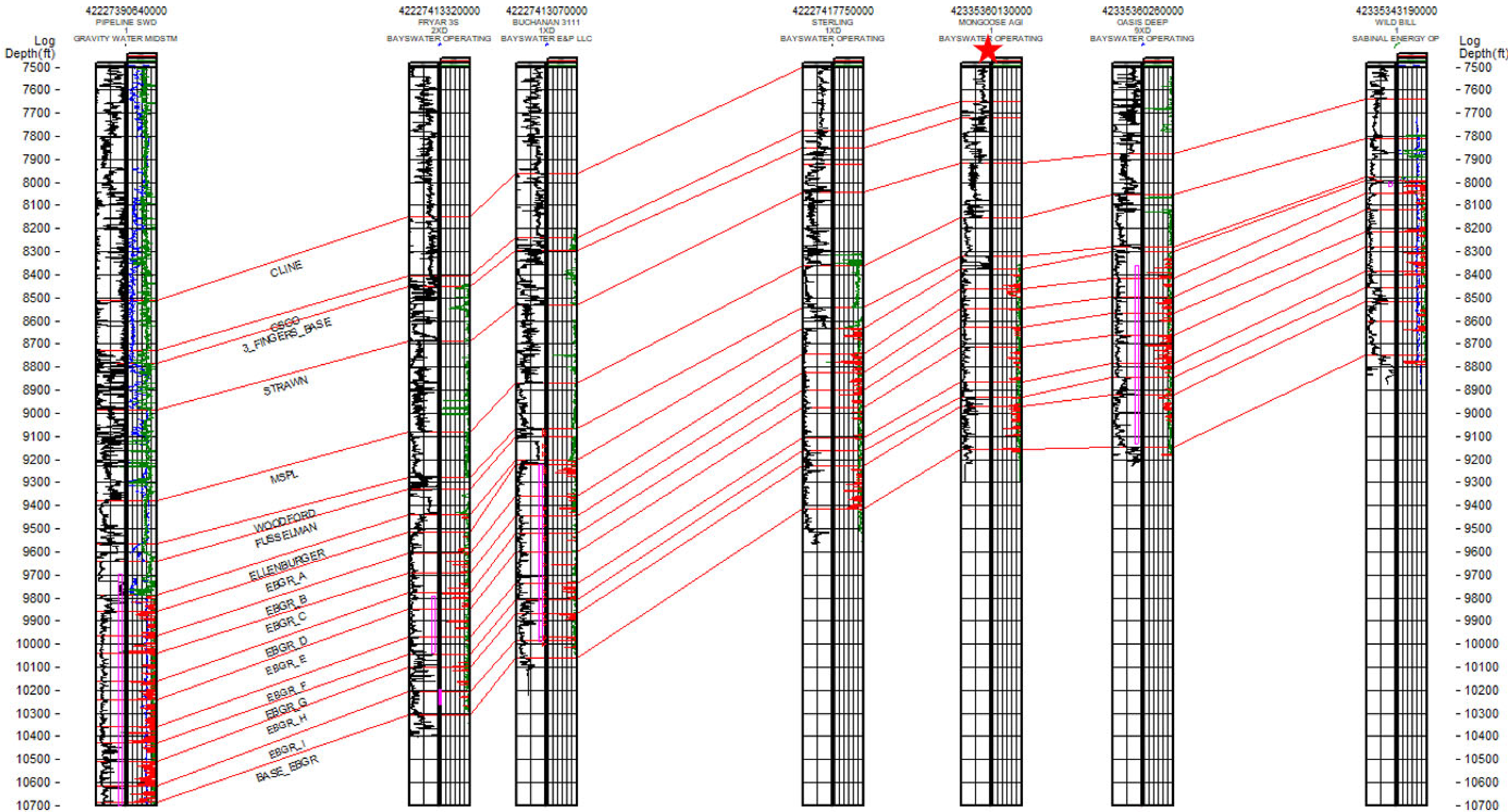
Mongoose AGI No. 1
Groundwater Wells within MMA
Bayswater Operating, LLC
Mitchell County, TX
Drawn by: SJL
Date: 9/28/2023
Approved by: SLP
PCS: NAD 1927 State Plane TX - N. Central FIPS 4202 (US Ft.)
LONQUIST SEQUESTRATION LLC
Mongoose AGI No. 1
TWDB Groundwater Wells within MMA
SDRDB Well Locations within MMA
Maximum Monitoring Area
Mongoose AGI #1
32.422878, -101.169593
287994
Well Depth: 200'
287998
Well Depth: 220'
2839802
Well Depth: 215'
County Road 280
County Road 282
Lake Gregory
1:25,000
0 ¼ ½ ¾ 1 MILES
Snyder
Howard
Mitchell
Big Spring
MAP EXTENT

Mongoose AGI No. 1

Area of Review: Freshwater Wells List									
WELL REPORT/ID NO.	OWNER'S NAME	OWNER ADDRESS	CITY/STATE/ZIP	LAT. WGS 84	LONG. WGS 84	WELL USE	WATER LEVEL (FT.)	TOTAL DEPTH (FT.)	DATE DRILLED
2839802	TOM JACKSON	-	-	32.413889	-101.168333	PLUGGED OR DESTROYED	-	215	11/1/1967
287994	BENNARD LAZY H RANCH	5933 LAZY RIVER RD	HOUSTON, TX 77057	32.426667	-101.151945	PLUGGED	DRY	200	9/2/2011
287998	BENNARD LAZY H RANCH	5933 LAZY RIVER RD	HOUSTON, TX 77057	32.421667	-101.143056	PLUGGED	DRY	220	9/1/2011

LONQUIST SEQUESTRATION LLC

APPENDIX D – SECTION 2 CROSS SECTIONS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1
GRAVITY WATER MIDSTM
42227413320000
FRYAR 3S
2XD
BAYSWATER OPERATING
42227413070000
BUCHANAN 3111
1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Log Depth(ft)
7500
7600
7700
7800
7900
8000
8100
8200
8300
8400
8500
8600
8700
8800
8900
9000
9100
9200
9300
9400
9500
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10000
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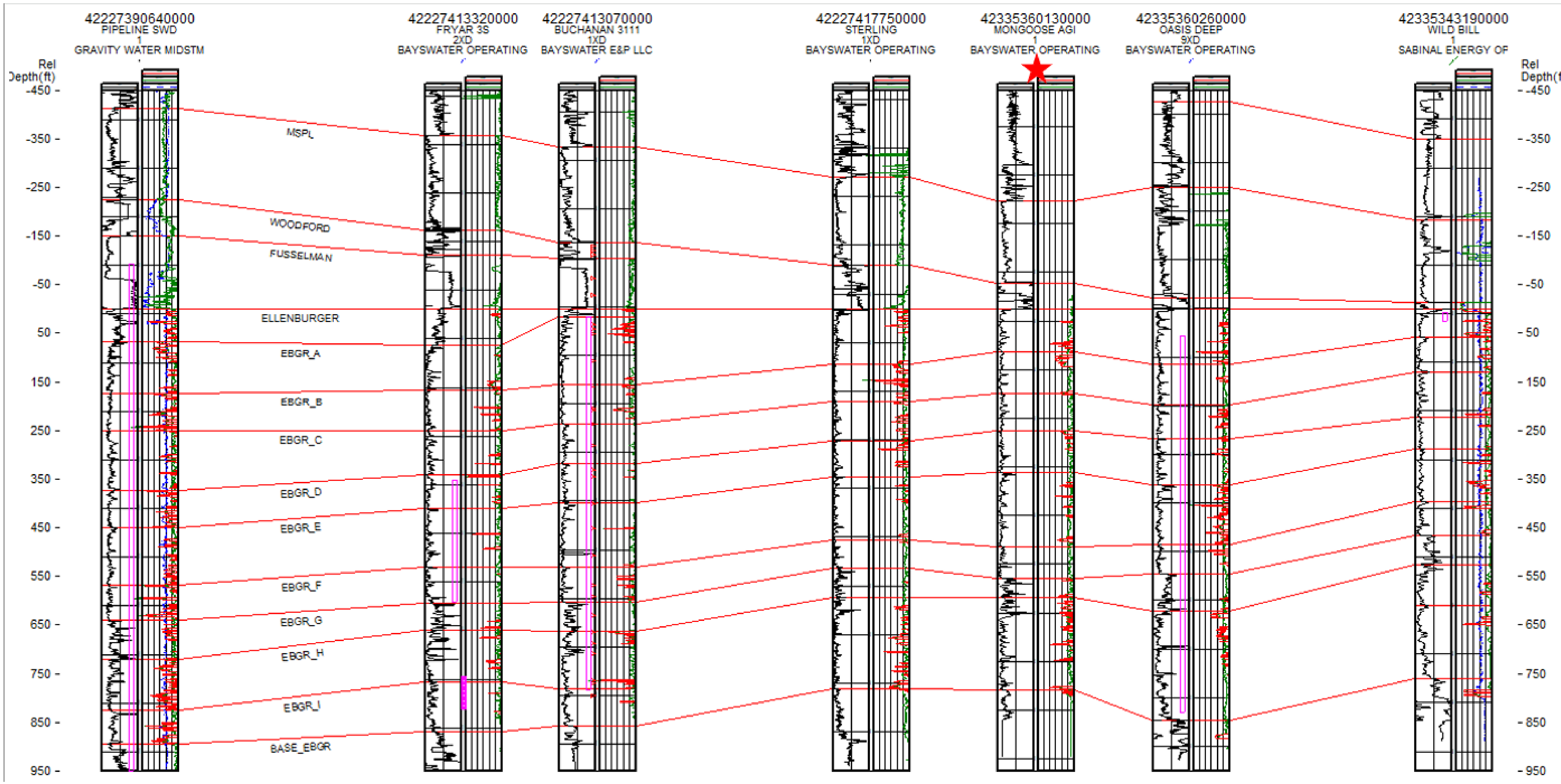
10200
10300
10400
10500
10600
10700
CLINE
CISCO
3_FINGERS_BASE
STRAWN
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR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PIPELINE SWD
1
GRAVITY WATER MIDSTM
42227413320000
FRYAR 3S
2XD
BAYSWATER OPERATING
42227413070000
BUCHANAN 3111
1XD
BAYSWATER E&P LLC
42227417750000
STERLING
1XD
BAYSWATER OPERATING
42335360130000
MONGOOSE AGI
1
BAYSWATER OPERATING
42335360260000
OASIS DEEP
9XD
BAYSWATER OPERATING
42335343190000
WILD BILL
1
SABINAL ENERGY OP
Rel Depth(ft)
-450
-350
-250
-150
-50
50
150
250
350
450
550
650
750
850
950
MSPL
WOODFORD
FUSSELMAN
ELLENBURGER
EBGR_A
EBGR_B
EBGR_C
EBGR_D
EBGR_E
EBGR_F
EBGR_G
EBGR_H
EBGR_I
BASE_EBGR